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RECORDS AND REPORTING

384 p.

December 18, 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: Petition of Tampa Electric Company to Establish its New Standard Offer Contract

Dear Ms. Bayo:

Enclosed for filing are fifteen (15) copies of Tampa Electric Company's Petition to Establish a New Standard Offer Contract for Qualifying Cogeneration and Small Power Production Facilities. Tampa Electric does not presently have a Standard Offer Contract available for cogenerators and small power producers. The company's revised Ten Year Site Plan filed August 25 of this year accelerates the need for additional combustion turbine (CT) capacity. This served as the basis for Tampa Electric's decision to prepare and file the enclosed Petition.

Tampa Electric's proposed standard offer is predicated on a CT with an in-service date of 2003. The revised Ten Year Site Plan shows the need for additional CT capacity in 2001. However, the use of that unit as the avoided unit for standard offer purposes would not allow sufficient time to process the petition and any signed Standard Offer Contracts resulting therefrom prior to the time the company will need to begin constructing the 2001 unit. As explained in the company's Petition, using the 2003 CT as the avoided unit will enable Tampa Electric to open a Standard Offer Contract with a reasonable open solicitation period. The 2003 unit is the best alternative for all concerned and will afford cogenerators and small power producers a meaningful opportunity to take advantage of the standard offer.

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

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

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JDB/pp
Enclosures

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition of Tampa Electric Company) to Establish Its New Standard Offer Contract)

DOCKET NO. ______________
FILED: December 18, 1998

TAMPA ELECTRIC COMPANY'S PETITION TO ESTABLISH A NEW STANDARD OFFER CONTRACT FOR QUALIFYING COGENERATION AND SMALL POWER PRODUCTION FACILITIES

Tampa Electric Company ("Tampa Electric" or "the company"), pursuant to Section 366.051, Florida Statutes, and Fla. Admin. Code Rule 25-17.0832(4) and 28-106.201, petitions the Commission to approve the attached Standard Offer Contract and related Tariff Sheets, and, as grounds therefor, says:

1. The name, address, telephone number and facsimile number of the petitioner are:

   Tampa Electric Company
   Post Office Box 111
   Tampa, Florida 33602
   (813) 228-4111
   (813) 228-1770 (fax)

2. The name, address, telephone number and facsimile number of the attorney and qualified representative of the Petitioner are:

   Lee L. Willis
   James D. Beasley
   Ausley & McMullen
   Post Office Box 391
   Tallahassee, FL 32302
   (850) 224-9115
   (850) 222-7952

   Angela Llewellyn
   Administrator, Regulatory Coordination
   Tampa Electric Company
   Post Office Box 111
   Tampa, FL 33601
   (813) 228-1752
   (813) 228-1770 (fax)

3. Tampa Electric is a Commission regulated electric utility company providing retail electric service to customers in Hillsborough and portions of Polk, Pinellas and Pasco Counties in Florida.

4. On August 22, 1994 the Commission entered two orders[1] granting the company's petition to withdraw a previously proposed standard offer and granting the company's petition to close its then existing standard offer.

5 On August 25, 1998 Tampa Electric presented its revised 1998 Ten Year Site Plan. That revised plan accelerates the need for the addition of combustion turbines on Tampa Electric's system and warrants Tampa Electric's request to make available the enclosed Standard Offer Contract for qualifying cogeneration and small power production facilities ("QFs").

6. After revising its 1998 Ten Year Site Plan the company considered designating a CT scheduled to be placed in service in 2001 as its avoided unit. However, the company recognized that by the time it prepared and obtained Commission approval of a new standard offer and went through the procedures of evaluating any signed contracts pursuant to the standard offer, the company would likely find itself well into the time frame needed to construct the 2001 unit. The company's proposed standard offer is predicated on a combustion turbine ("CT") with a 180-megawatt winter rating and 155-megawatt summer rating as Tampa Electric's avoided unit. This unit is scheduled to be placed in service in 2003, as reflected in the company's 1998 revised Ten Year Site Plan. Using the 2003 unit as the company's avoided unit will enable Tampa Electric to open a standard offer with a reasonable open solicitation period. The proposed standard offer would expire on December 31, 2000.

7. Tampa Electric is seeking approval of the revision of the following portions of Section 8 of its tariff: 1) **Schedule COG-2, Firm Capacity and Energy:** Standard Offer Contract Rate for Purchase of Firm Capacity and Energy from small Qualifying Facilities or Municipal Solid

[1]Order No. PSC-94-1008-FOF-EQ in Docket No. 940094-EQ and Order No. PSC-94-1009-FOF-EQ in Docket No. 931218-EQ

Waste Facilities (Qualifying Facilities) 2) **Standard Offer Contract:** Standard Offer Contract for the Purchase of Firm Capacity and Energy from a small Qualifying Facility or Municipal Solid Waste Facility, 3) **Interconnection Agreement:** Interconnection Agreement and 4) **General Standards for Safety:** General Standards for Safety and Interconnection of Cogeneration and Small Power Production Facilities to the Electric Utility System. In addition, to improve the usability of the tariff, a change in the software and font that is used to produce tariff sheets is also being made as the tariff sheets are revised or updated. This change has resulted in the repagination of a large portion of Section 8 Tampa Electric's tariff. To this end, Tampa Electric is submitting an otherwise unaltered version of **Schedule COG-1, As-Available Energy:** Standard Rate for Purchase of As-Available Energy from Qualifying Cogeneration and Small Power Production Facilities (Qualifying Facilities).

8. Tampa Electric's substantial interests will be affected by the Commission's determination of this Petition in that the company's Standard Offer Contract availability will be decided.

9. Tampa Electric is not aware of the existence of any disputed issues of material fact concerning the relief sought in this Petition.

10. The ultimate facts alleged are that it would be appropriate for the Commission to approve a new Standard Offer Contract for Tampa Electric predicated on a combustion turbine of the type described herein with an in-service date of 2003 as reflected in the company's 1998 revised Ten Year Site Plan.

11. Attached hereto as Exhibit "A" is a copy of the company's revised 1998 Generation Expansion Plan.

12. Attached hereto as Exhibit "B" are the requested amendments in standard format.

13. Attached hereto as Exhibit "C" is a composite exhibit consisting of the tariff pages included in Exhibit "B" but marked in legislative format to show the specific changes which the company is proposing.

WHEREFORE, Tampa Electric urges the Commission to approve the company's proposed standard offer contract based on a 2003 CT as the avoided unit.

DATED this 18th day of December, 1998.

Respectfully submitted,

LEE L. WILLIS
JAMES D. BEASLEY
Ausley & McMullen
Post Office Box 391
Tallahassee, FL 32302
(850) 224-9115

ATTORNEYS FOR TAMPA ELECTRIC COMPANY

Exhibit A

Exhibit B

Exhibit C

Exhibit A

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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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

Schedule I

TABLE I-1
Existing Generating Facilities
August 1998 Status

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt	Commercial	Expected	Gen. Max.	Net Capability	
	Unit		Unit	Fuel		Fuel Transport		Fuel	In-Service	Retirement	Nameplate	Summer	Winter
Plant Name	No.	Location	Type	Pri	Alt	Pri	Alt	Days	Mo/Yr	Mo/Yr	KW	MW	MW
Big Bend		Hillsborough Co. 14/31S/19E									1,998,000	1,052	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									231,600	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.

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.

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

Cooling Plant Name	Unit	Flue Gas Cleaning 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

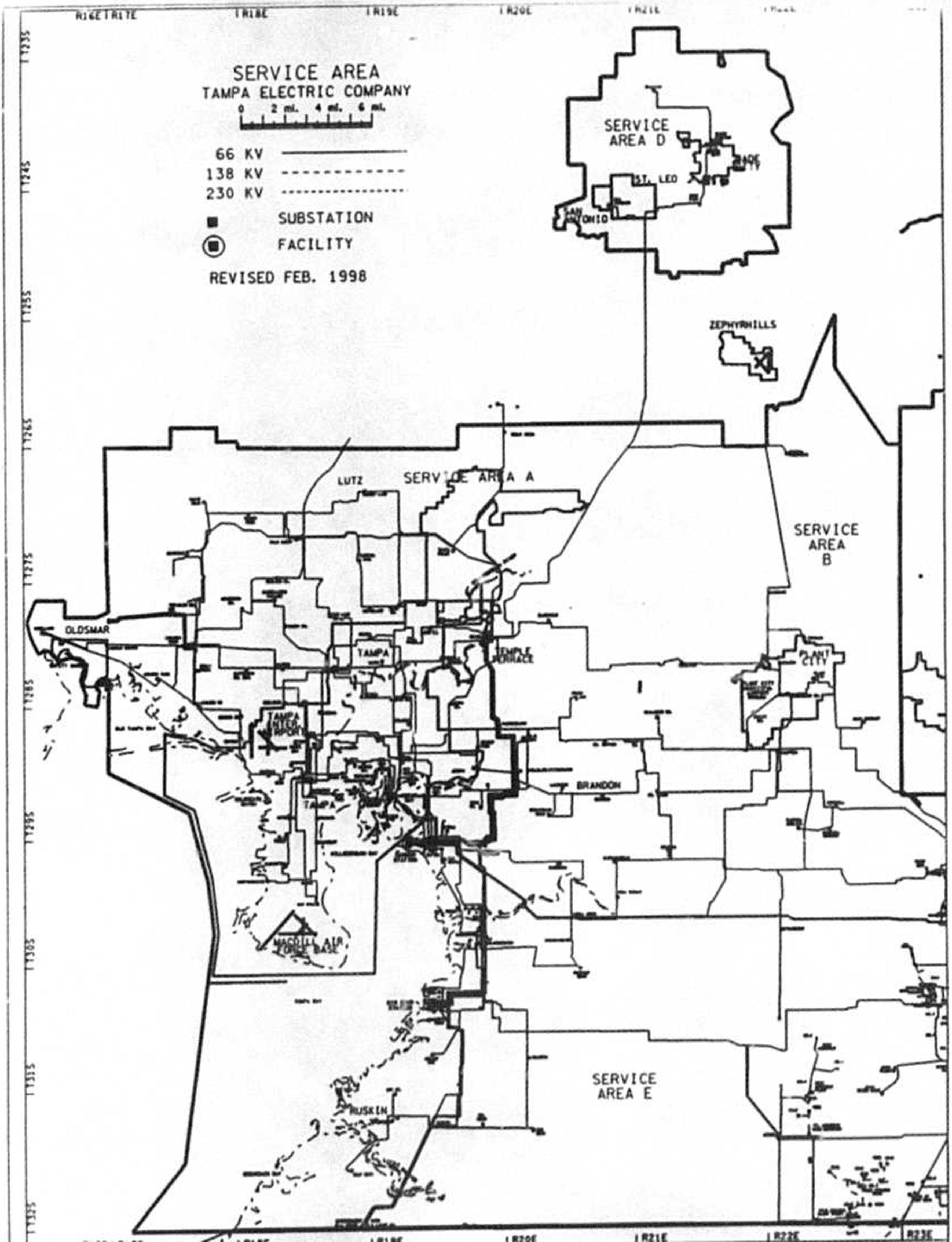
(1) Coal blending of units 1 and 2 will be replaced with a scrubber in 2000 to comply with Phase II of CAAA.
(2) NO_x controlled through unit operation.
(3) NO_x controlled through unit design and operation.
(4) OTS with fine mesh screens to minimize entrainment.

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

	Land Area		Plant Capital Investment ($000)			
Plant Name	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



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
SERVICE AREA A
LUTZ
SERVICE AREA B
OLDSMAR
TAMPA
TEMPLE TERRACE
PLANT CITY
BRANDON
MACDILL AIR FORCE BASE
RUSKIN
SERVICE AREA E
R16E
R17E
R18E
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R20E
R21E
R22E
R23E

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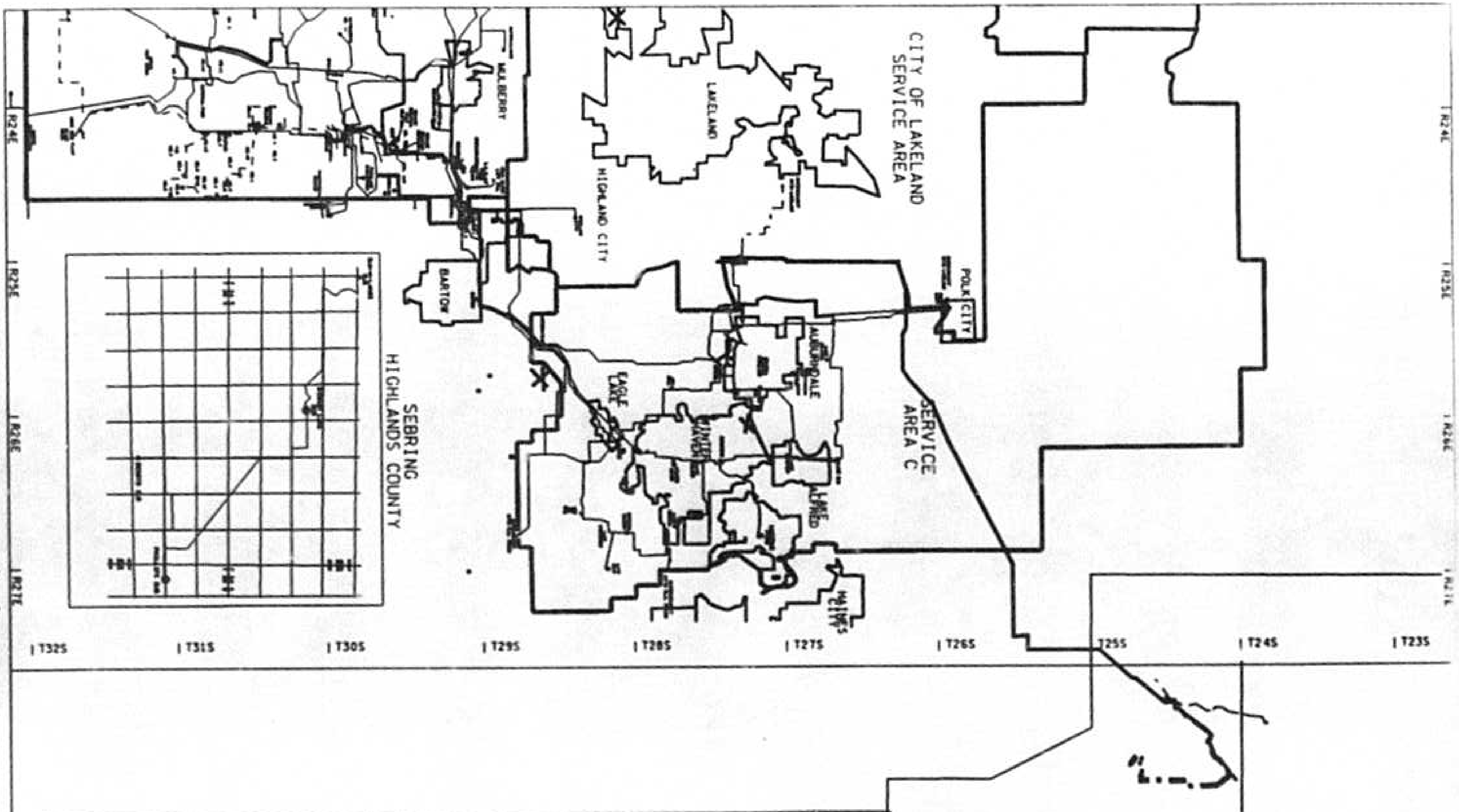


FIGURE I-1

TAMPA ELECTRIC RETAIL CUSTOMER SERVICE AREA

SOURCE: TAMPA ELECTRIC.

TAMPA ELECTRIC COMPANY

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

CHAPTER II

FORECAST OF ELECTRIC POWER, DEMAND, AND ENERGY CONSUMPTION

1. Table II-1: History and Forecast of Energy Consumption and Number of Customers by Customer Class
2. Table II-2: History and Forecast of Summer Peak Demand
3. Table II-3: History and Forecast of Winter Peak Demand
4. Table II-4: History and Forecast of Annual Net Energy for Load
5. Table II-5: Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month
6. Table II-6: History and Forecast of Fuel Requirements
7. Table II-7: History and Forecast of Net Energy for Load by Fuel Source

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 2.3

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

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for Resale GWH	Utility Use++ & Losses GWH	Net Energy** for Load GWH	Other* Customers (Average No.)	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 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	2,233	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~	2,408	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 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 3.2

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 3.1

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
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 3.2

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 3.3

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	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~	15,989	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
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 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 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 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	[illegible]	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 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 6.2

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

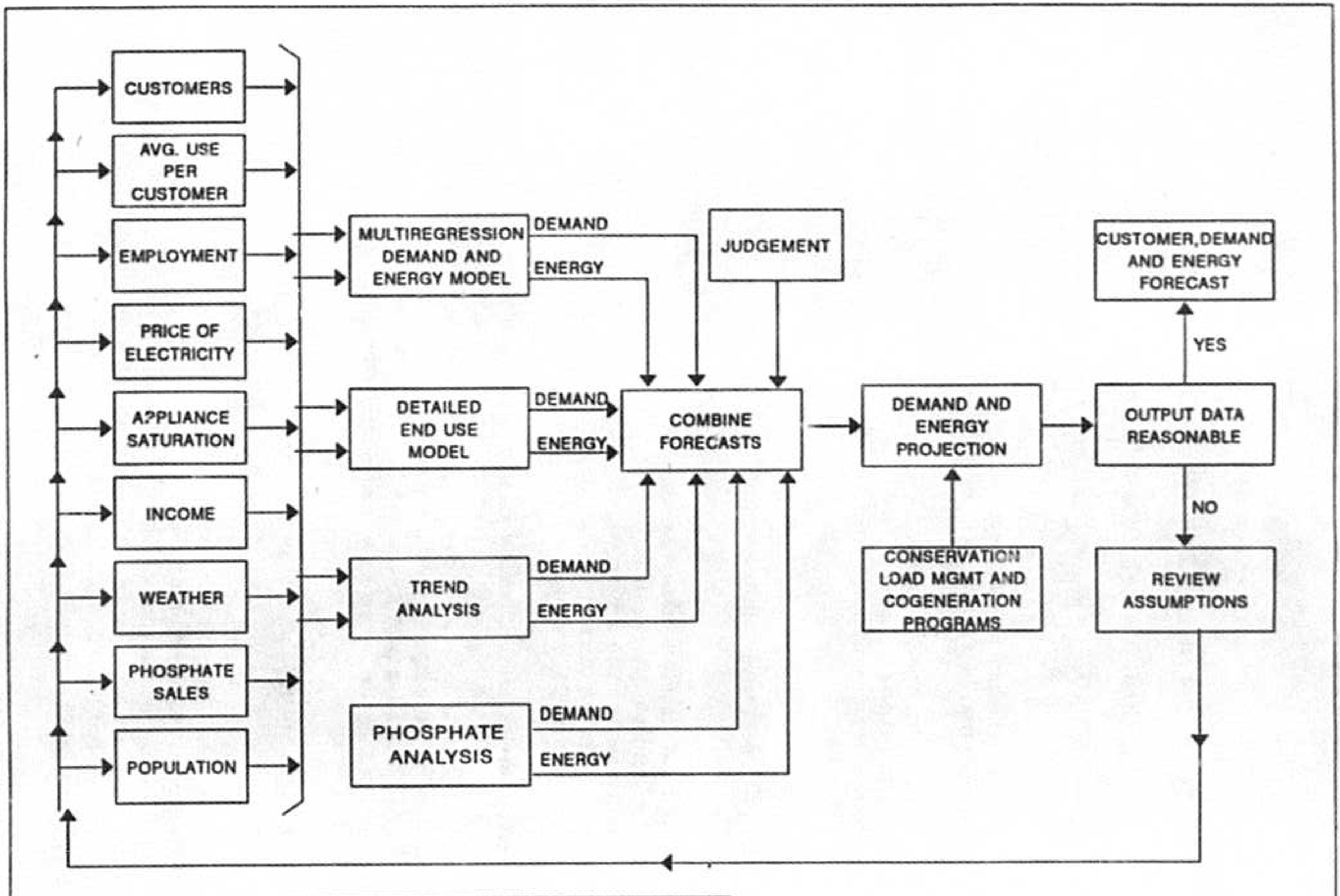


Figure III-1

TAMPA ELECTRIC COMPANY CUSTOMER, DEMAND AND ENERGY FORECAST PROCESS

SOURCE: TAMPA ELECTRIC COMPANY

TAMPA ELECTRIC COMPANY
Ten-Year Site Plan
For Electrical Generation Facilities
And Associated Transmission Lines

FIGURE III-1

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.

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.

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.

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-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

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

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	

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.

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.

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

(t = 35.8) (t = -3.7)

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

2.

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

(t = 25.5) (t = -4.9)

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

3.

$$\text{Temperature Sensitive Demand (Winter)} = (65 - F°)(-0.9842 + 0.13284 * \#\ \text{Electric Heaters})$$

(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.

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.

5.

$$\text{Sales to Public Authorities} = 530.50 + 2.4514 * \underset{(t = 10.9)}{\text{Residential Customers}} - 251.11 * \underset{(t = -4.4)}{\text{Chg in ¢/kWh}}$$

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

6.

$$\text{Street Lighting} = -29.073 + 0.10370 * \underset{(t = 34.8)}{\text{Population}}$$

$\bar{R}$-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.

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)	- 563.6 * ¢/kWh (lagged 1 year)	
		(t = 2.3)	(t = -8.9)	
		+ 1.06167 * Total Degree Days	+ 8362.9 * Htg/Cooling Saturation	
		(t = 4.5)	(t = 19.1)	

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

2.

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

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

3.

Other Industrial Energy Sales	= 334.44	+ 5.933 * Ind Prod Index	- 88.7825 *Chg. in ¢/kWh (lagged 1 year)
		(t = 7.7)	(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	- 331.39 * ¢/kWh (lagged 1 year)
		(t = 10.3)	(t = -3.3)

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

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.

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.

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.

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.

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.

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%

FORT MEADE MULTIREGRESSION EQUATIONS

1.

Average Customer Usage

$$= 1008.4 - 66.786 * ¢/kWh + 0.1100 * \text{Change in Per Capita Income}$$

(t = -2.1) (t = 2.1)

$$+ 1.1327 * \text{Cooling Degree Days} + 1.5189 * \text{Heating Degree Days}$$

(t = 12.5) (t = 4.7)

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

2.

Winter Peak Demand

$$= - 11.523 + 0.0072114 * \text{Total Customers} + 0.14632 * \text{Heating Degree Days}$$

(t = 5.1) (t = 4.7)

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

3.

Summer Peak Demand

$$= - 2.0035 + 0.0043383 * \text{Total Customers} + 0.10790 * \text{Cooling Degree Days}$$

(t = 5.0) (t = 2.6)

$$- 0.29532 * ¢/kWh$$

(t = -2.8)

$\bar{R}$-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.

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.

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.

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.

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.

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 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

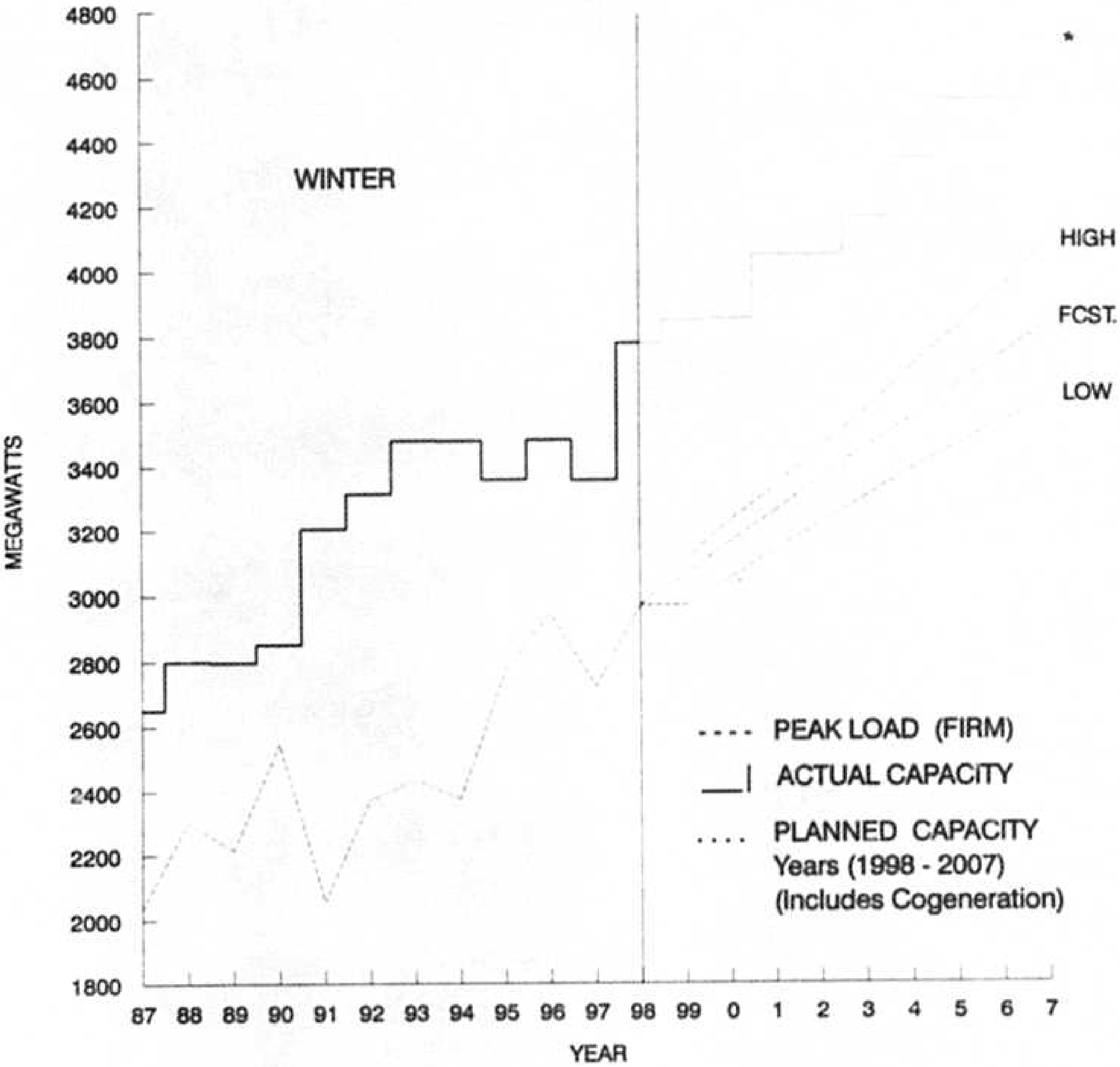
A monthly forecast of retail peak loads (MW) and net energy for load (GWh) for years 1 and 2 of the forecast is provided in Table II-5 (Schedule 4) along with actual for 1997.

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

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

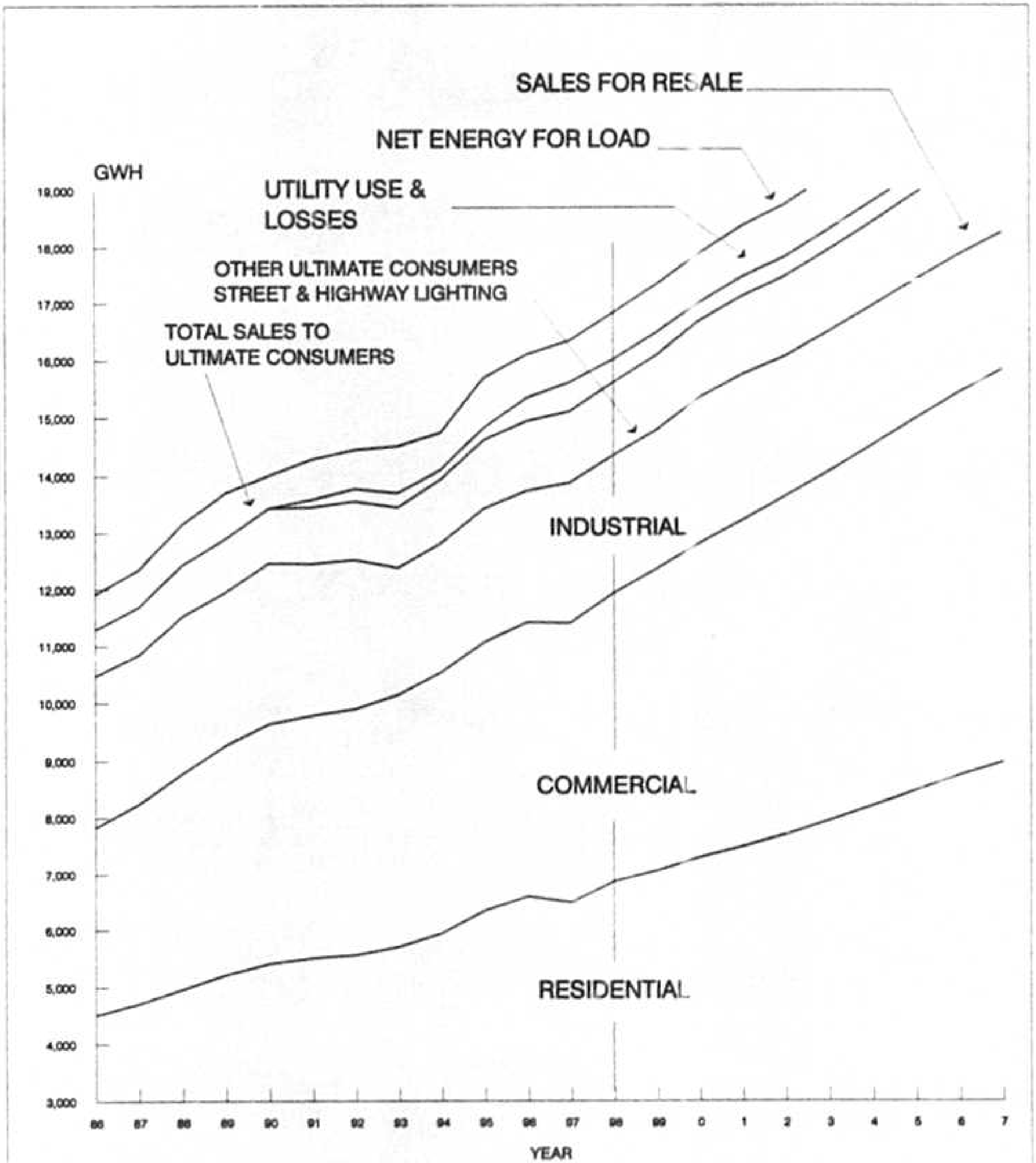


Figure III-2

HISTORY AND FORECAST OF ENERGY USE

SOURCE: TAMPA ELECTRIC COMPANY

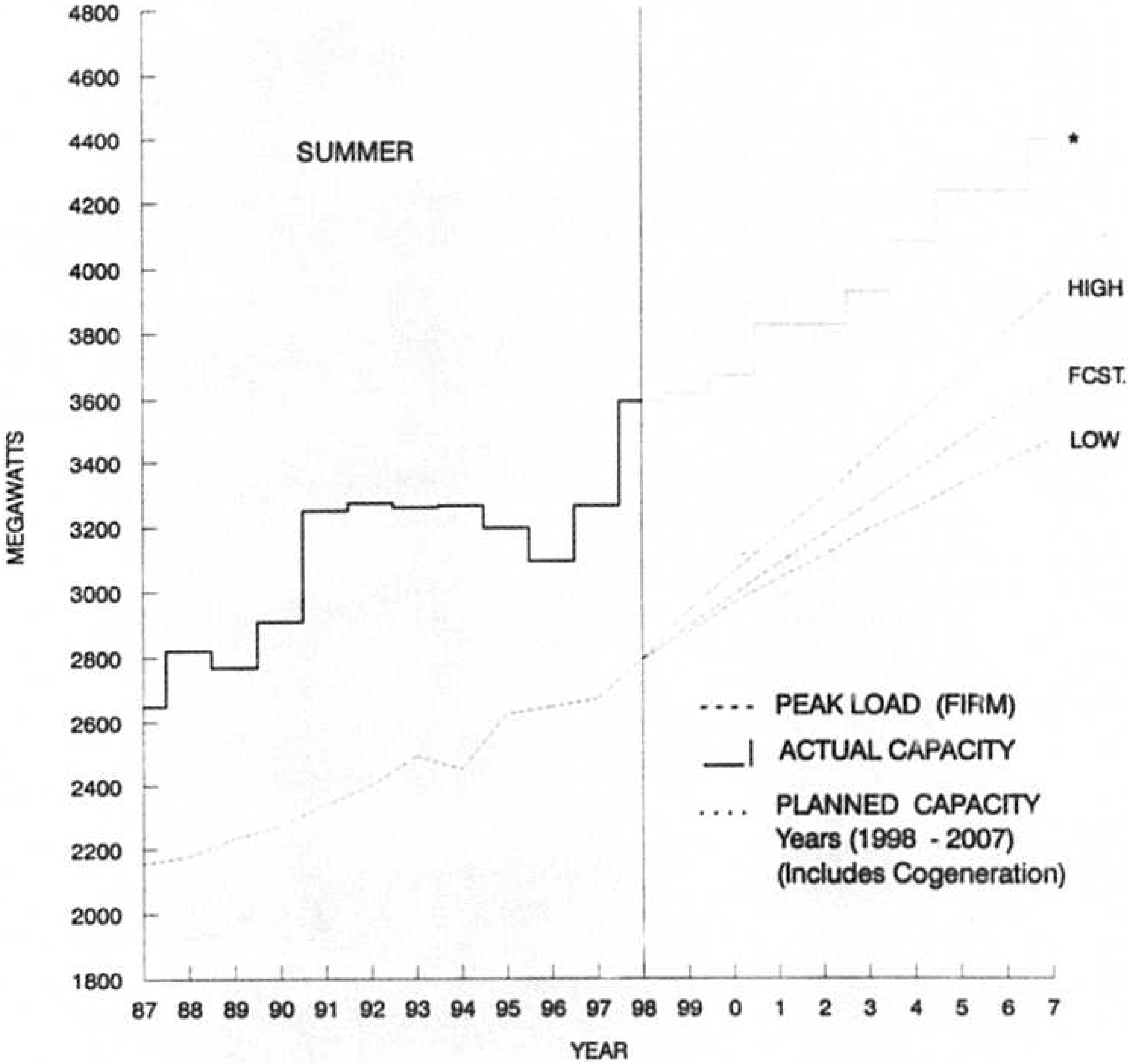
TAMPA ELECTRIC COMPANY

Ten-Year Site Plan

For Electrical Generating Facilities

And Associated Transmission Lines

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



* AGREES WITH SCHEDULE 7.1, COL. 6.

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

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.

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.

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	QF	Total Capacity Available	System Firm Summer Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
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, 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.

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 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	LO	1/03	1/05	unknown	unknown	155	180	PL	TK	P
	6	Polk Co.	CT	NG	LO	1/05	1/07	unknown	unknown	155	180	PL	TK	P

August 1998 Status

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 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 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 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 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)	9[illegible].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 $/kW)	3[illegible]3.74
	DIRECT CONSTRUCTION COST ($/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 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

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.

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.

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

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 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.

TAMPA ELECTRIC COMPANY
INTEGRATED RESOURCE PLAN METHODOLOGY

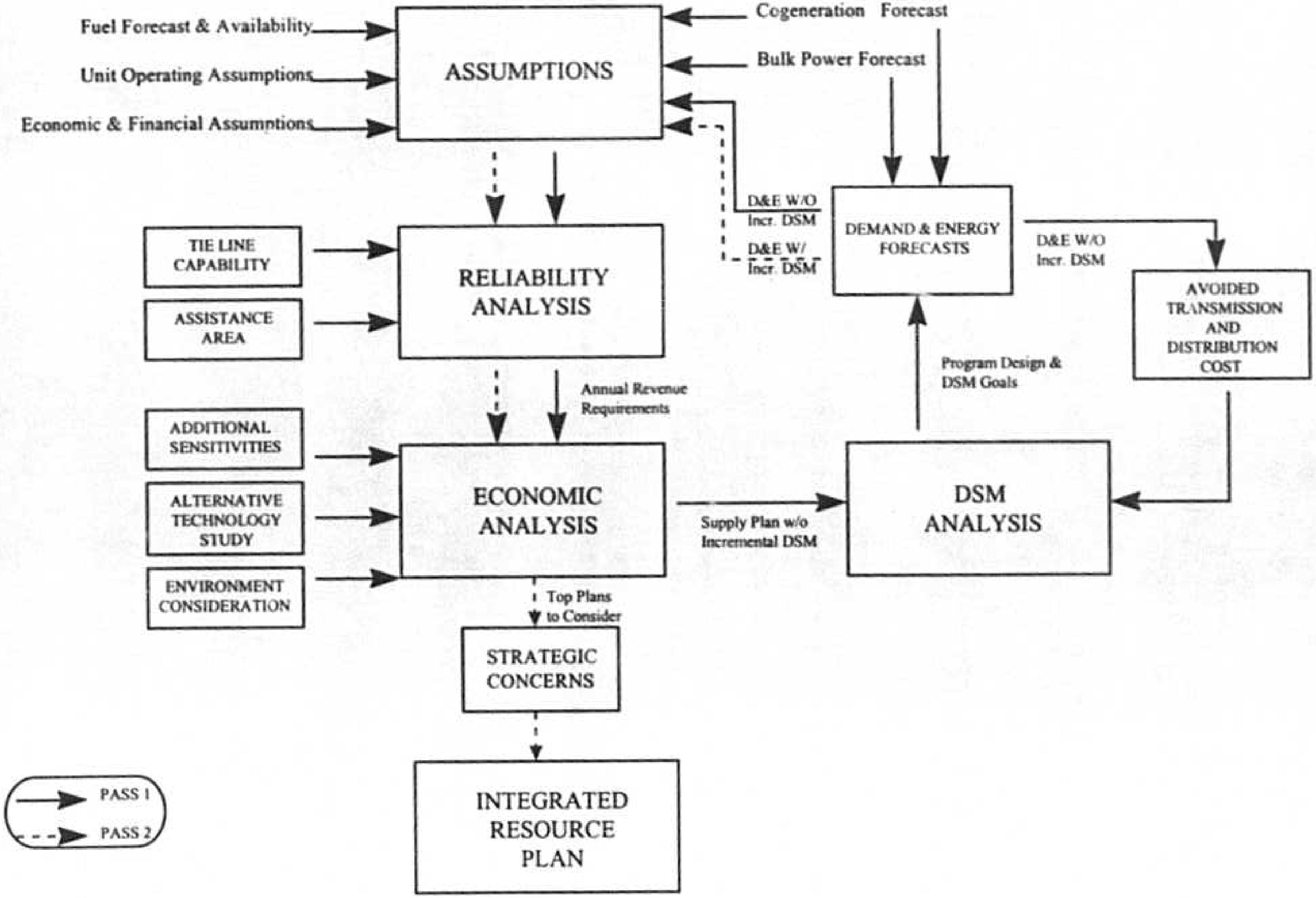


FIGURE V-1

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.

Generation Dispatch Modeled

The generation dispatched in the planning models is dictated on an economic basis and is calculated by the Economic Dispatch (ECDI) function of the PSS/E loadflow software. The ECDI function schedules the unit dispatch so that the total generation cost required to meet the projected load is minimized. This is the generation scenario contained in the power flow cases submitted to fulfill the requirements of FERC Form 715 and the 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

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.

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.

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.

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

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;

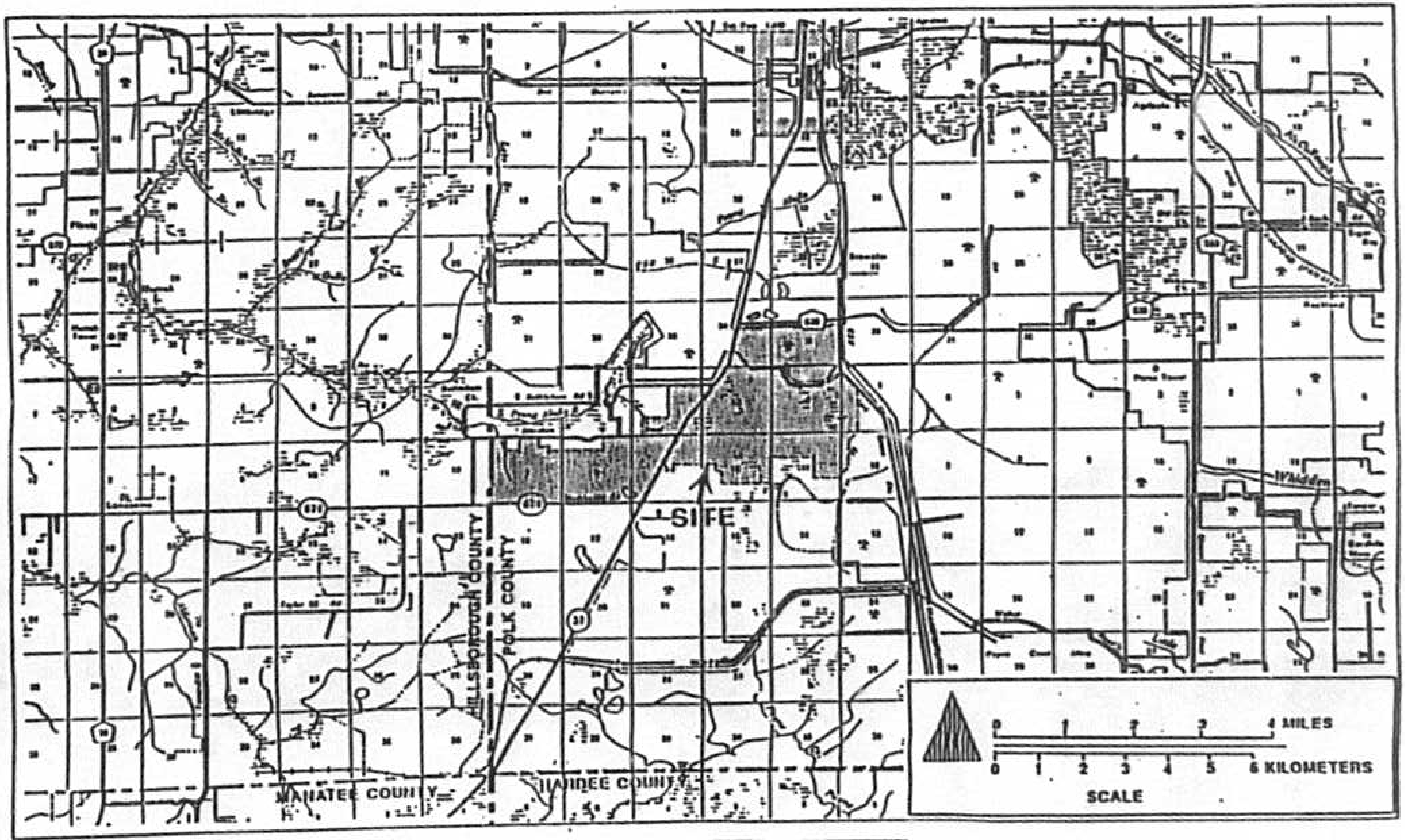
(2) bill analysis of program participants compared to control groups to minimize the impact of weather abnormalities; and

(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.



SITE LOCATION OF POLK POWER STATION

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

SOURCES: FDOT MAP, FLA. ECT.

FIGURE VI-1

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.

Exhibit B

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COGENERATION AND SMALL POWER PRODUCTION

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Schedule COG-1, As-Available Energy	
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Appendix A - Methodology to be Used in the Calculation of Avoided Energy Cost - Schedule COG-1	8.101
Schedule COG-2, Firm Capacity and Energy	
Standard Offer Contract Rate for Purchase of Firm Capacity and Energy from small Qualifying Facilities or Municipal Solid Waste Facilities (Qualifying Facilities)	8.200
Appendix A - Standard Offer Contract Rate for Purchase of Firm Capacity and Energy from small Qualifying Facilities or Municipal Solid Waste Facilities (Qualifying Facilities) Schedule COG-2	8.310
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STANDARD RATE FOR PURCHASE OF AS-AVAILABLE ENERGY FROM QUALIFYING COGENERATION AND SMALL POWER PRODUCTION FACILITIES (QUALIFYING FACILITIES)

SCHEDULE

COG-1, As-Available Energy

AVAILABLE

Tampa Electric Company will purchase energy offered by any Qualifying Facility irrespective of its location, which is directly or indirectly interconnected with the Company, under the provisions of this schedule or at contract negotiated rates. Tampa Electric Company will negotiate and may contract with a Qualifying Facility, irrespective of its location, which is directly or indirectly interconnected with the Company where such negotiated contracts are in the best interest of the Company's ratepayers.

APPLICABLE

To any cogeneration or small power production Qualifying Facility producing energy for sale to the Company on an As-Available basis. As-Available Energy is described by the Florida Public Service Commission (FPSC) Rule 25-17.0825, Florida Administrative Code (F.A.C.), and is energy produced and sold by a Qualifying Facility on an hour-by-hour basis for which contractual commitments as to the time, quantity, or reliability of delivery are not required. Because of the lack of assurance as to the quantity, time, or reliability of delivery of As-Available Energy, no Capacity Payment shall be made to a Qualifying Facility for delivery of As-Available Energy. Criteria for achieving Qualifying Facility status shall be those set out in FPSC Rule 25-17.080.

CHARACTER OF SERVICE

Purchases within the territory served by the Company shall be, at the option of the Company, single or three phase, 60 hertz, alternating current at any available standard Company voltage. Purchases from outside the territory served by the Company shall be three phase, 60 Hertz, alternating current at the voltage level available at the interchange point between the Company and the entity delivering As-Available Energy from the Qualifying Facility.

Continued to Sheet No. 8.030

Continued from Sheet No. 8.020

LIMITATIONS

All service pursuant to this schedule is subject to the Company's "General Standards for Safety and Interconnection of Cogeneration and Small Power Production Facilities to the Electric Utility System" and to FPSC Rules 25-17.080 through 25-17.091, F.A.C.

RATES FOR PURCHASES BY THE COMPANY

A. **Capacity Rates**

Capacity payments to Qualifying Facilities will not be paid under this schedule. Capacity payments to small Qualifying Facilities of less than 75 MWs or Solid Waste Facilities may be obtained under either a Standard Offer Contract as described in Schedule COG-2, Firm Capacity and Energy or a negotiated contract.

Capacity payments to Qualifying Facilities of 75 MWs or greater may only be obtained under a negotiated contract as described in FPSC Rule 25-17.0832.

B. **Energy Rates**

As-Available Energy is purchased at a unit cost, in cents per kilowatt-hour (¢/KWH), based on the Company's actual hourly avoided energy costs which are calculated by the Company in accordance with FPSC Rule 25-17.0825, F.A.C.

Avoided energy costs include incremental fuel, identifiable variable operation and maintenance expenses, and an adjustment for line losses reflecting delivery voltage. The calculation of payments to the Qualifying Facility shall be based on the energy deliveries from the Qualifying Facility to the Company and the applicable avoided energy rate, in accordance with FPSC Rule 25-17.082, F.A.C. All sales shall be adjusted for losses from the point of metering to the point of interconnection.

The methodology to be used in the calculation of the avoided energy cost is described in Appendix A.

C. **Negotiated Rates**

Upon agreement by both the Company and the Qualifying Facility, an alternate contract rate for the purchase of As-Available Energy may be separately negotiated.

Continued to Sheet No. 8.040

Continued from Sheet No. 8.030

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST

Upon request by a qualifying facility or any interested person, the Company shall provide within 30 days its most current projections of its generation mix, fuel price by type of fuel, and at least a five year projection of fuel forecasts to estimate future as-available energy prices as well as any other information reasonably required by the qualifying facility to project future avoided cost prices including, but not limited to, a 24 hour advance forecast of hour-by-hour avoided energy costs. The Company may charge an appropriate fee, not to exceed the actual cost of production and copying, for providing such information.

Continued to Sheet No. 8.050

Continued from Sheet No. 8.040

DELIVERY VOLTAGE ADJUSTMENT

For purchases from Qualifying Facilities directly interconnected to the Company, the Company's actual hourly avoided energy costs shall be adjusted according to the delivery voltage by the following multipliers:

Rate Schedule	Adjustment Factor
RS, GS	1.0616
GSD, GSLD, SBF	1.0561
IS-1, IS-3	1.0254
SBI-1, SBI-3	1.0254

For purchases from Qualifying Facilities not directly interconnected to the Company, any adjustments to the Company's actual hourly avoided energy costs for delivery voltage will be determined based on the Company's current annual system average transmission loss factor.

METERING REQUIREMENTS

The Qualifying Facility within the territory served by the Company shall be required to purchase from the Company the metering equipment necessary to measure its energy deliveries to the Company. Energy purchased from Qualifying Facilities outside the territory served by the Company shall be measured as the quantities scheduled for interchange to the Company by the entity delivering As-Available Energy to the Company. Unless special circumstances warrant, meters shall be read at monthly intervals on the approximate corresponding day of each meter reading period.

Hourly recording meters shall be required for Qualifying Facilities with an installed capacity of 100 kilowatts or more. Where the installed capacity is less than 100 kilowatts, the Qualifying Facility may select any one of the following options: (a) an hourly recording meter, (b) a dual kilowatt-hour register time-of-day meter, or (c) a standard kilowatt-hour meter.

For Qualifying Facilities with hourly recording meters, monthly payments for As-Available Energy shall be calculated based on the product of: (1) the Company's actual As-Available Energy Payment Rate for each hour during the month; and (2) the quantity of energy sold by the Qualifying Facility during that hour.

For Qualifying Facilities with dual kilowatt-hour register time-of-day meters, monthly payments for As-Available Energy shall be calculated based on the product of: (1) the average of the Company's actual hourly As-Available Energy Payment Rates for the on-peak and off-peak periods during the month; and (2) the quantity of energy sold by the Qualifying Facility during that period.

Continued to Sheet No. 8.060

Continued from Sheet No. 8.050

For Qualifying Facilities with standard kilowatt-hour meters, monthly payments for As-Available Energy shall be calculated based on the product of: (1) the average of the Company's actual hourly As-Available Energy Payment Rate for the off-peak periods during that month; and (2) the quantity of energy sold by the Qualifying Facility during that month.

For a time-of-day metered Qualifying Facility, the on-peak hours occur Monday through Friday except holidays, April 1 - October 31 from 12 noon to 9:00 p.m. and November 1 - March 31 from 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.. All hours not mentioned above and all hours of the holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day are off-peak hours.

BILLING OPTIONS

The Qualifying Facilities may elect to make either simultaneous purchases and sales or net sales. The billing option elected may only be changed in accordance with FPSC Rule 25-17.082:

1. when the Qualifying Facility selling As-Available Energy enters into a negotiated contract or standard offer contract for the sale of Firm Capacity and Energy; or
2. when a Firm Capacity and Energy contract expires or is lawfully terminated by either the Qualifying Facility or Tampa Electric Company; or
3. when the Qualifying Facility is selling As-Available Energy and has not changed billing methods within the last twelve months; and
4. when the election to change billing methods will not contravene the provisions of Rule 25-17.0832 or any contract between the Qualifying Facility and Tampa Electric Company.

If the Qualifying Facility elects to change billing methods in accordance with FPSC Rule 25-17.082, such a change shall be subject to the following provisions:

1. upon at least thirty (30) days advance written notice;

Continued to Sheet No. 8.061

Continued from Sheet No. 8.060

2. upon the installation by Tampa Electric Company of any additional metering equipment reasonably required to effect the change in billing and upon payment by the Qualifying Facility for such metering equipment and its installation; and

3. upon completion and approval by Tampa Electric Company of any alterations to the interconnection reasonably required to effect the change in billing and upon payment by the Qualifying Facility for such alterations.

Should a Qualifying Facility elect to make simultaneous purchases and sales, purchases of electric service by the Qualifying Facility from the interconnecting utility shall be billed at the retail rate schedule under which the Qualifying Facility load would receive service as a non-generating customer of the utility; sales of electricity delivered by the Qualifying Facility to the purchasing utility shall be purchased at the utility's avoided capacity and energy rates, where applicable, in accordance with Rules 25-17.0825 and 25-17.0832.

Should a Qualifying Facility elect a net billing arrangement, the hourly net energy sales delivered to the purchasing utility shall be purchased at the utilities avoided capacity and energy rates, where applicable, in accordance with Rules 25-17.0825 and 25-17.0832, purchases from the interconnecting utility shall be billed pursuant to the utility's applicable standby and supplemental service rate schedule.

Continued to Sheet No. 8.070

Continued from Sheet No. 8.061

CHARGES/CREDITS TO QUALIFYING FACILITY

A. Customer Charges

A monthly Customer Charge will be rendered for maintaining an account for a Qualifying Facility engaged in either an As-Available Energy or Firm Capacity and Energy transaction and for other applicable administrative costs. Actual charges will depend on how the QF is interconnected to the Company.

QFs not directly interconnected to the Company, will be billed $580 monthly as a Customer Charge.

Monthly customer charges, applicable to QFs directly interconnected to the Company, by Rate Schedule are:

Rate Schedule	Customer Charge	Rate Schedule	Customer Charge
RS	$ 8.50	RST	$ 11.50
GS	8.50	GST	11.50
GSD	42.00	GSDT	49.00
GSLD	255.00	GSLDT	255.00
SBF	280.00	SBFT	280.00
IS-1	1,000.00	IST-1	1,000.00
IS-3	1,000.00	IST-3	1,000.00
SBI-1	1,025.00	SBIT-1	1,025.00
SBI-3	1,025.00	SBIT-3	1,025.00

When appropriate, the Customer Charge will be deducted from the Qualifying Facility's monthly payment. A statement of the charges or payments due the Qualifying Facility will be rendered monthly. Payment normally will be made by the twentieth business day following the end of the billing period.

Continued to Sheet No. 8.071

Continued from Sheet No. 8.070

B. **Interconnection Charge for Non-Variable Utility Expenses:**
The Qualifying Facility shall bear the cost required for interconnection including the metering. The Qualifying Facility shall have the option of payment in full for interconnection or making equal monthly installment payments over a thirty-six (36) month period together with interest at the rate then prevailing for thirty (30) days highest grade commercial paper; such rate to be determined by the Company thirty (30) days prior to the date of each payment.

C. **Interconnection Charge for Variable Utility Expenses**
The Qualifying Facility shall be billed monthly for the cost of variable utility expenses associated with the operation and maintenance of the interconnection. These include: (a) the Company's inspections of the interconnection and (b) maintenance of any equipment beyond that which would be required to provide normal electric service to the Qualifying Facility if no sales to the Company are involved.

Continued to Sheet No. 8.080

Continued from Sheet No. 8.071

D. **Taxes and Assessments**

The Qualifying Facility shall be billed monthly an amount equal to the taxes, assessments, or other impositions, if any, for which the Company is liable as a result of its purchases of As-Available Energy produced by the Qualifying Facility.

If the Company obtains any tax savings as a result of its purchases of As-Available Energy produced by the Qualifying Facility, which tax savings would not have otherwise been obtained, those tax savings shall be credited to the Qualifying Facility.

TERMS OF SERVICE

1) It shall be the Qualifying Facility's responsibility to inform the Company of any change in its electric generation capability.

2) Any electric service delivered by the Company to the Qualifying Facility shall be metered separately and billed under the applicable retail rate schedule and the terms and conditions of the applicable rate schedule shall pertain.

3) A security deposit will be required in accordance with FPSC Rules 25-17.082(5) and 25-6.097, F.A.C. and the following:

   A) In the first year of operation, the security deposit shall be based upon the singular month in which the Qualifying Facility's projected purchases from the utility exceed, by the greatest amount, the utility's estimated purchases from the Qualifying Facility. The security deposit should be equal to twice the amount of the difference estimated for that month. The deposit shall be required upon interconnection.

   B) For each year thereafter, a review of the actual sales and purchases between the Qualifying Facility and the utility shall be conducted to determine the actual month of maximum difference. The security deposit shall be adjusted to equal twice the greatest amount by which the actual monthly purchases by the Qualifying Facility exceed the actual sales to the utility in that month.

Continued to Sheet No. 8.090

Continued from Sheet No. 8.080

4) The company shall specify the point of interconnection and voltage level.

5) The Company will, under the provisions of this schedule, require an interconnection agreement with the Qualifying Facility using either the Company's filed Interconnection Agreement or a negotiated Interconnection Agreement. The Qualifying Facility shall recognize that its generation facility may exhibit unique interconnection requirements which will be separately evaluated, and may require modifications to the Company's General Standards for Safety and Interconnection where applicable.

6) Service under this rate schedule is subject to the rules and regulations of the Company and the Florida Public Service Commission.

SPECIAL PROVISIONS

1) Negotiated contracts deviating from the above standard rate schedule are allowable provided they are agreed to by the Company and approved by the Florida Public Service Commission.

2) In accordance with the provision in Rule 25-17.0883, the Company is required to provide transmission and distribution service to enable a retail customer to transmit electrical power generated at one location to the customer's facilities at another location when provision of such service and its associated charge, terms, and other conditions are not reasonably projected to result in higher cost of electric service to the Company's general body of retail and wholesale customers or adversely affect the adequacy or reliability of electric service to all customers.

   A determination of whether or not transmission service for self-service wheeling is likely to result in higher cost electric service will be made by evaluating the results of an appropriately adjusted FPSC approved cost effectiveness methodology, in addition to other modeling analyses.

3) In accordance with Rule 25-17.089, upon request by a Qualifying Facility, Tampa Electric Company shall provide transmission service to wheel As-Available Energy produced by a Qualifying Facility from the Qualifying Facility to another electric utility.

Continued to Sheet No. 8.100

Continued from Sheet No. 8.090

4) Where existing Company transmission capacity exists, the Company will impose a charge for wheeling Qualifying Facility energy, measured at the point of delivery to the Company. The rates, terms, and conditions for such transmission service shall be those approved by the Federal Energy Regulatory Commission.

5) The Company's actual rates for providing transmission service will be determined on an individually negotiated case-by-case basis in order to allow for variations in providing such service under different circumstances. The Company will provide, upon request, estimates of the availability and cost and terms and conditions of providing the specified desired transmission wheeling service.

6) The Qualifying Facility shall be responsible for all costs associated with such wheeling and the Company will recover such costs from the Qualifying Facility including:

a) Wheeling charges
b) Line losses incurred by the Company
c) Inadvertent energy flows resulting from such wheeling.

7) Energy delivered to the Company shall be adjusted before delivery to another utility as follows:

Qualifying Facility Rate Schedule	Adjustment Factor
RS, GS	0.9438
GSD, GSLD, SBF	0.9494
IS-1, IS-3, SBI-1, SBI-3	0.9814

8) The Company may deny, curtail, or discontinue transmission service to a Qualifying Facility on a non-discriminatory basis if the provision of such service would adversely affect the safety, adequacy, reliability, or cost of providing electric service to the Company's general body of retail and wholesale customers.

**METHODOLOGY TO BE USED
IN THE CALCULATION OF
AVOIDED ENERGY COST
SCHEDULE COG-1
APPENDIX A**

The methodology Tampa Electric (TEC) has implemented in order to determine the appropriate avoided energy costs and any payments thereof to be rendered to qualifying facilities (QFs) is consistent with the provisions of Order No. 23625 in Docket No. 891049-EU, issued on October 16, 1990, and with the Amendment of Rules 25-17.080 et seq, Florida Administrative Code.

The avoided energy costs methodology used to determine payments to Qualified Facilities (QFs) on an hourly basis is based on the incremental cost of fuel using the average price of replacement fuel purchased in excess of contract minimums and is further described in Exhibit #1. Generally, avoided energy costs are defined to include incremental fuel, identifiable variable operation and maintenance expenses, identifiable variable purchase power cost, and an adjustment for line losses reflecting delivery voltage.

Under normal conditions the Company will have additional generation resources available which can carry its native load and firm interchange sales without the QF's contribution. When this is the case and the QF is present, the incremental fuel portion of the avoided energy cost is equal to the difference between TEC's production cost at two load levels, with and without the QFs' contribution.

In those situations where the Company's available maximum generation resources not including its minimum spinning reserves are insufficient to carry its native load and firm interchange sales, in the absence of the QF contribution, TEC's incremental fuel component of the avoided energy cost will be determined by:

1) system lambda - if "off-system purchases" are not being made and all available generation has been dispatched; or

2) the highest incremental cost of any "off-system purchases" that are being made for native load.

Examples of these situations are found in Exhibits #3-#6.

Continued to Sheet No. 8.102

Continued from Sheet No. 8.101

The as-available avoided energy cost, as determined by this methodology, is priced at a level not to exceed Tampa Electric's incremental fuel and identifiable variable operating and maintenance (O&M) expenses including the cost of any off-system purchases for native load.

Parameters For Determining As-Available Avoided Energy Costs
Tampa Electric Company uses production costing methods for determining avoided energy cost payments to qualifying facilities (QFs). Computerized production costing is accomplished on an hourly basis. The parameters used are as follows:

1. The system load is the actual system load at the Hour Ending with the clock hour (HE).

2. The first allocation of load for production costing is to those units that are base loaded at a certain level for operating reasons. The remainder of the load is allocated to units available for economic dispatch through the use of incremental cost curves.

3. The fuel costs associated with each of Tampa Electric's units operating at its allocated level of generation is determined by using the individual units input/output equation, its heat rate performance factor, and the composite price of supplemental fuel.

4. The Company's own production cost for each hour of operation at a particular generation level equals the sum of the individual units' fuel cost for that hour. The production cost, thus determined, consists of the composite price of replacement fuel based on supplemental purchases and the incremental heat rate for the generating system.

5. The Company's total cost equals its own production cost (4. above), identified variable O&M, plus the cost of any off-system purchases to serve native load.

6. Native load includes all firm and non-firm retail load.

7. The cost of off-system firm and non-firm variable purchases is defined as the highest energy cost energy block purchased for native load during the hour; i.e., SCHEDULES A, B, C, D, X, J, UPP (Unit Power Purchase).

8. Firm interchange sales are included in production cost calculations.

Continued to Sheet No. 8.103

Continued from Sheet No. 8.102

9. The Company's available maximum generation resources in this methodology is defined as the maximum capacity less spinning reserve requirements.

10. The "Standard Tariff Block" is defined to be an x-megawatt (XMW) block equivalent to the combined actual hourly generation delivered to Tampa Electric from all QFs making as-available energy sales to Tampa Electric. In the absence of metered information on exports from a QF making as-available energy sales to Tampa Electric, an estimate of the hourly exports from that Facility will be used, rounded to the nearest 5 MW and then added to the sum of all other known as-available energy purchases for that hour.

Supplemental Fuel

The term "supplemental fuel" refers to that fuel purchased in excess of Tampa Electric's long-term contract minimum requirements. As illustrated in Exhibit #1, supplemental fuel can be composed of contract fuel purchases above minimums and fuel purchases on the spot market. When spot prices are lower than prices for minimum tonnages on long term contract purchases, spot prices are "supplemental." Under market conditions where spot prices are greater than the price of coal purchased under contract, it is economical for Tampa Electric to purchase more than the contract minimums. In this instance the supplemental price is a combination of the contract price of coal above minimum contract requirements and any coal purchased on the spot market. The company looks to the supplemental fuel for purposes of incremental pricing to determine the level of as-available energy payments because contract minimum purchases are a fixed expense.

Supplemental fuel is composed of contract fuel purchases above minimum levels and fuel purchases on the spot market. Tampa Electric pursues the least expensive alternative whether it be spot purchases or purchases of contract coal above the contract minimum, or a mixture of both. The supplemental fuel price is calculated by weight averaging all of the supplemental fuel purchases, by fuel type, during the preceding month. A Supplemental Fuel Cost Worksheet is shown in Exhibit #2.

With regard to oil-fired generation, Tampa Electric treats all of its oil purchases as supplemental fuel inasmuch as it has no contract minimums. For graphic portrayal of Tampa Electric's definition of supplemental fuel see Exhibit #1 attached.

Continued to Sheet No. 8.1C4

Continued from Sheet No. 8.103

Avoid Energy Cost Calculations

Example: #1 No Off-System Purchases, TEC's Generation Is Capable Of Carrying Its Native Load and Firm Sales.

The procedure used to deterministically calculate the incremental avoided energy cost associated with as-available energy on an hour by hour basis when no off-system purchases are taking place is as follows:

In these instances, the price per megawatt hour ($/MWH) that Tampa Electric will pay the QFs is determined by calculating the production cost at two load levels.

This first calculation determines TEC's production cost "without" the benefit of cogeneration.

The second calculation determines TEC's production cost "with" the benefit of cogeneration.

After each of the two calculations are made, the avoided energy cost rate is calculated by dividing the difference in production cost between the two calculations described above by the "Standard Tariff Block." [The "Standard Tariff Block" is defined to be an x-megawatt (XMW) block equivalent to the combined actual hourly generation delivered to TEC from all QFs making as-available energy sales to Tampa Electric. In the absence of metered information on exports from a QF making as-available energy sales to Tampa Electric an estimate of the hourly exports from that Facility will be used, rounded to the nearest 5 MWs and then added to the sum of the other as-available purchases for that hour. Prior to the in-service date of the appropriate designated avoided unit, firm energy sales will be equivalent to as-available sales. Beginning with the in-service date of the appropriate designated avoided unit, firm energy purchases from QFs shall be treated as "as-available" energy for the purposes of determining the XMW block size only during the periods that the appropriate designated avoided unit would not be operated.] The difference in production costs divided by the XMW block determines the As-Available Energy Payment Rate (AEPR) for the hour. The AEPR will be applied to the "Actual" QF megawatts purchased during the hour to determine payment to each QF supplying as-available energy, and each QF supplying firm energy in those instances where the avoided unit would not have been operated during the hour. See Exhibit #3 (Example #1).

Continued to Sheet No. 8.105

Continued from Sheet No. 8.104

Example #2 Off-System Purchases Are Not Being Made. TEC's Generation Can Only Carry Its Native Load and Firm Sales With The QF Contribution.

The procedure used to deterministically calculate the incremental avoided energy cost associated with as-available energy on an hour by hour basis whenever Tampa Electric is not purchasing off-system interchange is as follows:

In this instance, the avoided energy cost that Tampa Electric will pay the QFs will be determined by calculating the production cost at the last MW load level. The avoided energy cost is the production cost at system lambda. See Exhibit #4. (Example #2a)

In the situation where TEC's generation is not fully dispatched, and additional generation capability is available to price a portion of the QF block, then the QF block will be priced at a combination of the difference between TEC's production cost at two load levels as previously defined and at system lambda. See Exhibit #5. (Example #2b)

Example #3 Off-System Purchases Are Being Made To Serve Native Load.

The procedure used to deterministically calculate the incremental avoided energy cost associated with as-available energy on an hour by hour basis whenever Tampa Electric is making off-system purchases for native load is as follows:

In this instance, the price per MWH that Tampa Electric will pay is determined by applying the highest incremental cost of the off-system purchases to the QF block. See Exhibit #6. (Example #3)

Line Loss Credit

A credit for avoided line losses reflecting the voltage at which generation by the QFs is received is included in Tampa Electric's procedure for the determination of incremental avoided energy cost associated with as-available energy. Tampa Electric uses the loss factors used in the Fuel and Purchase Power Cost Recovery Clause for calculating the compensation for avoided line losses at the transmission and distribution system voltage levels based upon the appropriate classification of service.

<u>Example</u>: (Firm Standby Time-of-Day)

Continued to Sheet No. 8.106

Continued from Sheet No. 8.105

Actual Incremental Hourly Avoided Energy Cost is:
$14.80/MWH
Adjustment Factor for Line Losses:
1.0555

The Actual Incremental hourly avoided Energy Cost adjusted for avoided line losses associated with as-available energy provided to Tampa Electric would then become, in this example, $15.62/MWH.

"Identifiable" Incremental Variable O&M

A procedure for approximating the "identifiable" incremental variable O&M expenses is included in Tampa Electric's methodology for the determination of incremental avoided energy costs associated with as-available energy.

The calculation of the variable O&M expense component associated with as-available energy is made annually in accordance with a system that differentiates actual annual total O&M costs into estimates of both fixed and variable components. This procedure, developed by the Electric Power Research Institute, was published in their Technical Assessment Guide (TAG) Special Report, dated May 1982, (EPRI P-2410-SR).

The EPRI-TAG assumptions provide an easily used and useful formula that approximates a fair payment for avoided variable O&M expenses. As such, it can be easily calculated and monitored using readily available information.
Once identified, based on the previous year's actual total O&M cost for coal-fired generation, the incremental avoided energy cost associated with as-available energy is adjusted to compensate for these variable expenses. (See Exhibit #7).

Continued to Sheet No. 8.107

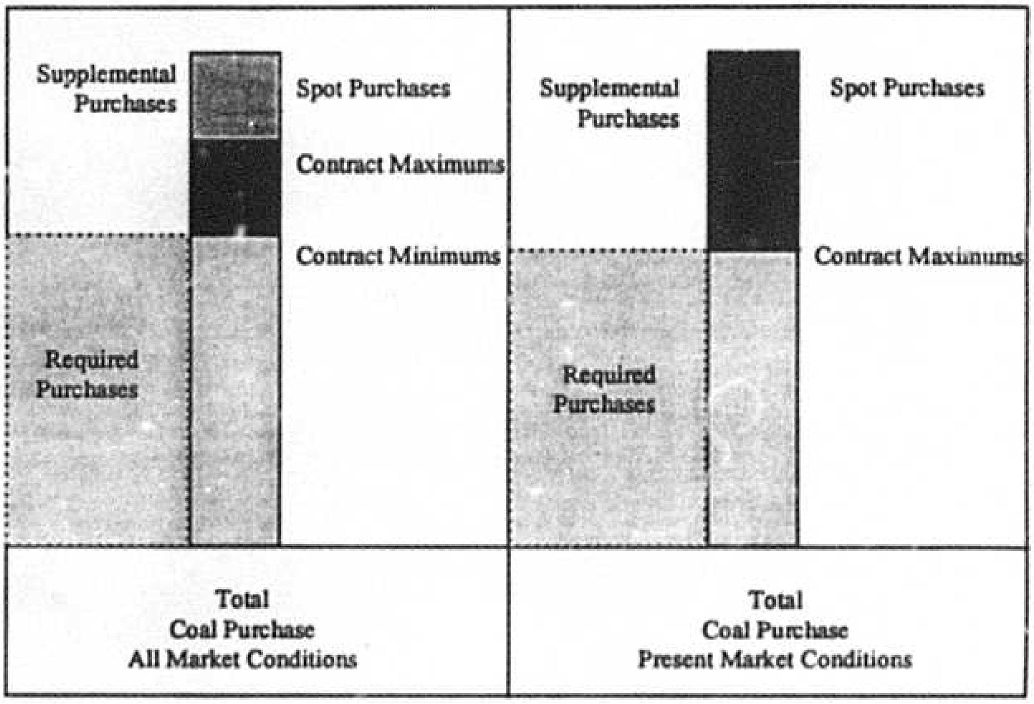
TAMPA ELECTRIC COMPANY

FIRST REVISED SHEET NO. 8.107
CANCELS ORIGINAL SHEET NO. 8.107

Continued from Sheet No. 8.106

EXHIBIT #1

REQUIRED AND SUPPLEMENTAL COAL PURCHASES
UNDER DIFFERENT MARKET CONDITIONS



Continued to Sheet No. 8.108

ISSUED BY: J. B. Ramil, President

DATE EFFECTIVE:

Continued from Sheet No. 8.107

EXHIBIT #2

SUPPLEMENTAL FUEL COST WORKSHEET

Revised December 1988

UNITS DELIVERED	SUPPLIER C/MMBTU	SUPPLEMENTAL COAL COST $/TON	INCREMENTAL TRANS. COST $/TON	TOTAL $/TON	AUGUST AVERAGE BTU/LB	AUGUST AVERAGE C/MMBTU	AUGUST TONS	SUPPLEMENT FUEL COST
Gannon 1-4	A			$45.30				177.50
Gannon 5&6	B			$45.48				176.44
Big Bend 1&2	C			$29.22				123.13
	D			$31.67				
	E			$32.08				
			Average	$29.87				
Big Bend 3[1]	F			$50.55				173.67
			Blended Average	$42.28				
Big Bend 4	G			$41.70				181.31
	H			$37.21				
			Average	$41.11				
#2 Oil	I			$19.41/BBL				334.64

[1] Revised: Big Bend Unit #3 is burning a 60/40 blend of blend/standard coal.

Continued to Sheet No. 8.109

Continued from Sheet No. 8.108

EXHIBIT #3

Example #1 **No Off-System Purchases, TEC's Generation Is Capable Of Carrying Its Native Load and Firm Sales.**

Given:

Actual QF Energy = 50 MWs
TEC's Maximum Available Generation = 1560 MWs
Native Load = 1550 MWs
Firm Sales = 10 MWs

First Calculation ("WITHOUT" QF):

Production Cost at 1560 MWs = $20,275/Hour

Second Calculation ("WITH" QF):

Production Cost at 1510 MWs = $19,500/Hour

Third Calculation (QF Rate $/MWH):

Actual Hourly Avoided Energy Cost =
($20,275/Hour - $19,500/Hour) / (50MW)

or

As-Available Energy Payment Rate (AEPR) = $15.50/MWH

Continued to Sheet No. 8.110

Continued from Sheet No. 8.109

EXHIBIT #4

Example #2a **Off-System Purchases Are Not Being Made. TEC's Generation Can Carry Its Native Load and Firm Sales Only With The QF Contribution.**

Given:

Actual QF Energy = 50 MWs
TEC's Maximum Available Generation = 1460 MWs
Native Load = 1500 MWs
Firm Sale = 10 MWs

First Calculation:

Production Cost at 1460 MWs = $18,900/Hour

Second Calculation:

Production Cost at 1459 MWs = $18,882.50/Hour

Third Calculation (QF Rate $/MWH):

Actual Hourly Avoided Energy Cost at 1 MW (System Lambda[1]) =
($18,900/Hour - $18,882.50/Hour) / (1 MW)

or

As-Available Energy Payment Rate (AEPR) = $17.50/MWH

NOTE:

[1] In this example, System Lambda is the production cost for the last MW segment to meet the load after dispatching all available generation capacity.

Continued to Sheet No. 8.111

Continued from Sheet No. 8.110

EXHIBIT #5

Example #2b **Off-System Purchases Are Not Being Made to Serve Native Load and Firm Sales. Available Generation Capacity Is Not Fully Dispatched. Without the QF's Contribution, TEC's Native Load and Firm Sales Can Be Carried Only With Additional Power Purchases.**

Given:

Actual QF Energy = 50 MWs
TEC's Maximum Available Generation = 1530 MWs
TEC's Actual Generation = 1500 MWs
Native Load = 1540 MWs
Firm Sale = 10 MWs

Step 1 (Calculations for First 30 MWs)

First Calculation ("WITHOUT" QF):
Production Cost at 1530 MWs = $20,590/Hour
Second Calculation ("With" QF):
Production Cost at 1500 MWs = $20,050/Hour
Third Calculation:
Actual Hourly Avoided Energy Cost at 30 MWs =
($20,590/Hour) - ($20,050/Hour) = $540/Hour

Step 2 (Calculations for Remaining 20 MWs)

First Calculation:
Production Cost at 1530 MWs = $20,590/Hour
Second Calculation:
Production Cost at 1529 MWs = $20,571.50/Hour
Third Calculation:
Actual Hourly Avoided Energy Cost at 1 MW (System Lambda[1]) for 20 MWs =
($20,590/Hour - $20,571.50/Hour) X (20 MWs) = $370/Hour

Step 3 (Calculation of Composite Rate for Total 50 MW Block)

Composite Actual Hourly Avoided Energy Cost of 50 MW Block =
$540 + $370 / 50 MW

or

As-Available Energy Payment Rate (AEPR) = $18.20/MWH

NOTE:

[1] In this example, System Lambda is the production cost for the last MW segment to meet the load after dispatching all available generation capacity.

Continued to Sheet No. 8.112

Continued from Sheet No. 8.111

EXHIBIT #6

Example #3 **Off-System Purchases Are Being Made, TEC's Native Load and Firm Sales Can Be Carried Only With Additional Purchase Power**

Given:

Actual QF Energy = 50 MWs
TEC's Maximum Available Generation = 1500 MWs
TEC's Actual Generation = 1500 MWs
Native Load = 1540 MWs
Firm Sales = 20 MWs
Off-System Purchases[1] = 10 MWs Costing $400/Hour

Actual Incremental Hourly Avoided Energy Cost = $400 / 10 MW

or

AEPR = $40/Hour

NOTE:

[1] Off-System Purchase shall be the highest cost purchased energy block bought during the hour for native load.

Continued to Sheet No. 8.113

Continued from Sheet No. 8.112

EXHIBIT #7

The calculation of the variable O&M cost adjustment factor associated with as available energy is made once each year, based on the previous year's actual total O&M cost for coal-fired generation, in accordance with the procedure found in the Technical Assessment Guide dated May 1982, published by the Electric Power Research Institute (EPRI P-2410-SR). The formula assumes the fixed portion of total annual O&M dollars equals the capacity factor (%) times the total annual O&M dollars. The variable portion is (1 - capacity factor) times the total annual O&M dollars. The capacity factor is based on the total period hours less those hours the units are off line due to economic dispatch for low load periods. Continuing the logic further, the adjustment factor to be added to the avoided energy cost equals the variable rate as determined annually and applied in the form of an hourly adjustment to the actual incremental hourly avoided energy cost.

Example Given:	1983 TEC Coal Generation	MW	
1) Big Bend	1	367	
	2	362	
	3	375	
	3	10	upgrade
Gannon	5	218	
	6	351	
	4	169	conversion

MW available per unit from net generation listed in the System Data Book for the same time period:

2) Coal Generation 1983 = 10,493,266 MWH

3) O&M for coal 1983 = $35,320,252

Continued to Sheet No. 8.114

Continued from Sheet No. 8.113

EXHIBIT #7 - continued

ESTIMATED
1983 VARIABLE O&M RATE CALCULATION

		(MW)		(Hours)	(MWH)
Big Bend	1	367	@	8760	3,214,920
	2	362	@	8760	3,171,120
	3	375	@	8760	3,285,000
Upgrade	3	10	@	2208	22,080
Gannon	5	218	@	8760	1,909,680
	6	351	@	8760	3,074,760
Conversion to Coal	4	169	@	2208	373,152
TOTAL					15,050,712
Generation (1983 Actual for Coal)					10,493,266

Average Coal Capacity Factor $= \frac{10,493,266}{15,050,712} \times 100\%$

$= 69.72\%$

Total O&M for Coal = \$35,320,252

Variable Component = \$35,320,252 X (1 - .6972)

= \$10,694,972

Estimated Variable O&M Cost[1] $= \frac{10,694,772}{10,493,266} = \$1.02/\text{MWH}$

1 Was added to 1984's actual incremental hourly avoided energy cost, after approval by the FPSC.

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STANDARD OFFER CONTRACT RATE FOR PURCHASE OF FIRM CAPACITY AND ENERGY FROM SMALL QUALIFYING FACILITIES OR MUNICIPAL SOLID WASTE FACILITIES

SCHEDULE: COG-2, Firm Capacity and Energy

AVAILABLE: Tampa Electric Company, herein after referred to as the "Company," will purchase Firm Capacity and Energy offered by any qualifying facility or municipal solid waste facility to which a Standard Offer Contract is available under Florida Public Service Commission (FPSC) Rule 25-17.0832(4)(a), Florida Administrative Code (F.A.C.). Unless specifically referred to, small "qualifying facilities" and "municipal solid waste facilities" may jointly be referred to as "qfs." The Company has designated a 180 megawatt (MW) (winter rating) natural gas fired combustion turbine generating unit with an in-service date of January 1, 2003, as its next Designated Avoided Unit. Until such time as the Designated Avoided Unit subscription limits have been fully and acceptably subscribed or the term of the Company's Standard Offer Contract has expired, the Company will accept Firm Capacity and Energy offered by qf under the provisions of this schedule.

The Company will negotiate and may contract with any qualifying facility as defined in FPSC Rule 25-17.080, F.A.C., irrespective of its location, which is either directly or indirectly interconnected with the Company, for the purchase of Firm Capacity and Energy pursuant to terms and conditions which deviate from this schedule where such negotiated contracts are in the best interest of the Company's ratepayers.

APPLICABLE: To any qf to which Standard Offer Contracts are available under FPSC Rule 25-17.0832(4)(a), F.A.C., irrespective of its location, producing capacity and energy for sale to the Company on a firm basis pursuant to the terms and conditions of this schedule and the Company's Standard Offer Contract or a separately negotiated contract.

Continued to Sheet No. 8.205

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Continued from Sheet No. 8.200

Firm Capacity and Energy are described in FPSC Rule 25-17.0832, F.A.C., and are capacity and energy produced and sold by a qf pursuant to a negotiated or Standard Offer Contract and subject to certain contractual provisions as to quantity, time and reliability of delivery. Criteria for achieving qualifying facility or municipal solid waste facility status shall be those set out in FPSC Rules 25-17.080, 25-17.082(4)(a), and 25-17.091, F.A.C., as applicable.

<u>CHARACTER OF SERVICE:</u> Purchases within the territory served by the Company shall be, at the option of the Company, single or three phase, 60 Hertz, alternating current at any available standard Company voltage. Purchases from outside the territory served by the Company shall be three phase, 60 Hertz, alternating current at the voltage level available at the interchange point between the Company and the entity delivering Firm Capacity and Energy from the qualifying facility or municipal solid waste facility.

<u>LIMITATIONS:</u> Purchases under this schedule are subject to the Company's "General Standards for Safety and Interconnection of Cogeneration and Small Power Production Facilities to the Electric Utility System," "NERC Planning Standards," September 1997, [Copyright @ 1997 by the North American Electric Reliability Council] that are applicable to generation and transmission facilities which are connected to, or being planned to be connected to the Company's transmission system (document provided upon request) and to FPSC Rules 25-17.080 through 25-17.091, F.A.C. and are limited to those qfs which are defined by FPSC Rule 25-17.082(4)(a), F.A.C. and which:

1. execute a Company Standard Offer Contract prior to January 1, 2001, for the Company's purchase of Firm Capacity and Energy; and

2. commit to commence deliveries of Firm Capacity and Energy no later than January 1, 2003, and to continue such deliveries through at least December 31, 2012; and

3. provide capacity which would not result in the Company's 180 MW subscription limit on capacity being exceeded.

<u>RATES FOR PURCHASES BY THE COMPANY:</u> Firm Capacity and Energy are purchased at unit costs, in dollars per kilowatt per month ($/kW/month) and cents per kilowatt-hour (¢/kWh), respectively, based on the value of deferring additional Company generating capacity.

Continued to Sheet No. 8.210

Continued from Sheet No. 8.205

For the purpose of this schedule, the Avoided Unit has been designated by the Company as a 180 MW combustion turbine generating unit with an in-service date of January 1, 2003. Appendix A of this schedule describes the methodology used to calculate payment schedules, general terms, and conditions applicable to the Company's Standard Offer Contract pursuant to FPSC Rules 25-17.080 through 25-17.091, F.A.C.

1. <u>Firm Capacity Rates:</u> Four options (i.e. Options 1, 2, 3, and 4, as set forth below) are available for payment of Firm Capacity which is produced by the qf and delivered to the Company. Once selected, the selected option shall remain in effect for the term of the contract with the Company. Exemplary payment schedules, shown on sheets following this section, contain the monthly rate per kilowatt (kW) of Firm Capacity the qf has contractually committed to deliver to the Company and are based on a minimum contract term which extends ten (10) years beyond the in-service date of the Designated Avoided Unit (i.e., through December 31, 2012). Payment schedules for longer contract terms will be made available to a qf upon request and may be calculated based on the methodologies described in Appendix A. At a maximum, Firm Capacity and Energy shall be delivered for a period of time equal to the anticipated plant life of the Designated Avoided Unit, commencing with the in-service date of the Designated Avoided Unit.

Option 1 - Value of Deferral Capacity Payments: Value of Deferral Capacity Payments shall commence on January 1, 2003, the in-service date of the Designated Avoided Unit, provided the qf is delivering Firm Capacity and Energy to the Company in accordance with the Minimum Performance Standards (MPS) as described in Appendix C. Capacity payments under this option shall consist of monthly payments, escalating annually of the avoided capital and fixed operating and maintenance expense associated with the Designated Avoided Unit and shall be equal to the value of the year-by-year deferral of the Designated Avoided Unit, calculated in conformance with FPSC Rule 25-17.0832, F.A.C., as described in Appendix A.

Continued to Sheet No. 8.215

Continued from Sheet No. 8.210

Option 2 - Early Capacity Payments: Payment schedules under this option are based on an equivalent net present value of the Value of Deferral Capacity Payments for the Designated Avoided Unit with an in-service date of January 1, 2003. The earliest date that Early Capacity Payments can be received by a qf shall be January 1, 2001. This is an approximation of the lead time required to site and construct the Designated Avoided Unit. The qf shall select the month and year in which the delivery of Firm Capacity and Energy to the Company is to commence and capacity payments are to start. Early Capacity Payments shall consist of monthly payments, escalating annually, of the avoided capital and fixed operating and maintenance expense associated with the Designated Avoided Unit. Avoided Capacity Payments shall be calculated in conformance with FPSC Rule 25-17.0832, F.A.C., as described in Appendix A. At the option of the qf, Early Capacity Payments may commence at any time after the specified earliest capacity payment date and before the in-service date of the Designated Avoided Unit provided the qf is delivering Firm Capacity and Energy to the Company in accordance with the Minimum Performance Standards as described in Appendix C. Where Early Capacity Payments are elected, the cumulative present value of the capacity paid to the qf over the term of the contract shall not exceed the cumulative present value of the capacity payments which would have been made to the qf had such payments been made pursuant to Option 1.

Option 3 - Levelized Capacity Payments: Levelized Capacity Payments shall commence on January 1, 2003, the in-service date of the Designated Avoided Unit, provided the qf is delivering Firm Capacity and Energy to the Company in accordance with the Minimum Performance Standards as described in Appendix C. The capital portion of the capacity payment under this option shall consist of equal monthly payments over the term of the contract, calculated in accordance with FPSC Rule 25-17.0832, F.A.C., as described in Appendix A. The fixed operation and maintenance expense portion of the capacity payment shall be equal to the value of the year-by-year deferral of fixed operation and maintenance expenses associated with the Designated Avoided Unit calculated in conformance with Appendix A. Where Levelized Capacity Payments are elected, the cumulative present value of the capacity paid to the qf over the term of the contract shall not exceed the cumulative present value of the capacity payments which would have been made to the qf had such payments been made pursuant to Option 1.

Continued to Sheet No. 8.220

Continued from Sheet No. 8.215

Option 4 - Early Levelized Capacity Payments: Early Levelized Capacity Payment schedules under this option are based on an equivalent net present value of the Value of Deferral Capacity Payments for the Designated Avoided Unit with an in-service date of January 1, 2003. The earliest date that Early Levelized Capacity Payments can be received by a qf shall be January 1, 2001. This is an approximation of the lead time required to site and construct the Designated Avoided Unit. The capital portion of the capacity payment under this Option shall consist of equal monthly payments over the term of the contract, calculated in accordance with FPSC Rule 25-17.0832, F.A.C., as described in Appendix A. The fixed operation and maintenance expense portion of the capacity payments shall be equal to the value of the year-by-year deferral of fixed operation and maintenance expenses associated with the Designated Avoided Unit calculated in conformance with Appendix A. At the option of the qf, Early Levelized Capacity Payments shall commence at any time after the specified earliest capacity payment date and before the in-service date of the Designated Avoided Unit provided the qf is delivering Firm Capacity and Energy to the Company in accordance with the Minimum Performance Standards as described in Appendix C. The qf shall select the month and year in which the delivery of Firm Capacity and Energy to the Company is to commence and capacity payments are to start. Where Early Levelized Capacity Payments are elected, the cumulative present value of the capacity payments paid to the qf over the term of the contract shall not exceed the cumulative present value of the capacity payments which would have been made to the qf had such payments been made pursuant to Option 1.

The Company will provide the qf with a schedule of capacity payment rates based on the month and year in which the delivery of Firm Capacity and Energy are to commence and the term of the contract. The following exemplary payment schedules are based on the minimum required contract term which must extend at least ten (10) years beyond the in-service date of the Designated Avoided Unit. The currently approved parameters used to calculate the following schedule of payments are found in Appendix B of this schedule.

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Continued from Sheet No. 8.220

UNIT TYPE: 180 MW (Winter Rating) COMBUSTION TURBINE (IN-SERVICE 1/1/2003)
MONTHLY CAPACITY PAYMENT RATE $/kW/MONTH

CONTRACT YEAR FROM	TO	OPTION 1 NORMAL PAYMENT STARTING 1/1/2003 $/kW/MO	OPTION 2 EARLY PAYMENT STARTING 1/1/2002 $/kW/MO	OPTION 2 EARLY PAYMENT STARTING 1/1/2001 $/kW/MO	OPTION 3 LEVELIZED PAYMENT STARTING 1/1/2003 $/kW/MO	OPTION 4 EARLY LEVELIZED PAYMENT STARTING 1/1/2002 $/kW/MO	OPTION 4 EARLY LEVELIZED PAYMENT STARTING 1/1/2001 $/kW/MO
1/1/01	12/31/01	-	-	2.44	-	-	2.70
1/1/02	12/31/02	-	2.83	2.50	-	3.10	2.70
1/1/03	12/31/03	3.31	2.90	2.56	3.60	3.11	2.71
1/1/04	12/31/04	3.39	2.97	2.62	3.61	3.12	2.72
1/1/05	12/31/05	3.47	3.04	2.69	3.61	3.12	2.72
1/1/06	12/31/06	3.56	3.12	2.75	3.62	3.13	2.73
1/1/07	12/31/07	3.64	3.19	2.82	3.63	3.14	2.74
1/1/08	12/31/08	3.73	3.27	2.89	3.64	3.15	2.74
1/1/09	12/31/09	3.82	3.35	2.96	3.65	3.16	2.75
1/1/10	12/31/10	3.91	3.43	3.03	3.66	3.16	2.76
1/1/11	12/31/11	4.01	3.51	3.10	3.67	3.17	2.76
1/1/12	12/31/12	4.11	3.60	3.18	3.68	3.18	2.77

2. **Energy Payment Rates:**

a. **Payments Prior to January 1, 2003**: The As-Available Energy Payment Rate in ¢/kWh will apply and shall be based on the Company's actual hourly avoided energy costs which are calculated by the Company in accordance with FPSC Rule 25-17.0825, F.A.C. Avoided energy costs include incremental fuel, identifiable variable operation and maintenance expenses, and an adjustment for line losses reflecting delivery voltage.

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The calculation of energy payments to the qf shall be based on the sum, over all hours of the Monthly Period, of the product of each hour's Energy Payment Rate times the energy purchased from the qf by the Company for that hour. All purchases shall be adjusted for losses from the point of metering to the point of interconnection.

The methodology to be used in the calculation of the avoided energy costs is described in Appendix D.

b. Payments Starting on January 1, 2003: To the extent that the Designated Avoided Unit is dispatched by the Company and operates, the Unit Energy Payment Rate in ¢/kWh will apply and shall be based on the Designated Avoided Unit's energy cost (fuel and variable operation and maintenance expense). Otherwise, when not dispatched by the Company the As-Available Energy Payment Rate will apply to the qf when operating will be based on the Company's actual hourly avoided energy cost.

Calculation of energy payments to the qf shall be based on the sum, over all hours of the Monthly Period, of the product of each hour's Energy Payment Rate times the energy purchased from the qf by the Company for that hour. All purchases shall be adjusted for losses from the point of metering to the point of interconnection.

The methodology to be used in the calculation of the avoided energy costs is described in Appendix D.

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PERFORMANCE CRITERIA: In addition to the following provisions, payments for Firm Capacity are conditioned on the qf's ability to meet or exceed the Minimum Performance Standards (MPS) for the Company's Designated Avoided Unit as described in Appendix C:

1. **QF's Commercial In-Service Date:** Capacity Payments shall not commence until the qf has attained and demonstrated commercial in-service status. The Commercial In-Service Date of a qf shall be defined as the first day of the month following the successful completion by the qf of maintaining an hourly kW output for a 24 hour period, as metered at the point of interconnection with the Company, equal to or greater than the qf's "Contracted Capacity" as designated in the Standard Offer Contract. A qf shall coordinate the operation of its facility during this test period with the Company to insure that the performance of its facility during this 24 hour period is reflective of the anticipated day to day operation of the qf.

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2. **Monthly Availability and Monthly Capacity Factor:** Upon achieving commercial in-service status, payments for Firm Capacity shall be made monthly in accordance with the capacity payment rate option selected by the qf and subject to the provision that the qf equals or exceeds the MPS for Monthly Availability and Monthly Capacity Factor of the Company's Designated Avoided Unit, as defined in Appendix C of this schedule.

3. **QF's Obligation if QF Receives Early, Levelized, or Early Levelized Capacity Payments:** The qf's payment option choice pursuant to Paragraph 4.b.iii of the Company's Standard Offer Contract may result in payments made by the Company for capacity delivered prior to January 1, 2003. Similarly, Levelized and Early-Levelized Capacity Payments for capacity delivered on or after January 1, 2003, may also exceed the year-by-year value of deferring the Designated Avoided Unit as specified in this Agreement. The parties recognize that capacity payments that exceed the year-by-year value of deferring the avoided unit may have to be repaid by the qf in the event the qf fails to perform pursuant to the terms and conditions of the Company's Standard Offer Contract.

To ensure that the qf will satisfy its obligation to make any repayment to the Company, the following provisions will apply:

The Company shall establish a Repayment Account to accrue the sum of the capacity payments that may have to be repaid by the qf to the Company. Amounts shall be added to the Repayment Account each month through December 2002, in the amount of the Company's early capacity payments made to the qf pursuant to the qf's chosen payment option.

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Beginning on January 1, 2003, the difference between the capacity payment made to the qf and the "normal" capacity payment calculated pursuant to Option 1 will also be added each month to the Repayment Account, so long as the payment to the qf is greater than the monthly payment the qf would have received if it had selected Option 1 in Paragraph 4.b.iii, of the Company's Standard Offer Contract.

Also beginning on January 1, 2003, at such time that the monthly capacity payment made to the qf, pursuant to the Repayment Payment Option selected, is less than the "normal" monthly capacity payment in Option 1, there shall be debited from the Repayment Account an Early Payment Offset Amount to reduce the balance in the Repayment Account. Such Early Payment Offset Amount shall be equal to the amount which the Company would have paid for capacity in that month if capacity payments had been calculated pursuant to Option 1 and the qf had elected to begin receiving capacity payments on January 1, 2003 minus the monthly capacity payment the Company makes to the qf (assuming the MPS are met or exceeded), pursuant to the Capacity Payment Option chosen by the qf. Monthly Capacity Payments will not be made to the qf for any month the qf fails to meet the MPS and if applicable, a payment will be required by the qf to the Company in an amount equal to the Early Payment Offset for that month. In the event a payment is required from the qf to the Company, the qf's Repayment Account will be reduced by the amount of such payment provided that any such payment will not exceed the current balance in the Repayment Account.

The qf shall owe the Company and be liable for the current balance in the Repayment Account. The annual balance in the Repayment Account shall accrue interest at an annual rate of 9.37%. The Company agrees to notify the qf monthly as to the current Repayment Account balance.

In the event of default by the qf, the total Repayment Account balance shall become due and payable within twenty (20) business days of receipt of written notice, as reimbursement for the early capacity payments made to the qf by the Company.

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The qf's obligation to reimburse the Company in the amount of the balance in the Repayment Account shall survive the termination of the qf's Standard Offer Contract with the Company. Such reimbursement shall not be construed to constitute liquidated damages and shall in no way limit the right of the Company to pursue all its remedies at law or in equity against the qf.

Prior to receipt of Early, Levelized, or Early-Levelized Capacity Payments the qf shall secure its obligation to repay any balance in the Repayment Account in the event the qf defaults under the terms of its Standard Offer Contract with the Company.

Such security shall be in the form of cash deposited in an interest bearing escrow account mutually acceptable to the Company and the qf; an unconditional and irrevocable direct pay letter of credit in form and substance satisfactory to the Company; or a performance bond in form and substance satisfactory to the Company. The form of security required will be in the sole discretion of the Company and will be in such form as to allow the Company immediate access to the funds in the event of default by the qf.

Florida Statute 377.709(4) requires a local government to refund early capacity payments should a municipal solid waste facility owned, operated by or on the behalf of the local government be abandoned, closed down or rendered illegal. Therefore a utility may not require risk-related guarantees from a municipal solid waste facility as required in FPSC Rule 25-17.0832 (2)(c) and (3)(e)(8), F. A. C. However, at its option, a municipal solid waste facility may provide such risk-related guarantees.

4. <u>Additional Criteria:</u>

   a. The qf shall provide monthly generation estimates by April 1 for the next calendar year; and

   b. The qf shall promptly update its yearly generation schedule when any changes are determined necessary; and

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c. The qf shall agree to reduce generation or take other appropriate action as requested by the Company for safety reasons or to preserve system integrity; and

d. The qf shall coordinate scheduled outages with the Company; and

e. The qf shall comply with the reasonable requests of the Company regarding daily or hourly communications.

DELIVERY VOLTAGE ADJUSTMENT: Energy Payments to qfs within the Company's service territory shall be adjusted according to the delivery voltage by the following multipliers:

Rate Schedule	Adjustment Factor
RS, GS	1.0616
GSD, GSLD, SBF	1.0561
IS-1, IS-3	1.0254
SBI-1, SBI-3	1.0254

METERING REQUIREMENTS: Qfs within the territory served by the Company shall be required to purchase from the Company the necessary hourly recording meters to measure their energy production. Unless special circumstances warrant, meters shall be read at monthly intervals on the approximate corresponding day of each meter reading period. Energy purchases from qfs outside the territory served by the Company shall be measured as the quantities scheduled for interchange to the Company by the entity delivering Firm Capacity and Energy to the Company.

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BILLING OPTIONS: The qf upon entering into a contract for the sale of Firm Capacity and Energy or prior to delivery of As-Available Energy to the Company shall elect to make either simultaneous purchases from the interconnecting utility and sales to the Company or net sales to the Company. The billing option elected may only be changed:

1. when the qf selling As-Available Energy enters into a negotiated contract or standard offer contract for the sale of Firm Capacity and Energy; or

2. when a Firm Capacity and Energy contract expires or is lawfully terminated by either the qf, or the Company; or

3. when the qf is selling As-Available Energy and has not changed billing methods within the last twelve months; and

4. when the election to change billing methods will not contravene the provisions of FPSC Rule 25-17.0832, F.A.C., or any contract between the qf and the Company.

If the qf elects to change billing methods in accordance with FPSC Rule 25-17.082, F.A.C., such a change shall be subject to the following provisions:

1. upon at least thirty (30) days advance written notice to the Company; and

2. upon the installation by the Company of any additional metering equipment reasonably required to effect the change in billing methodology and upon payment by the qf for such metering equipment and its installation; and

3. upon completion and approval by the Company of any alterations to the interconnection reasonably required to effect the change in billing methodology and upon payment by the qf for such alterations.

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Should a qf elect to make simultaneous purchases and sales, purchases of electric service by the qf from the interconnecting utility shall be billed at the retail rate schedule under which the qf load would receive service as a non-generating customer of the utility; sales of electricity delivered by the qf to the purchasing utility shall be purchased at the utilities avoided capacity and energy rates, where applicable, in accordance with FPSC Rules 25-17.0825 and 25-17.0832, F.A.C.

Should a qf elect a net billing arrangement, the hourly net capacity and energy sales delivered to the purchasing utility shall be purchased at the utility's avoided capacity and energy rates, where applicable, in accordance with FPSC Rules 25-17.0825 and 25-17.0832, F.A.C. Purchases from the interconnecting utility shall be billed pursuant to the utility's applicable standby service or supplemental service rate schedules.

Under the net sales billing option, the qf may commit Firm Capacity to the Company's system. Committed capacity is described in the Standard Offer Contract. For the net sales billing option, the committed capacity is additional to internal use, and the rates for purchase, and the performance criteria apply only to the power delivered to the Company. Although a billing option may be changed in accordance with FPSC Rule 25-17.082, F.A.C., the Contracted Capacity may only change through mutual negotiations satisfactory to the qf and the Company.

Customer charges that are directly attributable to the purchase of Firm Capacity and Energy from the qf are deducted from the qf's total monthly payment. A statement covering the charges and payments due the qf is rendered monthly and payment normally is made by the twentieth (20th) business day following the end of the Monthly Period.

CHARGES/CREDITS TO THE QF:

1. Customer Charges: A monthly Customer Charge will be rendered for maintaining an account for a Qualifying Facility engaged in either an As-Available Energy or Firm Capacity and Energy transaction and for other applicable administrative costs. Actual charges will depend on how the QF is interconnected to the Company.

QFs not directly interconnected to the Company, will be billed $580 monthly as a Customer Charge.

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Monthly customer charges, applicable to QFs directly interconnected to the Company, by Rate Schedule are:

Rate Schedule	Customer Charge	Rate Schedule	Customer Charge
RS	$ 8.50	RST	$ 11.50
GS	8.50	GST	11.50
GSD	42.00	GSDT	49.00
GSLD	255.00	GSLDT	255.00
SBF	280.00	SBFT	280.00
IS-1	1,000.00	IST-1	1,000.00
IS-3	1,000.00	IST-3	1,000.00
SBI-1	1,025.00	SBIT-1	1,025.00
SBI-3	1,025.00	SBIT-3	1,025.00

When appropriate, the Customer Charge will be deducted from the Qualifying Facility's monthly payment. A statement of the charges or payments due the Qualifying Facility will be rendered monthly. Payment normally will be made by the twentieth (20th) business day following the end of the billing period.

2. Interconnection Charge for Non-Variable Utility Expenses: The qf shall bear the cost required for interconnection including the metering. The qf shall have the option of payment in full for interconnection or make equal monthly installment payments over a thirty-six (36) month period together with interest at the rate then prevailing for thirty (30) days highest grade commercial paper; such rate to be determined by the Company thirty (30) days prior to the date of each payment.

3. Interconnection Charge for Variable Utility Expenses: The qf shall be billed monthly for the cost of variable utility expenses associated with the operation and maintenance of the interconnection. These costs include a) the Company's inspections of the interconnection and b) maintenance of any equipment beyond that which would be required to provide normal electric service to the qf with respect to other Customers with similar load characteristics.

4. Taxes and Assessments: The qf shall be billed monthly an amount equal to the taxes, assessments, or other impositions, if any, for which the Company is liable as a result of its purchases of Firm Capacity and Energy produced by the qf.

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RESERVED FOR FUTURE USE

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If the Company obtains any tax savings as a result of its purchases of Firm Capacity and Energy produced by the qf, which tax savings would not have otherwise been obtained, those tax savings shall be credited to the qf.

5. **Emission Allowance Clause:** Subject to approval by the FPSC, the qf shall receive a monthly credit, to the extent the Company can identify the same, equal to the value, if any, of any reduction in the number of air emission allowances used by the Company as a result of its purchase of Firm Capacity and Energy produced by the qf; provided that no such credit shall be given if the cost of compliance associated with air emission standards is included in the determination of full avoided cost.

TERMS OF SERVICE:

1. It shall be the qf's responsibility to inform the Company of any change in its electric generation capability.

2. Any electric service delivered by the Company to the qf shall be metered separately and billed under the applicable retail rate schedule and the terms and conditions of the applicable rate schedule shall pertain.

3. A security deposit will be required in accordance with FPSC Rules 25-17.082(5) and 25-6.097, F.A.C., and the following:

   a. In the first year of operation, the security deposit should be based upon the singular month in which the qf's projected purchases from the utility exceed, by the greatest amount, the utility's estimated purchases from the qf. The security deposit should be equal to twice the amount of the difference estimated for that month. The deposit should be required upon interconnection.

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RESERVED FOR FUTURE USE

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b. For each year thereafter, a review of the actual sales and purchases between the qf and the utility shall be conducted to determine the actual month of maximum difference. The security deposit shall be adjusted to equal twice the greatest amount by which the actual monthly purchases by the qf exceed the actual sales to the utility in that month.

4. The Company shall specify the point of interconnection and voltage level.

5. The Company will, under the provisions of this Schedule, require an agreement with the qf upon the Company's filed Standard Offer Contract and Interconnection Agreement. The qf shall recognize that its generation facility may exhibit unique interconnection requirements which will be separately evaluated and may require modifications to the Company's General Standards for Safety and Interconnection where applicable.

6. Service under this rate schedule is subject to the rules and regulations of the Company and the FPSC.

SPECIAL PROVISIONS:

1. Negotiated contracts deviating from the above standard rate schedule are allowable provided they are agreed to by the Company and approved by the FPSC.

2. In accordance with the provision in FPSC Rule 25-17.0883, F.A.C., the Company is required to provide transmission and distribution service to enable a retail customer to transmit electrical power generated at one location to the customer's facilities at another location when provision of such service and its associated charges, terms, and other conditions are not reasonably projected to result in higher cost of electric service to the Company's general body of retail and wholesale Customers or adversely affect the adequacy or reliability of electric service to all Customers.

A determination of whether or not such service is likely to result in higher cost electric service will be made by evaluating the results of an appropriately adjusted FPSC approved cost effectiveness methodology, in addition to other modeling analyses.

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3. In accordance with FPSC Rule 25-17.089, F.A.C., upon request by a qf, the Company shall provide transmission service in accordance with its Open Access Transmission Tariff to wheel As-Available Energy or Firm Capacity and Energy produced by a qf from the qf to another electric utility.

4. The rates, terms, and conditions for any transmission and ancillary services provide to a qf shall be those approved by the Federal Energy Regulatory Commission (FERC) and contained in the Company's Open Access Transmission Tariff.

5. A qf may apply for transmission and ancillary services from the Company in accordance with the Company's Open Access Transmission Tariff. Requests for service must be submitted on the Company's Open Access Same-Time Information System ("OASIS"). The Company's contact person, phone number and address is posted and updated on the OASIS and can be viewed by the public on the Internet at the address: http://www.enx.com/FOA_Contacts.html. A copy of the Company's Open Access Transmission Tariff is also posted at the address: http://www.enx.com/FOA/teco_home.html.

6. If the qf is located outside of the Company's transmission area, then the qf must arrange for long term firm third-party transmission, ancillary services and an interconnection agreement on all necessary external transmission paths for the term of the contract.

PROCEDURE FOR PROCESSING STANDARD OFFER CONTRACTS: The Company's Standard Offer Contract will initially become available for subscription during a 2-week open-season period which will commence on the effective date of the Standard Offer Contract, as approved by the FPSC.

The Company will only "receive" Standard Offer Contracts during a 2-week open-season period. All Standard Offer Contracts delivered to the Company during a 2-week open-season period will be considered to have been "received" on the final day of the period.

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Within 60 days of the receipt of a signed Standard Offer Contract (60 days from the expiration of a 2-week open-season period), the Company shall either accept and sign the Standard Offer Contract and return it within 5 days to the qf or petition the Commission not to accept the Standard Offer Contract and provide justification for the refusal.

The Company's initial 2-week open-season period will be defined as the ten (10) successive business days beginning on the effective date of the Company's Standard Offer Contract. On the tenth (10th) business day, the initial 2-week open-season period will expire at the close of business, 5 PM Eastern Prevailing Time (EPT). All Standard Offer Contracts received during the initial 2-week open-season period will be given equal consideration and each will be reviewed in accordance with the Company's Evaluation Procedure for Standard Offer Contracts. The criteria and procedure used to evaluate Standard Offer Contracts are attached to the Standard Offer Contract as Appendix C.

Each delivered Standard Offer Contract should be clearly labeled "Standard Offer Contract" and shall only be received at the Company's main business address:

Tampa Electric Company
TECO Plaza 4
c/o Director, Phosphate Sales & Cogeneration Services
702 North Franklin Street
P. O. Box 111
Tampa, Florida 33601

Certified mail will be the preferred means of Standard Offer Contract delivery. Any Standard Offer Contracts delivered prior to or following the expiration of the initial 2-week open-season will not be considered eligible and will be promptly returned.

Each eligible Standard Offer Contract received during the initial 2-week open-season period, will be evaluated as to its technical reliability, viability and financial stability, as well as other relevant information, in accordance with FPSC Rule 25-17.0832, F.A.C.

Each of the eligible Standard Offer Contracts will be prioritized following the evaluation process. The Company will select and accept Standard Offer Contracts, after the evaluation process, which have convincingly demonstrated that their project is financially and technically viable and that the committed capacity and energy would be available by the date specified in the Standard Offer Contract.

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The Company will accept successive Standard Offer Contracts, beginning with the Standard Offer Contract with the highest priority, until further acceptance of a Standard Offer Contract would cause the subscription limit to be exceeded.

If the subscription limit is not exceeded after evaluating all eligible Standard Offer Contracts received during the initial 2-week open-season period, then the Standard Offer Contract will be reopened for subscription, for an additional 2-week open-season period, beginning 90 days from the expiration of the initial 2-week open-season period. The Company will notify the FPSC in the event an additional 2-week open-season period is required.

Those qfs that previously submitted Standard Offer Contracts which were not accepted by the Company may resubmit their Standard Offer Contracts for evaluation during the additional 2-week open-season period. Other interested qfs may also submit Standard Offer Contracts for consideration during this time.

This procedure will replicate itself until such time as the Standard Offer Contract is no longer available for subscription. All interested parties should be aware of this possibility and should remain in frequent communication with the Company or the FPSC.

Once the Company's Standard Offer Contract is fully and acceptably subscribed or has expired, the Company will petition the Commission to close its Standard Offer Contract. Any executed Standard Offer Contracts received by the Company during the pendency of such a petition ("Interim SOCs") shall be held in abeyance pending final disposition of the petition. If the petition is finally approved (including any appellate review process), any Interim SOCs received during the pendency of the petition shall be rendered void and of no force and effect. If the petition is finally disapproved (including any appellate review process), any Interim SOCs received during the pendency of the petition shall be reactivated and processed in accordance with the Company's approved Procedure for Processing Standard Offer Contracts.

In its petition, the Company will provide the Commission with an estimate of the date that it will be filing a petition with respect to its new Standard Offer needs. The Company will then reassess its needs for capacity and petition the Commission regarding a Standard Offer Contract which reflects its updated needs for capacity. If the Company's petition for a new Standard Offer Contract is based on a different generation expansion plan than its previously approved Standard Offer Contract, then the Company will include the generation expansion plan in support of its petition.

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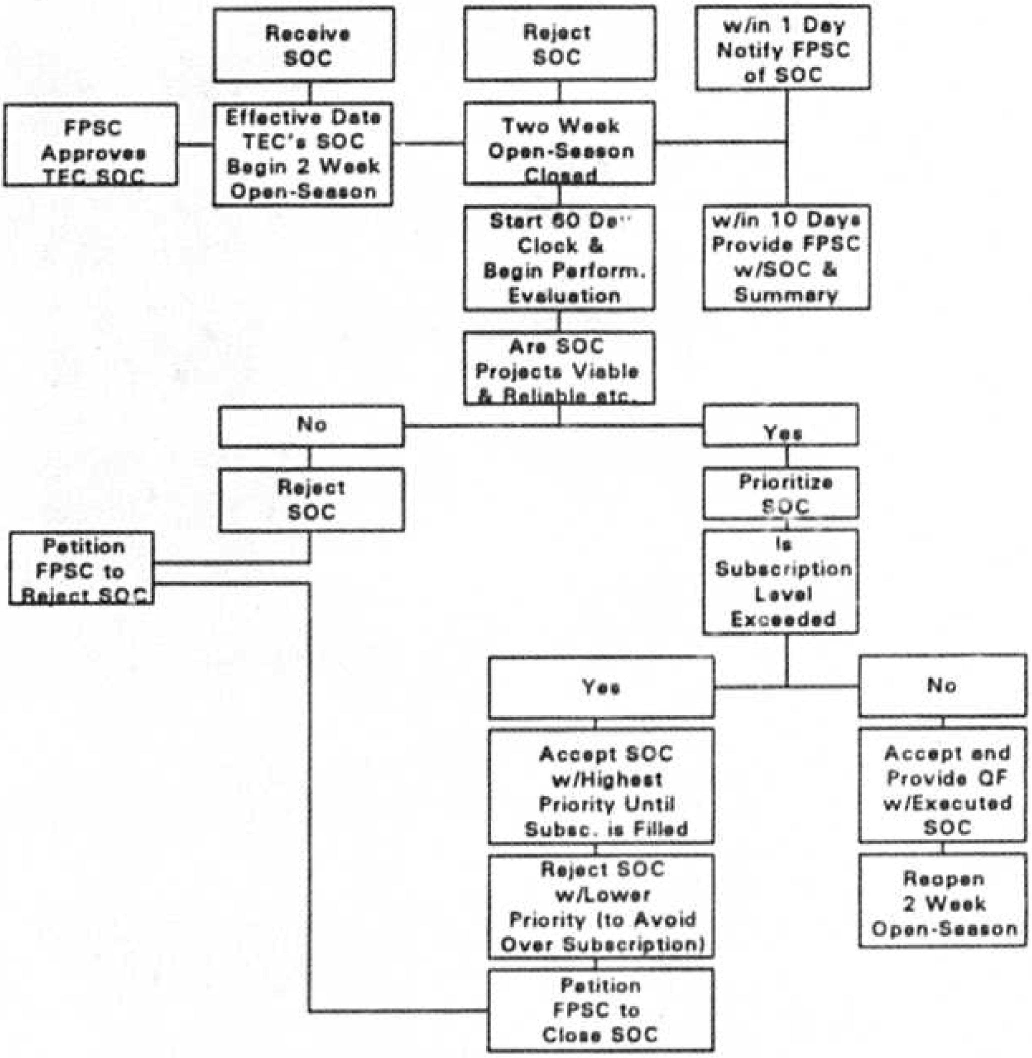
PROCEDURE FOR PROCESSING STANDARD OFFER CONTRACTS



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B	DESIGNATED AVOIDED UNIT PARAMETERS FOR AVOIDED CAPACITY COSTS SCHEDULE COG-2 APPENDIX B	8.355
C	DESIGNATED AVOIDED UNIT MINIMUM PERFORMANCE STANDARDS SCHEDULE COG-2 APPENDIX C	8.365
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STANDARD OFFER CONTRACT RATE FOR PURCHASE OF FIRM CAPACITY AND ENERGY FROM SMALL QUALIFYING FACILITIES OR MUNICIPAL SOLID WASTE FACILITIES
SCHEDULE COG-2
APPENDIX A

Appendix A provides a detailed description of the methodology used by the Company to calculate the monthly value of deferring the Designated Avoided Unit referred to in Schedule COG-2. When used in conjunction with the current FPSC approved cost parameters associated with the Designated Avoided Unit contained in Appendix B, a qf may determine the applicable value of deferral capacity payment rate associated with the timing and operation of its particular facility should the qf enter into a Standard Offer Contract with the utility.

Also contained in Appendix A is a discussion of the types and forms of surety bond requirements or equivalent assurance of repayment of early capacity payments acceptable to the Company in the event of contractual default by a qf.

__CALCULATION OF VALUE OF DEFERRAL:__ FPSC Rule 25-17.0832(6), F.A.C., specifies that avoided capacity costs, in dollars per kilowatt per month, associated with firm capacity sold to a utility by a qf pursuant to the utility's Standard Offer shall be defined as the value of a year-by-year deferral of the Designated Avoided Unit and shall be calculated as follows:

$$VAC_m = \frac{1}{12}\left[KI_n \frac{\left[1 - \frac{(1+i_p)}{(1+r)}\right]}{\left[1 - \frac{(1+i_p)^L}{(1+r)^L}\right]} + O_n \right]$$

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FPSC Rule 25-17.0832(6)(a), F.A.C., specifies that, beginning with the in-service date of the Company's Designated Avoided Unit, for a one year deferral:

VAC_m = Company's monthly value of avoided capacity, $/kW/month, for each month of year n;

K = present value of carrying charges for one dollar of investment over L years with carrying charges computed using average annual rate base and assumed to be paid at the middle of each year and present value to the middle of the first year;

I_n = total direct and indirect cost, in mid-year dollars per kilowatt ($/kW) including AFUDC but excluding CWIP, of the Designated Avoided Unit(s) with an in-service date of year n, including all identifiable and quantifiable costs relating to the construction of the Designated Avoided Unit(s) that would have been paid had the Designated Avoided Unit(s) been constructed;

O_n = total fixed operation and maintenance expense for the year n, in mid-year dollars per kilowatt per year $/kW/year, of the Designated Avoided Unit(s);

i_p = annual escalation rate associated with the plant cost of the Designated Avoided Unit(s);

i_o = annual escalation rate associated with the operation and maintenance expense of the Designated Avoided Unit(s);

r = annual discount rate, defined as the Company's incremental after tax cost of capital;

L = expected life of the Designated Avoided Unit(s); and

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n = year for which the Designated Avoided Unit(s) is deferred starting with its original anticipated in-service date and ending with the termination of the contract for the purchase of firm capacity and energy.

FPSC Rule 25-17.0832(6)(b), F.A.C., specifies that, normally, payment for Firm Capacity shall not commence until the in-service date of the Designated Avoided Unit(s). At the option of the qf, however, the Company may begin making early capacity payments consisting of the fixed operation and maintenance expense and the capital cost component of the value of a year-by-year deferral of the Designated Avoided Unit(s) starting as early as two years prior to the in-service date of the Designated Avoided Unit(s). When such early capacity payments are elected, capacity payments shall be paid monthly commencing no earlier than the Commercial In-Service date of the qf, and shall be calculated as follows:

$$A_m = A_c \left[\frac{(1 + i_p)^{(m-1)}}{12} \right] + A_o \left[\frac{(1 + i_o)^{(m-1)}}{12} \right] \text{ for } m = 1 \text{ to } t$$

Beginning with the earliest avoidance date of the Company's Designated Avoided Unit(s), for a one year deferral:

A_m = monthly early capacity payments to be made to the qf starting as early as two years prior to the in-service date of the Company's Designated Avoided Unit(s), in \$/kW/month;

i_p = annual escalation rate associated with the plant cost of the Designated Avoided Unit(s);

i_o = annual escalation rate associated with the operation and maintenance expense of the Designated Avoided Unit(s);

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m = earliest year for which capacity payments to a qf may be made;

t = the minimum term, in years, of the contract for the purchase of firm capacity if early capacity payments commence in year m;

$$A_c = F \left[\frac{1 - \frac{(1 + i_p)}{(1 + r)}}{1 - \frac{(1 + i_p)^t}{(1 + r)^t}} \right]$$

Where:

F = the cumulative present value of the annual avoided capital cost component of capacity payments for a ten year period, commencing with the in-service date of the Designated Avoided Unit(s) (in \$/kW/year in 2001 dollars);

r = annual discount rate, defined as the Company's incremental after tax cost of capital; and

$$A_o = G \left[\frac{1 - \frac{(1 + i_o)}{(1 + r)}}{1 - \frac{(1 + i_o)^t}{(1 + r)^t}} \right]$$

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Where: G = the cumulative present value in the year that the contractual payments will begin, of the avoided fixed operation and maintenance expense component of capacity payments which would have been made had capacity payments commenced with the anticipated in-service date of the Designated Avoided Unit(s).

FPSC Rule 25-17.0832(6)(c), F.A.C., specifies that, Monthly Levelized and Early Levelized Capacity Payments shall be calculated as follows:

$$P_L = \frac{F}{12} \times \frac{r}{1-(1+r)^{-t}} + O$$

Where:

P_L = the monthly Levelized Capacity Payment, starting on or prior to the in-service date of the Designated Avoided Unit(s);

F = the cumulative present value of the annual avoided capital cost component of the capacity payments for a ten year period, commencing with the in-service date of the Designated Avoided Unit (in \$/kW/year in 2001 dollars);

r = the annual discount rate, defined as the Company's incremental after tax cost of capital;

t = the term, in years, of the contract for the purchase of firm capacity; and

O = the monthly fixed operation and maintenance component of the capacity payments, calculated in accordance with FPSC Rule 25-17.0832, paragraph 6(a) for Levelized Capacity Payments or with paragraph 6(b) for Early Levelized Capacity Payments, F.A.C.

Currently approved parameters applicable to the formulas above are found in Appendix B.

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Continued from Sheet No. 8.330

CALCULATION OF MONTHLY AVAILABILITY AND CAPACITY FACTOR: Pursuant to FPSC Rule 25-17.0832, F.A.C., and Docket No. 891049-EU, a qf must meet or exceed, on a monthly basis, the MPS of the Company's Designated Avoided Unit(s) as described in Appendix C of COG-2 in order to receive monthly capacity payments. At the end of each monthly period, beginning with the monthly period specified in Paragraph 4.b.ii of the Company's Standard Offer Contract, the Company will calculate qf's Monthly Availability and Monthly Capacity Factor.

SECURITY GUARANTEES: The Company requires certain security deposits to ensure the completion of construction and performance under this Agreement in order to protect its ratepayers in the event the qf fails to deliver Firm Capacity and Energy in the amount and times specified in this Agreement, which shall be in form and substance as described herein. Such security may be refunded in the manner described in Paragraphs 4.b.iv.(1) and 4.b.iv.(2) of the Company's Standard Offer Contract.

Pursuant to FPSC Rule 25-17.091, F.A.C., a utility may not require security guarantees from a municipal solid waste facility as required in FPSC Rule 25-17.0832(2)(d) and (3)(f)(1), F.A.C. However, at its option, a municipal solid waste facility may provide such risk-related guarantees.

COMPLETION SECURITY: The qf shall pay to the Company a security deposit equal to $10.00 per kilowatt ($10.00/kW) of Anticipated Contracted Capacity as described herein as security for qf's completion of the Facility by the in-service date of the Designated Avoided Unit(s). Such security will be required within 60 days of contract execution. Such security shall be in the form of cash deposited in an interest bearing escrow account mutually acceptable to the Company and the qf; an unconditional and irrevocable direct pay letter of credit in form and substance satisfactory to the Company; or a performance bond in form and substance satisfactory to the Company. The form of security required will be in the sole discretion of the Company and will be in such form as to allow the Company immediate access to the funds in the event that the qf fails to complete the construction and achieve Commercial In-Service Status by the in-service date of the Designated Avoided Unit(s).

Continued to Sheet No. 8.340

Continued from Sheet No. 8.335

If the qf achieves commercial in-service status by the in-service date of the Designated Avoided Unit(s) then the entire deposit and any interest therein, if applicable, shall be refunded to the qf upon payment by the qf of the Performance Security as required in Paragraph 4.b.iv.(2). of the Company's Standard Offer Contract. If the qf's Commercial In-Service Date is delayed beyond the in-service date of the Designated Avoided Unit(s), the Company may, upon the request of the qf, extend such date for a period not to exceed five (5) months, in which case the Company shall be entitled to retain or draw down on an amount equal to 20% of the original deposit amount for each month (or portion thereof) that the completion of the project is delayed. If the qf's Commercial In-Service Date is delayed and an extension has not been granted or such date is delayed beyond the extended completion date, then the Company shall retain all of the deposit and terminate this Agreement.

PERFORMANCE SECURITY: Within sixty (60) days after the later of the qf's Commercial In-Service Date or the in-service date of the Designated Avoided Unit(s), the qf shall pay the Company a deposit in the amount of $10.00/kW of Actual Contracted Capacity as security for the qf's performance under this Agreement. Such security deposit shall be provided in the same manner as the completion security deposit as described in Paragraph 4.b.iv.(1). of the Company's Standard Offer Contract. Such performance security shall be retained by the Company for twelve (12) months from the later of the qf's Commercial In-Service Date or the in-service date of the Designated Avoided Unit(s).

If, at the end of the twelve month period so described, the qf's 12-month average of each month's numerical value for both the Monthly Availability Factor and the Monthly Capacity Factor meet the MPS as set forth in Rate Schedule COG-2, then the qf shall be entitled to a refund of such deposit. However, if, at the end of the first twelve month period, the qf's 12-month average of each month's numerical value for both the Monthly Availability Factor and the Monthly Capacity Factor fail to meet the MPS, then the Company shall be entitled to retain or draw down 50% of such deposit and retain the remainder of the security for an additional twelve month period.

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If, at the end of the twenty fourth month, the qf's 12-month average of each month's numerical value for both the Monthly Availability Factor and the Monthly Capacity Factor again fail to achieve the MPS, for the most recent 12-month period, then the Company shall be entitled to retain the remainder of the security and to terminate the contract. However, if at the end of the twenty fourth month, the qf's 12-month average of each month's numerical value for both the Monthly Availability Factor and the Monthly Capacity Factor meet the MPS, for the most recent 12-month period, then the qf shall be entitled to a refund of the remaining deposit.

For the purpose of this calculation, the 12-month average of a parameter shall be defined to equal the sum of each month's average numerical value for that parameter, for the most recent 12-month period, divided by twelve (12).

LIQUIDATED DAMAGES: The parties hereto agree that the Company would be substantially damaged in amounts that would be difficult or impossible to ascertain in the event that the qf fails to complete the Facility by the in-service date of the Designated Avoided Unit(s) or to provide a Facility which meets the MPS. In the event that the Company terminates this Agreement for the qf's failure to achieve commercial in-service status by the in-service date of the Designated Avoided Unit(s) or achieve the MPS once in service, the Company may retain all of the completion or performance security as liquidated damages, not as penalty, in lieu of actual damages and the qf hereby waives any defenses as to the validity of any such liquidated damages. In the event the qf defaults, it forfeits the aforesaid Completion and/or Performance Security. In addition thereto, the Company shall be entitled to pursue such equitable remedies against the qf as may be available.

REPAYMENT OF EARLY CAPACITY PAYMENTS: FPSC Rule 25-17.0832(3)(c), F.A.C., also requires that when early capacity payments are elected, the qf must provide a security deposit for assurance of repayment of Early Capacity Payments in the event the qf is unable to meet the terms and conditions of its contract. Depending on the nature of the qf's operation, financial health and solvency, and its ability to meet the terms and conditions of the Company's Standard Offer Contract; one of the following may constitute an equivalent assurance of repayment:

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1. cash deposited in an interest bearing escrow account mutually acceptable to the Company and the qf; or

2. an unconditional and irrevocable direct pay letter of credit in form and substance satisfactory to the Company; or

3. a performance bond in form and substance satisfactory to the Company.

The form of security required will be in the sole discretion of the Company and will be in such form as to allow the Company immediate access to the funds in the event that the qf fails to meet the terms and conditions of its contract.

The Company will cooperate with each qf applying for early capacity payments to determine the exact form of an "equivalent assurance of repayment" to be required based on the particular aspects of the qf. The Company will endeavor to accommodate an equivalent assurance of repayment which is in the best interests of both the qf and the Company's ratepayers.

Florida Statute 377.709(4), requires the local government to refund early capacity payments should a municipal solid waste facility owned, operated by or on behalf of a local government be abandoned, closed down or rendered illegal, therefore a utility may not require risk-related guarantees from a municipal solid waste facility as required in FPSC Rule 25-17.0832(2)(c) and (3)(e)(8), F.A.C. However, at its option, a municipal solid waste facility may provide such risk-related guarantees.

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DESIGNATED AVOIDED UNIT
PARAMETERS FOR AVOIDED CAPACITY COSTS
SCHEDULE COG-2
APPENDIX B

Beginning with the in-service date (1/1/2003) of the Company's Designated Avoided Unit (a 180 MW (Winter Rating) natural gas-fired Combustion Turbine), for a one year deferral:			<u>Value</u>
VAC_m	=	Company's monthly value of avoided capacity, in $/kW/month, for each month of year n;	<u>3.31</u>
K	=	present value of carrying charges for one dollar of investment over L years with carrying charges computed using average annual rate base and assumed to be paid at the middle of each year and present value to the middle of the first year;	<u>1.6093</u>
I_n	=	total direct and indirect cost, in mid-year $/kW including AFUDC but excluding CWIP, of the Designated Avoided Unit with an in-service date of year n, including all identifiable and quantifiable costs relating to the construction of the Designated Avoided Unit(s) that would have been paid had the Designated Avoided Unit(s) been constructed;	<u>303.00</u>
O_n	=	total fixed operation and maintenance expense for the year n, in mid-year $/kW/year, of the Designated Avoided Unit(s);	<u>3.62</u>
i_p	=	annual escalation rate associated with the plant cost of the Designated Avoided Unit(s);	<u>2.4%</u>
i_o	=	annual escalation rate associated with the operation and maintenance expense of the Designated Avoided Unit(s);	<u>2.7%</u>
r	=	annual discount rate, defined as the Company's incremental after tax cost of capital;	<u>9.37%</u>
L	=	expected life of the Designated Avoided Unit(s); and	<u>30</u>

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			Value
n	=	year for which the Designated Avoided Unit(s) is deferred starting with its original anticipated in-service date and ending with the termination of the contract for the purchase of firm capacity and energy;	2003
A_m	=	monthly early capacity payments to be made to the qf starting as early as two years prior to the in-service date of the Company's Designated Avoided Unit(s), in \$/kW/month;	2.44
i_p	=	annual escalation rate associated with the plant cost of the Designated Avoided Unit(s);	2.4%
m	=	earliest year for which capacity payments to a qf may be made;	2001
F	=	the cumulative present value of the annual avoided capital cost component of capacity payments for a ten year period, commencing with the in-service date of the Designated Avoided Unit(s) (in \$/kW/year in 2001 dollars);	228.30
r	=	annual discount rate, defined as the Company's incremental after tax cost of capital; and	9.37%
t	=	the minimum term, in years, of the contract for the purchase of firm capacity if early capacity payments commence in year m.	12

Parameters for Avoided Energy and Variable Operation and Maintenance Costs

Beginning on January 1, 2003, to the extent that the Designated Avoided Unit(s) would have been operated had it been installed by the Company:

O_v	=	total variable operating and maintenance expense, in \$/MWH, of the Designated Avoided Unit(s), in year n;	2.80
i_o	=	annual escalation rate associated with the operation and maintenance expense of the Designated Avoided Unit(s); and	2.7%
h	=	the average annual heat rate, in British Thermal Units (Btus) per kilowatt-hour (Btu/kWh), of the Designated Avoided Unit(s).	11,114

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DESIGNATED AVOIDED UNIT
MINIMUM PERFORMANCE STANDARDS
SCHEDULE COG-2
APPENDIX C

The Company's Standard Offer Contract is based on a 180 MW fully dispatchable simple cycle, natural gas fired Combustion Turbine generating unit with an in-service date of January 1, 2003. In order to receive a Monthly Capacity Payment, all Firm Capacity and Energy provided by qfs shall meet or exceed the following MPS on a monthly basis. The MPS are based on the anticipated peak and off-peak dispatchability, unit availability, and operating factor of a 2003 Combustion Turbine designated as the Avoided Unit over the term of this Standard Offer Contract. The qf's facility will be evaluated against the anticipated performance of the Company's Designated Avoided Unit, starting with the first Monthly Period following the date selected in Paragraph 4.b.ii of the Company's Standard Offer Contract.

1. <u>Dispatch Requirements:</u> The qf shall provide peaking capacity to the Company on a firm commitment, first-call, on-call, as-needed basis. In order to receive a Monthly Capacity Payment, for months the unit is to be dispatched, the qf must meet or exceed both the minimum Monthly Availability and Monthly Capacity Factor requirements.

2. <u>Dispatch Procedure:</u> The Company shall electronically transmit the next day's expected hour-by-hour dispatch schedule for the qf's unit based on the hour-by-hour Committed Capacity schedule supplied by the qf at 3:00 PM that day. Friday's electronic transmissions will include Saturday, Sunday, and Monday schedules. Communications between the Company and the qf during holiday periods will be similarly adjusted. The qf shall control and operate its unit consistent with the Company's dispatch schedule. From time to time (i.e. during emergency conditions), the Company may be required to adjust or ignore scheduled levels altogether, however, each party shall make reasonable efforts to minimize departures from the daily schedule.

3. <u>Automatic Generation Control:</u> At the Company's discretion, the qf will operate its unit with Automatic Generation Control (AGC) equipment, speed governors, and voltage regulators in-service, except at such times when operational constraints of the equipment prevent AGC operation.

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a. Start-up Time: Upon notification by the Company, the qf's unit shall provide its Committed Capacity within thirty (30) minutes from a cold-start condition.

b. Minimum Run Time: Minimum run time for the qf's unit shall be one (1) hour.

BASIS FOR MONTHLY CAPACITY PAYMENT CALCULATION:

1. Monthly Availability Factor: The qf's Monthly Availability Factor will be calculated by averaging the Hourly Availability Factors for each hour of the Monthly Period. The Hourly Availability Factor may not exceed 100% and shall be defined as the hourly Committed Capacity expressed as a percentage of Contracted Capacity to the nearest whole percentile. The qf is required to achieve a minimum Monthly Availability Factor of ninety percent (90%) in order to meet the MPS and be eligible to receive a Monthly Capacity Payment. Periods of Annual Planned Maintenance will be excluded from the calculation of the Monthly Availability Factor. For purposes of calculating the Monthly Availability Factor, the qf's Committed Capacity may not exceed its Contracted Capacity.

2. Monthly Capacity Factor: In addition to the MPS for Monthly Availability, the qf shall provide Committed Capacity into the Company's electric grid in order to meet or exceed a Monthly Capacity Factor of eighty percent (80%). The Monthly Capacity Factor for the period April 1 through October 31, shall be defined as the sum of eighty percent (80%) of the Monthly Average On-peak Operating Factor plus twenty percent (20%) of the Monthly Average Off-peak Operating Factor. The Monthly Capacity Factor for the period November 1 through March 31, shall be defined as the sum of ninety percent (90%) of the Monthly Average On-peak Operating Factor plus ten percent (10%) of the Monthly Average Off-peak Operating Factor.

a. Operating Factor: The qf shall endeavor to provide capacity in the amount dispatched by the Company. The Company may at times request capacity in an amount that exceeds the Committed Capacity as declared by qf the previous day.

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However, the Operating Factor may not exceed 100% and shall be defined as the actual energy received during each hour divided by the lessor of the qf's committed capacity or the capacity requested by the Company for that hour, expressed to the nearest whole percentile.

b. <u>Monthly Average On-peak Operating Factor:</u> The monthly average of the Operating Factor for all hours the qf unit has been dispatched during On-peak Hours will be termed the Monthly Average On-peak Operating Factor.

c. <u>Monthly Average Off-peak Operating Factor:</u> The monthly average of the Operating Factor for all hours the qf unit has been dispatched during Off-peak Hours will be termed the Monthly Average Off-peak Operating Factor.

3. <u>Off-Peak and On-Peak Hours:</u> Those weekday hours occurring April 1 through October 31, from 12:00 noon to 9:00 p.m. and November 1 through March 31, from 6:00 a.m. to 10:00 a.m. and from 6:00 p.m. to 10:00 p.m. All other weekday hours and weekends shall be deemed Off-peak Hours including the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. The Company shall have the right to change such On-peak Hours by providing written notice to qf a minimum of ninety (90) calendar days prior to such change.

4. <u>Annual Scheduled Maintenance:</u> Each year the qf shall prepare, coordinate, and provide by April 1st all planned maintenance with the Company. The Company will review and approve annual/major scheduled maintenance by July 1st, for the balance of the current year and following calendar year. A maximum of two (2) weeks (336 hours) each year for annual maintenance and a total of five (5) weeks (840 hours) every fifth year for major overhauls will be allowed. Scheduled maintenance shall not be planned during December through February without prior written consent from the Company. At the option of the qf and by written notification to the Company, scheduled outage time may be utilized during any other months to improve the qf's Availability and Capacity Factors and such scheduled outage hours will be disregarded from the Monthly Availability Factor and Capacity Factor calculations. However, once allowable maintenance hours have been utilized, all other hours during the year will be considered in Availability and Capacity Factor calculations.

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5. <u>Monthly Capacity Payment:</u> Starting with the qf's Commercial In-Service Date, for months when the qf unit has been dispatched (provided that qf has achieved at least a 90% Monthly Availability Factor), the Monthly Capacity Payment for each Monthly Period shall be calculated according to the following:

a. In the event that the Monthly Capacity Factor is less than 80%, no Monthly Capacity Payment shall be paid to the qf. That is:

$$MCP = \$0$$

b. In the event that the Monthly Capacity Factor is greater than or equal to 80% but less than 90%, the Monthly Capacity Payment shall be calculated from the following formula:

$$MCP = [(BCC) \times (.02 \times (CF-45))] \times CC$$

c. In the event that the Monthly Capacity Factor is greater than or equal to 90%, the Monthly Capacity Payment shall be calculated from the following formula:

$$MCP = (BCC) \times CC$$

Where:

MCP = Monthly Capacity Payment in dollars.

BCC = Base Capacity Credit in $/KW-Month pursuant to Tariff Sheet No. 8.225.

CC = Contracted Capacity in KW.

CF = Monthly Capacity Factor; or

During April 1 - October 31:

= 80% x Monthly Average On-peak Operating Factor + 20% x Monthly Average Off-peak Operating Factor

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During November 1 - March 31:

= 90% x Monthly Average On-peak Operating Factor +

10% x Monthly Average Off-peak Operating Factor

6. Non-Dispatch Condition: The qf may be entitled to a Monthly Capacity Payment (BCC X CC) even if the qf's unit was not dispatched by the Company during a Monthly Period. In this instance however, in order to cover the Company's operating reserve criteria, the qf unit must have achieved a minimum Monthly Availability Factor of 90% for the Monthly Period to be eligible to receive a Monthly Capacity Payment.

In the event the qf unit is dispatched during one but not the other (On-peak vs. Off-peak) period during the month, the qf's Monthly Average Operating Factor for the "non-dispatched" period will be set equal to the Monthly Average Operating Factor achieved during the "dispatched" period, for the purpose of calculating the Monthly Capacity Factor, as defined in the Section entitled Basis for Monthly Capacity Payment Calculation, Paragraph 2 herein.

The qf may be entitled to a Monthly Capacity Payment when the qf's unit is out of service during the month for allowable scheduled maintenance in accordance with the Section entitled Basis for Monthly Capacity Payment Calculation, Paragraph 4.

BASIS FOR MONTHLY ENERGY PAYMENT CALCULATION:

1. Energy Payment Rate: Prior to January 1, 2003, the qf's Energy Payment Rate shall be the Company's As-Available Energy Payment Rate, as described in Appendix D. Starting January 1, 2003, the basis for determining the Energy Payment Rate will be whether;

a. The Company has dispatched the qf's unit on AGC; or

b. The Company has dispatched the qf's unit off AGC and the qf is operating its unit at or below the dispatched level; or

c. The Company has dispatched the qf's unit off AGC but the qf is operating its unit above the dispatched level; or

d. The Company has not dispatched the qf's unit but the qf is providing capacity and energy.

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Note: For any given hour the qf unit must be operating on AGC a minimum of 30 minutes to qualify under case (a).

The qf's total monthly energy payment shall equal; (1) the sum of the hourly energy at the Unit Energy Payment Rate (EPR), when the qf's unit was dispatched by the Company, plus (2) the sum of the hourly energy at the corresponding hourly As-Available Energy Rate when the qf's unit was operating at times other than when the Company dispatched the unit.

2. **Unit Energy Payment Rate:** Starting January 1, 2003, the qf will be paid at the EPR for energy provided in Paragraph 1.a, Paragraph 1.b and that portion of the energy provided up to the dispatched level in Paragraph 1.c as defined in the Section entitled Basis for Monthly Energy Payment Calculations. The EPR, which is based on the Company's Designated Avoided Unit and Heat Rate value of 11,114 Btu/kWh, will be calculated monthly by the following formula:

$$EPR = FC + VOM,$$

where;

VOM = Unit Variable Operation & Maintenance Expense in \$/MWH defined in Rate Schedule COG-2, Appendix B.

FC = Fuel Component of the Energy Payment in \$/MWH as defined by:

$$FC = \frac{11{,}114 \text{ Btu/kWh} \times FP}{1{,}000}$$

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where;

FP = Fuel Price in \$/MMBTU determined by:

FP = GC + TC + GRI + ACA + TCR + FRC,

where;

GC = Fuel Price in \$/MMBTU determined by taking the first publication of each month of Inside FERC's Gas Market Report low price quotation under the column titled "Range" for "Florida Gas Transmission Co., Louisiana" listings.

TC = then currently approved Florida Gas Transmission (FGT) Company tariff rate in \$/MMBTU for Interruptible Transmission Service (ITS-1).

GRI = then currently approved FGT Company tariff rate in \$/MMBTU for recovery of charges for the Gas Research Institute.

ACA = then currently approved FGT Company tariff rate in \$/MMBTU for recovery of charges permitted by Section 154.38(d)(6) of the FERC regulations under the Natural Gas Act.

TCR = then currently approved FGT Company tariff rate in \$/MMBTU for recovery of costs associated with FGT's obligation to satisfy long term take-or-pay agreements.

FRC = then currently approved FGT Company tariff rate in \$/MMBTU for recovery of costs associated with the natural gas used to operate FGT's pipeline system.

3. As-Available Energy Payment Rate: For energy provided and not covered under Paragraph 2 above, the As-Available Energy Payment Rate will be applicable and will be based on the system avoided energy cost as defined in Appendix D.

METHODOLOGY TO BE USED IN THE CALCULATION OF AVOIDED ENERGY COST SCHEDULE COG-2 APPENDIX D

The methodology the Company has implemented in order to determine the appropriate avoided energy costs and any payments thereof to be rendered to qfs is consistent with the provisions of Order No. 23625 in Docket No. 891049-EU, issued on October 16, 1990, and with the Amendment of FPSC Rules 25-17.080 et seq, F.A.C..

The avoided energy costs methodology used to determine payments to qfs on an hourly basis is based on the incremental cost of fuel using the average price of replacement fuel purchased in excess of contract minimums and is further described in Exhibit #1. Generally, avoided energy costs are defined to include incremental fuel, identifiable variable operation and maintenance expenses, identifiable variable purchased power costs and an adjustment for line losses reflecting delivery voltage.

Under normal conditions the Company will have additional generation resources available which can carry its native load and firm interchange sales without the qf's contribution. When this is the case and the qf is present, the incremental fuel portion of the avoided energy cost is equal to the difference between the Company's production cost at two load levels, with and without the qf's contribution.

In those situations where the Company's available maximum generation resources (not including its minimum spinning reserves) are insufficient to carry its native load and firm interchange sales, in the absence of the qf contribution, the Company's incremental fuel component of the avoided energy cost will be determined by:

1. system lambda - if "off-system purchases" are not being made and all available generation has been dispatched; or

2. the highest incremental cost of any "off-system purchases" that are being made for native load.

Examples of these situations are found in Exhibits #3-#6.

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The As-Available Avoided Energy Cost, as determined by this methodology, is priced at a level not to exceed the Company's incremental fuel and identifiable variable operating and maintenance (O&M) expenses including the cost of any off-system purchases for native load.

PARAMETERS FOR DETERMINING AS-AVAILABLE AVOIDED ENERGY COSTS: The Company uses production costing methods for determining avoided energy cost payments to qfs. Computerized production costing is accomplished on an hourly basis. The parameters used are as follows:

1. The system load is the actual system load at the Hour Ending with the clock hour (HE).

2. The first allocation of load for production costing is to those units that are base loaded at a certain level for operating reasons. The remainder of the load is allocated to units available for economic dispatch through the use of incremental cost curves.

3. The fuel costs associated with each of the Company's units operating at its allocated level of generation is determined by using the individual units input/output equation, its heat rate performance factor and the composite price of supplemental fuel.

4. The Company's own production cost for each hour of operation at a particular generation level equals the sum of the individual units' fuel cost for that hour. The production cost, thus determined, consists of the composite price of replacement fuel based on supplemental purchases and the incremental heat rate for the generating system.

5. The Company's total cost equals its own production cost (Paragraph 4 above), identified variable O&M, plus the cost of any off-system purchases to serve native load.

6. Native load includes all firm and non-firm retail load.

7. The cost of off-system firm and non-firm variable purchases is defined as the highest energy cost energy block purchased for native load during the hour; i.e., SCHEDULES A, B, C, D, X, J, UPP (Unit Power Purchase).

8. Firm interchange sales are included in production cost calculations.

9. The Company's available maximum generation resources in this methodology is defined as the maximum capacity less spinning reserve requirements.

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10. The "Standard Tariff Block" is defined to be an x-megawatt (XMW) block equivalent to the combined actual hourly generation delivered to the Company from all qfs making as-available energy sales to the Company. In the absence of metered information on exports from a qf making as-available energy sales to the Company, an estimate of the hourly exports from that Facility will be used, rounded to the nearest 5 MW and then added to the sum of all other known as-available energy purchases for that hour.

PARAMETERS FOR DETERMINING ENERGY PAYMENT RATES: The Company uses production costing methods for determining avoided energy cost payments to qfs. Computerized production costing is accomplished on an hourly basis. The parameters used are as follows:

1. Prior to the in-service date: For payments prior to the in-service date of the Designated Avoided Unit, the As-Available Energy Payment Rate in ¢/kWh, calculated in accordance with the Section entitled Basis for Monthly Energy Payment, Paragraph 1 in Appendix C of this Rate Schedule, shall be based on the Company's actual hourly avoided energy costs which are calculated by the Company in accordance with FPSC Rule 25-17.0825, F.A.C.

2. After the in-service date: For payments after the in-service date of the Designated Avoided Unit, the Unit Energy Payment Rate in ¢/kWh, calculated in accordance with the Section entitled Basis for Monthly Energy Payment, Paragraph 2 in Appendix C of this Rate Schedule, shall be based on the Designated Avoided Unit's energy cost (fuel and variable Operation and Maintenance), to the extent that the Designated Avoided Units would have operated had it been installed by the Company.

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SUPPLEMENTAL FUEL: The term "supplemental fuel" refers to that fuel purchased in excess of the Company's long-term contract minimum requirements. As illustrated in Exhibit #1, supplemental fuel can be composed of contract fuel purchases above minimums and fuel purchases on the spot market. When spot prices are lower than prices for minimum tonnages on long term contract purchases, spot prices are "supplemental." Under market conditions where spot prices are greater than the price of coal purchased under contract, it is economical for the Company to purchase more than the contract minimums. In this instance the supplemental price is a combination of the contract price of coal above minimum contract requirements and any coal purchased on the spot market. The Company looks to the supplemental fuel for purposes of incremental pricing to determine the level of as-available energy payments because contract minimum purchases are a fixed expense.

Supplemental fuel is composed of contract fuel purchases above minimum levels and fuel purchases on the spot market. The Company pursues the least expensive alternative whether it be spot purchases or purchases of contract coal above the contract minimum, or a mixture of both. The supplemental fuel price is calculated by weight averaging all of the supplemental fuel purchases, by fuel type, during the preceding month. A Supplemental Fuel Cost Worksheet is shown in Exhibit #2.

With regard to oil-fired generation, the Company treats all of its oil purchases as supplemental fuel inasmuch as it has no contract minimums. For graphic portrayal of Tampa Electric's definition of supplemental fuel see Exhibit #1 attached.

AVOIDED ENERGY COST CALCULATIONS:

Example: #1 No off-system purchases, the Company's generation is capable of carrying its native load and firm sales.

The procedure used to deterministically calculate the incremental avoided energy cost associated with as-available energy on an hour by hour basis when no off-system purchases are taking place is as follows:

In these instances, the $/MWH price that the Company will pay the qfs is determined by calculating the production cost at two load levels.

The first calculation determines the Company's production cost without the benefit of cogeneration.

Continued to Sheet No. 8.420

Continued from Sheet No. 8.415

The second calculation determines the Company's production cost with the benefit of cogeneration.

After each of the two calculations are made, the avoided energy cost rate is calculated by dividing the difference in production cost between the two calculations described above by the "Standard Tariff Block." [The "Standard Tariff Block" is defined to be an XMW block equivalent to the combined actual hourly generation delivered to the Company from all qfs making as-available energy sales to the Company. In the absence of metered information on exports from a qf making as-available energy sales to the Company, an estimate of the hourly exports from that Facility will be used, rounded to the nearest 5 MWs and then added to the sum of the other as-available purchases for that hour. Prior to the in-service date of the appropriate designated avoided unit, firm energy sales will be equivalent to as-available sales. Beginning with the in-service date of the appropriate Designated Avoided Unit(s), firm energy purchases from qfs shall be treated as "as-available" energy for the purposes of determining the XMW block size only during the periods that the appropriate designated avoided unit would not be operated.] The difference in production costs divided by the XMW block determines the As-Available Energy Payment Rate (AEPR) for the hour. The AEPR will be applied to the "Actual" qf MWs purchased during the hour to determine payment to each qf supplying as-available energy, and each qf supplying firm energy in those instances where the avoided unit would not have been operated during the hour. See Exhibit #3 (Example #1).

Example #2 Off-system purchases are not being made. The Company's generation can only carry its native load and firm sales with the qf contribution.

The procedure used to deterministically calculate the incremental avoided energy cost associated with as-available energy on an hour by hour basis whenever the Company is not purchasing off-system interchange is as follows:

In this instance, the avoided energy cost that the Company will pay the qfs will be determined by calculating the production cost at the last MW load level. The avoided energy cost is the production cost at system lambda. See Exhibit #4. (Example #2a)

Continued to Sheet No. 8.425

Continued from Sheet No. 8.420

In the situation where the Company's generation is not fully dispatched, and additional generation capability is available to price a portion of the qf block, then the qf block will be priced at a combination of the difference between the Company's production cost at two load levels as previously defined and at system lambda. See Exhibit #5. (Example #2b)

Example #3 Off-system purchases are being made to serve native load.

The procedure used to deterministically calculate the incremental avoided energy cost associated with as-available energy on an hour by hour basis whenever the Company is making off-system purchases for native load is as follows:

In this instance, the $/MWH price that the Company will pay is determined by applying the highest incremental cost of the off-system purchases to the qf block. See Exhibit #6. (Example #3)

Line Loss Credit: A credit for avoided line losses reflecting the voltage at which generation by the qfs is received is included in the Company's procedure for the determination of incremental avoided energy cost associated with as-available energy. The Company uses the loss factors used in the Fuel and Purchase Power Cost Recovery Clause for calculating the compensation for avoided line losses at the transmission and distribution system voltage levels based upon the appropriate classification of service.

Example: (Firm Standby Time-of-Day)

Actual Incremental Hourly Avoided Energy Cost is:
$14.80/MWH
Adjustment Factor for Line Losses:
1.0555

The Actual Incremental Hourly Avoided Energy Cost adjusted for avoided line losses associated with as-available energy provided to the Company would then become, in this example, $15.62/MWH.

"Identifiable" Incremental Variable O&M: A procedure for approximating the "Identifiable" Incremental Variable O&M expenses is included in the Company's methodology for the determination of incremental avoided energy costs associated with as-available energy.

Continued to Sheet No. 8.430

Continued from Sheet No. 8.425

The calculation of the variable O&M expense component associated with as-available energy is made annually in accordance with a system that differentiates actual annual total O&M costs into estimates of both fixed and variable components. This procedure, developed by the Electric Power Research Institute (EPRI), was published in their Technical Assessment Guide (TAG) Special Report, dated May 1982, (EPRI P-2410-SR).

The EPRI-TAG assumptions provide an easily used and useful formula that approximates a fair payment for avoided variable O&M expenses. As such, it can be easily calculated and monitored using readily available information. Once identified, based on the previous year's actual total O&M cost for coal-fired generation, the incremental avoided energy cost associated with as-available energy is adjusted to compensate for these variable expenses. (See Exhibit #7)

Continued to Sheet No. 8.435

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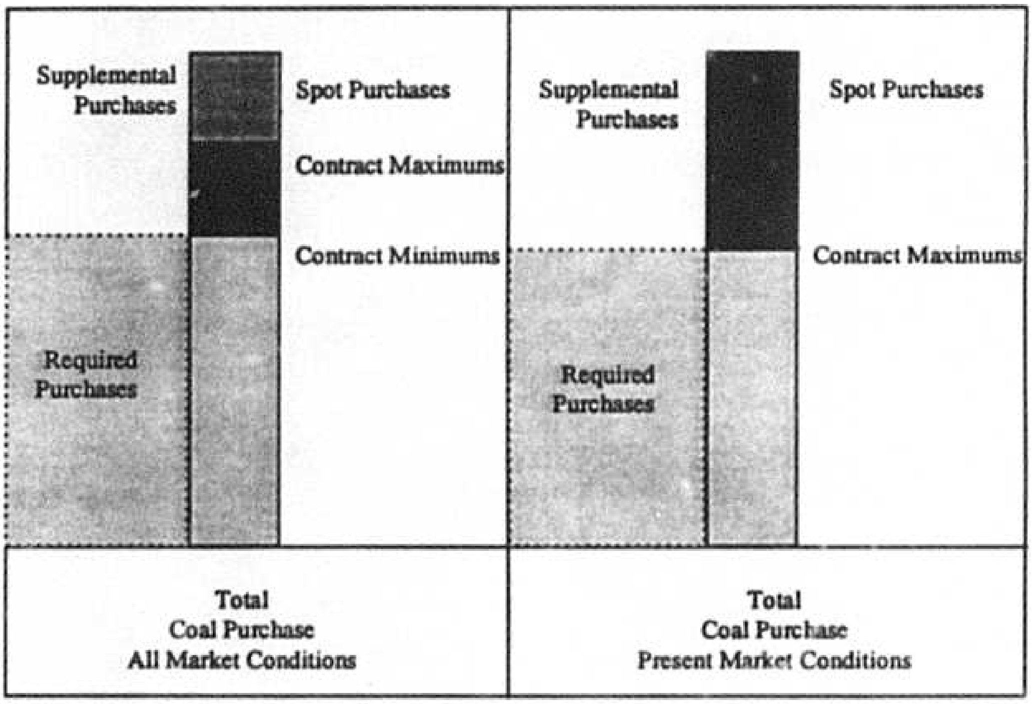
Continued from Sheet No. 8.430

EXHIBIT #1

REQUIRED AND SUPPLEMENTAL COAL PURCHASES UNDER DIFFERENT MARKET CONDITIONS



Continued to Sheet No. 8.440

Continued from Sheet No. 8.435

EXHIBIT #2

SUPPLEMENTAL FUEL COST WORKSHEET

Revised December 1988

UNITS DELIVERED	SUPPLIER C/MMBTU	SUPPLEMENTAL COAL COST $/TON	INCREMENTAL TRANS. COST $/TON	TOTAL $/TON	AUGUST AVERAGE BTU/LB	AUGUST AVERAGE C/MMBTU	AUGUST TONS	SUPPLEMENTAL FUEL COST
Gannon 1-4	A			$45.30				177.50
Gannon 5&6	B			$45.48				176.44
Big Bend 1&2	C			$29.22				123.13
	D			$31.67				
	E			$32.08				
			Average	$29.87				
Big Bend 3[1]	F			$50.55				173.67
			Blended Average	$42.28				
Big Bend 4	G			$41.70				181.31
	H			$37.21				
			Average	$41.11				
#2 Oil	I			$19.41/BBL				334.64

[1] Revised: Big Bend Unit #3 is burning a 60/40 blend of blend/standard coal.

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Continued from Sheet No. 8.440

EXHIBIT #3

Example #1 No off-system purchases, the Company's generation is capable of carrying its native load and firm sales.

Given:

Actual qf Energy = 50 MWs
The Company's Maximum Available Generation = 1560 MWs
Native Load = 1550 MWs
Firm Sales = 10 MWs

First Calculation (WITHOUT qf):

Production Cost at 1560 MWs = $20,275/hour

Second Calculation (WITH qf):

Production Cost at 1510 MWs = $19,500/hour

Third Calculation (qf Rate $/MWH):

Actual Hourly Avoided Energy Cost =
($20,275/hour - $19,500/hour) / (50MW)

or

As-Available Energy Payment Rate (AEPR) = $15.50/MWH

Continued to Sheet No. 8.450

Continued from Sheet No. 8.445

EXHIBIT #4

Example #2a Off-system purchases are not being made. The Company's generation can carry its native load and firm sales only with the qf contribution.

Given:

Actual qf Energy = 50 MWs
The Company's Maximum Available Generation = 1460 MWs
Native Load = 1500 MWs
Firm Sale = 10 MWs

First Calculation:

Production Cost at 1460 MWs = $18,900/hour

Second Calculation:

Production Cost at 1459 MWs = $18,882.50/hour

Third Calculation (qf Rate $/MWH):

Actual Hourly Avoided Energy Cost at 1 MW (system lambda[1]) =
($18,900/hour - $18,882.50/hour) / (1 MW)

or

As-Available Energy Payment Rate (AEPR) = $17.50/MWH

NOTE:

[1] In this example, system lambda is the production cost for the last MW segment to meet the load after dispatching all available generation capacity.

Continued to Sheet No. 8.455

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Continued from Sheet No. 8.450

EXHIBIT #5

Example #2b Off-system purchases are not being made to serve native load and firm sales. Available generation capacity is not fully dispatched. Without the qf's contribution, the Company's native load and firm sales can be carried only with additional power purchases.

Given:

Actual qf Energy = 50 MWs
The Company's Maximum Available Generation = 1530 MWs
The Company's Actual Generation = 1500 MWs
Native Load = 1540 MWs
Firm Sale = 10 MWs

Step 1 (Calculations for First 30 MWs)

First Calculation (Without qf):
Production Cost at 1530 MWs = \$20,590/hour
Second Calculation (With qf):
Production Cost at 1500 MWs = \$20,050/hour
Third Calculation:
Actual Hourly Avoided Energy Cost at 30 MWs =
(\$20,590/hour) - (\$20,050/hour) = \$540/hour

Step 2 (Calculations for Remaining 20 MWs)

First Calculation:
Production Cost at 1530 MWs = \$20,590/hour
Second Calculation:
Production Cost at 1529 MWs = \$20,571.50/hour
Third Calculation:
Actual Hourly Avoided Energy Cost at 1 MW (system lambda[1]) for 20 MWs =
(\$20,590/hour - \$20,571.50/hour) X (20 MWs) = \$370/hour

Step 3 (Calculation of Composite Rate for Total 50 MW Block)

Composite Actual Hourly Avoided Energy Cost of 50 MW Block =
(\$540 + \$370) / 50 MW

or

As-Available Energy Payment Rate (AEPR) = \$18.20/MWH

NOTE:

1 In this example, system lambda is the production cost for the last MW segment to meet the load after dispatching all available generation capacity.

Continued to Sheet No. 8.460

Continued from Sheet No. 8.455

EXHIBIT #6

Example #3 Off-system purchases are being made, the Company's native load and firm sales can be carried only with additional purchase power

Given:

Actual qf Energy = 50 MWs
The Company's Maximum Available Generation = 1500 MWs
The Company's Actual Generation = 1500 MWs
Native Load = 1540 MWs
Firm Sales = 20 MWs
Off-System Purchase[1] = 10 MWs Costing $400/hour

Actual Incremental Hourly Avoided Energy Cost = $400 / 10 MW

or

As-Available Energy Payment Rate (AEPR) = $40/hour

NOTE:

[1] Off-System Purchase shall be the highest cost purchased energy block bought during the hour for native load.

Continued to Sheet No. 8.465

Continued from Sheet No. 8.460

EXHIBIT #7

The calculation of the variable O&M cost adjustment factor associated with as available energy is made once each year, based on the previous year's actual total O&M cost for coal-fired generation, in accordance with the procedure found in the EPRI-TAG Special Report dated May 1982, (EPRI P-2410-SR). The formula assumes the fixed portion of total annual O&M dollars equals the capacity factor (%) times the total annual O&M dollars. The variable portion is (1 - capacity factor) times the total annual O&M dollars. The capacity factor is based on the total period hours less those hours the units are off line due to economic dispatch for low load periods. Continuing the logic further, the adjustment factor to be added to the avoided energy cost equals the variable rate as determined annually and applied in the form of an hourly adjustment to the actual incremental hourly avoided energy cost.

Example Given:	1983 TEC Coal Generation	MW	
1) Big Bend	1	367	
	2	362	
	3	375	
	3	10	upgrade
Gannon	5	218	
	6	351	
	4	169	conversion

MW available per unit from net generation listed in the System Data Book for the same time period:

2) Coal Generation 1983 = 10,493,266 MWH

3) O&M for coal 1983 = $35,320,252

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Continued from Sheet No. 8.465

EXHIBIT #7 - continued

ESTIMATED
1983 VARIABLE O&M RATE CALCULATION

		(MW)		(Hours)	(MWH)
Big Bend	1	367	@	8760	3,214,920
	2	362	@	8760	3,171,120
	3	375	@	8760	3,285,000
Upgrade	3	10	@	2208	22,080
Gannon	5	218	@	8760	1,909,680
	6	351	@	8760	3,074,760
Conversion to Coal	4	169	@	2208	373,152
TOTAL					15,050,712
Generation (1983 Actual for Coal)					10,493,266

Average Coal Capacity Factor $= \frac{10,493,266}{15,050,712} \times 100\%$

$= 69.72\%$

Total O&M for Coal = \$35,320,252

Variable Component = \$35,320,252 X (1 - .6972)

= \$10,694,972

Estimated Variable O&M Cost[1] $= \frac{10,694,772}{10,493,266} = \$1.02/\text{MWH}$

1 Was added to 1984's actual incremental hourly avoided energy cost, after approval by the FPSC.

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STANDARD OFFER CONTRACT FOR THE PURCHASE OF FIRM CAPACITY AND ENERGY FROM A SMALL QUALIFYING FACILITY OR A MUNICIPAL SOLID WASTE FACILITY

This agreement is made and entered into this __________ day of ______________, ______by and between __________________, hereinafter referred to as the "QF" and Tampa Electric Company, a private utility corporation organized under the laws of the State of Florida, hereinafter referred to as the "Company". The QF and the Company shall collectively be referred to herein as the "Parties."

WITNESSETH:

WHEREAS, QF desires to sell, and the Company desires to purchase, Firm Capacity and Energy to be generated by small Qualifying Facilities or by Municipal Solid Waste Facilities (unless specifically referred to, small "Qualifying Facilities" and "Municipal Solid Waste Facilities" will jointly be referred to as "QFs") consistent with Florida Public Service Commission (FPSC) Rules 25-17.080 through 25-17.091, Florida Administrative Code (F.A.C.); of Order No. 23625 issued October 16, 1990, Docket No. 891049-EU; and the Company's Rate Schedule COG-2; and

WHEREAS, QF has signed an Interconnection Agreement with the utility in whose service territory the QF's generating facility is located, attached hereto as Appendix A; and

WHEREAS, the FPSC has approved the following Standard Offer Contract for the purchase of Firm Capacity and Energy from QFs;

NOW, THEREFORE, for mutual consideration the Parties agree as follows:

1. <u>Facilities</u>

a. <u>Designated Avoided Unit:</u> The Company has identified a 180 megawatt (MW) (Winter Rating) natural gas fired Combustion Turbine generating unit with an in-service date of January 1, 2003, as its Designated Avoided Unit. The avoided unit will be fully subscribed at 180 MW of committed Firm Capacity and Energy. The Company's Standard Offer Contract is scheduled to expire on December 31, 2000, in order to allow adequate lead-time for the Company to construct the Avoided Unit.

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Continued from Sheet No. 8.475

b. **Qualifying Facility**

i. On or before the in-service date of the Designated Avoided Unit, the QF shall be a cogeneration facility or small power production facility that is a Qualifying Facility under Subpart B of Subchapter K, Part 292 of Chapter I, Title 18, Code of Federal Regulations (C.F.R.), promulgated by the Federal Energy Regulatory Commission (FERC), as the same may be amended from time to time. Such a facility must be "new capacity" pursuant to the Public Utilities Regulatory Policies Act of 1978 (PURPA), construction of which began on or after November 9, 1978. On or before the in-service date of the Designated Avoided Unit and at all times throughout the remaining term of this Agreement, such QF shall maintain its status as a QF as defined herein and as certified by the FERC. By the end of the first quarter of each calendar year, the QF shall furnish the Company a notarized certificate by an officer of the QF certifying that the Facility has continuously maintained qualifying status on a calendar year basis since the commencement of the term of this Agreement.

ii. QF contemplates installing and operating a __________ MVA generator located at ____________________________________ which shall be and remain the specific site of the QF throughout the term of this Agreement. The generator is designed to produce a maximum of ______ megawatts (MW) of electric power designed, operated and controlled to provide reactive power requirements from 0.95 lagging to 0.95 leading power factor at the point of interconnection with the Company, such equipment being hereinafter referred to as the "Facility".

c. **Evaluation Procedure:** Each eligible Standard Offer Contract received by the Company will be evaluated as to its technical reliability, viability and financial stability, as well as other relevant information, in accordance with FPSC Rule 25-17.0832, F.A.C., and the Company's Procedure for Processing Standard Offer Contracts as defined in Rate Schedule COG-2 (COG-2). The criteria and procedure used to evaluate Standard Offer Contracts are attached to the Standard Offer Contract as Appendix A.

2. **Term of the Agreement:** This Agreement shall begin immediately upon its execution by the parties and shall end at 12:01 a.m., _____________, 20___.

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Continued from Sheet No. 8.480

Notwithstanding the foregoing if the QF does not meet the Construction Commencement Date or its Commercial In-Service Date as defined in COG-2 in accordance with the terms and conditions of this Agreement, then this Agreement shall be rendered of no force and effect. This Agreement shall consist of the Company's Rate Schedule COG-2 and all attached appendices thereto attached hereto and made a part hereof as Appendix B. For the purpose of this Agreement, "Construction Commencement Date" shall mean the date on which QF's on site activity is coordinated and continuous and active construction efforts are undertaken and ongoing relative to the actual construction of major project features other than site preparation work, which shall occur no later than January 1, 2001.

3. Sale of Electricity by QF. The Company agrees to purchase all of the Actual Contracted Capacity and associated energy generated at the Facility and transmitted to the Company by the QF pursuant to this tariff, less the amount of electric power consumed by the QF's generator auxiliaries. The Facility shall be fully dispatchable in the manner set forth in COG-2, Appendix C. The purchase and sale of electricity pursuant to this Agreement shall be construed as a: ( ) Net Billing Arrangement or: ( ) Simultaneous Purchase and Sale Arrangement. Once made, the selection of a billing methodology may only be changed in accordance with FPSC Rule 25-17.082, F.A.C., and shall be in accordance with the following provisions:

a. upon at least thirty (30) days advance written notice to the Company; and

b. upon the installation by the Company of any additional metering equipment reasonably required to effect the change in billing methodology and upon payment by the QF for such metering equipment and its installation; and

c. upon completion and approval by the Company of any alterations to the interconnection reasonably required to effect the change in billing methodology and upon payment by the QF for such alterations.

Continued to Sheet No. 8.490

Continued from Sheet No. 8.485

The parties agree that QF's obligation to generate and sell electricity from the Facility is subject to both scheduled and unscheduled outages of the Facility. Neither party shall be required to compensate the other party for electrical energy which from time to time may not be generated and sold by QF or received and purchased by the Company as a result of such scheduled and unscheduled outages. The parties agree to use best efforts to minimize the duration of any scheduled or unscheduled outages which from time to time may interrupt the purchase and sale of electricity under this Agreement.

4. Payment for Electricity Produced by QF:

a. Energy: The Company agrees to pay the QF for energy produced by the Facility and delivered to the Company in accordance with the rates and procedures contained in Rate Schedule COG-2 attached hereto as Appendix B. Prior to January 1, 2003, QF will receive energy payments based on the Company's actual avoided energy costs. Starting January 1, 2003, to the extent that the Designated Avoided Unit would have been operated had it been installed by the Company, the QF's energy payments will be based on the Company's Designated Avoided Unit's energy costs, otherwise QF's energy payment will be based on the Company's actual avoided energy costs as defined in COG-2, Appendix D, such determination to be made hourly.

b. Capacity:

i. Anticipated Contracted Capacity: QF intends to sell _______ MW of Firm Capacity and achieve commercial in-service status, beginning on or before January 1, 2003, the in-service date of the Designated Avoided Unit.

After initial Facility testing and on one occasion only, QF may finalize, increase or decrease its Anticipated Contracted Capacity by no more than 10% of the Anticipated Contracted Capacity and specify when capacity payments are to begin, by completing Paragraph 4.b.ii at a later time. However, QF must complete Paragraph 4.b.ii. by January 1, 2003 in order to be entitled to any capacity payments pursuant to this Agreement.

Continued to Sheet No. 8.495

Continued from Sheet No. 8.490

ii. **Actual Contracted Capacity:** The Firm Capacity committed by QF for purposes of this Agreement is ________ MW. To the extent that the Company pays for but declines to take all of the Actual Contracted Capacity (Non-dispatched Capacity) in any given hour, such Non-dispatched Capacity and Associated Energy shall not be sold by the QF or otherwise used in any way or disposed of without the Company's prior written consent. QF elects to receive, and the Company agrees to commence calculating, capacity payments in accordance with this Agreement starting with the first Monthly Period following __________, 20____.

iii. **Firm Capacity Payment Options:** The following options are available to the QF for payment for Firm Capacity delivered by the QF:

1) Value of Deferral Capacity Payments;
2) Early Capacity Payments;
3) Levelized Capacity Payments;
4) Early Levelized Capacity Payments.

QF chooses to receive firm capacity payments from the Company under Option: ____________. Each of these options is further defined in and subject to the provisions of the Company's Rate Schedule COG-2, Appendix A.

At the end of each Monthly Period, beginning with the Monthly Period specified in Paragraph 4.b.ii, the Company will calculate QF's Monthly Availability and Capacity Factor. During the term of this Agreement, if the QF's Monthly Availability and Capacity Factor equals or exceeds the Minimum Performance Standards (MPS), attached hereto as Appendix C in Rate Schedule COG-2, then the Company agrees to pay QF a Monthly Capacity Payment as calculated in the Section entitles Basis for Monthly Capacity Payment Calculation, Paragraph 5 of COG-2, Appendix C.

The capacity payment for a given month will be added to the energy payment for such month and tendered by the Company to QF as a single payment as promptly as possible, normally by the twentieth business day following the day the meter is read.

Continued to Sheet No. 8.500

Continued from Sheet No. 8.495

iv. **Security Guarantees:** The Company requires certain security deposits to ensure the completion of construction and performance under this Agreement in order to protect its ratepayers in the event the QF fails to deliver Firm Capacity and Energy in the amount and times specified in this Agreement, which shall be in form and substance as described herein. Such security may be refunded in the manner described in Paragraphs 4.b.iv.(1) and 4.b.iv.(2). Pursuant to FPSC Rule 25-17.091, F.A.C., a utility may not require security guarantees from a municipal solid waste facility as required in FPSC Rule 25-17.0832(2)(d) and (3)(f)(1), F.A.C. However, at its option, a municipal solid waste facility may provide such risk-related guarantees.

(1) **Completion Security:** The QF shall pay to the Company a security deposit equal to $10.00 per kilowatt ($10.00/kW) of Anticipated Contracted Capacity as described herein as security for QF's completion of the Facility by the in-service date of the Designated Avoided Unit. Such security will be required within 60 days of contract execution. Such security shall be in the form of cash deposited in an interest bearing escrow account mutually acceptable to the Company and the QF; an unconditional and irrevocable direct pay letter of credit in form and substance satisfactory to the Company; or a performance bond in form and substance satisfactory to the Company. The form of security required will be in the sole discretion of the Company and will be in such form as to allow the Company immediate access to the funds in the event that the QF fails to complete the construction and achieve commercial in-service status by the in-service date of the Designated Avoided Unit.

If the QF achieves commercial in-service status by the in-service date of the Designated Avoided Unit then the entire deposit and any interest therein, if applicable, shall be refunded to the QF upon payment by the QF of the Performance Security as required in Paragraph 4.b.iv.(2).

Continued to Sheet No. 8.505

Continued from Sheet No. 8.500

If the QF's Commercial In-Service Date is delayed beyond the in-service date of the Designated Avoided Unit, the Company may, upon the request of the QF, extend such date for a period not to exceed five (5) months, in which case the Company shall be entitled to retain or draw down on an amount equal to 20% of the original deposit amount for each month (or portion thereof) that the completion of the project is delayed. If the QF's Commercial In-Service Date is delayed and an extension has not been granted or such date is delayed beyond the extended completion date, then the Company shall retain all of the deposit and terminate this Agreement.

(2) <u>Performance Security:</u> Within sixty (60) days after the later of the QF's Commercial In-Service Date or the in-service date of the Designated Avoided Unit, the QF shall pay the Company a deposit in the amount of $10.00/kW of Actual Contracted Capacity as security for QF's performance under this Agreement. Such security deposit shall be provided in the same manner as the completion security deposit as described in Paragraph 4.b.iv.(1). Such performance security shall be retained by the Company for twelve (12) months from the later of the QF's Commercial In-Service Date or the in-service date of the Designated Avoided Unit.

If, at the end of the twelve month period so described, the QF's 12-month average of each month's numerical value for both the Monthly Availability Factor and the Monthly Capacity Factor meet the Minimum Performance Standards (MPS) as set forth in Rate Schedule COG-2, then QF shall be entitled to a refund of such deposit. However, if at the end of the first twelve month period, the QF's 12-month average of each month's numerical value for both the Monthly Availability Factor and the Monthly Capacity Factor fail to meet the MPS, then the Company shall be entitled to retain or draw down 50% of such deposit and retain the remainder of the security for an additional twelve month period.

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Continued from Sheet No. 8.505

If, at the end of the twenty fourth month, the QF's 12-month average of each month's numerical value for both the Monthly Availability Factor and the Monthly Capacity Factor again fail to achieve the MPS, for the most recent 12-month period, then the Company shall be entitled to retain the remainder of the security and to terminate the contract. However, if at the end of the twenty fourth month, the QF's 12-month average of each month's numerical value for both the Monthly Availability Factor and the Monthly Capacity Factor meet the MPS, for the most recent 12-month period, then the QF shall be entitled to a refund of the remaining deposit.

For the purpose of this calculation, the 12-month average of a parameter shall be defined to equal the sum of each month's average numerical value for that parameter, for the most recent 12-month period, divided by twelve (12).

(3) Liquidated Damages: The parties hereto agree that the Company would be substantially damaged in amounts that would be difficult or impossible to ascertain in the event that QF fails to complete the Facility by the in-service date of the Designated Avoided Unit or to provide a Facility which meets the MPS. In the event that the Company terminates this Agreement for the QF's failure to achieve commercial in-service status by the in-service date of the Designated Avoided Unit or achieve the MPS once in service, the Company may retain all of the completion or performance security as liquidated damages, not as penalty, in lieu of actual damages and the QF hereby waives any defenses as to the validity of any such liquidated damages. In the event the QF defaults, it forfeits the aforesaid Completion or Performance Security. In addition thereto, the Company shall be entitled to pursue such equitable remedies against the QF as may be available.

5. Electricity Production Schedule: During the term of this Agreement, the QF agrees to the following:

Continued to Sheet No. 8.515

Continued from Sheet No. 8.510

a. Qf shall provide the Company in writing prior to April 1 of each calendar year an estimate of the amount of electricity to be generated by the QF and delivered to the Company for each month of the following calendar year, including the time, duration and magnitude of any planned outages or reductions in capacity.

b. By July 1 of each calendar year, the Company shall notify the QF in writing whether the requested scheduled maintenance period(s) are acceptable. If the Company cannot accept any of the requested period(s), the Company shall advise the QF of the time period closest to the requested period(s) when the outage(s) can be scheduled. QF shall only schedule outages during periods approved by the Company and such approval shall not be unreasonably withheld. Once the schedule has been established and approved, either party requesting a subsequent change in such schedule, except when such event is due to Force Majeure, must obtain approval for such change from the other party. Such approval shall not be unreasonably withheld or delayed.

c. During the term of this Agreement, the QF shall employ qualified personnel for managing, operating and maintaining the Facility and for coordinating such with the Company. The QF shall ensure that operating personnel are on duty at all times, twenty-four hours a calendar day and seven calendar days a week. Additionally, during the term of this Agreement, the QF shall operate and maintain the Facility in such a manner as to ensure compliance with its obligations hereunder.

d. The Company shall not be obligated to purchase and may require curtailed or reduced deliveries of energy, to the extent necessary to maintain the reliability and integrity of any part of the Company's system, or if the Company determines that a failure to do so is likely to endanger life or property, or is likely to result in significant disruption of electric service to the Company's Customers. The Company shall give QF prior notice, if practicable, of its intent to refuse, curtail or reduce the Company's acceptance of energy pursuant to this Section and will act to minimize the frequency and duration of such occurrences.

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e. The Company shall not be required to accept or purchase energy during any period in which, due to operational circumstances, acceptance or purchase of such energy would result in the Company's incurring costs greater than those which it would incur by generating an equal additional amount of energy with its own resources. The Company shall give the QF as much prior notice as practicable of its intent not to accept energy pursuant to this Section.

f. Qf shall promptly update the yearly generation schedule and maintenance schedule as and when any changes may be determined necessary;

g. Qf shall comply with reasonable requirements of the Company regarding day-to-day or hour-by-hour communications between the parties relative to the performance of this Agreement.

6. QF's Obligation if QF Receives Early, Levelized, or Early Levelized Capacity Payments: The parties recognize that Rule 25-17.0832, F. A. C., may require the repayment by the QF of all one portion of any payments made to it pursuant to Option 2, 3, or 4 of Section 4.2.3 if the QF fails to perform pursuant to the terms and conditions of this Agreement. To ensure that the QF will satisfy its obligation to make any such repayments, the following provisions will apply:

The Company shall establish a Repayment Account to accrue the sum of the capacity payments that may have to be repaid by the QF to the Company. Amounts shall be added to the Repayment Account each month through December 2002, in the amount of the Company's payments to the QF for capacity delivered prior to January 1, 2003.

Beginning on January 1, 2003, the difference between the capacity payment made to the QF and the "normal" capacity payment calculated pursuant to Option 1 in COG-2 will also be added each month to the Repayment Account, so long as the payment made to the QF is greater than the monthly payment the QF would have received if it had selected Option 1 in Paragraph 4.b.iii. The annual balance in the Repayment Account shall accrue interest at an annual rate of 9.37%.

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Also beginning on January 1, 2003, at such time that the monthly capacity payment made to the QF, pursuant to the Capacity Payment Option selected, is less than the "normal" monthly capacity payment in Option 1 in COG-2, there shall be debited from the Repayment Account an Early Payment Offset Amount to reduce the balance in the Repayment Account. Such Early Payment Offset Amount shall be equal to the amount which the Company would have paid for capacity in that month if capacity payments had been calculated pursuant to Option 1 in COG-2 and the QF had elected to begin receiving capacity payments on January 1, 2003, minus the monthly capacity payment the Company makes to the QF (assuming the MPS are met or exceeded), pursuant to the Capacity Payment Option chosen by the QF in Paragraph 4.b.iii.

QF shall owe the Company and be liable for the current balance in the Repayment Account. The Company agrees to notify the QF monthly as to the current Repayment Account balance.

In the event of default by the QF, the total Repayment Account balance shall become due and payable within twenty (20) business days of receipt of written notice, as reimbursement for the early capacity payments made to the QF by the Company. The QF's obligation to reimburse the Company in the amount of the balance in the Repayment Account shall survive the termination of the QF's Standard Offer Contract with the Company. Such reimbursement shall not be construed to constitute liquidated damages and shall in no way limit the right of the Company to pursue all its remedies at law or in equity against the QF.

Prior to receipt of Early Levelized or Early-Levelized Capacity Payments, the QF shall secure its obligation to repay any balance in the Repayment Account in the event QF defaults pursuant to this Agreement. Such security shall be in the form of cash deposited in an interest bearing escrow account mutually acceptable to the Company and the QF; an unconditional and irrevocable direct pay letter of credit in form and substance satisfactory to the Company; or a performance bond in form and substance satisfactory to the Company. The form of security required will be in the sole discretion of the Company and will be in such form as to allow the Company immediate access to the funds in the event of default by the QF. Florida Statute 377.709(4) requires the local government to refund early capacity payments should a Municipal Solid Waste Facility owned, operated by or on the behalf of a local government be abandoned, closed down or rendered illegal. Therefore a utility may not require risk-related guarantees from a Municipal Solid Waste Facility as required in FPSC Rule 25-17.0832(2)(c) and (3)(e)(8), F.A.C. However, at its option, a Municipal Solid Waste Facility may provide such risk-related guarantees.

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7. **Nonperformance Provisions:** QF shall not receive a capacity payment during any month in which the QF fails to meet the MPS for Monthly Availability and Monthly Capacity Factor of the Company's Designated Avoided Unit as defined in Appendix C in COG-2. In addition, if for any month starting January 1, 2003, the QF fails to achieve the MPS and the monthly capacity payment that would have been made to the QF pursuant to the capacity payment option selected is less than the "normal" monthly capacity payment had the QF selected Option 1, then the QF shall be liable for and shall pay the Company an amount equal to the Early Payment Offset Amount for the month; provided, however, that such calculation shall assume that the QF satisfied the MPS. Any payments thus required of QF shall be separately invoiced by the Company to QF after each month for which such payment is due and shall be paid by QF within twenty (20) business days after receipt of such invoice by QF. Such payment shall be debited from the Capacity Account as an Early Payment Offset Amount provided that any such payment will not exceed the current balance in the Capacity Account.

8. **Default**

a. **Mandatory Default:** QF shall be in default under this Agreement if:

i. QF voluntarily declares bankruptcy; or

ii. QF fails to achieve, on both accounts, a minimum Monthly Availability Factor of 25% and fails to achieve a minimum Monthly Capacity Factor of 25%, during the same month, for 12 consecutive months starting January 1, 2003; or

iii. QF fails to maintain its status as a QF as required herein; or

iv. QF fails to perform in accordance with Section 4.b.iv.(2).

b. **Optional Default:** The Company may declare the QF to be in default:

i. If at any time prior to January 1, 2003, and after Monthly Capacity Payments have begun, the Company has sufficient reason to believe that the QF is unable to deliver its Actual Contracted Capacity; or

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iii. after Monthly Capacity Payments have begun, the QF fails each month, for 24 consecutive months, to meet the MPS; or

iv. QF refuses, is unable or anticipatorily breaches its obligation to deliver its Actual Contracted Capacity after January 1, 2003.

c. Default Remedy: In the event of default by the QF, the total Repayment Account balance shall become due and payable within twenty (20) business days of receipt of written notice, as reimbursement for the early capacity payments made to the QF by the Company. The QF's obligation to reimburse the Company in the amount of the balance in the Repayment Account shall survive the termination of the QF's Standard Offer Contract with the Company. Such reimbursement shall not be construed to constitute liquidated damages and shall in no way limit the right of the Company to pursue all its remedies at law or in equity against the QF.

9. General Provisions:

a. Permits: QF hereby agrees to seek to obtain any and all governmental permits, certifications, or other authority QF is required to obtain as a prerequisite to engaging in the activities provided for in this Agreement. The Company hereby agrees to seek to obtain at QF's expense any and all governmental permits, certifications or other authority the Company is required to obtain as a prerequisite to engaging in the activities provided for in this Agreement.

b. Indemnification: The Company and QF shall each be responsible for its own facilities. The Company and the QF shall each be responsible for its own facilities in ensuring adequate safeguards for other Company Customers, the Company and QF personnel and equipment, and for the protection of its own generating system. The Company and the QF shall each indemnify and save the other harmless from any and all claims, demands, costs, or expense for loss, damage, or injury to persons or property of the other caused by, arising out of, or resulting from:

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i. any act or omission by a party or that party's contractors, agents, servants and employees in connection with the installation or operation of that party's generation system or the operation thereof in connection with the other party's system; and

ii. any defect in, failure of, or fault related to a party's generation system; and

iii. the negligence of a party or negligence of that party's contractors, agents servants and employees; and

iv. any other event or act that is the result of, or proximately caused by a party.

For the purpose of this subsection, the term party shall mean either the Company or QF, as the case may be.

c. Insurance: The QF shall deliver to the Company, at least fifteen (15) days prior to the start of any interconnection work, a certificate of insurance certifying the QF's coverage under a liability insurance policy issued by a reputable insurance company authorized to do business in the state of Florida naming the QF as named insured, and the Company as an additional named insured, which policy shall contain a broad form contractual endorsement specifically covering the liabilities accepted under this Agreement arising out of the interconnection to the QF, or caused by operation of any of the QF's equipment or by the QF's failure to maintain its equipment in satisfactory and safe operating condition.

i. In subsequent years, a certificate of insurance renewal must be provided annually to the Company indicating the QF's continued coverage as described herein. Renewal certification shall be sent to:

Tampa Electric Company
c/o Director of Risk Management
P. O. Box 111
Tampa, FL 33601

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ii. The policy providing such coverage shall provide public liability insurance, including coverage for personal injury, death and property damage, in an amount not less than $1,000,000 for each occurrence; provided however, if QF has insurance with limits greater than the minimum limits required herein, the QF shall set any amount higher than the minimum limits required by the Company to satisfy the insurance requirements of this Agreement.

iii. The above required policy shall be endorsed with a provision whereby the insurance company to notify the Company thirty (30) days prior to the effective date of any cancellation or material change in said policy.

iv. QF shall pay all premiums and other charges due on said policy and keep said policy in force during the entire period of interconnection with the Company.

d. Force Majeure: If either party shall be unable, by reason of force majeure, to carry out its obligations under this Agreement, either wholly or in part, the party so failing shall give written notice and full particulars of such cause or causes to the other party as soon as possible after the occurrence of any such cause; and such obligations shall be suspended during the continuance of such hindrance, which, however, shall be remedied with all possible dispatch; and the obligations, terms and conditions of this Agreement shall be extended for such period as may be necessary for the purpose of making good any suspension so caused. The term "force majeure" shall be taken to mean all acts of God, strikes, lockouts or other industrial disturbances at the manufacturing site of the major equipment components or the construction site, wars, blockades, insurrections, riots, arrests and restraints of rules and people, explosions, fires, floods, lightning, wind, perils of the sea, accidents to equipment or machinery or similar occurrences; provided, however that no occurrence may be claimed to be a force majeure occurrence if it is caused by the negligence or lack of due diligence on the part of the party attempting to make such claim and specifically does not include interruption in fuel supply. QF agrees to pay the costs necessary to reactivate the Facility and/or the interconnection with the Company's system if the same are rendered inoperable due to actions of QF, its agents, or force majeure events affecting the Facility or the interconnection with the Company.

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The Company agrees to reactivate at its own cost the interconnection with the Facility in circumstances where any interruptions to such interconnections are caused by the Company or its agents.

e. <u>Conditions Precedent:</u> Notwithstanding any other provisions of this Agreement including the provisions of Paragraph 9.d, the Company shall have the right to terminate this Agreement by notice to the QF, without cause, liability or obligation, if one or more of the following conditions, after reasonable effort by QF, shall not have been or cannot be satisfied in the Company's good faith judgement, and in the time periods described below. The Company in its sole discretion may extend QF's time for satisfying these conditions if one or more of the events described below is pending as of such date and it is reasonable to expect that such event will be accomplished within sixty (60) days:

i. QF meets the Construction Commencement Date;

ii. On or before the QF's Commercial In-Service Date: QF secures certification of the facility as a QF as defined herein and as certified by the FERC;

iii. On or before January 1, 2001: QF secures any and all land use and zoning approvals reasonably necessary to obtain construction financing and authorizes the commencement of construction of the facility on a basis not substantially adverse to the Company;

iv. On or before January 1, 2001: QF has secured all other environmental and construction permits and other governmental approvals reasonably necessary to obtain construction financing and to begin construction of the facility on a basis not substantially adverse to the Company;

v. On or before January 1, 2001: QF achieves closing of financing for construction of the facility;

vi. On or before January 1, 2002: QF provides to the Company written evidence of the rights to adequate fuel supply for the facility in a form satisfactory to the Company;

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vii. Within 6 months after the effective date of this Agreement: QF provides evidence in writing in a form satisfactory to the Company indicating and substantiating the ownership of or the right to use the real property as the specific site upon which the facility will be located; and

viii. On or before January 1, 2001: Sufficient information satisfactory to the Company has been provided to the Company describing the technical capability and experience of the Facility's technology, including its environmental performance of the facility.

f. **Assignment:** The QF shall have the right to assign its benefits under this Agreement, but the QF shall not have the right to assign its obligations and duties without the Company's prior written consent and such consent shall not be unreasonably withheld.

g. **Disclaimer:** In executing this Agreement, the Company does not, nor should it be construed, to extend its credit or financial support for the benefit of any third parties lending money to or having other transactions with QF or any assignee of this Agreement.

h. **Notification:** For purposes of making any and all non-emergency oral and written notices, payments or the like required under the provisions of this Agreement, the parties designate the following to be notified or to whom payment shall be sent until such time as either party furnishes the other party written instructions changing such designate.

For: QF	For: Tampa Electric Company manager-Industrial/Governmental Marketing & Sales Tampa Electric Company P.O. Box 111 Tampa, Florida 33601

i. **Applicable Law:** This Agreement shall be governed by and construed and enforced in accordance with the laws, rules, and regulations of the State of Florida and the Company's Tariff as may be modified, changed, or amended from time to time.

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j. Severability: If any part of this Agreement, for any reason, be declared invalid, or unenforceable by a court or public authority of appropriate jurisdiction, then such decision shall not affect the validity of the remainder of the Agreement, which remainder shall remain in force and effect as if this Agreement had been executed without the invalid or unenforceable portion.

k. Complete Agreement and Amendments: All previous communications or agreements between the parties, whether verbal or written, with reference to the subject matter of this Agreement are hereby abrogated. No amendment or modification to this Agreement shall be binding unless it shall be set forth in writing and duly executed by both parties to this Agreement.

l. Incorporation of Rate Schedule: The parties agree that this Agreement shall be subject to all of the provisions contained in the Company's published Rate Schedule COG-2 as approved and on file with the FPSC. The Rate Schedule is incorporated herein by reference.

m. Survival of Agreement: This Agreement, as it may be amended from time to time, shall be binding and inure to the benefit of the Parties' respective successors-in-interest and legal representatives.

IN WITNESS WHEREOF, QF and the Company have executed this Agreement the day and year first above written.

WITNESSES: **Qualifying Facility**

_____________________ **By:**_____________________

_____________________ **Its:**_____________________

WITNESSES: **Tampa Electric Company**

_____________________ **By:**_____________________

_____________________ **Its:**_____________________

EVALUATION PROCEDURE
FOR STANDARD OFFER CONTRACTS
APPENDIX A
STANDARD OFFER CONTRACT

The Company believes that Standard Offer Contracts should be evaluated and then accepted based on meeting specific criteria rather than ranking them entirely on the timing of their receipt. This Evaluation Procedure will insure the acceptance of Standard Offer Contracts that meet the Company's needs and are in the best interest of Customers.

Each eligible Standard Offer Contract received by the Company will be evaluated as to its technical reliability, viability and financial stability, as well as other relevant information, in accordance with FPSC Rule 25-17.0832, F.A.C., and the Company's Procedure for Processing Standard Offer Contracts as defined in Rate Schedule COG-2.

QFs submitting Standard Offer Contracts to the Company should, at the same time, provide considerable detail regarding their projects by submitting specific information for each of the following evaluation criteria. Failure to provide this information may result in a determination of non-viability by the Company. Each eligible Standard Offer Contract received will be evaluated based upon the information provided in response to the following list of parameters:

EVALUATION PARAMETERS:

1. **Technical Viability:**

   a. What is the technology being proposed?

   b. Has the technology been demonstrated or commercially applied? Please explain.

   c. Has the QF previously utilized this technology elsewhere?

Construction:	Please provide performance record and experience with project technology.
Operations:	Please provide operator's experience and performance record in comparable facilities.

   d. Has a project feasibility study been conducted by an Independent Engineer to assess project technology and its potential effect on the project's financial results? Please explain.

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e. What thermal efficiency must be maintained by the unit(s) in order to retain status as a QF?

2. <u>Fuel Supply:</u>

a. What is the primary fuel type?

b. What are the annual fuel requirements? (primary/alternate)

c. Has primary fuel supply been secured? Is the fuel supply domestic, cross-border or foreign? Is the term of the fuel supply agreement equal to the debt term?

d. Is an alternate fuel required?

e. Has an alternate fuel supply been secured?

f. Have transportation arrangements for both primary and alternate fuels been secured (firm/interruptible, provide detail)?

g. Are the pricing terms of the fuel supply agreement(s) directly tied to the corresponding energy payments?

3. <u>Reliability:</u>

a. Dispatchability: Will the facility be dispatched on request or will it be base loaded? Please explain.

b. QF Status: Has project obtained FERC certification as a QF? Has application been made for FERC certification? Please explain.

c. Operations and Maintenance: Who will provide O & M for the facility: (a) developer; or (b) third party?

d. Steam Host:
- Please explain the importance of the thermal energy (steam), taken by the steam host, to the overall operations of the steam host.
- Are there adequate alternative candidates in close proximity to the facility that could serve as a potential steam host replacement?
- What is the minimum "steam take" necessary for the project to maintain QF status?

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- Has a steam host been secured?
- Is the steam host already in existence?
- Is it a new steam host? (Is it identifiable?)
- What are the steam host's operating hours?
- Is steam host's business cycle or thermal requirements seasonal? If so explain.

e. Permits: What permits or licenses will be required for the project? Have the necessary permits or licenses been secured? What specific environmental considerations must the project meet?

f. Construction Schedule: Has a construction schedule including milestones been formulated? Please provide detail.

g. Site Control: Has the project's location been identified? Has the site been secured? Does the site require specific environmental considerations, i.e. wetlands, etc.? Please explain.

4. <u>Developer's Qualifications:</u>

a. Project's Financial Stability: Does the project Developer's credit rating qualify for Investment-Grade Status? Please provide detail.

b. Developer's Experience: Has developer any projects in operation? Has developer any other projects under construction? Please provide details for each previous IPP or QF projects undertaken by the Developer, including but not limited to:

- Financial arrangements and Institutions,
- Fuel contracts,
- Scheduling/project control information,
- Regulatory treatment,
- Ownership structure, i.e. partnership, limited partnership, contract buy-outs, etc., and
- Total operating experience and performance.

c. Project Financing: Has project financing been secured? Will ownership equity in project be 15% or greater? Will the project be structured as a nonrecourse financing project? Please provide detail.

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d. Working Capital: Has long-term working capital been secured? Are sufficient reserves available to fund six-months of debt service? Are sufficient funds available to cover six-months of O&M expenses? Does project have warranties for key operating equipment during the first year of operations? Please provide detail.

EVALUATION CRITERIA AND SCORING: The QF will receive a score of 2, 1, or 0 in each of the categories listed below. A score of "2" indicates that the project fully meets or exceeds the specific requirements that the Company has established for that parameter. A score of "1" indicates that the project may only marginally meet some portion of the established requirements. And, a score of "0" indicates that a sufficient number of the established requirements have not been satisfactorily met.

The Company will accept Standard Offer Contracts on the basis of the information provided in response to the evaluation criteria and upon its judgement of other relevant factors. The Standard Offer Contract receiving the most points and which has convincingly demonstrated that the project is financially and technically viable and that the committed capacity would be available by the date specified in the Standard Offer Contract will be accepted first. The Company will continue to accept successive Standard Offer Contracts until further acceptance of a Standard Offer Contract would cause the subscription limit to be exceeded. Points for each category will be given as follows:

Technical Viability

2 Technology has been proven through commercial application.
1 Technology has been satisfactorily demonstrated in a pilot project (more than two years).
0 Technology has not been satisfactorily demonstrated or proven.

Fuel Availability

2 Primary fuel supply has been secured.
1 Letter of intent to supply primary fuel is in-hand.
0 Primary fuel supply is unsecured.

Fuel Diversity

2 An alternate fuel supply has been secured.
1 Letter of intent to supply alternate fuel is in-hand.
0 Alternate fuel supply is unsecured.

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Fuel Transportation

2 Transportation agreement for both primary and alternate fuels has been secured.
1 Transportation agreement appears likely.
0 Transportation agreement is uncertain.

Dispatchability

2 Unit(s) is completely dispatchable or base loaded.
1 Unit(s) is somewhat dispatchable.
0 Unit(s) is not dispatchable.

QF Status

2 QF status has been certified by FERC or the FPSC and has been provided.
1 Application for FERC Certification has been made and has been provided.
0 Application for FERC Certification has not been made.

Operations and Maintenance

2 A long-term O&M agreement (five years or more) has been reached.
1 A long-term O&M agreement appears likely or a short-term O&M agreement (less than five years) has been reached.
0 No decision has been made toward achieving an O&M agreement.

Steam Host

2 A letter of intent with a steam host has been provided.
1 The steam host exists and has been identified, but a letter of intent has not been provided.
0 Steam Host does not exist and/or is unidentified.

Permits

2 Permits and licenses are in-hand.
1 Permits and licenses are not yet secured but no permitting or zoning problems are apparent.
0 Significant doubts exist regarding environmental considerations, permitting and/or zoning.

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Construction Schedule and Milestones

2 A Construction schedule exists and Milestones are appropriate for timely completion.

1 Timely completion of project appears likely.

0 Timely completion appears doubtful.

Site Control

2 Site has been secured and does not require specific environmental considerations.

1 Site is identified and is sufficiently secured.

0 Site is uncertain or it requires specific environmental considerations, i.e. wetlands, etc.

Developer's Financial Stability

2 Project developer has a credit rating comparable to Investment-Grade Status.

1 Project developer has a credit rating that is less favorable than Investment-Grade Status.

0 Project developer's credit rating is considered too risky.

Developer's Experience

2 Developer has proven experience developing cogeneration projects.

1 Developer has marginal experience developing cogeneration projects.

0 Developer has no experience developing cogeneration projects.

Project Financing

2 Project financing has been secured.

1 Project financing appears likely.

0 Project financing is uncertain.

Working Capital

2 Working capital has been secured.

1 Working capital appears likely.

0 Working capital is uncertain.

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Please provide the following general information to assist the Company in evaluating your Standard Offer Contract

- Standard Offer Committed Capacity (MW):
- Size and type of generation:
- Any existing or planned capacity commitments or energy sales to other utilities, if so provide detail:
- Will the project directly interconnect into the Company's transmission grid? Please explain:
- If the project is located external to the Company's retail service area, how will the power be delivered to the Company? Please explain:
- Will steam host use a portion of electric generation, if so provide detail:
- Please provide developer's ownership structure for this project:
- Developer's Insurance Carrier:
  - Property damage insurance:
  - Business interruption insurance:
  - Rating of insurance carrier:
- Please provide estimates of the following:
  - Expected annual metered electric output,
  - Expected annual metered useful thermal output, in Btu/hr X operating hours/year,
  - Expected annual metered fuel input, in Btu/hr X operating hours/year.
- Other:

INTERCONNECTION AGREEMENT

This agreement is made and entered into this _______ day of ______________, _____ by and between ______________________, hereinafter referred to as "QF" and Tampa Electric Company, a private utility corporation organized under the laws of the State of Florida, hereinafter referred to as the "Company". The QF and the Company shall collectively be referred to herein as the "Parties."

1. Facility: The QF's generating facility, hereinafter referred to as "Facility," is located at ________________________, within the Company's service territory. QF intends to have its Facility installed and operational on or about _____________, _____. QF shall provide the Company reasonable prior notice of the Facility's initial operation, and it shall cooperate with the Company to arrange initial deliveries of power to the Company's system.

The Facility has been or will be certified as a Qualifying Facility pursuant to the rules and regulations of the Florida Public Service Commission (FPSC) or the Federal Energy Regulatory Commission (FERC). The QF shall maintain the qualifying status of the Facility throughout the terms of the Interconnection Agreement. By the end of the first quarter of each year, QF shall furnish the Company a notarized certificate by an officer of QF certifying that the Facility has continuously maintained qualifying status on a calendar year basis since the commencement of the contract term.

2. Construction Activities: QF shall provide the Company with written instructions to proceed with construction of the interconnection facilities as described in this Agreement at least 24 months prior to the date on which the facilities shall be completed.

The Company agrees to complete the interconnection facilities as described in this Agreement within 24 months of receipt of written instructions to proceed.

Upon the parties' agreement as to the appropriate interconnection design requirements and receipt of written instructions to proceed delivered by QF, the Company shall design and perform or cause to be performed all of the work necessary to interconnect the Facility with the Company's system.

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Prior to any work being done by the Company, the Company shall supply QF with a written cost estimate of all required materials and labor and an estimate of the date by which construction of the interconnection will be completed. This estimate shall be provided to QF within 60 days after QF provides the Company with its final electrical one-line diagrams. The Company shall also provide project timing and feasibility information to the QF.

QF agrees to pay the Company all expenses incurred by the Company necessary for integration of the Facility into the Company's electrical system, including but not limited to the design, construction, operation, maintenance and repair of the interconnection facilities described in Exhibit A. Exhibit A shall contain a complete description of the interconnection facilities including the final electrical on-line diagram. Such interconnection costs shall not include any interconnection costs which the Company would otherwise incur if it were not engaged in interconnected operations with QF but instead provided through its own generation facilities the electric power required by the Facility.

QF agrees to pay the costs for complete interconnection work ($___ dollars): (   ) within 30 days after the Company notifies QF that such interconnection work has been completed; or (   ) payable in (up to 36) _____ monthly installments, plus interest on the outstanding balance calculated at the 30-day highest grade commercial paper rate in effect 30 days prior to the date each payment is due, such rate to be determined by the Company, with the first such installment payment being due 30 days after the Company notifies QF that such interconnection work has been completed.

In the event QF notifies the Company in writing to cease interconnection work before its completion, QF shall be obligated to reimburse the Company for the interconnection costs incurred up to the date such notification is received. The payment terms shall be in accordance with the payment option selected by the QF in the proceeding paragraph.

3. <u>Cost Estimates:</u> Attached hereto as Exhibit B and incorporated herein by this reference is a document entitled, "QF Interconnection Cost Estimates." The parties agree that the cost of the interconnection work contained in Exhibit B is a good faith estimate of the actual cost to be incurred.

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4. <u>Technical Requirements and Operations:</u> The parties agree that QF's interconnection with, and delivery of electricity into, the Company's system must be accomplished in accordance with the provisions of the Company's "General Standards for Safety and Interconnection of Cogeneration and Small Power Production Facilities to the Electric Utility System," "NERC Planning Standards," September 1997, [Copyright @ 1997 by the North American Electric Reliability Council] attached hereto as Exhibit C, that are applicable to generation and transmission facilities which are connected to, or are being planned to be connected to the Company's transmission system (document provided upon request).

In the event that changes in the engineering or operating standards or practices in the utility industry, and the Company's corresponding standards or practices or changes in regulatory requirements, affect the design or operation of the Company's electrical system, and this in turn necessitates additions to or modifications of the equipment or facilities utilized in order to ensure the continued safe and reliable operations contemplated by this Agreement, as well as the continued compatibility of the Facility with the Company's system, QF agrees to bear the cost of such additions or modifications which are directly attributable to the Facility. The costs of such additions or modifications shall not include any costs which the Company would otherwise incur if it were not engaged in interconnected operations with the Facility, but instead provided through its own generation facilities the electrical power required by the Facility.

In addition, QF agrees to require that the Facility operator immediately notify the Company's System Dispatcher by telephone in the event hazardous or unsafe conditions associated with the parties' parallel operations are discovered. If such conditions are detected by the Company, then the Company will likewise immediately contact the operator of the Facility by telephone. Each party agrees to immediately take whatever appropriate corrective action is necessary to correct the hazardous or unsafe conditions.

To the extent the Company reasonably determines the same to be necessary to ensure the safe operation of the Facility or to protect the integrity of the Company's system, QF agrees to reduce power generation or take other appropriate actions.

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Continued from Sheet No. 8.610

5. **Interconnection Facilities:** The interconnection facilities shall include the items listed in Exhibit A. Interconnection facilities on the Company's side of the ownership line with QF shall be owned, operated, maintained and repaired by the Company. QF shall be responsible for the cost of designing, installing, operating and maintaining the interconnection facilities on QF's side of the ownership line as indicated in Exhibit A. The QF shall be responsible for establishing and maintaining controlled access by third parties to the interconnection facilities owned by the QF.

6. **Maintenance and Repair Payments:** The Company will separately invoice QF monthly for all costs associated with the operation, maintenance and repair of the interconnection facilities. QF agrees to pay the Company within 20 business days of receipt of each such invoice.

7. **Site Access:** In order to help ensure the continuous, safe, reliable and compatible operation of the Facility with the Company's system, QF hereby grants to the Company for the period of interconnection the reasonable right of ingress and egress, consistent with the safe operation of the Facility, over property owned or controlled by QF to the extent the Company deems such ingress and egress necessary in order to examine, test, calibrate, coordinate, operate, maintain or repair any interconnection equipment involved in the parallel operation of the Facility and the Company's system, including the Company's metering equipment.

8. **Construction Responsibility:** In no event shall any the Company statement, representation, or lack thereof, either express or implied, relieve QF of its exclusive responsibility for the Facility. Specifically, any the Company inspection of the Facility shall not be construed as confirming or endorsing the Facility's design or its operating or maintenance procedures nor as a warranty or guarantee as to the safety, reliability, or durability of the Facility's equipment. The Company's inspection, acceptance, or its failure to inspect shall not be deemed an endorsement of any Facility equipment or procedure.

Continued to Sheet No. 8.620

Continued from Sheet No. 8.615

9. <u>Insurance:</u> The QF shall deliver to the Company, at least fifteen (15) days prior to the start of any interconnection work, a certificate of insurance certifying the QF's coverage under a liability insurance policy issued by a reputable insurance company authorized to do business in the State of Florida naming the QF as named insured, and the Company as an additional named insured, which policy shall contain a broad form contractual endorsement specifically covering the liabilities accepted under this Agreement arising out of the interconnection to the QF, or caused by operation of any of the QF's equipment or by the QF's failure to maintain its equipment in satisfactory and safe operating condition.

a. In subsequent years, a certificate of insurance renewal must be provided annually to the Company indicating the QF's continued coverage as described herein. Renewal certification shall be sent to:

Tampa Electric Company
Risk Management Department
P. O. Box 111
Tampa, FL 33601

b. The policy providing such coverage for a Standard Offer Contract shall provide public liability insurance, including coverage for personal injury, death and property damage, in an amount not less than $1,000,000 for each occurrence; provided however, if QF has insurance with limits greater than the minimum limits required herein, the QF shall set any amount higher than the minimum limits required by the Company to satisfy the insurance requirements of this Agreement.

c. The policy providing such coverage for a Negotiated Contract shall provide public liability insurance, including coverage for personal injury, death and property damage, in an amount not less than $1,000,000 for each occurrence. The Parties may negotiate the amount of insurance over $1,000,000.

d. The above required policy shall be endorsed with a provision requiring the insurance company to notify the Company thirty (30) days prior to the effective date of any cancellation or material change in said policy.

Continued to Sheet No. 8.625

Continued from Sheet No. 8.620

e. The QF shall pay all premiums and other charges due on said policy and keep said policy in force during the entire period of interconnection with the Company.

10. **Electric Service to QF:** The Company will provide the class or classes of electric service requested by QF, to the extent that they are consistent with applicable tariffs; provided, however, that interruptible service will not be available under circumstances where interruptions would impair QF's ability to generate and deliver Firm Capacity and Energy to the Company under the terms of the Company's Standard Offer Contract.

11. **Assignment:** The QF shall have the right to assign its benefits under this Agreement, but the QF shall not have the right to assign its obligations and duties without the Company's prior written consent and such consent shall not be unreasonably withheld.

12. **Disclaimer:** In executing this Agreement, the Company does not, nor should it be construed to extend its credit or financial support for the benefit of any third parties lending money to or having other transactions with QF or any assignee of this Agreement.

13. **Applicable Law:** This Agreement shall be governed by and construed and enforced in accordance with the laws, rules and regulations of the State of Florida and the Company's Tariff as may be modified, changed or amended from time to time.

14. **Severability:** If any part of this Agreement, for any reason, be declared invalid, or unenforceable by a court or public authority of appropriate jurisdiction, then such decision shall not affect the validity of the remainder of the Agreement, which remainder shall remain in force and effect as if this Agreement had been executed without the invalid or unenforceable portion.

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Continued from Sheet No. 8.625

15. Complete Agreement and Amendments: All previous communications or agreements between parties, whether verbal or written, with reference to the subject matter of this Agreement are hereby abrogated. No amendment or modification to this Agreement shall be binding unless it shall be set forth in writing and duly executed by both parties to this Agreement.

16. Incorporation of Rate Schedule: The parties agree that this Agreement shall be subject to all of the provisions contained in the Company's published Rate Schedule COG-1 or COG-2 as approved and on file with the FPSC. The Rate Schedule is incorporated herein by reference.

17. Survival of Agreement: This Agreement, as it may be amended from time to time, shall be binding and inure to the benefit of the Parties' respective successors-in-interest and legal representatives.

18. Notification: For purpose of making emergency or any communications relating to the operation of the Facility, under the provisions of this Agreement, the parties designate the following persons for notification:

For QF:

__________________ ______________

__________________ Phone: ______________

For Tampa Electric:

Dispatcher

Palm River Phone: (813) 621-2929

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For purposes of making any and all non-emergency oral and written notices, payments or the like required under the provisions of this Agreement, the parties designate the following to be notified or to whom payment shall be sent until such time as either party furnishes the other written instructions changing such designate.

For QF:

For Tampa Electric:
Tampa Electric Company
manager-Industrial/Governmental Marketing & Sales
P.O. Box 111
Tampa, Florida 33601

IN WITNESS WHEREOF, QF and the Company have executed this Agreement the day and year first above written.

WITNESSES:

____

____

Qualifying Facility

By: ______________________

Its: ______________________

WITNESSES:

____

____

Tampa Electric Company

By: ______________________

Its: ______________________

RESERVED FOR FUTURE USE

RESERVED FOR FUTURE USE

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RESERVED FOR FUTURE USE

GENERAL STANDARDS FOR SAFETY AND INTERCONNECTION OF COGENERATION AND SMALL POWER PRODUCTION FACILITIES TO THE ELECTRIC UTILITY SYSTEM

The following section is based on Florida Public Service Commission (FPSC) Rule 25-17.87, Florida Administrative Code, (F.A.C.), Interconnection and Standards and is applicable throughout Tampa Electric Company's (the Company's) service area:

1. The Company shall interconnect with any qualifying facility (qf) which:

    a. is in its service area;

    b. requests interconnection;

    c. agrees to meet system standards specified in this Rule;

    d. agrees to pay the cost of interconnection; and

    e. signs an interconnection agreement.

2. Nothing in this rule shall be construed to preclude the Company from evaluating each request for interconnection on its own merits and modifying the general standards specified in this Rule to reflect the result of such an evaluation.

3. Where the Company refuses to interconnect with a qf or attempts to impose unreasonable standards pursuant to subsection (2) of this rule, the qf may petition the FPSC for relief. The Company shall have the burden of demonstrating to the FPSC why interconnection with the qfs should not be required or that the standards the Company seeks to impose on the qfs pursuant to subsection (2) are reasonable.

4. Upon a showing of credit worthiness, the qfs shall have the option of making monthly installment payments over a period no longer than 36 months toward the full cost of interconnection. However, where the qfs exercises that option, the Company shall charge interest on the amount owing. The Company shall charge such interest at the 30 day highest grade commercial paper rate. In any event, no the Company may not bear the cost of interconnection.

Continued to Sheet No. 8.705

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5. <u>Application for Interconnection:</u> A qf shall not operate electric generating equipment in parallel with the Company's electric system without the prior written consent of the Company. Formal application for interconnection shall be made by the qf prior to the installation of any generation related equipment. This application shall be accompanied by the following:

a. Physical layout drawings, including dimensions;

b. All associated equipment specifications and characteristics including technical parameters, ratings, basic impulse levels, electrical main one-line diagrams, schematic diagrams, system protections, frequency, voltage, current and interconnection distance;

c. Functional and logic diagrams, control and meter diagrams, conductor sizes and length, and any other relevant data which might be necessary to understand the proposed system and to be able to make a coordinated system;

d. Power characteristics in watts and vars;

e. Expected radio-noise, harmonic generation and telephone interference factor;

f. Synchronizing methods; and

g. Operating/instruction manuals.

Any subsequent change in the system must also be submitted for review and written approval prior to actual modification. The above mentioned review, recommendations and approval by the Company do not relieve the qf from complete responsibility for the adequate engineering design, construction and operation of the qf equipment and for any liability for injuries to property or persons associated with any failure to perform in a proper and safe manner for any reason.

Continued to Sheet No. 8.710

Continued from Sheet No. 8.705

6. <u>Personnel Safety:</u> Adequate protection and safe operational procedures must be developed and followed by the joint system. These operating procedures must be approved by both the Company and the qf. The qf shall be required to furnish, install, operate and maintain in good order and repair, and be solely responsible for, without cost to the Company, all facilities required for the safe operation of the generation system in parallel with the Company's system.

The qf shall permit the Company's employees to enter upon its property at any reasonable time for the purpose of inspection and/or testing the qf's equipment, facilities, or apparatus. Such inspections shall not relieve the qf from its obligation to maintain its equipment in safe and satisfactory operating condition.

The Company's approval of isolating devices used by the qf will be required to ensure that these will comply with the Company's switching and tagging procedure for safe working clearances.

a. <u>Disconnect switch:</u> A manual disconnect switch, of the visible load break type, to provide a separation point between the qf's generation system and the Company's system, shall be required. The Company will specify the location of the disconnect switch. The switch shall be mounted separate from the meter socket and shall be readily accessible to the Company and be capable of being locked in the open position with a Company padlock. The Company may reserve the right to open the switch (i.e., isolating the qf's generation system) without prior notice to the qf. To the extent practicable, however, prior notice shall be given.

Continued to Sheet No. 8.715

Continued from Sheet No. 8.710

Any of the following conditions shall be cause for disconnection:

i. The Company's system emergencies and/or maintenance requirements; Hazardous conditions existing on the qf's generating or protective equipment as determined by the Company;

ii. Adverse effects of the qf's generation to the Company's other electric consumers and/or system as determined by the Company;

iii. Failure of the qf to maintain any required insurance; or

iv. Failure of the qf to comply with any existing or future regulations, rules, orders or decisions of any governmental or regulatory authority having jurisdiction over the qf's electric generating equipment or the operation of such equipment.

b. **Responsibility and Liability:** The Company and the qf shall each be responsible for its own facilities. The Company and the qf shall each be responsible for ensuring adequate safeguards for other Company customers, the Company and qf personnel and equipment, and for the protection of its own generating system. The Company and the qf shall each indemnify and save the other harmless from any and all claims, demands, costs, or expense for loss, damage, or injury to persons or property of the other caused by, arising out of, or resulting from:

i. Any act or omission by a party, or that party's contractors, agents, servants and employees in connection with the installation or operation of that party's generation system or the operation thereof in connection with the other party's system;

ii. Any defect in, failure of, or fault related to a party's generation system;

iii. The negligence of a party or negligence of that party's contractors, agents, servants or employees; or

Continued to Sheet No. 8.720

Continued from Sheet No. 8.715

iv. Any other event or act that is the result of, or proximately caused by a party.

For the purpose of this paragraph, the term party shall mean either the Company or qf, as the case may be.

c. **Insurance:** The qf shall deliver to the Company, at least fifteen (15) days prior to the start of any interconnection work, a certificate of insurance certifying the qf's coverage under a liability insurance policy issued by a reputable insurance company authorized to do business in the State of Florida naming the qf as named insured, and the Company as an additional named insured, which policy shall contain a broad form contractual endorsement specifically covering the liabilities accepted under this agreement arising out of the interconnection to the qf, or caused by operation of any of the qf's equipment or by the qf's failure to maintain its equipment in satisfactory and safe operating condition.

i. In subsequent years, a certificate of insurance renewal must be provided annually to the Company indicating the qf's continued coverage as described herein. Renewal certification shall be sent to:

Tampa Electric Company
Risk Management Department
P. O. Box 111
Tampa, FL 33601

ii. The policy providing such coverage for a Standard Offer Contract shall provide public liability insurance, including coverage for personal injury, death and property damage, in an amount not less than $1,000,000 for each occurrence; provided however, if qf has insurance with limits greater than the minimum limits required herein, the qf shall set any amount higher than the minimum limits required by the Company to satisfy the insurance requirements of this Agreement.

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iii. The policy providing such coverage for a Negotiated Contract shall provide public liability insurance, including coverage for personal injury, death and property damage, in an amount not less than $1,000,000 for each occurrence. The Parties may negotiate the amount of insurance over $1,000,000.

iv. The above required policy shall be endorsed with a provision requiring the insurance company will notify the Company thirty (30) days prior to the effective date of cancellation or material change in said policy.

v. The qf shall pay all premiums and other charges due on said policy and keep said policy in force during the entire period of interconnection with the Company.

7. **Protection and Operation:** It will be the responsibility of the qf to provide all devices necessary to protect the qf's equipment from damage by the abnormal conditions and operations which occur on the Company system that result from interruptions and restorations of service by the Company's equipment and personnel. The qf shall protect its generator and associated equipment from overvoltage, undervoltage, overload, short circuits (including ground fault condition), open circuits, phase unbalance and reversal, over or under frequency condition, and other injurious electrical conditions that may arise on the Company's system and any reclose attempt by the Company.

The Company may reserve the right to perform such tests as it deems necessary to ensure safe and efficient protection and operation of the qf's equipment.

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a. Loss of source: The qf shall provide, or the Company will provide at the qf's expense, approved protective equipment necessary to immediately, completely, and automatically disconnect the qf's generation from the Company's system in the event of a fault on the qf's system, a fault on the Company's system, or loss of source on the Company's system. Disconnection must be completed within the time specified by the Company in its standard operating procedure for its electric system for loss of a source on the Company's system.

This automatic disconnecting device may be of the manual or automatic reclose type and shall not be capable of reclosing until after service is restored by the Company. The type and size of the device shall be approved by the Company depending upon the installation. Adequate test data or technical proof that the device meets the above criteria must be supplied by the qf to the Company. The Company shall approve a device that will perform the above functions at minimal capital and operating costs to the qf.

b. Coordination and Synchronization: The qf shall be responsible for coordination and synchronization of the qf's equipment with the Company's electrical system, and assumes all responsibility for damage that may occur from improper coordination or synchronization of the generator with the Company's system.

c. Electrical characteristics: Single phase generator interconnections with the Company are permitted at power levels up to 20 KW. For power levels exceeding 20 KW, a three phase balanced interconnection will normally be required. For the purpose of calculating connected generation, 1 horsepower equals 1 kilowatt. The qf shall interconnect with the Company at the voltage of the available distribution or transmission line of the Company for the locality of the interconnection, and shall utilize one of the standard connections (single phase, three phase, wye, delta) as approved by the Company.

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The Company may reserve the right to require a separate transformation and/or service for a qf's generation system, at the qf's expense. The qf shall bond all neutrals of the qf's system to the Company's neutral, and shall install a separate driven ground with a resistance value which shall be determined by the Company and bond this ground to the qf's system neutral.

d. <u>Exceptions</u> A qf's generator having a capacity rating that can:

i. Produce power in excess of one half of the minimum Company customer requirements of the interconnected distribution or transmission circuit; or

ii. produce power flows approaching or exceeding the thermal capacity of the connected Company distribution or transmission lines or transformers; or

iii. adversely affect the operation of the Company or other Company customer's voltage, frequency or overcurrent control and protection devices; or

iv. adversely affect the quality of service to other Company customers; or

v. interconnect at voltage levels greater than distribution voltages, will require more complex interconnection facilities as deemed necessary by the Company.

8. <u>Quality of Service:</u> The qf's generated electricity shall meet the following minimum guidelines:

a. <u>Frequency:</u> The governor control on the prime mover shall be capable of maintaining the generator output frequency within limits for loads from no-load up to rated output. The limits for frequency shall be 60 hertz (cycles per second), plus or minus an instantaneous variation of less than 1%.

b. <u>Voltage:</u> The regulator control shall be capable of maintaining the generator output voltage within limits for loads from no-load up to rated output. The limits for voltage shall be the nominal operating voltage level, plus or minus 5%.

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c. Harmonics: The output sine wave distortion shall be deemed acceptable when it does not have a higher content (root mean square) of harmonics than the Company's normal harmonic content at the interconnection point.

d. Power Factor: The qf's generation system shall be designed, operated and controlled to provide reactive power requirements from 0.95 lagging to 0.95 leading power factor at the point of interconnection with Company. Induction generators shall have static capacitors that provide at least 95% of the magnetizing current requirements of the induction generator field. (Capacitors shall not be so large as to permit self-excitation of the qf's generator field).

e. DC Generators: Direct current generators may be operated in parallel with the Company's system through a synchronous invertor. The invertor must meet all criteria in these rules.

9. Metering: The actual metering equipment required, its voltage rating, number of phases, size, current transformers, potential transformers, number of inputs and associated memory is dependent on the type, size and location of the electric service provided. In situations where power may flow both in and out of the qf's system, power flowing into the qf's system will be measured separately from power flowing out of the qf's system.

The Company will provide, at no additional cost to the qf, the metering equipment necessary to measure capacity and energy deliveries to the qf. The Company will provide, at the qf's expense, the necessary additional metering equipment to measure capacity and energy deliveries by the qf to the Company.

10. Cost Responsibility: The qf is required to bear all costs associated with the change-out, upgrading or addition of protective devices, transformers,

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lines, services, meters, switches, and associated equipment and devices beyond that which would be required to provide normal service to the qf if the qf were a non-generating customer. These costs shall be paid by the qf to the Company for all material and labor that is required. Prior to any work being done by the Company, the Company shall supply the qf with a written cost estimate of all its required materials and labor and an estimate of the date by which construction of the interconnection will be completed. This estimate shall be provided to the qf within 60 days after the qf provides the Company with its final electrical plans. The Company shall also provide project timing and feasibility information to the qf.

11. The Company shall submit, to the FPSC, a standard agreement for the interconnection by qfs as part of their Standard Offer contract or contracts required by FPSC Rule 25-17.0832(3), F.A.C.

Exhibit C

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COGENERATION AND SMALL POWER PRODUCTION

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STANDARD RATE FOR PURCHASE OF AS-AVAILABLE ENERGY FROM QUALIFYING COGENERATION AND SMALL POWER PRODUCTION FACILITIES (QUALIFYING FACILITIES)

SCHEDULE
COG-1, As-Available Energy

AVAILABLE
Tampa Electric Company will purchase energy offered by any Qualifying Facility irrespective of its location, which is directly or indirectly interconnected with the Company, under the provisions of this schedule or at contract negotiated rates. Tampa Electric Company will negotiate and may contract with a Qualifying Facility, irrespective of its location, which is directly or indirectly interconnected with the Company where such negotiated contracts are in the best interest of the Company's ratepayers.

APPLICABLE
To any cogeneration or small power production Qualifying Facility producing energy for sale to the Company on an As-Available basis. As-Available Energy is described by the Florida Public Service Commission (FPSC) Rule 25-17.0825, Florida Administrative Code (F.A.C.), and is energy produced and sold by a Qualifying Facility on an hour-by-hour basis for which contractual commitments as to the time, quantity, or reliability of delivery are not required. Because of the lack of assurance as to the quantity, time, or reliability of delivery of As-Available Energy, no Capacity Payment shall be made to a Qualifying Facility for delivery of As-Available Energy. Criteria for achieving Qualifying Facility status shall be those set out in FPSC Rule 25-17.080.

CHARACTER OF SERVICE
Purchases within the territory served by the Company shall be, at the option of the Company, single or three phase, 60 hertz, alternating current at any available standard Company voltage. Purchases from outside the territory served by the Company shall be three phase, 60 Hertz, alternating current at the voltage level available at the interchange point between the Company and the entity delivering As-Available Energy from the Qualifying Facility.

Continued to Sheet No. 8.030

Continued from Sheet No. 8.020

LIMITATIONS

All service pursuant to this schedule is subject to the Company's "General Standards for Safety and Interconnection of Cogeneration and Small Power Production Facilities to the Electric Utility System" and to FPSC Rules 25-17.080 through 25-17.091, F.A.C.

RATES FOR PURCHASES BY THE COMPANY

A. **Capacity Rates**

Capacity payments to Qualifying Facilities will not be paid under this schedule. Capacity payments to small Qualifying Facilities of less than 75 MWs or Solid Waste Facilities may be obtained under either a Standard Offer Contract as described in Schedule COG-2, Firm Capacity and Energy or a negotiated contract.

Capacity payments to Qualifying Facilities of 75 MWs or greater may only be obtained under a negotiated contract as described in FPSC Rule 25-17.0832.

B. **Energy Rates**

As-Available Energy is purchased at a unit cost, in cents per kilowatt-hour (¢/KWH), based on the Company's actual hourly avoided energy costs which are calculated by the Company in accordance with FPSC Rule 25-17.0825, F.A.C.

Avoided energy costs include incremental fuel, identifiable variable operation and maintenance expenses, and an adjustment for line losses reflecting delivery voltage. The calculation of payments to the Qualifying Facility shall be based on the energy deliveries from the Qualifying Facility to the Company and the applicable avoided energy rate, in accordance with FPSC Rule 25-17.082, F.A.C. All sales shall be adjusted for losses from the point of metering to the point of interconnection.

The methodology to be used in the calculation of the avoided energy cost is described in Appendix A.

C. **Negotiated Rates**

Upon agreement by both the Company and the Qualifying Facility, an alternate contract rate for the purchase of As-Available Energy may be separately negotiated.

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Continued from Sheet No. 8.030

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST

Upon request by a qualifying facility or any interested person, the Company shall provide within 30 days its most current projections of its generation mix, fuel price by type of fuel, and at least a five year projection of fuel forecasts to estimate future as-available energy prices as well as any other information reasonably required by the qualifying facility to project future avoided cost prices including, but not limited to, a 24 hour advance forecast of hour-by-hour avoided energy costs. The Company may charge an appropriate fee, not to exceed the actual cost of production and copying, for providing such information.

RESERVED FOR FUTURE USE

Continued to Sheet No. 8.050

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DELIVERY VOLTAGE ADJUSTMENT

For purchases from Qualifying Facilities directly interconnected to the Company, the Company's actual hourly avoided energy costs shall be adjusted according to the delivery voltage by the following multipliers:

Rate Schedule	Adjustment Factor
RS, GS	1.0616
GSD, GSLD, SBF	1.0561
IS-1, IS-3	1.0254
SBI-1, SBI-3	1.0254

For purchases from Qualifying Facilities not directly interconnected to the Company, any adjustments to the Company's actual hourly avoided energy costs for delivery voltage will be determined based on the Company's current annual system average transmission loss factor.

METERING REQUIREMENTS

The Qualifying Facility within the territory served by the Company shall be required to purchase from the Company the metering equipment necessary to measure its energy deliveries to the Company. Energy purchased from Qualifying Facilities outside the territory served by the Company shall be measured as the quantities scheduled for interchange to the Company by the entity delivering As-Available Energy to the Company. Unless special circumstances warrant, meters shall be read at monthly intervals on the approximate corresponding day of each meter reading period.

Hourly recording meters shall be required for Qualifying Facilities with an installed capacity of 100 kilowatts or more. Where the installed capacity is less than 100 kilowatts, the Qualifying Facility may select any one of the following options: (a) an hourly recording meter, (b) a dual kilowatt-hour register time-of-day meter, or (c) a standard kilowatt-hour meter.

For Qualifying Facilities with hourly recording meters, monthly payments for As-Available Energy shall be calculated based on the product of: (1) the Company's actual As-Available Energy Payment Rate for each hour during the month; and (2) the quantity of energy sold by the Qualifying Facility during that hour.

For Qualifying Facilities with dual kilowatt-hour register time-of-day meters, monthly payments for As-Available Energy shall be calculated based on the product of: (1) the average of the Company's actual hourly As-Available Energy Payment Rates for the on-peak and off-peak periods during the month; and (2) the quantity of energy sold by the Qualifying Facility during that period.

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For Qualifying Facilities with standard kilowatt-hour meters, monthly payments for As-Available Energy shall be calculated based on the product of: (1) the average of the Company's actual hourly As-Available Energy Payment Rate for the off-peak periods during that month; and (2) the quantity of energy sold by the Qualifying Facility during that month.

For a time-of-day metered Qualifying Facility, the on-peak hours occur Monday through Friday except holidays, April 1 - October 31 from 12 noon to 9:00 p.m. and November 1 - March 31 from 6:00 a.m. to 10:00 a.m. and 6:00 p.m. to 10:00 p.m.. All hours not mentioned above and all hours of the holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day are off-peak hours.

BILLING OPTIONS

The Qualifying Facilities may elect to make either simultaneous purchases and sales or net sales. The billing option elected may only be changed in accordance with FPSC Rule 25-17.082:

1. when the Qualifying Facility selling As-Available Energy enters into a negotiated contract or standard offer contract for the sale of Firm Capacity and Energy; or
2. when a Firm Capacity and Energy contract expires or is lawfully terminated by either the Qualifying Facility or Tampa Electric Company; or
3. when the Qualifying Facility is selling As-Available Energy and has not changed billing methods within the last twelve months; and
4. when the election to change billing methods will not contravene the provisions of Rule 25-17.0832 or any contract between the Qualifying Facility and Tampa Electric Company.

If the Qualifying Facility elects to change billing methods in accordance with FPSC Rule 25-17.082, such a change shall be subject to the following provisions:

1. upon at least thirty (30) days advance written notice;

Continued to Sheet No. 8.061

Continued from Sheet No. 8.060

2. upon the installation by Tampa Electric Company of any additional metering equipment reasonably required to effect the change in billing and upon payment by the Qualifying Facility for such metering equipment and its installation; and

3. upon completion and approval by Tampa Electric Company of any alterations to the interconnection reasonably required to effect the change in billing and upon payment by the Qualifying Facility for such alterations.

Should a Qualifying Facility elect to make simultaneous purchases and sales, purchases of electric service by the Qualifying Facility from the interconnecting utility shall be billed at the retail rate schedule under which the Qualifying Facility load would receive service as a non-generating customer of the utility; sales of electricity delivered by the Qualifying Facility to the purchasing utility shall be purchased at the utility's avoided capacity and energy rates, where applicable, in accordance with Rules 25-17.0825 and 25-17.0832.

Should a Qualifying Facility elect a net billing arrangement, the hourly net energy sales delivered to the purchasing utility shall be purchased at the utilities avoided capacity and energy rates, where applicable, in accordance with Rules 25-17.0825 and 25-17.0832, purchases from the interconnecting utility shall be billed pursuant to the utility's applicable standby and supplemental service rate schedule.

Continued to Sheet No. 8.070

Continued from Sheet No. 8.061

CHARGES/CREDITS TO QUALIFYING FACILITY

A. **Customer Charges**

A monthly Customer Charge will be rendered for maintaining an account for a Qualifying Facility engaged in either an As-Available Energy or Firm Capacity and Energy transaction and for other applicable administrative costs. Actual charges will depend on how the QF is interconnected to the Company.

QFs not directly interconnected to the Company, will be billed $580 monthly as a Customer Charge.

Monthly customer charges, applicable to QFs directly interconnected to the Company, by Rate Schedule are:

Rate Schedule	Customer Charge	Rate Schedule	Customer Charge
RS	$ 8.50	RST	$ 11.50
GS	8.50	GST	11.50
GSD	42.00	GSDT	49.00
GSLD	255.00	GSLDT	255.00
SBF	280.00	SBFT	280.00
IS-1	1,000.00	IST-1	1,000.00
IS-3	1,000.00	IST-3	1,000.00
SBI-1	1,025.00	SBIT-1	1,025.00
SBI-3	1,025.00	SBIT-3	1,025.00

When appropriate, the Customer Charge will be deducted from the Qualifying Facility's monthly payment. A statement of the charges or payments due the Qualifying Facility will be rendered monthly. Payment normally will be made by the twentieth business day following the end of the billing period.

Continued to Sheet No. 8.071

Continued from Sheet No. 8.070

B. <u>Interconnection Charge for Non-Variable Utility Expenses:</u>
The Qualifying Facility shall bear the cost required for interconnection including the metering. The Qualifying Facility shall have the option of payment in full for interconnection or making equal monthly installment payments over a thirty-six (36) month period together with interest at the rate then prevailing for thirty (30) days highest grade commercial paper; such rate to be determined by the Company thirty (30) days prior to the date of each payment.

C. <u>Interconnection Charge for Variable Utility Expenses</u>
The Qualifying Facility shall be billed monthly for the cost of variable utility expenses associated with the operation and maintenance of the interconnection. These include: **(a)** the Company's inspections of the interconnection and **(b)** maintenance of any equipment beyond that which would be required to provide normal electric service to the Qualifying Facility if no sales to the Company are involved.

Continued to Sheet No. 8.080

Continued from Sheet No. 8.071

D. **Taxes and Assessments**

The Qualifying Facility shall be billed monthly an amount equal to the taxes, assessments, or other impositions, if any, for which the Company is liable as a result of its purchases of As-Available Energy produced by the Qualifying Facility.

If the Company obtains any tax savings as a result of its purchases of As-Available Energy produced by the Qualifying Facility, which tax savings would not have otherwise been obtained, those tax savings shall be credited to the Qualifying Facility.

TERMS OF SERVICE

1) It shall be the Qualifying Facility's responsibility to inform the Company of any change in its electric generation capability.

2) Any electric service delivered by the Company to the Qualifying Facility shall be metered separately and billed under the applicable retail rate schedule and the terms and conditions of the applicable rate schedule shall pertain.

3) A security deposit will be required in accordance with FPSC Rules 25-17.082(5) and 25-6.097, F.A.C. and the following:

   A) In the first year of operation, the security deposit shall be based upon the singular month in which the Qualifying Facility's projected purchases from the utility exceed, by the greatest amount, the utility's estimated purchases from the Qualifying Facility. The security deposit should be equal to twice the amount of the difference estimated for that month. The deposit shall be required upon interconnection.

   B) For each year thereafter, a review of the actual sales and purchases between the Qualifying Facility and the utility shall be conducted to determine the actual month of maximum difference. The security deposit shall be adjusted to equal twice the greatest amount by which the actual monthly purchases by the Qualifying Facility exceed the actual sales to the utility in that month.

Continued to Sheet No. 8.090

Continued from Sheet No. 8.080

4) The company shall specify the point of interconnection and voltage level.

5) The Company will, under the provisions of this schedule, require an interconnection agreement with the Qualifying Facility using either the Company's filed Interconnection Agreement or a negotiated Interconnection Agreement. The Qualifying Facility shall recognize that its generation facility may exhibit unique interconnection requirements which will be separately evaluated, and may require modifications to the Company's General Standards for Safety and Interconnection where applicable.

6) Service under this rate schedule is subject to the rules and regulations of the Company and the Florida Public Service Commission.

SPECIAL PROVISIONS

1) Negotiated contracts deviating from the above standard rate schedule are allowable provided they are agreed to by the Company and approved by the Florida Public Service Commission.

2) In accordance with the provision in Rule 25-17.0883, the Company is required to provide transmission and distribution service to enable a retail customer to transmit electrical power generated at one location to the customer's facilities at another location when provision of such service and its associated charge, terms, and other conditions are not reasonably projected to result in higher cost of electric service to the Company's general body of retail and wholesale customers or adversely affect the adequacy or reliability of electric service to all customers.

   A determination of whether or not transmission service for self-service wheeling is likely to result in higher cost electric service will be made by evaluating the results of an appropriately adjusted FPSC approved cost effectiveness methodology, in addition to other modeling analyses.

3) In accordance with Rule 25-17.089, upon request by a Qualifying Facility, Tampa Electric Company shall provide transmission service to wheel As-Available Energy produced by a Qualifying Facility from the Qualifying Facility to another electric utility.

Continued to Sheet No. 8.100

Continued from Sheet No. 8.090

4) Where existing Company transmission capacity exists, the Company will impose a charge for wheeling Qualifying Facility energy, measured at the point of delivery to the Company. The rates, terms, and conditions for such transmission service shall be those approved by the Federal Energy Regulatory Commission.

5) The Company's actual rates for providing transmission service will be determined on an individually negotiated case-by-case basis in order to allow for variations in providing such service under different circumstances. The Company will provide, upon request, estimates of the availability and cost and terms and conditions of providing the specified desired transmission wheeling service.

6) The Qualifying Facility shall be responsible for all costs associated with such wheeling and the Company will recover such costs from the Qualifying Facility including:

   a) Wheeling charges
   b) Line losses incurred by the Company
   c) Inadvertent energy flows resulting from such wheeling.

7) Energy delivered to the Company shall be adjusted before delivery to another utility as follows:

Qualifying Facility Rate Schedule	Adjustment Factor
RS, GS	0.9438
GSD, GSLD, SBF	0.9494
IS-1, IS-3, SBI-1, SBI-3	0.9814

8) The Company may deny, curtail, or discontinue transmission service to a Qualifying Facility on a non-discriminatory basis if the provision of such service would adversely affect the safety, adequacy, reliability, or cost of providing electric service to the Company's general body of retail and wholesale customers.

**METHODOLOGY TO BE USED
IN THE CALCULATION OF
AVOIDED ENERGY COST
SCHEDULE COG-1
APPENDIX A**

The methodology Tampa Electric (TEC) has implemented in order to determine the appropriate avoided energy costs and any payments thereof to be rendered to qualifying facilities (QFs) is consistent with the provisions of Order No. 23625 in Docket No. 891049-EU, issued on October 16, 1990, and with the Amendment of Rules 25-17.080 et seq, Florida Administrative Code.

The avoided energy costs methodology used to determine payments to Qualified Facilities (QFs) on an hourly basis is based on the incremental cost of fuel using the average price of replacement fuel purchased in excess of contract minimums and is further described in Exhibit #1. Generally, avoided energy costs are defined to include incremental fuel, identifiable variable operation and maintenance expenses, identifiable variable purchase power cost, and an adjustment for line losses reflecting delivery voltage.

Under normal conditions the Company will have additional generation resources available which can carry its native load and firm interchange sales without the QF's contribution. When this is the case and the QF is present, the incremental fuel portion of the avoided energy cost is equal to the difference between TEC's production cost at two load levels, with and without the QFs' contribution.

In those situations where the Company's available maximum generation resources not including its minimum spinning reserves are insufficient to carry its native load and firm interchange sales, in the absence of the QF contribution, TEC's incremental fuel component of the avoided energy cost will be determined by:

1) system lambda - if "off-system purchases" are not being made and all available generation has been dispatched; or

2) the highest incremental cost of any "off-system purchases" that are being made for native load.

Examples of these situations are found in Exhibits #3-#6.

Continued to Sheet No. 8.102

Continued from Sheet No. 8.101

The as-available avoided energy cost, as determined by this methodology, is priced at a level not to exceed Tampa Electric's incremental fuel and identifiable variable operating and maintenance (O&M) expenses including the cost of any off-system purchases for native load.

Parameters For Determining As-Available Avoided Energy Costs
Tampa Electric Company uses production costing methods for determining avoided energy cost payments to qualifying facilities (QFs). Computerized production costing is accomplished on an hourly basis. The parameters used are as follows:

1. The system load is the actual system load at the Hour Ending with the clock hour (HE).

2. The first allocation of load for production costing is to those units that are base loaded at a certain level for operating reasons. The remainder of the load is allocated to units available for economic dispatch through the use of incremental cost curves.

3. The fuel costs associated with each of Tampa Electric's units operating at its allocated level of generation is determined by using the individual units input/output equation, its heat rate performance factor, and the composite price of supplemental fuel.

4. The Company's own production cost for each hour of operation at a particular generation level equals the sum of the individual units' fuel cost for that hour. The production cost, thus determined, consists of the composite price of replacement fuel based on supplemental purchases and the incremental heat rate for the generating system.

5. The Company's total cost equals its own production cost (4. above), identified variable O&M, plus the cost of any off-system purchases to serve native load.

6. Native load includes all firm and non-firm retail load.

7. The cost of off-system firm and non-firm variable purchases is defined as the highest energy cost energy block purchased for native load during the hour; i.e., SCHEDULES A, B, C, D, X, J, UPP (Unit Power Purchase).

8. Firm interchange sales are included in production cost calculations.

Continued to Sheet No. 8.103

Continued from Sheet No. 8.102

9. The Company's available maximum generation resources in this methodology is defined as the maximum capacity less spinning reserve requirements.

10. The "Standard Tariff Block" is defined to be an x-megawatt (XMW) block equivalent to the combined actual hourly generation delivered to Tampa Electric from all QFs making as-available energy sales to Tampa Electric. In the absence of metered information on exports from a QF making as-available energy sales to Tampa Electric, an estimate of the hourly exports from that Facility will be used, rounded to the nearest 5 MW and then added to the sum of all other known as-available energy purchases for that hour.

Supplemental Fuel

The term "supplemental fuel" refers to that fuel purchased in excess of Tampa Electric's long-term contract minimum requirements. As illustrated in Exhibit #1, supplemental fuel can be composed of contract fuel purchases above minimums and fuel purchases on the spot market. When spot prices are lower than prices for minimum tonnages on long term contract purchases, spot prices are "supplemental." Under market conditions where spot prices are greater than the price of coal purchased under contract, it is economical for Tampa Electric to purchase more than the contract minimums. In this instance the supplemental price is a combination of the contract price of coal above minimum contract requirements and any coal purchased on the spot market. The company looks to the supplemental fuel for purposes of incremental pricing to determine the level of as-available energy payments because contract minimum purchases are a fixed expense.

Supplemental fuel is composed of contract fuel purchases above minimum levels and fuel purchases on the spot market. Tampa Electric pursues the least expensive alternative whether it be spot purchases or purchases of contract coal above the contract minimum, or a mixture of both. The supplemental fuel price is calculated by weight averaging all of the supplemental fuel purchases, by fuel type, during the preceding month. A Supplemental Fuel Cost Worksheet is shown in Exhibit #2.

With regard to oil-fired generation, Tampa Electric treats all of its oil purchases as supplemental fuel inasmuch as it has no contract minimums. For graphic portrayal of Tampa Electric's definition of supplemental fuel see Exhibit #1 attached.

Continued to Sheet No. 8.104

Continued from Sheet No. 8.103

Avoid Energy Cost Calculations

Example: #1 No Off-System Purchases, TEC's Generation Is Capable Of Carrying Its Native Load and Firm Sales.

The procedure used to deterministically calculate the incremental avoided energy cost associated with as-available energy on an hour by hour basis when no off-system purchases are taking place is as follows:

In these instances, the price per megawatt hour ($/MWH) that Tampa Electric will pay the QFs is determined by calculating the production cost at two load levels.

This first calculation determines TEC's production cost "without" the benefit of cogeneration.

The second calculation determines TEC's production cost "with" the benefit of cogeneration.

After each of the two calculations are made, the avoided energy cost rate is calculated by dividing the difference in production cost between the two calculations described above by the "Standard Tariff Block." [The "Standard Tariff Block" is defined to be an x-megawatt (XMW) block equivalent to the combined actual hourly generation delivered to TEC from all QFs making as-available energy sales to Tampa Electric. In the absence of metered information on exports from a QF making as-available energy sales to Tampa Electric an estimate of the hourly exports from that Facility will be used, rounded to the nearest 5 MWs and then added to the sum of the other as-available purchases for that hour. Prior to the in-service date of the appropriate designated avoided unit, firm energy sales will be equivalent to as-available sales. Beginning with the in-service date of the appropriate designated avoided unit, firm energy purchases from QFs shall be treated as "as-available" energy for the purposes of determining the XMW block size only during the periods that the appropriate designated avoided unit would not be operated.] The difference in production costs divided by the XMW block determines the As-Available Energy Payment Rate (AEPR) for the hour. The AEPR will be applied to the "Actual" QF megawatts purchased during the hour to determine payment to each QF supplying as-available energy, and each QF supplying firm energy in those instances where the avoided unit would not have been operated during the hour. See Exhibit #3 (Example #1).

Continued to Sheet No. 8.105

Continued from Sheet No. 8.104

Example #2 Off-System Purchases Are Not Being Made. TEC's Generation Can Only Carry Its Native Load and Firm Sales With The QF Contribution.

The procedure used to deterministically calculate the incremental avoided energy cost associated with as-available energy on an hour by hour basis whenever Tampa Electric is not purchasing off-system interchange is as follows:

In this instance, the avoided energy cost that Tampa Electric will pay the QFs will be determined by calculating the production cost at the last MW load level. The avoided energy cost is the production cost at system lambda. See Exhibit #4. (Example #2a)

In the situation where TEC's generation is not fully dispatched, and additional generation capability is available to price a portion of the QF block, then the QF block will be priced at a combination of the difference between TEC's production cost at two load levels as previously defined and at system lambda. See Exhibit #5. (Example #2b)

Example #3 Off-System Purchases Are Being Made To Serve Native Load.

The procedure used to deterministically calculate the incremental avoided energy cost associated with as-available energy on an hour by hour basis whenever Tampa Electric is making off-system purchases for native load is as follows:

In this instance, the price per MWH that Tampa Electric will pay is determined by applying the highest incremental cost of the off-system purchases to the QF block. See Exhibit #6. (Example #3)

Line Loss Credit

A credit for avoided line losses reflecting the voltage at which generation by the QFs is received is included in Tampa Electric's procedure for the determination of incremental avoided energy cost associated with as-available energy. Tampa Electric uses the loss factors used in the Fuel and Purchase Power Cost Recovery Clause for calculating the compensation for avoided line losses at the transmission and distribution system voltage levels based upon the appropriate classification of service.

Example: (Firm Standby Time-of-Day)

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Actual Incremental Hourly Avoided Energy Cost is:
$14.80/MWH
Adjustment Factor for Line Losses:
1.0555

The Actual Incremental hourly avoided Energy Cost adjusted for avoided line losses associated with as-available energy provided to Tampa Electric would then become, in this example, $15.62/MWH.

"Identifiable" Incremental Variable O&M

A procedure for approximating the "identifiable" incremental variable O&M expenses is included in Tampa Electric's methodology for the determination of incremental avoided energy costs associated with as-available energy.

The calculation of the variable O&M expense component associated with as-available energy is made annually in accordance with a system that differentiates actual annual total O&M costs into estimates of both fixed and variable components. This procedure, developed by the Electric Power Research Institute, was published in their Technical Assessment Guide (TAG) Special Report, dated May 1982, (EPRI P-2410-SR).

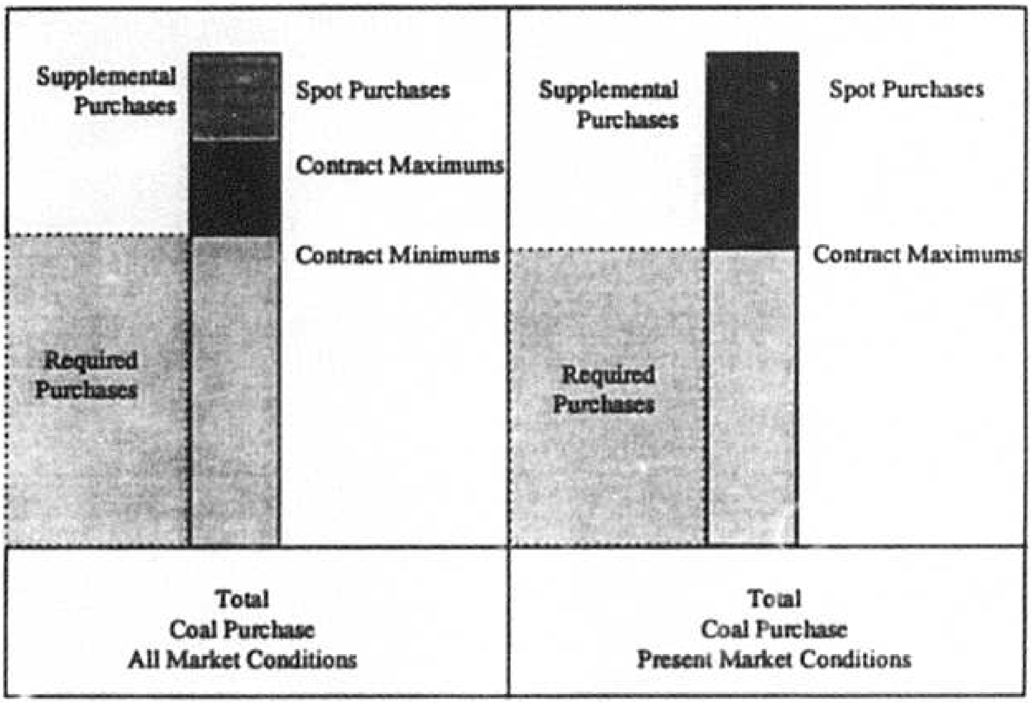
The EPRI-TAG assumptions provide an easily used and useful formula that approximates a fair payment for avoided variable O&M expenses. As such, it can be easily calculated and monitored using readily available information.
Once identified, based on the previous year's actual total O&M cost for coal-fired generation, the incremental avoided energy cost associated with as-available energy is adjusted to compensate for these variable expenses. (See Exhibit #7).

Continued to Sheet No. 8.107

Continued from Sheet No. 8.106

EXHIBIT #1

REQUIRED AND SUPPLEMENTAL COAL PURCHASES UNDER DIFFERENT MARKET CONDITIONS



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ISSUED BY: J. B. Ramil ~~G. F. Anderson~~, President

DATE EFFECTIVE: ~~March 31, 1992~~

Continued from Sheet No. 8.107

EXHIBIT #2

SUPPLEMENTAL FUEL COST WORKSHEET

Revised December 1988

UNITS DELIVERED	SUPPLIER C/MMBTU	SUPPLEMENTAL COAL COST $/TON	INCREMENTAL TRANS. COST $/TON	TOTAL $/TON	AUGUST AVERAGE BTU/LB	AUGUST AVERAGE C/MMBTU	AUGUST TONS	SUPPLEMENT FUEL COST
Gannon 1-4	A			$45.30				177.50
Gannon 5&6	B			$45.48				176.44
Big Bend 1&2	C			$29.22				123.13
	D			$31.67				
	E			$32.08				
			Average	$29.87				
Big Bend 3[1]	F			$50.55				173.67
			Blended Average	$42.28				
Big Bend 4	G			$41.70				181.31
	H			$37.21				
			Average	$41.11				
#2 Oil	I			$19.41/BBL				334.64

[1] Revised: Big Bend Unit #3 is burning a 60/40 blend of blend/standard coal.

Continued to Sheet No. 8.109

ISSUED BY: J. B. Ramil ~~G. F. Anderson~~, President

DATE EFFECTIVE: ~~March 31, 1992~~

Continued from Sheet No. 8.108

EXHIBIT #3

Example #1 **No Off-System Purchases, TEC's Generation Is Capable Of Carrying Its Native Load and Firm Sales.**

Given:
Actual QF Energy = 50 MWs
TEC's Maximum Available Generation = 1560 MWs
Native Load = 1550 MWs
Firm Sales = 10 MWs

First Calculation ("WITHOUT" QF):
Production Cost at 1560 MWs = $20,275/Hour

Second Calculation ("WITH" QF):
Production Cost at 1510 MWs = $19,500/Hour

Third Calculation (QF Rate $/MWH):
Actual Hourly Avoided Energy Cost =
($20,275/Hour - $19,500/Hour) / (50MW)

or

As-Available Energy Payment Rate (AEPR) = $15.50/MWH

Continued to Sheet No. 8.110

Continued from Sheet No. 8.109

EXHIBIT #4

Example #2a **Off-System Purchases Are Not Being Made. TEC's Generation Can Carry Its Native Load and Firm Sales Only With The QF Contribution.**

Given:

Actual QF Energy = 50 MWs
TEC's Maximum Available Generation = 1460 MWs
Native Load = 1500 MWs
Firm Sale = 10 MWs

First Calculation:

Production Cost at 1460 MWs = $18,900/Hour

Second Calculation:

Production Cost at 1459 MWs = $18,882.50/Hour

Third Calculation (QF Rate $/MWH):

Actual Hourly Avoided Energy Cost at 1 MW (System Lambda[1]) =
($18,900/Hour - $18,882.50/Hour) / (1 MW)

or

As-Available Energy Payment Rate (AEPR) = $17.50/MWH

NOTE:

[1] In this example, System Lambda is the production cost for the last MW segment to meet the load after dispatching all available generation capacity.

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Continued to Sheet No. 8.111

Continued from Sheet No. 8.110

EXHIBIT #5

Example #2b **Off-System Purchases Are Not Being Made to Serve Native Load and Firm Sales. Available Generation Capacity Is Not Fully Dispatched. Without the QF's Contribution, TEC's Native Load and Firm Sales Can Be Carried Only With Additional Power Purchases.**

Given:
Actual QF Energy = 50 MWs
TEC's Maximum Available Generation = 1530 MWs
TEC's Actual Generation = 1500 MWs
Native Load = 1540 MWs
Firm Sale = 10 MWs

Step 1 (Calculations for First 30 MWs)
First Calculation ("WITHOUT" QF):
Production Cost at 1530 MWs = $20,590/Hour
Second Calculation ("With" QF):
Production Cost at 1500 MWs = $20,050/Hour
Third Calculation:
Actual Hourly Avoided Energy Cost at 30 MWs =
($20,590/Hour) - ($20,050/Hour) = $540/Hour

Step 2 (Calculations for Remaining 20 MWs)
First Calculation:
Production Cost at 1530 MWs = $20,590/Hour
Second Calculation:
Production Cost at 1529 MWs = $20,571.50/Hour
Third Calculation:
Actual Hourly Avoided Energy Cost at 1 MW (System Lambda[1]) for 20 MWs =
($20,590/Hour - $20,571.50/Hour) X (20 MWs) = $370/Hour

Step 3 (Calculation of Composite Rate for Total 50 MW Block)
Composite Actual Hourly Avoided Energy Cost of 50 MW Block =
$540 + $370 / 50 MW
or
As-Available Energy Payment Rate (AEPR) = $18.20/MWH

NOTE:
[1] In this example, System Lambda is the production cost for the last MW segment to meet the load after dispatching all available generation capacity.

Continued to Sheet No. 8.112

Continued from Sheet No. 8.111

EXHIBIT #6

Example #3 **Off-System Purchases Are Being Made, TEC's Native Load and Firm Sales Can Be Carried Only With Additional Purchase Power**

Given:

Actual QF Energy = 50 MWs
TEC's Maximum Available Generation = 1500 MWs
TEC's Actual Generation = 1500 MWs
Native Load = 1540 MWs
Firm Sales = 20 MWs
Off-System Purchases[1] = 10 MWs Costing $400/Hour

Actual Incremental Hourly Avoided Energy Cost = $400 / 10 MW

or

AEPR = $40/Hour

NOTE:

[1] Off-System Purchase shall be the highest cost purchased energy block bought during the hour for native load.

Continued to Sheet No. 8.113

Continued from Sheet No. 8.112

EXHIBIT #7

The calculation of the variable O&M cost adjustment factor associated with as available energy is made once each year, based on the previous year's actual total O&M cost for coal-fired generation, in accordance with the procedure found in the Technical Assessment Guide dated May 1982, published by the Electric Power Research Institute (EPRI P-2410-SR). The formula assumes the fixed portion of total annual O&M dollars equals the capacity factor (%) times the total annual O&M dollars. The variable portion is (1 - capacity factor) times the total annual O&M dollars. The capacity factor is based on the total period hours less those hours the units are off line due to economic dispatch for low load periods. Continuing the logic further, the adjustment factor to be added to the avoided energy cost equals the variable rate as determined annually and applied in the form of an hourly adjustment to the actual incremental hourly avoided energy cost.

Example Given:	1983 TEC Coal Generation	MW	
1) Big Bend	1	367	
	2	362	
	3	375	
	3	10	upgrade
Gannon	5	218	
	6	351	
	4	169	conversion

MW available per unit from net generation listed in the System Data Book for the same time period:

2) Coal Generation 1983 = 10,493,266 MWH

3) O&M for coal 1983 = $35,320,252

Continued to Sheet No. 8.114

Continued from Sheet No. 8.113

EXHIBIT #7 - continued

ESTIMATED
1983 VARIABLE O&M RATE CALCULATION

		(MW)		(Hours)	(MWH)
Big Bend	1	367	@	8760	3,214,920
	2	362	@	8760	3,171,120
	3	375	@	8760	3,285,000
Upgrade	3	10	@	2208	22,080
Gannon	5	218	@	8760	1,909,680
	6	351	@	8760	3,074,760
Conversion to Coal	4	169	@	2208	373,152
TOTAL					15,050,712
Generation (1983 Actual for Coal)					10,493,266

Average Coal Capacity Factor $= \frac{10,493,266}{15,050,712} \times 100\%$

$= 69.72\%$

Total O&M for Coal = \$35,320,252

Variable Component = \$35,320,252 X (1 - .6972)

= \$10,694,972

Estimated Variable O&M Cost[1] $= \frac{10,694,772}{10,493,266} = \$1.02/\text{MWH}$

1 Was added to 1984's actual incremental hourly avoided energy cost, after approval by the FPSC.

ISSUED BY: J. B. Ram ~~G. F. Anderson~~, President

DATE EFFECTIVE: ~~March 31, 1992~~

STANDARD OFFER CONTRACT RATE FOR PURCHASE OF FIRM CAPACITY AND ENERGY FROM SMALL QUALIFYING FACILITIES OR MUNICIPAL SOLID WASTE FACILITIES

SCHEDULE: COG-2, Firm Capacity and Energy

AVAILABLE: Tampa Electric Company, herein after referred to as the "Company," will purchase Firm Capacity and Energy offered by any qualifying facility or municipal solid waste facility to which a Standard Offer Contract is available under Florida Public Service Commission (FPSC) Rule 25-17.0832(4)(a), Florida Administrative Code (F.A.C.). Unless specifically referred to, small "qualifying facilities" and "municipal solid waste facilities" may jointly be referred to as "qfs." The Company has designated a 180 megawatt (MW) (winter rating) natural gas fired combustion turbine generating unit with an in-service date of January 1, 2003, as its next Designated Avoided Unit. Until such time as the Designated Avoided Unit subscription limits have been fully and acceptably subscribed or the term of the Company's Standard Offer Contract has expired, the Company will accept Firm Capacity and Energy offered by any qf under the provisions of this schedule.

The Company will negotiate and may contract with any qualifying facility as defined in FPSC Rule 25-17.080, F.A.C., irrespective of its location, which is either directly or indirectly interconnected with the Company, for the purchase of Firm Capacity and Energy pursuant to terms and conditions which deviate from this schedule where such negotiated contracts are in the best interest of the Company's ratepayers.

APPLICABLE: To any qf to which Standard Offer Contracts are available under FPSC Rule 25-17.0832(4)(a), F.A.C., irrespective of its location, producing capacity and energy for sale to the Company on a firm basis pursuant to the terms and conditions of this schedule and the Company's Standard Offer Contract or a separately negotiated contract.

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Continued from Sheet No. 8.200

Firm Capacity and Energy are described in FPSC Rule 25-17.0832, F.A.C., and are capacity and energy produced and sold by a qf pursuant to a negotiated or Standard Offer Contract and subject to certain contractual provisions as to quantity, time and reliability of delivery. Criteria for achieving qualifying facility or municipal solid waste facility status shall be those set out in FPSC Rules 25-17.080, 25-17.082(4)(a), and 25-17.091, F.A.C., as applicable.

<u>CHARACTER OF SERVICE:</u> Purchases within the territory served by the Company shall be, at the option of the Company, single or three phase, 60 Hertz, alternating current at any available standard Company voltage. Purchases from outside the territory served by the Company shall be three phase, 60 Hertz, alternating current at the voltage level available at the interchange point between the Company and the entity delivering Firm Capacity and Energy from the qualifying facility or municipal solid waste facility.

<u>LIMITATIONS:</u> Purchases under this schedule are subject to the Company's "General Standards for Safety and Interconnection of Cogeneration and Small Power Production Facilities to the Electric Utility System," "NERC Planning Standards," September 1997, [Copyright @ 1997 by the North American Electric Reliability Council] that are applicable to generation and transmission facilities which are connected to, or being planned to be connected to the Company's transmission system (document provided upon request) and to FPSC Rules 25-17.080 through 25-17.091, F.A.C. and are limited to those qfs which are defined by FPSC Rule 25-17.082(4)(a), F.A.C. and which:

1. execute a Company Standard Offer Contract prior to January 1, 2001, for the Company's purchase of Firm Capacity and Energy; and

2. commit to commence deliveries of Firm Capacity and Energy no later than January 1, 2003, and to continue such deliveries through at least December 31, 2012; and

3. provide capacity which would not result in the Company's 180 MW subscription limit on capacity being exceeded.

<u>RATES FOR PURCHASES BY THE COMPANY:</u> Firm Capacity and Energy are purchased at unit costs, in dollars per kilowatt per month ($/kW/month) and cents per kilowatt-hour (¢/kWh), respectively, based on the value of deferring additional Company generating capacity.

Continued to Sheet No. 8.210

Continued from Sheet No. 8.205

For the purpose of this schedule, the Avoided Unit has been designated by the Company as a 180 MW combustion turbine generating unit with an in-service date of January 1, 2003. Appendix A of this schedule describes the methodology used to calculate payment schedules, general terms, and conditions applicable to the Company's Standard Offer Contract pursuant to FPSC Rules 25-17.080 through 25-17.091, F.A.C.

1. <u>Firm Capacity Rates:</u> Four options (i.e. Options 1, 2, 3, and 4, as set forth below) are available for payment of Firm Capacity which is produced by the qf and delivered to the Company. Once selected, the selected option shall remain in effect for the term of the contract with the Company. Exemplary payment schedules, shown on sheets following this section, contain the monthly rate per kilowatt (kW) of Firm Capacity the qf has contractually committed to deliver to the Company and are based on a minimum contract term which extends ten (10) years beyond the in-service date of the Designated Avoided Unit (i.e., through December 31, 2012). Payment schedules for longer contract terms will be made available to a qf upon request and may be calculated based on the methodologies described in Appendix A. At a maximum, Firm Capacity and Energy shall be delivered for a period of time equal to the anticipated plant life of the Designated Avoided Unit, commencing with the in-service date of the Designated Avoided Unit.

Option 1 - Value of Deferral Capacity Payments: Value of Deferral Capacity Payments shall commence on January 1, 2003, the in-service date of the Designated Avoided Unit, provided the qf is delivering Firm Capacity and Energy to the Company in accordance with the Minimum Performance Standards (MPS) as described in Appendix C. Capacity payments under this option shall consist of monthly payments, escalating annually of the avoided capital and fixed operating and maintenance expense associated with the Designated Avoided Unit and shall be equal to the value of the year-by-year deferral of the Designated Avoided Unit, calculated in conformance with FPSC Rule 25-17.0832, F.A.C., as described in Appendix A.

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Continued from Sheet No. 8.210

Option 2 - Early Capacity Payments: Payment schedules under this option are based on an equivalent net present value of the Value of Deferral Capacity Payments for the Designated Avoided Unit with an in-service date of January 1, 2003. The earliest date that Early Capacity Payments can be received by a qf shall be January 1, 2001. This is an approximation of the lead time required to site and construct the Designated Avoided Unit. The qf shall select the month and year in which the delivery of Firm Capacity and Energy to the Company is to commence and capacity payments are to start. Early Capacity Payments shall consist of monthly payments, escalating annually, of the avoided capital and fixed operating and maintenance expense associated with the Designated Avoided Unit. Avoided Capacity Payments shall be calculated in conformance with FPSC Rule 25-17.0832, F.A.C., as described in Appendix A. At the option of the qf, Early Capacity Payments may commence at any time after the specified earliest capacity payment date and before the in-service date of the Designated Avoided Unit provided the qf is delivering Firm Capacity and Energy to the Company in accordance with the Minimum Performance Standards as described in Appendix C. Where Early Capacity Payments are elected, the cumulsuve present value of the capacity paid to the qf over the term of the contract shall not exceed the cumulative present value of the capacity payments which would have been made to the qf had such payments been made pursuant to Option 1.

Option 3 - Levelized Capacity Payments: Levelized Capacity Payments shall commence on January 1, 2003, the in-service date of the Designated Avoided Unit, provided the qf is delivering Firm Capacity and Energy to the Company in accordance with the Minimum Performance Standards as described in Appendix C. The capital portion of the capacity payment under this option shall consist of equal monthly payments over the term of the contract, calculated in accordance with FPSC Rule 25-17.0832, F.A.C., as described in Appendix A. The fixed operation and maintenance expense portion of the capacity payment shall be equal to the value of the year-by-year deferral of fixed operation and maintenance expenses associated with the Designated Avoided Unit calculated in conformance with Appendix A. Where Levelized Capacity Payments are elected, the cumulative present value of the capacity paid to the qf over the term of the contract shall not exceed the cumulative present value of the capacity payments which would have been made to the qf had such payments been made pursuant to Option 1.

Continued to Sheet No. 8.220

Continued from Sheet No. 8.215

Option 4 - Early Levelized Capacity Payments: Early Levelized Capacity Payment schedules under this option are based on an equivalent net present value of the Value of Deferral Capacity Payments for the Designated Avoided Unit with an in-service date of January 1, 2003. The earliest date that Early Levelized Capacity Payments can be received by a qf shall be January 1, 2001. This is an approximation of the lead time required to site and construct the Designated Avoided Unit. The capital portion of the capacity payment under this Option shall consist of equal monthly payments over the term of the contract, calculated in accordance with FPSC Rule 25-17.0832, F.A.C., as described in Appendix A. The fixed operation and maintenance expense portion of the capacity payments shall be equal to the value of the year-by-year deferral of fixed operation and maintenance expenses associated with the Designated Avoided Unit calculated in conformance with Appendix A. At the option of the qf, Early Levelized Capacity Payments shall commence at any time after the specified earliest capacity payment date and before the in-service date of the Designated Avoided Unit provided the qf is delivering Firm Capacity and Energy to the Company in accordance with the Minimum Performance Standards as described in Appendix C. The qf shall select the month and year in which the delivery of Firm Capacity and Energy to the Company is to commence and capacity payments are to start. Where Early Levelized Capacity Payments are elected, the cumulative present value of the capacity payments paid to the qf over the term of the contract shall not exceed the cumulative present value of the capacity payments which would have been made to the qf had such payments been made pursuant to Option 1.

The Company will provide the qf with a schedule of capacity payment rates based on the month and year in which the delivery of Firm Capacity and Energy are to commence and the term of the contract. The following exemplary payment schedules are based on the minimum required contract term which must extend at least ten (10) years beyond the in-service date of the Designated Avoided Unit. The currently approved parameters used to calculate the following schedule of payments are found in Appendix B of this schedule.

~~RESERVED FOR FUTURE USE~~

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UNIT TYPE: 180 MW (Winter Rating) COMBUSTION TURBINE (IN-SERVICE 1/1/2003)
MONTHLY CAPACITY PAYMENT RATE $/kW/MONTH

CONTRACT YEAR FROM	TO	OPTION 1 NORMAL PAYMENT STARTING 1/1/2003 $/kW/MO	OPTION 2 EARLY PAYMENT STARTING 1/1/2002 $/kW/MO	OPTION 2 EARLY PAYMENT STARTING 1/1/2001 $/kW/MO	OPTION 3 LEVELIZED PAYMENT STARTING 1/1/2003 $/kW/MO	OPTION 4 EARLY LEVELIZED PAYMENT STARTING 1/1/2002 $/kW/MO	OPTION 4 EARLY LEVELIZED PAYMENT STARTING 1/1/2001 $/kW/MO
1/1/01	12/31/01	-	-	2.44	-	-	2.70
1/1/02	12/31/02	-	2.83	2.50	-	3.10	2.70
1/1/03	12/31/03	3.31	2.90	2.56	3.60	3.11	2.71
1/1/04	12/31/04	3.39	2.97	2.62	3.61	3.12	2.72
1/1/05	12/31/05	3.45	3.04	2.69	3.61	3.12	2.72
1/1/06	12/31/06	3.56	3.12	2.75	3.62	3.13	2.73
1/1/07	12/31/07	3.64	3.19	2.82	3.63	3.14	2.74
1/1/08	12/31/08	3.73	3.27	2.89	3.64	3.15	2.74
1/1/09	12/31/09	3.82	3.35	2.96	3.65	3.16	2.75
1/1/10	12/31/10	3.91	3.43	3.03	3.66	3.16	2.76
1/1/11	12/31/11	4.01	3.51	3.10	3.67	3.17	2.76
1/1/12	12/31/12	4.11	3.60	3.18	3.68	3.18	2.77

2. **Energy Payment Rates:**

a. **Payments Prior to January 1, 2003**: The As-Available Energy Payment Rate in ¢/kWh will apply and shall be based on the Company's actual hourly avoided energy costs which are calculated by the Company in accordance with FPSC Rule 25-17.0825, F.A.C. Avoided energy costs include incremental fuel, identifiable variable operation and maintenance expenses, and an adjustment for line losses reflecting delivery voltage.

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The calculation of energy payments to the qf shall be based on the sum, over all hours of the Monthly Period, of the product of each hour's Energy Payment Rate times the energy purchased from the qf by the Company for that hour. All purchases shall be adjusted for losses from the point of metering to the point of interconnection.

The methodology to be used in the calculation of the avoided energy costs is described in Appendix D.

b. Payments Starting on January 1, 2003: To the extent that the Designated Avoided Unit is dispatched by the Company and operates, the Unit Energy Payment Rate in ¢/kWh will apply and shall be based on the Designated Avoided Unit's energy cost (fuel and variable operation and maintenance expense). Otherwise, when not dispatched by the Company the As-Available Energy Payment Rate will apply to the qf when operating will be based on the Company's actual hourly avoided energy cost.

Calculation of energy payments to the qf shall be based on the sum, over all hours of the Monthly Period, of the product of each hour's Energy Payment Rate times the energy purchased from the qf by the Company for that hour. All purchases shall be adjusted for losses from the point of metering to the point of interconnection.

The methodology to be used in the calculation of the avoided energy costs is described in Appendix D.

~~RESERVED FOR FUTURE USE~~

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Continued from Sheet No. 8.230

PERFORMANCE CRITERIA: In addition to the following provisions, payments fc Firm Capacity are conditioned on the qf's ability to meet or exceed the Minimum Performance Standards (MPS) for the Company's Designated Avoided Unit as described in Appendix C:

1. **QF's Commercial In-Service Date:** Capacity Payments shall not commence until the qf has attained and demonstrated commercial in-service status. The Commercial In-Service Date of a qf shall be defined as the first day of the month following the successful completion by the qf of maintaining an hourly kW output for a 24 hour period, as metered at the point of interconnection with the Company, equal to or greater than the qf's "Contracted Capacity" as designated in the Standard Offer Contract. A qf shall coordinate the operation of its facility during this test period with the Company to insure that the performance of its facility during this 24 hour period is reflective of the anticipated day to day operation of the qf.

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2. **Monthly Availability and Monthly Capacity Factor:** Upon achieving commercial in-service status, payments for Firm Capacity shall be made monthly in accordance with the capacity payment rate option selected by the qf and subject to the provision that the qf equals or exceeds the MPS for Monthly Availability and Monthly Capacity Factor of the Company's Designated Avoided Unit, as defined in Appendix C of this schedule.

3. **QF's Obligation if QF Receives Early, Levelized, or Early Levelized Capacity Payments:** The qf's payment option choice pursuant to Paragraph 4.b.iii of the Company's Standard Offer Contract may result in payments made by the Company fo capacity delivered prior to January 1, 2003. Similarly, Levelized and Early-Levelized Capacity Payments for capacity delivered on or after January 1, 2003, may also exceed the year-by-year value of deferring the Designated Avoided Unit as specified in this Agreement. The parties recognize that capacity payments that exceed the year-by-year value of deferring the avoided unit may have to be repaid by the qf in the event the qf fails to perform pursuant to the terms and conditions of the Company's Standard Offer Contract.

To ensure that the qf will satisfy its obligation to make any repayment to the Company, the following provisions will apply:

The Company shall establish a Repayment Account to accrue the sum of the capacity payments that may have to be repaid by the qf to the Company. Amounts shall be added to the Repayment Account each month through December 2002, in the amount of the Company's early capacity payments made to the qf pursuant to the qf's chosen payment option.

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Beginning on January 1, 2003, the difference between the capacity payment made to the qf and the "normal" capacity payment calculated pursuant to Option 1 will also be added each month to the Repayment Account, so long as the payment to the qf is greater than the monthly payment the qf would have received if it had selected Option 1 in Paragraph 4.b.iii, of the Company's Standard Offer Contract.

Also beginning on January 1, 2003, at such time that the monthly capacity payment made to the qf, pursuant to the Capacity Payment Option selected, is less than the "normal" monthly capacity payment in Option 1, there shall be debited from the Repayment Account an Early Payment Offset Amount to reduce the balance in the Repayment Account. Such Early Payment Offset Amount shall be equal to the amount which the Company would have paid for capacity in that month if capacity payments had been calculated pursuant to Option 1 and the qf had elected to begin receiving capacity payments on January 1, 2003 minus the monthly capacity payment the Company makes to the qf (assuming the MPS are met or exceeded), pursuant to the Capacity Payment Option chosen by the qf. Monthly Capacity Payments will not be made to the qf for any month the qf fails to meet the MPS and if applicable, a payment will be required by the qf to the Company in an amount equal to the Early Payment Offset for that month. In the event a payment is required from the qf to the Company, the qf's Repayment Account will be reduced by the amount of such payment provided that any such payment will not exceed the current balance in the Repayment Account.

The qf shall owe the Company and be liable for the current balance in the Repayment Account. The annual balance in the Repayment Account shall accrue interest at an annual rate of 9.37%. The Company agrees to notify the qf monthly as to the current Repayment Account balance.

In the event of default by the qf, the total Repayment Account balance shall become due and payable within twenty (20) business days of receipt of written notice, as reimbursement for the early capacity payments made to the qf by the Company.

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The qf's obligation to reimburse the Company in the amount of the balance in the Repayment Account shall survive the termination of the qf's Standard Offer Contract with the Company. Such reimbursement shall not be construed to constitute liquidated damages and shall in no way limit the right of the Company to pursue all its remedies at law or in equity against the qf.

Prior to receipt of Early, Levelized, or Early-Levelized Capacity Payments the qf shall secure its obligation to repay any balance in the Repayment Account in the event the qf defaults under the terms of its Standard Offer Contract with the Company.

Such security shall be in the form of cash deposited in an interest bearing escrow account mutually acceptable to the Company and the qf; an unconditional and irrevocable direct pay letter of credit in form and substance satisfactory to the Company; or a performance bond in form and substance satisfactory to the Company. The form of security required will be in the sole discretion of the Company and will be in such form as to allow the Company immediate access to the funds in the event of default by the qf.

Florida Statute 377.709(4) requires a local government to refund early capacity payments should a municipal solid waste facility owned, operated by or on the behalf of the local government be abandoned, closed down or rendered illegal. Therefore a utility may not require risk-related guarantees from a municipal solid waste facility as required in FPSC Rule 25-17.0832 (2)(c) and (3)(e)(8), F. A. C. However, at its option, a municipal solid waste facility may provide such risk-related guarantees.

4. <u>Additional Criteria:</u>

   a. The qf shall provide monthly generation estimates by April 1 for the next calendar year; and

   b. The qf shall promptly update its yearly generation schedule when any changes are determined necessary; and

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Continued to Sheet No. 8.255

Continued from Sheet No. 8.250

c. The qf shall agree to reduce generation or take other appropriate action as requested by the Company for safety reasons or to preserve system integrity; and

d. The qf shall coordinate scheduled outages with the Company; and

e. The qf shall comply with the reasonable requests of the Company regarding daily or hourly communications.

DELIVERY VOLTAGE ADJUSTMENT: Energy Payments to qfs within the Company's service territory shall be adjusted according to the delivery voltage by the following multipliers:

Rate Schedule	Adjustment Factor
RS, GS	1.0616
GSD, GSLD, SBF	1.0561
IS-1, IS-3	1.0254
SBI-1, SBI-3	1.0254

METERING REQUIREMENTS. Qfs within the territory served by the Company shall be required to purchase from the Company the necessary hourly recording meters to measure their energy production. Unless special circumstances warrant, meters shall be read at monthly intervals on the approximate corresponding day of each meter reading period. Energy purchases from qfs outside the territory served by the Company shall be measured as the quantities scheduled for interchange to the Company by the entity delivering Firm Capacity and Energy to the Company.

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TAMPA ELECTRIC COMPANY

SIXTH ~~FIFTH~~ REVISED SHEET NO. 8.260
CANCELS FIFTH ~~FOURTH~~ REVISED SHEET NO. 8.260

Continued from Sheet No. 8.255

BILLING OPTIONS: The qf upon entering into a contract for the sale of Firm Capacity and Energy or prior to delivery of As-Available Energy to the Company shall elect to make either simultaneous purchases from the interconnecting utility and sales to the Company or net sales to the Company. The billing option elected may only be changed:

1. when the qf selling As-Available Energy enters into a negotiated contract or standard offer contract for the sale of Firm Capacity and Energy; or

2. when a Firm Capacity and Energy contract expires or is lawfully terminated by either the qf, or the Company; or

3. when the qf is selling As-Available Energy and has not changed billing methods within the last twelve months; and

4. when the election to change billing methods will not contravene the provisions of FPSC Rule 25-17.0832, F.A.C., or any contract between the qf and the Company.

If the qf elects to change billing methods in accordance with FPSC Rule 25-17.082, F.A.C., such a change shall be subject to the following provisions:

1. upon at least thirty (30) days advance written notice to the Company; and

2. upon the installation by the Company of any additional metering equipment reasonably required to effect the change in billing methodology and upon payment by the qf for such metering equipment and its installation; and

3. upon completion and approval by the Company of any alterations to the interconnection reasonably required to effect the change in billing methodology and upon payment by the qf for such alterations.

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Continued to Sheet No. 8.265

ISSUED BY: J. B. Ramil ~~K. S. Surgenor~~, President

DATE EFFECTIVE: ~~September 13, 1994~~

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Should a qf elect to make simultaneous purchases and sales, purchases of electric service by the qf from the interconnecting utility shall be billed at the retail rate schedule under which the qf load would receive service as a non-generating customer of the utility; sales of electricity delivered by the qf to the purchasing utility shall be purchased at the utilities avoided capacity and energy rates, where applicable, in accordance with FPSC Rules 25-17.0825 and 25-17.0832, F.A.C.

Should a qf elect a net billing arrangement, the hourly net capacity and energy sales delivered to the purchasing utility shall be purchased at the utility's avoided capacity and energy rates, where applicable, in accordance with FPSC Rules 25-17.0825 and 25-17.0832, F.A.C. Purchases from the interconnecting utility shall be billed pursuant to the utility's applicable standby service or supplemental service rate schedules.

Under the net sales billing option, the qf may commit Firm Capacity to the Company's system. Committed capacity is described in the Standard Offer Contract. For the net sales billing option, the committed capacity is additional to internal use, and the rates for purchase, and the performance criteria apply only to the power delivered to the Company. Although a billing option may be changed in accordance with FPSC Rule 25-17.082, F.A.C., the Contracted Capacity may only change through mutual negotiations satisfactory to the qf and the Company.

Customer charges that are directly attributable to the purchase of Firm Capacity and Energy from the qf are deducted from the qf's total monthly payment. A statement covering the charges and payments due the qf is rendered monthly and payment normally is made by the twentieth (20th) business day following the end of the Monthly Period.

CHARGES/CREDITS TO THE QF:

1. **Customer Charges:** A monthly Customer Charge will be rendered for maintaining an account for a Qualifying Facility engaged in either an As-Available Energy or Firm Capacity and Energy transaction and for other applicable administrative costs. Actual charges will depend on how the QF is interconnected to the Company.

QFs not directly interconnected to the Company, will be billed $580 monthly as a Customer Charge.

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Monthly customer charges, applicable to QFs directly interconnected to the Compan , by Rate Schedule are:

Rate Schedule	Customer Charge	Rate Schedule	Customer Charge
RS	$ 8.50	RST	$ 11.50
GS	8.50	GST	11.50
GSD	42.00	GSDT	49.00
GSLD	255.00	GSLDT	255.00
SBF	280.00	SBFT	280.00
IS-1	1,000.00	IST-1	1,000.00
IS-3	1,000.00	IST-3	1,000.00
SBI-1	1,025.00	SBIT-1	1,025.00
SBI-3	1,025.00	SBIT-3	1,025.00

When appropriate, the Customer Charge will be deducted from the Qualifying Facility's monthly payment. A statement of the charges or payments due the Qualifying Facility will be rendered monthly. Payment normally will be made by the twentieth (20th) business day following the end of the billing period.

2. Interconnection Charge for Non-Variable Utility Expenses: The qf shall bear the cost required for interconnection including the metering. The qf shall have the option of payment in full for interconnection or make equal monthly installment payments over a thirty-six (36) month period together with interest at the rate then prevailing for thirty (30) days highest grade commercial paper; such rate to be determined by the Company thirty (30) days prior to the date of each payment.

3. Interconnection Charge for Variable Utility Expenses: The qf shall be billed monthly for the cost of variable utility expenses associated with the operation and maintenance of the interconnection. These costs include a) the Company's inspections of the interconnection and b) maintenance of any equipment beyond that which would be required to provide normal electric service to the qf with respect to other Customers with similar load characteristics.

4. Taxes and Assessments: The qf shall be billed monthly an amount equal to the taxes, assessments, or other impositions, if any, for which the Company is liable as a result of its purchases of Firm Capacity and Energy produced by the qf.

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Continued from Sheet No. 8.270

If the Company obtains any tax savings as a result of its purchases of Firm Capacity and Energy produced by the qf, which tax savings would not have otherwise been obtained, those tax savings shall be credited to the qf.

5. <u>Emission Allowance Clause:</u> Subject to approval by the FPSC, the qf shall receive a monthly credit, to the extent the Company can identify the same, equal to the value, if any, of any reduction in the number of air emission allowances used by the Company as a result of its purchase of Firm Capacity and Energy produced by the qf; provided that no such credit shall be given if the cost of compliance associated with air emission standards is included in the determination of full avoided cost.

<u>TERMS OF SERVICE:</u>

1. It shall be the qf's responsibility to inform the Company of any change in its electric generation capability.

2. Any electric service delivered by the Company to the qf shall be metered separately and billed under the applicable retail rate schedule and the terms and conditions of the applicable rate schedule shall pertain.

3. A security deposit will be required in accordance with FPSC Rules 25-17.082(5) and 25-6.097, F.A.C., and the following:

   a. In the first year of operation, the security deposit should be based upon the singular month in which the qf's projected purchases from the utility exceed, by the greatest amount, the utility's estimated purchases from the qf. The security deposit should be equal to twice the amount of the difference estimated for that month. The deposit should be required upon interconnection.

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b. For each year thereafter, a review of the actual sales and purchases between the qf and the utility shall be conducted to determine the actual month of maximum difference. The security deposit shall be adjusted to equal twice the greatest amount by which the actual monthly purchases by the qf exceed the actual sales to the utility in that month.

4. The Company shall specify the point of interconnection and voltage level.

5. The Company will, under the provisions of this Schedule, require an agreement with the qf upon the Company's filed Standard Offer Contract and Interconnection Agreement. The qf shall recognize that its generation facility may exhibit unique interconnection requirements which will be separately evaluated and may require modifications to the Company's General Standards for Safety and Interconnection where applicable.

6. Service under this rate schedule is subject to the rules and regulations of the Company and the FPSC.

SPECIAL PROVISIONS:

1. Negotiated contracts deviating from the above standard rate schedule are allowable provided they are agreed to by the Company and approved by the FPSC.

2. In accordance with the provision in FPSC Rule 25-17.0883, F.A.C., the Company is required to provide transmission and distribution service to enable a retail customer to transmit electrical power generated at one location to the customer's facilities at another location when provision of such service and its associated charges, terms, and other conditions are not reasonably projected to result in higher cost of electric service to the Company's general body of retail and wholesale Customers or adversely affect the adequacy or reliability of electric service to all Customers.

A determination of whether or not such service is likely to result in higher cost electric service will be made by evaluating the results of an appropriately adjusted FPSC approved cost effectiveness methodology, in addition to other modeling analyses.

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Continued to Sheet No. 8.285

ISSUED BY: J. B. Ramil ~~K. S. Surgenor~~, President DATE EFFECTIVE: ~~September 13, 1994~~

Continued from Sheet No. 8.280

3. In accordance with FPSC Rule 25-17.089, F.A.C., upon request by a qf, the Company shall provide transmission service in accordance with its Open Access Transmission Tariff to wheel As-Available Energy or Firm Capacity and Energy produced by a qf from the qf to another electric utility.

4. The rates, terms, and conditions for any transmission and ancillary services provide to a qf shall be those approved by the Federal Energy Regulatory Commission (FERC) and contained in the Company's Open Access Transmission Tariff.

5. A qf may apply for transmission and ancillary services from the Company in accordance with the Company's Open Access Transmission Tariff. Requests for service must be submitted on the Company's Open Access Same-Time Information System ("OASIS"). The Company's contact person, phone number and address is posted and updated on the OASIS and can be viewed by the public on the Internet at the address: http://www.enx.com/FOA_Contacts.html. A copy of the Company's Open Access Transmission Tariff is also posted at the address: http://www.enx.com/FOA/teco_home.html.

6. If the qf is located outside of the Company's transmission area, then the qf must arrange for long term firm third-party transmission, ancillary services and an interconnection agreement on all necessary external transmission paths for the term of the contract.

__PROCEDURE FOR PROCESSING STANDARD OFFER CONTRACTS:__ The Company's Standard Offer Contract will initially become available for subscription during a 2-week open-season period which will commence on the effective date of the Standard Offer Contract, as approved by the FPSC.

The Company will only "receive" Standard Offer Contracts during a 2-week open-season period. All Standard Offer Contracts delivered to the Company during a 2-week open-season period will be considered to have been "received" on the final day of the period.

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Within 60 days of the receipt of a signed Standard Offer Contract (60 days from the expiration of a 2-week open-season period), the Company shall either accept and sign the Standard Offer Contract and return it within 5 days to the qf or petition the Commission not to accept the Standard Offer Contract and provide justification for the refusal.

The Company's initial 2-week open-season period will be defined as the ten (10) successive business days beginning on the effective date of the Company's Standard Offer Contract. On the tenth (10th) business day, the initial 2-week open-season period will expire at the close of business, 5 PM Eastern Prevailing Time (EPT). All Standard Offer Contracts received during the initial 2-week open-season period will be given equal consideration and each will be reviewed in accordance with the Company's Evaluation Procedure for Standard Offer Contracts. The criteria and procedure used to evaluate Standard Offer Contracts are attached to the Standard Offer Contract as Appendix C.

Each delivered Standard Offer Contract should be clearly labeled "Standard Offer Contract" and shall only be received at the Company's main business address:

> Tampa Electric Company
> TECO Plaza 4
> c/o Director, Phosphate Sales & Cogeneration Services
> 702 North Franklin Street
> P. O. Box 111
> Tampa, Florida 33601

Certified mail will be the preferred means of Standard Offer Contract delivery. Any Standard Offer Contracts delivered prior to or following the expiration of the initial 2-week open-season will not be considered eligible and will be promptly returned.

Each eligible Standard Offer Contract received during the initial 2-week open-season period, will be evaluated as to its technical reliability, viability and financial stability, as well as other relevant information, in accordance with FPSC Rule 25-17.0832, F.A.C.

Each of the eligible Standard Offer Contracts will be prioritized following the evaluation process. The Company will select and accept Standard Offer Contracts, after the evaluation process, which have convincingly demonstrated that their project is financially and technically viable and that the committed capacity and energy would be available by the date specified in the Standard Offer Contract.

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The Company will accept successive Standard Offer Contracts, beginning with the Standard Offer Contract with the highest priority, until further acceptance of a Standard Offer Contract would cause the subscription limit to be exceeded.

If the subscription limit is not exceeded after evaluating all eligible Standard Offer Contracts received during the initial 2-week open-season period, then the Standard Offer Contract will be reopened for subscription, for an additional 2-week open-season period, beginning 90 days from the expiration of the initial 2-week open-season period. The Company will notify the FPSC in the event an additional 2-week open-season period is required.

Those qfs that previously submitted Standard Offer Contracts which were not accepted by the Company may resubmit their Standard Offer Contracts for evaluation during the additional 2-week open-season period. Other interested qfs may also submit Standard Offer Contracts for consideration during this time.

This procedure will replicate itself until such time as the Standard Offer Contract is no longer available for subscription. All interested parties should be aware of this possibility and should remain in frequent communication with the Company or the FPSC.

Once the Company's Standard Offer Contract is fully and acceptably subscribed or has expired, the Company will petition the Commission to close its Standard Offer Contract. Any executed Standard Offer Contracts received by the Company during the pendency of such a petition ("Interim SOCs") shall be held in abeyance pending final disposition of the petition. If the petition is finally approved (including any appellate review process), any Interim SOCs received during the pendency of the petition shall be rendered void and of no force and effect. If the petition is finally disapproved (including any appellate review process), any Interim SOCs received during the pendency of the petition shall be reactivated and processed in accordance with the Company's approved Procedure for Processing Standard Offer Contracts.

In its petition, the Company will provide the Commission with an estimate of the date that it will be filing a petition with respect to its new Standard Offer needs. The Company will then reassess its needs for capacity and petition the Commission regarding a Standard Offer Contract which reflects its updated needs for capacity. If the Company's petition for a new Standard Offer Contract is based on a different generation expansion plan than its previously approved Standard Offer Contract, then the Company will include the generation expansion plan in support of its petition.

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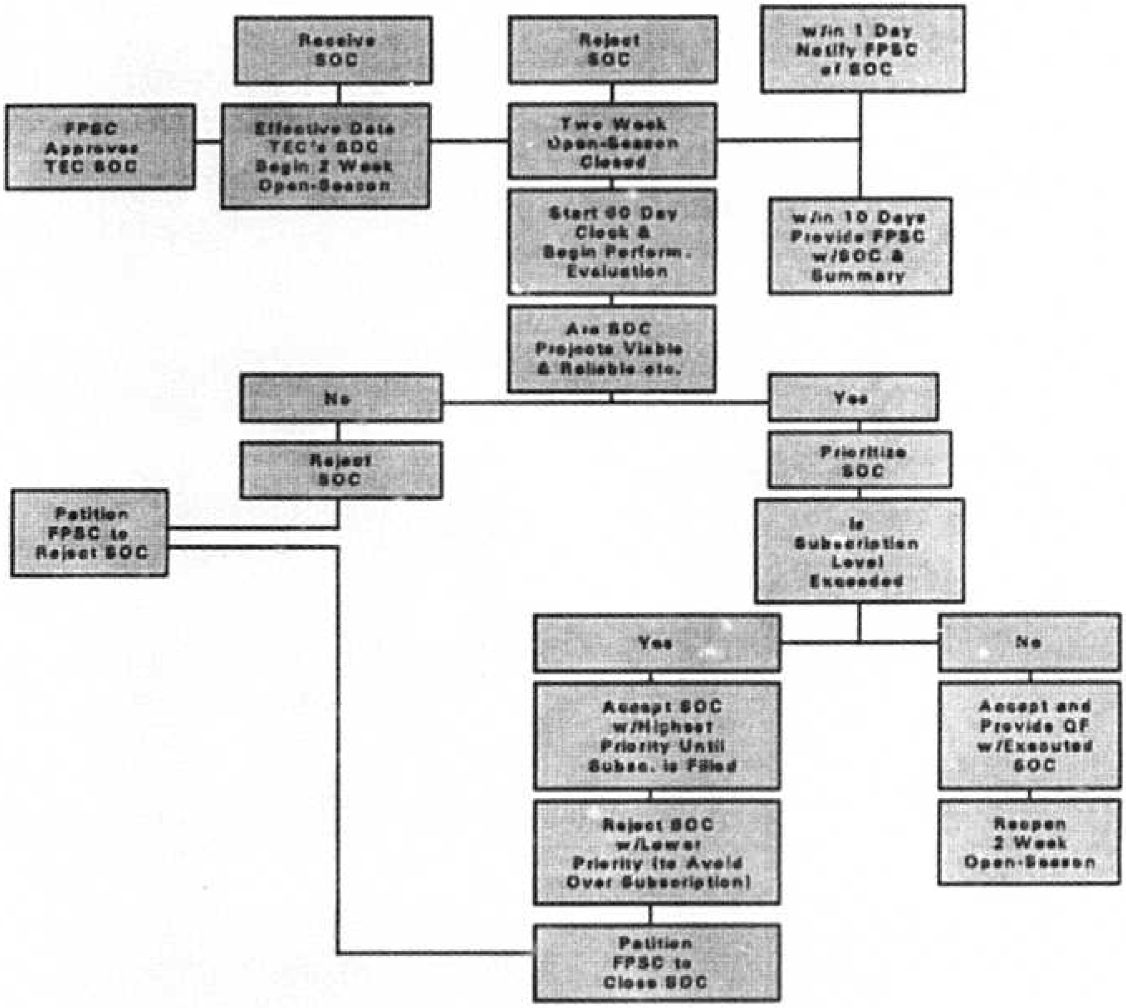
PROCEDURE FOR PROCESSING STANDARD OFFER CONTRACTS



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Schedule of COG-2

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STANDARD OFFER CONTRACT RATE FOR PURCHASE OF FIRM CAPACITY AND ENERGY FROM SMALL QUALIFYING FACILITIES OR MUNICIPAL SOLID WASTE FACILITIES
SCHEDULE COG-2
APPENDIX A

Appendix A provides a detailed description of the methodology used by the Company to calculate the monthly value of deferring the Designated Avoided Unit referred to in Schedule COG-2. When used in conjunction with the current FPSC approved cost parameters associated with the Designated Avoided Unit contained in Appendix B, a qf may determine the applicable value of deferral capacity payment rate associated with the timing and operation of its particular facility should the qf enter into a Standard Offer Contract with the utility.

Also contained in Appendix A is a discussion of the types and forms of surety bond requirements or equivalent assurance of repayment of early capacity payments acceptable to the Company in the event of contractual default by a qf.

<u>CALCULATION OF VALUE OF DEFERRAL:</u> FPSC Rule 25-17.0832(6), F.A.C., specifies that avoided capacity costs, in dollars per kilowatt per month, associated with firm capacity sold to a utility by a qf pursuant to the utility's Standard Offer shall be defined as the value of a year-by-year deferral of the Designated Avoided Unit and shall be calculated as follows:

$$VAC_m = \frac{1}{12}\left[KI_n \frac{\left[1 - \frac{(1+i_p)}{(1+r)}\right]}{\left[1 - \frac{(1+i_p)^L}{(1+r)^L}\right]} + O_n \right]$$

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FPSC Rule 25-17.0832(6)(a), F.A.C., specifies that, beginning with the in-service date of the Company's Designated Avoided Unit, for a one year deferral:

VAC_m = Company's monthly value of avoided capacity, \$/kW/month, for each month of year n;

K = present value of carrying charges for one dollar of investment over L years with carrying charges computed using average annual rate base and assumed to be paid at the middle of each year and present value to the middle of the first year;

I_n = total direct and indirect cost, in mid-year dollars per kilowatt (\$/kW) including AFUDC but excluding CWIP, of the Designated Avoided Unit(s) with an in-service date of year n, including all identifiable and quantifiable costs relating to the construction of the Designated Avoided Unit(s) that would have been paid had the Designated Avoided Unit(s) been constructed;

O_n = total fixed operation and maintenance expense for the year n, in mid-year dollars per kilowatt per year \$/kW/year, of the Designated Avoided Unit(s);

i_p = annual escalation rate associated with the plant cost of the Designated Avoided Unit(s);

i_o = annual escalation rate associated with the operation and maintenance expense of the Designated Avoided Unit(s);

r = annual discount rate, defined as the Company's incremental after tax cost of capital;

L = expected life of the Designated Avoided Unit(s); and

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TAMPA ELECTRIC COMPANY

FIFTH ~~FOURTH~~ REVISED SHEET NO. 8.320
CANCELS FOURTH ~~THIRD~~ REVISED SHEET NO. 8.320

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n = year for which the Designated Avoided Unit(s) is deferred starting with its original anticipated in-service date and ending with the termination of the contract for the purchase of firm capacity and energy.

FPSC Rule 25-17.0832(6)(b), F.A.C., specifies that, normally, payment for Firm Capacity shall not commence until the in-service date of the Designated Avoided Unit(s). At the option of the qf, however, the Company may begin making early capacity payments consisting of the fixed operation and maintenance expense and the capital cost component of the value of a year-by-year deferral of the Designated Avoided Unit(s) starting as early as two years prior to the in-service date of the Designated Avoided Unit(s). When such early capacity payments are elected, capacity payments shall be paid monthly commencing no earlier than the Commercial In-Service date of the qf, and shall be calculated as follows:

$$A_m = A_s \left[\frac{(1 + i_p)^{(m-1)}}{12} \right] + A_o \left[\frac{(1 + i_o)^{(m-1)}}{12} \right] \text{ for } m = 1 \text{ to } t$$

Beginning with the earliest avoidance date of the Company's Designated Avoided Unit(s), for a one year deferral:

A_m = monthly early capacity payments to be made to the qf starting as early as two years prior to the in-service date of the Company's Designated Avoided Unit(s), in \$/kW/month;

i_p = annual escalation rate associated with the plant cost of the Designated Avoided Unit(s);

i_o = annual escalation rate associated with the operation and maintenance expense of the Designated Avoided Unit(s);

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Continued to Sheet No. 8.325

ISSUED BY: J. B. Ramil ~~K. S. Surgenor~~, President

DATE EFFECTIVE: ~~September 13, 1994~~

Continued from Sheet No. 8.320

m = earliest year for which capacity payments to a qf may be made;

t = the minimum term, in years, of the contract for the purchase of firm capacity if early capacity payments commence in year m;

$$A_e = F \left[\frac{1 - \dfrac{(1 + i_e)}{(1 + r)}}{1 - \dfrac{(1 + i_e)^t}{(1 + r)^t}} \right]$$

Where:

F = the cumulative present value of the annual avoided capital cost component of capacity payments for a ten year period, commencing with the in-service date of the Designated Avoided Unit(s) (in $/kW/year in 2001 dollars);

r = annual discount rate, defined as the Company's incremental after tax cost of capital; and

$$A_o = G \left[\frac{1 - \dfrac{(1 + i_o)}{(1 + r)}}{1 - \dfrac{(1 + i_o)^t}{(1 + r)^t}} \right]$$

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Where: G = the cumulative present value in the year that the contractual payments will begin, of the avoided fixed operation and maintenance expense component of capacity payments which would have been made had capacity payments commenced with the anticipated in-service date of the Designated Avoided Unit(s).

FPSC Rule 25-17.0832(6)(c), F.A.C., specifies that, Monthly Levelized and Early Levelized Capacity Payments shall be calculated as follows:

$$P_L = \frac{F}{12} \times \frac{r}{1-(1+r)^{-t}} + O$$

Where:

P_L = the monthly Levelized Capacity Payment, starting on or prior to the in-service date of the Designated Avoided Unit(s);

F = the cumulative present value of the annual avoided capital cost component of the capacity payments for a ten year period, commencing with the in-service date of the Designated Avoided Unit (in $/kW/year in 2001 dollars);

r = the annual discount rate, defined as the Company's incremental after tax cost of capital;

t = the term, in years, of the contract for the purchase of firm capacity; and

O = the monthly fixed operation and maintenance component of the capacity payments, calculated in accordance with FPSC Rule 25-17.0832, paragraph 6(a) for Levelized Capacity Payments or with paragraph 6(b) for Early Levelized Capacity Payments, F.A.C.

Currently approved parameters applicable to the formulas above are found in Appendix B.

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CALCULATION OF MONTHLY AVAILABILITY AND CAPACITY FACTOR: Pursuant to FPSC Rule 25-17.0832, F.A.C., and Docket No. 891049-EU, a qf must meet or exceed, on a monthly basis, the MPS of the Company's Designated Avoided Unit(s) as described in Appendix C of COG-2 in order to receive monthly capacity payments. At the end of each monthly period, beginning with the monthly period specified in Paragraph 4.b.ii of the Company's Standard Offer Contract, the Company will calculate qf's Monthly Availability and Monthly Capacity Factor.

SECURITY GUARANTEES: The Company requires certain security deposits to ensure the completion of construction and performance under this Agreement in order to protect its ratepayers in the event the qf fails to deliver Firm Capacity and Energy in the amount and times specified in this Agreement, which shall be in form and substance as described herein. Such security may be refunded in the manner described in Paragraphs 4.b.iv.(1) and 4.b.iv.(2) of the Company's Standard Offer Contract.

Pursuant to FPSC Rule 25-17.091, F.A.C., a utility may not require security guarantees from a municipal solid waste facility as required in FPSC Rule 25-17.0832(2)(d) and (3)(f)(1), F.A.C. However, at its option, a municipal solid waste facility may provide such risk-related guarantees.

COMPLETION SECURITY: The qf shall pay to the Company a security deposit equal to $10.00 per kilowatt ($10.00/kW) of Anticipated Contracted Capacity as described herein as security for qf's completion of the Facility by the in-service date of the Designated Avoided Unit(s). Such security will be required within 60 days of contract execution. Such security shall be in the form of cash deposited in an interest bearing escrow account mutually acceptable to the Company and the qf; an unconditional and irrevocable direct pay letter of credit in form and substance satisfactory to the Company; or a performance bond in form and substance satisfactory to the Company. The form of security required will be in the sole discretion of the Company and will be in such form as to allow the Company immediate access to the funds in the event that the qf fails to complete the construction and achieve Commercial In-Service Status by the in-service date of the Designated Avoided Unit(s).

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If the qf achieves commercial in-service status by the in-service date of the Designated Avoided Unit(s) then the entire deposit and any interest therein, if applicable, shall be refunded to the qf upon payment by the qf of the Performance Security as required in Paragraph 4.b.iv.(2). of the Company's Standard Offer Contract. If the qf's Commercial In-Service Date is delayed beyond the in-service date of the Designated Avoided Unit(s), the Company may, upon the request of the qf, extend such date for a period not to exceed five (5) months, in which case the Company shall be entitled to retain or draw down on an amount equal to 20% of the original deposit amount for each month (or portion thereof) that the completion of the project is delayed. If the qf's Commercial In-Service Date is delayed and an extension has not been granted or such date is delayed beyond the extended completion date, then the Company shall retain all of the deposit and terminate this Agreement.

<u>PERFORMANCE SECURITY:</u> Within sixty (60) days after the later of the qf's Commercial In-Service Date or the in-service date of the Designated Avoided Unit(s), the qf shall pay the Company a deposit in the amount of $10.00/kW of Actual Contracted Capacity as security for the qf's performance under this Agreement. Such security deposit shall be provided in the same manner as the completion security deposit as described in Paragraph 4.b.iv.(1). of the Company's Standard Offer Contract. Such performance security shall be retained by the Company for twelve (12) months from the later of the qf's Commercial In-Service Date or the in-service date of the Designated Avoided Unit(s).

If, at the end of the twelve month period so described, the qf's 12-month average of each month's numerical value for both the Monthly Availability Factor and the Monthly Capacity Factor meet the MPS as set forth in Rate Schedule COG-2, then the qf shall be entitled to a refund of such deposit. However, if, at the end of the first twelve month period, the qf's 12-month average of each month's numerical value for both the Monthly Availability Factor and the Monthly Capacity Factor fail to meet the MPS, then the Company shall be entitled to retain or draw down 50% of such deposit and retain the remainder of the security for an additional twelve month period.

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If, at the end of the twenty fourth month, the qf's 12-month average of each month's numerical value for both the Monthly Availability Factor and the Monthly Capacity Factor again fail to achieve the MPS, for the most recent 12-month period, then the Company shall be entitled to retain the remainder of the security and to terminate the contract. However, if at the end of the twenty fourth month, the qf's 12-month average of each month's numerical value for both the Monthly Availability Factor and the Monthly Capacity Factor meet the MPS, for the most recent 12-month period, then the qf shall be entitled to a refund of the remaining deposit.

For the purpose of this calculation, the 12-month average of a parameter shall be defined to equal the sum of each month's average numerical value for that parameter, for the most recent 12-month period, divided by twelve (12).

LIQUIDATED DAMAGES: The parties hereto agree that the Company would be substantially damaged in amounts that would be difficult or impossible to ascertain in the event that the qf fails to complete the Facility by the in-service date of the Designated Avoided Unit(s) or to provide a Facility which meets the MPS. In the event that the Company terminates this Agreement for the qf's failure to achieve commercial in-service status by the in-service date of the Designated Avoided Unit(s) or achieve the MPS once in service, the Company may retain all of the completion or performance security as liquidated damages, not as penalty, in lieu of actual damages and the qf hereby waives any defenses as to the validity of any such liquidated damages. In the event the qf defaults, it forfeits the aforesaid Completion and/or Performance Security. In addition thereto, the Company shall be entitled to pursue such equitable remedies against the qf as may be available.

REPAYMENT OF EARLY CAPACITY PAYMENTS: FPSC Rule 25-17.0832(3)(c), F.A.C., also requires that when early capacity payments are elected, the qf must provide a security deposit for assurance of repayment of Early Capacity Payments in the event the qf is unable to meet the terms and conditions of its contract. Depending on the nature of the qf's operation, financial health and solvency, and its ability to meet the terms and conditions of the Company's Standard Offer Contract: one of the following may constitute an equivalent assurance of repayment:

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1. cash deposited in an interest bearing escrow account mutually acceptable to the Company and the qf; or

2. an unconditional and irrevocable direct pay letter of credit in form and substance satisfactory to the Company; or

3. a performance bond in form and substance satisfactory to the Company.

The form of security required will be in the sole discretion of the Company and will be in such form as to allow the Company immediate access to the funds in the event that the qf fails to meet the terms and conditions of its contract.

The Company will cooperate with each qf applying for early capacity payments to determine the exact form of an "equivalent assurance of repayment" to be required based on the particular aspects of the qf. The Company will end :avor to accommodate an equivalent assurance of repayment which is in the best interests of both the qf and the Company's ratepayers.

Florida Statute 377.709(4), requires the local government to refund early capacity payments should a municipal solid waste facility owned, operated by or on behalf of a local government be abandoned, closed down or rendered illegal, therefore a utility may not require risk-related guarantees from a municipal solid waste facility as required in FPSC Rule 25-17.0832(2)(c) and (3)(e)(8), F.A.C. However, at its option, a municipal solid waste facility may provide such risk-related guarantees.

DESIGNATED AVOIDED UNIT
PARAMETERS FOR AVOIDED CAPACITY COSTS
SCHEDULE COG-2
APPENDIX B

Beginning with the in-service date (1/1/2003) of the Company's Designated Avoided Unit (a 180 MW (Winter Rating) natural gas-fired Combustion Turbine), for a one year deferral:			Value
VAC_m	=	Company's monthly value of avoided capacity, in $/kW/month, for each month of year n;	3.31
K	=	present value of carrying charges for one dollar of investment over L years with carrying charges computed using average annual rate base and assumed to be paid at the middle of each year and present value to the middle of the first year;	1.6093
I_n	=	total direct and indirect cost, in mid-year $/kW including AFUDC but excluding CWIP, of the Designated Avoided Unit with an in-service date of year n, including all identifiable and quantifiable costs relating to the construction of the Designated Avoided Unit(s) that would have been paid had the Designated Avoided Unit(s) been constructed;	303.00
O_n	=	total fixed operation and maintenance expense for the year n, in mid-year $/kW/year, of the Designated Avoided Unit(s);	3.62
i_p	=	annual escalation rate associated with the plant cost of the Designated Avoided Unit(s);	2.4%
i_o	=	annual escalation rate associated with the operation and maintenance expense of the Designated Avoided Unit(s);	2.7%
r	=	annual discount rate, defined as the Company's incremental after tax cost of capital;	9.37%
L	=	expected life of the Designated Avoided Unit(s); and	30

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Continued from Sheet No. 8.355

			Value
n	=	year for which the Designated Avoided Unit(s) is deferred starting with its original anticipated in-service date and ending with the termination of the contract for the purchase of firm capacity and energy;	2003
A_m	=	monthly early capacity payments to be made to the qf starting as early as two years prior to the in-service date of the Company's Designated Avoided Unit(s), in $/kW/month;	2.44
i_p	=	annual escalation rate associated with the plant cost of the Designated Avoided Unit(s);	2.4%
m	=	earliest year for which capacity payments to a qf may be made;	2001
F	=	the cumulative present value of the annual avoided capital cost component of capacity payments for a ten year period, commencing with the in-service date of the Designated Avoided Unit(s) (in $/kW/year in 2001 dollars);	228.30
r	=	annual discount rate, defined as the Company's incremental after tax cost of capital; and	9.37%
t	=	the minimum term, in years, of the contract for the purchase of firm capacity if early capacity payments commence in year m.	12

Parameters for Avoided Energy and Variable Operation and Maintenance Costs

Beginning on January 1, 2003, to the extent that the Designated Avoided Unit(s) would have been operated had it been installed by the Company:

O_v	=	total variable operating and maintenance expense, in $/MWH, of the Designated Avoided Unit(s), in year n;	2.80
i_o	=	annual escalation rate associated with the operation and maintenance expense of the Designated Avoided Unit(s); and	2.7%
h	=	the average annual heat rate, in British Thermal Units (Btus) per kilowatt-hour (Btu/kWh), of the Designated Avoided Unit(s).	11,114

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ISSUED BY: J. B. Ramil ~~G. F. Anderson~~, President

DATE EFFECTIVE: ~~December 10, 1992~~

DESIGNATED AVOIDED UNIT
MINIMUM PERFORMANCE STANDARDS
SCHEDULE COG-2
APPENDIX C

The Company's Standard Offer Contract is based on a 180 MW fully dispatchable simple cycle, natural gas fired Combustion Turbine generating unit with an in-service date of January 1, 2003. In order to receive a Monthly Capacity Payment, all Firm Capacity and Energy provided by qfs shall meet or exceed the following MPS on a monthly basis. The MPS are based on the anticipated peak and off-peak dispatchability, unit availability, and operating factor of a 2003 Combustion Turbine designated as the Avoided Unit over the term of this Standard Offer Contract. The qf's facility will be evaluated against the anticipated performance of the Company's Designated Avoided Unit, starting with the first Monthly Period following the date selected in Paragraph 4.b.ii of the Company's Standard Offer Contract.

1. Dispatch Requirements: The qf shall provide peaking capacity to the Company on a firm commitment, first-call, on-call, as-needed basis. In order to receive a Monthly Capacity Payment, for months the unit is to be dispatched, the qf must meet or exceed both the minimum Monthly Availability and Monthly Capacity Factor requirements.

2. Dispatch Procedure: The Company shall electronically transmit the next day's expected hour-by-hour dispatch schedule for the qf's unit based on the hour-by-hour Committed Capacity schedule supplied by the qf at 3:00 PM that day. Friday's electronic transmissions will include Saturday, Sunday, and Monday schedules. Communications between the Company and the qf during holiday periods will be similarly adjusted. The qf shall control and operate its unit consistent with the Company's dispatch schedule. From time to time (i.e. during emergency conditions), the Company may be required to adjust or ignore scheduled levels altogether, however, each party shall make reasonable efforts to minimize departures from the daily schedule.

3. Automatic Generation Control: At the Company's discretion, the qf will operate its unit with Automatic Generation Control (AGC) equipment, speed governors, and voltage regulators in-service, except at such times when operational constraints of the equipment prevent AGC operation.

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Continued to Sheet No. 8.370

Continued from Sheet No. 8.365

a. Start-up Time: Upon notification by the Company, the qf's unit shall provide its Committed Capacity within thirty (30) minutes from a cold-start condition.

b. Minimum Run Time: Minimum run time for the qf's unit shall be one (1) hour.

BASIS FOR MONTHLY CAPACITY PAYMENT CALCULATION:

1. Monthly Availability Factor: The qf's Monthly Availability Factor will be calculated by averaging the Hourly Availability Factors for each hour of the Monthly Period. The Hourly Availability Factor may not exceed 100% and shall be defined as the hourly Committed Capacity expressed as a percentage of Contracted Capacity to the nearest whole percentile. The qf is required to achieve a minimum Monthly Availability Factor of ninety percent (90%) in order to meet the MPS and be eligible to receive a Monthly Capacity Payment. Periods of Annual Planned Maintenance will be excluded from the calculation of the Monthly Availability Factor. For purposes of calculating the Monthly Availability Factor, the qf's Committed Capacity may not exceed its Contracted Capacity.

2. Monthly Capacity Factor: In addition to the MPS for Monthly Availability, the qf shall provide Committed Capacity into the Company's electric grid in order to meet or exceed a Monthly Capacity Factor of eighty percent (80%). The Monthly Capacity Factor for the period April 1 through October 31, shall be defined as the sum of eighty percent (80%) of the Monthly Average On-peak Operating Factor plus twenty percent (20%) of the Monthly Average Off-peak Operating Factor. The Monthly Capacity Factor for the period November 1 through March 31, shall be defined as the sum of ninety percent (90%) of the Monthly Average On-peak Operating Factor plus ten percent (10%) of the Monthly Average Off-peak Operating Factor.

a. Operating Factor: The qf shall endeavor to provide capacity in the amount dispatched by the Company. The Company may at times request capacity in an amount that exceeds the Committed Capacity as declared by qf the previous day.

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TAMPA ELECTRIC COMPANY

SECOND ~~FIRST~~ REVISED SHEET NO. 8.375
CANCELS FIRST REVISED ~~ORIGINAL~~ SHEET NO. 8.375

Continued from Sheet No. 8.370

However, the Operating Factor may not exceed 100% and shall be defined as the actual energy received during each hour divided by the lessor of the qf's committed capacity or the capacity requested by the Company for that hour, expressed to the nearest whole percentile.

b. Monthly Average On-peak Operating Factor: The monthly average of the Operating Factor for all hours the qf unit has been dispatched during On-peak Hours will be termed the Monthly Average On-peak Operating Factor.

c. Monthly Average Off-peak Operating Factor: The monthly average of the Operating Factor for all hours the qf unit has been dispatched during Off-peak Hours will be termed the Monthly Average Off-peak Operating Factor.

3. Off-Peak and On-Peak Hours: Those weekday hours occurring April 1 through October 31, from 12:00 noon to 9:00 p.m. and November 1 through March 31, from 6:00 a.m. to 10:00 a.m. and from 6:00 p.m. to 10:00 p.m. All other weekday hours and weekends shall be deemed Off-peak Hours including the following holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. The Company shall have the right to change such On-peak Hours by providing written notice to qf a minimum of ninety (90) calendar days prior to such change.

4. Annual Scheduled Maintenance: Each year the qf shall prepare, coordinate, and provide by April 1st all planned maintenance with the Company. The Company will review and approve annual/major scheduled maintenance by July 1st, for the balance of the current year and following calendar year. A maximum of two (2) weeks (336 hours) each year for annual maintenance and a total of five (5) weeks (840 hours) every fifth year for major overhauls will be allowed. Scheduled maintenance shall not be planned during December through February without prior written consent from the Company. At the option of the qf and by written notification to the Company, scheduled outage time may be utilized during any other months to improve the qf's Availability and Capacity Factors and such scheduled outage hours will be disregarded from the Monthly Availability Factor and Capacity Factor calculations. However, once allowable maintenance hours have been utilized, all other hours during the year will be considered in Availability and Capacity Factor calculations.

~~RESERVED FOR FUTURE USE~~

Continued to Sheet No. 8.380

ISSUED BY: J. B. Ramil ~~K. S. Surgenor~~, President

DATE EFFECTIVE: ~~September 13, 1994~~

Continued from Sheet No. 8.375

5. <u>Monthly Capacity Payment:</u> Starting with the qf's Commercial In-Service Date, for months when the qf unit has been dispatched (provided that qf has achieved at least a 90% Monthly Availability Factor), the Monthly Capacity Payment fo each Monthly Period shall be calculated according to the following:

a. In the event that the Monthly Capacity Factor is less than 80%, no Monthly Capacity Payment shall be paid to the qf. That is:

MCP = $0

b. In the event that the Monthly Capacity Factor is greater than or equal to 80% but less than 90%, the Monthly Capacity Payment shall be calculated from the following formula:

MCP = [(BCC) x (.02 x (CF-45))] x CC

c. In the event that the Monthly Capacity Factor is greater than or equal to 90%, the Monthly Capacity Payment shall be calculated from the following formula:

MCP = (BCC)xCC

Where:

MCP = Monthly Capacity Payment in dollars.

BCC = Base Capacity Credit in $/KW-Month pursuant to Tariff Sheet No. 8.225.

CC = Contracted Capacity in KW.

CF = Monthly Capacity Factor; or

During April 1 - October 31:

= 80% x Monthly Average On-peak Operating Factor +

20% x Monthly Average Off-peak Operating Factor

~~RESERVED FOR FUTURE USE~~

Continued to Sheet No. 8.385

Continued from Sheet No. 8.380

During November 1 - March 31:

= 90% x Monthly Average On-peak Operating Factor +

10% x Monthly Average Off-peak Operating Factor

6. <u>Non-Dispatch Condition:</u> The qf may be entitled to a Monthly Capacity Payment (BCC X CC) even if the qf's unit was not dispatched by the Company during a Monthly Period. In this instance however, in order to cover the Company's operating reserve criteria, the qf unit must have achieved a minimum Monthly Availability Factor of 90% for the Monthly Period to be eligible to receive a Monthly Capacity Payment.

In the event the qf unit is dispatched during one but not the other (On-peak vs. Off-peak) period during the month, the qf's Monthly Average Operating Factor for the "non-dispatched" period will be set equal to the Monthly Average Operating Factor achieved during the "dispatched" period, for the purpose of calculating the Monthly Capacity Factor, as defined in the Section entitled Basis for Monthly Capacity Payment Calculation, Paragraph 2 herein.

The qf may be entitled to a Monthly Capacity Payment when the qf's unit is out of service during the month for allowable scheduled maintenance in accordance with the Section entitled Basis for Monthly Capacity Payment Calculation, Paragraph 4.

<u>BASIS FOR MONTHLY ENERGY PAYMENT CALCULATION:</u>

1. <u>Energy Payment Rate:</u> Prior to January 1, 2003, the qf's Energy Payment Rate shall be the Company's As-Available Energy Payment Rate, as described in Appendix D. Starting January 1, 2003, the basis for determining the Energy Payment Rate will be whether;

a. The Company has dispatched the qf's unit on AGC; or

b. The Company has dispatched the qf's unit off AGC and the qf is operating its unit at or below the dispatched level; or

c. The Company has dispatched the qf's unit off AGC but the qf is operating its unit above the dispatched level; or

d. The Company has not dispatched the qf's unit but the qf is providing capacity and energy.

~~RESERVED FOR FUTURE USE~~

Continued to Sheet No. 8.390

Continued from Sheet No. 8.385

Note: For any given hour the qf unit must be operating on AGC a minimum of 30 minutes to qualify under case (a).

The qf's total monthly energy payment shall equal; (1) the sum of the hourly energy at the Unit Energy Payment Rate (EPR), when the qf's unit was dispatched by the Company, plus (2) the sum of the hourly energy at the corresponding hourly As-Available Energy Rate when the qf's unit was operating at times other than when the Company dispatched the unit.

2. <u>Unit Energy Payment Rate:</u> Starting January 1, 2003, the qf will be paid at the EPR for energy provided in Paragraph 1.a, Paragraph 1.b and that portion of the energy provided up to the dispatched level in Paragraph 1.c as defined in the Section entitled Basis for Monthly Energy Payment Calculations. The EPR, which is based on the Company's Designated Avoided Unit and Heat Rate value of 11,114 Btu/kWh, will be calculated monthly by the following formula:

$$EPR = FC + VOM,$$

where;

VOM = Unit Variable Operation & Maintenance Expense in $/MWH defined in Rate Schedule COG-2, Appendix B.

FC = Fuel Component of the Energy Payment in $/MWH as defined by:

$$FC = \frac{11{,}114 \text{ Btu/kWh} \times FP}{1{,}000}$$

~~RESERVED FOR FUTURE USE~~

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where;

FP = Fuel Price in $/MMBTU determined by:

FP = GC + TC + GRI + ACA + TCR + FRC,

where;

GC = Fuel Price in $/MMBTU determined by taking the first publication of each month of Inside FERC's Gas Market Report low price quotation under the column titled "Range" for "Florida Gas Transmission Co., Louisiana" listings.

TC = then currently approved Florida Gas Transmission (FGT) Company tariff rate in $/MMBTU for Interruptible Transmission Service (ITS-1).

GRI = then currently approved FGT Company tariff rate in $/MMBTU for recovery of charges for the Gas Research Institute.

ACA = then currently approved FGT Company tariff rate in $/MMBTU for recovery of charges permitted by Section 154.38(d)(6) of the FERC regulations under the Natural Gas Act.

TCR = then currently approved FGT Company tariff rate in $/MMBTU for recovery of costs associated with FGT's obligation to satisfy long term take-or-pay agreements.

FRC = then currently approved FGT Company tariff rate in $/MMBTU for recovery of costs associated with the natural gas used to operate FGT's pipeline system.

3. As-Available Energy Payment Rate: For energy provided and not covered under Paragraph 2 above, the As-Available Energy Payment Rate will be applicable and will be based on the system avoided energy cost as defined in Appendix D.

METHODOLOGY TO BE USED
IN THE CALCULATION OF
AVOIDED ENERGY COST
SCHEDULE COG-2
APPENDIX D

The methodology the Company has implemented in order to determine the appropriate avoided energy costs and any payments thereof to be rendered to qfs is consistent with the provisions of Order No. 23625 in Docket No. 891049-EU, issued on October 16, 1990, and with the Amendment of FPSC Rules 25-17.080 et seq, F.A.C..

The avoided energy costs methodology used to determine payments to qfs on an hourly basis is based on the incremental cost of fuel using the average price of replacement fuel purchased in excess of contract minimums and is further described in Exhibit #1. Generally, avoided energy costs are defined to include incremental fuel, identifiable variable operation and maintenance expenses, identifiable variable purchased power costs and an adjustment for line losses reflecting delivery voltage.

Under normal conditions the Company will have additional generation resources available which can carry its native load and firm interchange sales without the qf's contribution. When this is the case and the qf is present, the incremental fuel portion of the avoided energy cost is equal to the difference between the Company's production cost at two load levels, with and without the qf's contribution.

In those situations where the Company's available maximum generation resources (not including its minimum spinning reserves) are insufficient to carry its native load and firm interchange sales, in the absence of the qf contribution, the Company's incremental fuel component of the avoided energy cost will be determined by:

1. system lambda - if "off-system purchases" are not being made and all available generation has been dispatched; or

2. the highest incremental cost of any "off-system purchases" that are being made for native load.

Examples of these situations are found in Exhibits #3-#6.

~~RESERVED FOR FUTURE USE~~

Continued to Sheet No. 8.405

Continued from Sheet No. 8.400

The As-Available Avoided Energy Cost, as determined by this methodology, is priced at a level not to exceed the Company's incremental fuel and identifiable variable operating and maintenance (O&M) expenses including the cost of any off-system purchases for native load.

PARAMETERS FOR DETERMINING AS-AVAILABLE AVOIDED ENERGY COSTS: The Company uses production costing methods for determining avoided energy cost payments to qfs. Computerized production costing is accomplished on an hourly basis. The parameters used are as follows:

1. The system load is the actual system load at the Hour Ending with the clock hour (HE).

2. The first allocation of load for production costing is to those units that are base loaded at a certain level for operating reasons. The remainder of the load is allocated to units available for economic dispatch through the use of incremental cost curves.

3. The fuel costs associated with each of the Company's units operating at its allocated level of generation is determined by using the individual units input/output equation, its heat rate performance factor and the composite price of supplemental fuel.

4. The Company's own production cost for each hour of operation at a particular generation level equals the sum of the individual units' fuel cost for that hour. The production cost, thus determined, consists of the composite price of replacement fuel based on supplemental purchases and the incremental heat rate for the generating system.

5. The Company's total cost equals its own production cost (Paragraph 4 above), identified variable O&M, plus the cost of any off-system purchases to serve native load.

6. Native load includes all firm and non-firm retail load.

7. The cost of off-system firm and non-firm variable purchases is defined as the highest energy cost energy block purchased for native load during the hour; i.e., SCHEDULES A, B, C, D, X, J, UPP (Unit Power Purchase).

8. Firm interchange sales are included in production cost calculations.

9. The Company's available maximum generation resources in this methodology is defined as the maximum capacity less spinning reserve requirements.

Continued to Sheet No. 8.410

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10. The "Standard Tariff Block" is defined to be an x-megawatt (XMW) block equivalent to the combined actual hourly generation delivered to the Company from all qfs making as-available energy sales to the Company. In the absence of metered information on exports from a qf making as-available energy sales to the Company, an estimate of the hourly exports from that Facility will be used, rounded to the nearest 5 MW and then added to the sum of all other known as-available energy purchases for that hour.

PARAMETERS FOR DETERMINING ENERGY PAYMENT RATES: The Company uses production costing methods for determining avoided energy cost payments to qfs. Computerized production costing is accomplished on an hourly basis. The parameters used are as follows:

1. Prior to the in-service date: For payments prior to the in-service date of the Designated Avoided Unit, the As-Available Energy Payment Rate in ¢/kWh, calculated in accordance with the Section entitled Basis for Monthly Energy Payment, Paragraph 1 in Appendix C of this Rate Schedule, shall be based on the Company's actual hourly avoided energy costs which are calculated by the Company in accordance with FPSC Rule 25-17.0825, F.A.C.

2. After the in-service date: For payments after the in-service date of the Designated Avoided Unit, the Unit Energy Payment Rate in ¢/kWh, calculated in accordance with the Section entitled Basis for Monthly Energy Payment, Paragraph 2 in Appendix C of this Rate Schedule, shall be based on the Designated Avoided Unit's energy cost (fuel and variable Operation and Maintenance), to the extent that the Designated Avoided Units would have operated had it been installed by the Company.

~~RESERVED FOR FUTURE USE~~

Continued to Sheet No. 8.415

Continued from Sheet No. 8.410

SUPPLEMENTAL FUEL: The term "supplemental fuel" refers to that fuel purchased in excess of the Company's long-term contract minimum requirements. As illustrated in Exhibit #1, supplemental fuel can be composed of contract fuel purchases above minimums and fuel purchases on the spot market. When spot prices are lower than prices for minimum tonnages on long term contract purchases, spot prices are "supplemental." Under market conditions where spot prices are greater than the price of coal purchased under contract, it is economical for the Company to purchase more than the contract minimums. In this instance the supplemental price is a combination of the contract price of coal above minimum contract requirements and any coal purchased on the spot market. The Company looks to the supplemental fuel for purposes of incremental pricing to determine the level of as-available energy payments because contract minimum purchases are a fixed expense.

Supplemental fuel is composed of contract fuel purchases above minimum levels and fuel purchases on the spot market. The Company pursues the least expensive alternative whether it be spot purchases or purchases of contract coal above the contract minimum, or a mixture of both. The supplemental fuel price is calculated by weight averaging all of the supplemental fuel purchases, by fuel type, during the preceding month. A Supplemental Fuel Cost Worksheet is shown in Exhibit #2.

With regard to oil-fired generation, the Company treats all of its oil purchases as supplemental fuel inasmuch as it has no contract minimums. For graphic portrayal of Tampa Electric's definition of supplemental fuel see Exhibit #1 attached.

AVOIDED ENERGY COST CALCULATIONS:

Example: #1 No off-system purchases, the Company's generation is capable of carrying its native load and firm sales.

The procedure used to deterministically calculate the incremental avoided energy cost associated with as-available energy on an hour by hour basis when no off-system purchases are taking place is as follows:

In these instances, the $/MWH price that the Company will pay the qfs is determined by calculating the production cost at two load levels.

The first calculation determines the Company's production cost without the benefit of cogeneration.

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The second calculation determines the Company's production cost with the benefit of cogeneration.

After each of the two calculations are made, the avoided energy cost rate is calculated by dividing the difference in production cost between the two calculations described above by the "Standard Tariff Block." [The "Standard Tariff Block" is defined to be an XMW block equivalent to the combined actual hourly generation delivered to the Company from all qfs making as-available energy sales to the Company. In the absence of metered information on exports from a qf making as-available energy sales to the Company, an estimate of the hourly exports from that Facility will be used, rounded to the nearest 5 MWs and then added to the sum of the other as-available purchases for that hour. Prior to the in-service date of the appropriate designated avoided unit, firm energy sales will be equivalent to as-available sales. Beginning with the in-service date of the appropriate Designated Avoided Unit(s), firm energy purchases from qfs shall be treated as "as-available" energy for the purposes of determining the XMW block size only during the periods that the appropriate designated avoided unit would not be operated.] The difference in production costs divided by the XMW block determines the As-Available Energy Payment Rate (AEPR) for the hour. The AEPR will be applied to the "Actual" qf MWs purchased during the hour to determine payment to each qf supplying as-available energy, and each qf supplying firm energy in those instances where the avoided unit would not have been operated during the hour. See Exhibit #3 (Example #1).

Example #2 Off-system purchases are not being made. The Company's generation can only carry its native load and firm sales with the qf contribution.

The procedure used to deterministically calculate the incremental avoided energy cost associated with as-available energy on an hour by hour basis whenever the Company is not purchasing off-system interchange is as follows:

In this instance, the avoided energy cost that the Company will pay the qfs will be determined by calculating the production cost at the last MW load level. The avoided energy cost is the production cost at system lambda. See Exhibit #4. (Example #2a)

~~RESERVED FOR FUTURE USE~~

Continued to Sheet No. 8.425

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In the situation where the Company's generation is not fully dispatched, and additional generation capability is available to price a portion of the qf block, then the qf block will be priced at a combination of the difference between the Company's production cost at two load levels as previously defined and at system lambda. See Exhibit #5. (Example #2b)

Example #3 Off-system purchases are being made to serve native load.

The procedure used to deterministically calculate the incremental avoided energy cost associated with as-available energy on an hour by hour basis whenever the Company is making off-system purchases for native load is as follows:

In this instance, the $/MWH price that the Company will pay is determined by applying the highest incremental cost of the off-system purchases to the qf block. See Exhibit #6. (Example #3)

Line Loss Credit: A credit for avoided line losses reflecting the voltage at which generation by the qfs is received is included in the Company's procedure for the determination of incremental avoided energy cost associated with as-available energy. The Company uses the loss factors used in the Fuel and Purchase Power Cost Recovery Clause for calculating the compensation for avoided line losses at the transmission and distribution system voltage levels based upon the appropriate classification of service.

Example: (Firm Standby Time-of-Day)

Actual Incremental Hourly Avoided Energy Cost is:
$14.80/MWH
Adjustment Factor for Line Losses:
1.0555

The Actual Incremental Hourly Avoided Energy Cost adjusted for avoided line losses associated with as-available energy provided to the Company would then become, in this example, $15.62/MWH.

"Identifiable" Incremental Variable O&M: A procedure for approximating the "Identifiable" Incremental Variable O&M expenses is included in the Company's methodology for the determination of incremental avoided energy costs associated with as-available energy.

Continued to Sheet No. 8.430

TAMPA ELECTRIC COMPANY

SIXTH ~~FIFTH~~ REVISED SHEET NO. 8.430
CANCELS FIFTH ~~FOURTH~~ REVISED SHEET NO. 8.430

Continued from Sheet No. 8.425

The calculation of the variable O&M expense component associated with as-available energy is made annually in accordance with a system that differentiates actual annual total O&M costs into estimates of both fixed and variable components. This procedure, developed by the Electric Power Research Institute (EPRI), was published in their Technical Assessment Guide (TAG) Special Report, dated May 1982, (EPRI P-2410-SR).

The EPRI-TAG assumptions provide an easily used and useful formula that approximates a fair payment for avoided variable O&M expenses. As such, it can be easily calculated and monitored using readily available information. Once identified, based on the previous year's actual total O&M cost for coal-fired generation, the incremental avoided energy cost associated with as-available energy is adjusted to compensate for these variable expenses. (See Exhibit #7)

~~RESERVED FOR FUTURE USE~~

Continued to Sheet No. 8.435

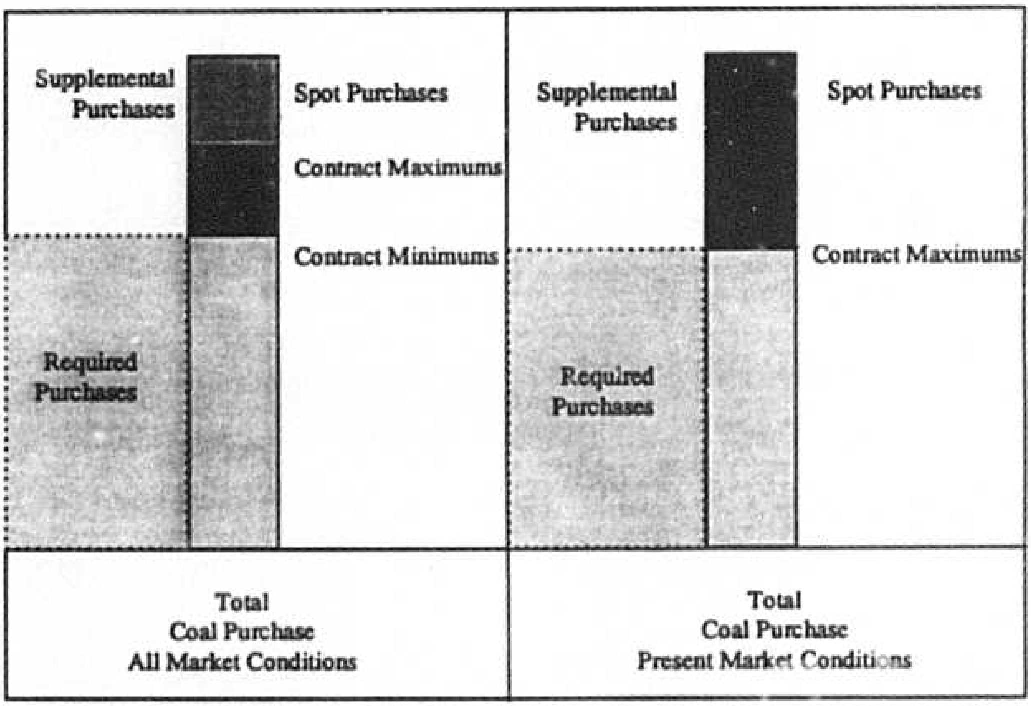
ISSUED BY: J. B. Ramil ~~K. S. Surgenor~~, President

DATE EFFECTIVE: ~~September 13, 1994~~

Continued from Sheet No. 8.430

EXHIBIT #1

REQUIRED AND SUPPLEMENTAL COAL PURCHASES UNDER DIFFERENT MARKET CONDITIONS



Continued to Sheet No. 8.440

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EXHIBIT #2

SUPPLEMENTAL FUEL COST WORKSHEET

Revised December 1988

UNITS DELIVERED	SUPPLIER C/MMBTU	SUPPLEMENTAL COAL COST $/TON	INCREMENTAL TRANS. COST $/TON	TOTAL $/TON	AUGUST AVERAGE BTU/LB	AUGUST AVERAGE C/MMBTU	AUGUST TONS	SUPPLEMENTAL FUEL COST
Gannon 1-4	A			$45.30				177.50
Gannon 5&6	B			$45.48				176.44
Big Bend 1&2	C			$29.22				123.13
	D			$31.67				
	E			$32.08				
			Average	$29.87				
Big Bend 3[1]	F			$60.55				173.87
			Blended Average	$42.28				
Big Bend 4	G			$41.70				181.31
	H			$37.21				
			Average	$41.11				
#2 Oil	I			$19.41/BBL				334.84

[1] Revised: Big Bend Unit #3 is burning a 60/40 blend of blend/standard coal.

~~RESERVED FOR FUTURE USE~~

Continued to Sheet No. 8.445

ISSUED BY: J. B. Ramil ~~K. S. Surgenor~~, President

DATE EFFECTIVE: ~~September 13, 1994~~

Continued from Sheet No. 8.440

EXHIBIT #3

Example #1 No off-system purchases, the Company's generation is capable of carrying its native load and firm sales.

Given:

Actual qf Energy = 50 MWs
The Company's Maximum Available Generation = 1560 MWs
Native Load = 1550 MWs
Firm Sales = 10 MWs

First Calculation (WITHOUT qf):

Production Cost at 1560 MWs = $20,275/hour

Second Calculation (WITH qf):

Production Cost at 1510 MWs = $19,500/hour

Third Calculation (qf Rate $/MWH):

Actual Hourly Avoided Energy Cost =
($20,275/hour - $19,500/hour) / (50MW)

or

As-Available Energy Payment Rate (AEPR) = $15.50/MWH

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Continued from Sheet No. 8.445

EXHIBIT #4

Example #2a Off-system purchases are not being made. The Company's generation can carry its native load and firm sales only with the qf contribution.

Given:

Actual qf Energy = 50 MWs
The Company's Maximum Available Generation = 1460 MWs
Native Load = 1500 MWs
Firm Sale = 10 MWs

First Calculation:

Production Cost at 1460 MWs = $18,900/hour

Second Calculation:

Production Cost at 1459 MWs = $18,882.50/hour

Third Calculation (qf Rate $/MWH):

Actual Hourly Avoided Energy Cost at 1 MW (system lambda[1]) =
(\$18,900/hour - \$18,882.50/hour) / (1 MW)

or

As-Available Energy Payment Rate (AEPR) = $17.50/MWH

NOTE:

[1]. In this example, system lambda is the production cost for the last MW segment to meet the load after dispatching all available generation capacity.

~~RESERVED FOR FUTURE USE~~

Continued to Sheet No. 8.455

Continued from Sheet No. 8.450

EXHIBIT #5

Example #2b Off-system purchases are not being made to serve native load and firm sales. Available generation capacity is not fully dispatched. Without the qf's contribution, the Company's native load and firm sales can be carried only with additional power purchases.

Given:

Actual qf Energy = 50 MWs
The Company's Maximum Available Generation = 1530 MWs
The Company's Actual Generation = 1500 MWs
Native Load = 1540 MWs
Firm Sale = 10 MWs

Step 1 (Calculations for First 30 MWs)

First Calculation (Without qf):
Production Cost at 1530 MWs = \$20,590/hour
Second Calculation (With qf):
Production Cost at 1500 MWs = \$20,050/hour
Third Calculation:
Actual Hourly Avoided Energy Cost at 30 MWs =
(\$20,590/hour) - (\$20,050/hour) = \$540/hour

Step 2 (Calculations for Remaining 20 MWs)

First Calculation:
Production Cost at 1530 MWs = \$20,590/hour
Second Calculation:
Production Cost at 1529 MWs = \$20,571.50/hour
Third Calculation:
Actual Hourly Avoided Energy Cost at 1 MW (system lambda[1]) for 20 MWs =
(\$20,590/hour - \$20,571.50/hour) X (20 MWs) = \$370/hour

Step 3 (Calculation of Composite Rate for Total 50 MW Block)

Composite Actual Hourly Avoided Energy Cost of 50 MW Block =
(\$540 + \$370) / 50 MW

or

As-Available Energy Payment Rate (AEPR) = \$18.20/MWH

NOTE:

[1] In this example, system lambda is the production cost for the last MW segment to meet the load after dispatching all available generation capacity.

Continued to Sheet No. 8.460

Continued from Sheet No. 8.455

EXHIBIT #6

Example #3 Off-system purchases are being made, the Company's native load and firm sales can be carried only with additional purchase power

Given:

Actual qf Energy = 50 MWs
The Company's Maximum Available Generation = 1500 MWs
The Company's Actual Generation = 1500 MWs
Native Load = 1540 MWs
Firm Sales = 20 MWs
Off-System Purchase[1] = 10 MWs Costing $400/hour

Actual Incremental Hourly Avoided Energy Cost = $400 / 10 MW

or

As-Available Energy Payment Rate (AEPR) = $40/hour

NOTE:

[1] Off-System Purchase shall be the highest cost purchased energy block bought during the hour for native load.

~~RESERVED FOR FUTURE USE~~

Continued to Sheet No. 8.465

Continued from Sheet No. 8.460

EXHIBIT #7

The calculation of the variable O&M cost adjustment factor associated with as available energy is made once each year, based on the previous year's actual total O&M cost for coal-fired generation, in accordance with the procedure found in the EPRI-TAG Special Report dated May 1982, (EPRI P-2410-SR). The formula assumes the fixed portion of total annual O&M dollars equals the capacity factor (%) times the total annual O&M dollars. The variable portion is (1 - capacity factor) times the total annual O&M dollars. The capacity factor is based on the total period hours less those hours the units are off line due to economic dispatch for low load periods. Continuing the logic further, the adjustment factor to be added to the avoided energy cost equals the variable rate as determined annually and applied in the form of an hourly adjustment to the actual incremental hourly avoided energy cost.

Example Given:	1983 TEC Coal Generation	MW	
1) Big Bend	1	367	
	2	362	
	3	375	
	3	10	upgrade
Gannon	5	218	
	6	351	
	4	169	conversion

MW available per unit from net generation listed in the System Data Book for the same time period:

2) Coal Generation 1983 = 10,493,266 MWH

3) O&M for coal 1983 = $35,320,252

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Continued from Sheet No. 8.465

EXHIBIT #7 - continued

ESTIMATED
1983 VARIABLE O&M RATE CALCULATION

		(MW)		(Hours)	(MWH)
Big Bend	1	367	@	8760	3,214,920
	2	362	@	8760	3,171,120
	3	375	@	8760	3,285,000
Upgrade	3	10	@	2208	22,080
Gannon	5	218	@	8760	1,909,680
	6	351	@	8760	3,074,760
Conversion to Coal	4	169	@	2208	373,152
TOTAL					15,050,712
Generation (1983 Actual for Coal)					10,493,266

Average Coal Capacity Factor = $\frac{10,493,266}{15,050,712}$ X 100%

= 69.72%

Total O&M for Coal = \$35,320,252

Variable Component = \$35,320,252 X (1 - .6972)

= \$10,694,972

Estimated Variable O&M Cost[1] = $\frac{10,694,772}{10,493,266}$ = \$1.02/MWH

1 Was added to 1984's actual incremental hourly avoided energy cost, after approval by the FPSC.

~~RESERVED FOR FUTURE USE~~

STANDARD OFFER CONTRACT FOR THE PURCHASE OF FIRM CAPACITY AND ENERGY FROM A SMALL QUALIFYING FACILITY OR A MUNICIPAL SOLID WASTE FACILITY

This agreement is made and entered into this _______ day of ______________, _______ by and between ___________________, hereinafter referred to as the "QF" and Tampa Electric Company, a private utility corporation organized under the laws of the State of Florida, hereinafter referred to as the "Company". The QF and the Company shall collectively be referred to herein as the "Parties."

WITNESSETH:

WHEREAS, QF desires to sell, and the Company desires to purchase, Firm Capacity and Energy to be generated by small Qualifying Facilities or by Municipal Solid Waste Facilities (unless specifically referred to, small "Qualifying Facilities" and "Municipal Solid Waste Facilities" will jointly be referred to as "QFs") consistent with Florida Public Service Commission (FPSC) Rules 25-17.080 through 25-17.091, Florida Administrative Code (F.A.C.); of Order No. 23625 issued October 16, 1990, Docket No. 891049-EU; and the Company's Rate Schedule COG-2; and

WHEREAS, QF has signed an Interconnection Agreement with the utility in whose service territory the QF's generating facility is located, attached hereto as Appendix A; and

WHEREAS, the FPSC has approved the following Standard Offer Contract for the purchase of Firm Capacity and Energy from QFs;

NOW, THEREFORE, for mutual consideration the Parties agree as follows:

1. **Facilities**

   a. Designated Avoided Unit: The Company has identified a 180 megawatt (MW) (Winter Rating) natural gas fired Combustion Turbine generating unit with an in-service date of January 1, 2003, as its Designated Avoided Unit. The avoided unit will be fully subscribed at 180 MW of committed Firm Capacity and Energy. The Company's Standard Offer Contract is scheduled to expire on December 31, 2000, in order to allow adequate lead-time for the Company to construct the Avoided Unit.

~~RESERVED FOR FUTURE USE~~

Continued to Sheet No. 8.480

Continued from Sheet No. 8.475

b. Qualifying Facility

i. On or before the in-service date of the Designated Avoided Unit, the QF shall be a cogeneration facility or small power production facility that is a Qualifying Facility under Subpart B of Subchapter K, Part 292 of Chapter I, Title 18, Code of Federal Regulations (C.F.R.), promulgated by the Federal Energy Regulatory Commission (FERC), as the same may be amended from time to time. Such a facility must be "new capacity" pursuant to the Public Utilities Regulatory Policies Act of 1978 (PURPA), construction of which began on or after November 9, 1978. On or before the in-service date of the Designated Avoided Unit and at all times throughout the remaining term of this Agreement, such QF shall maintain its status as a QF as defined herein and as certified by the FERC. By the end of the first quarter of each calendar year, the QF shall furnish the Company a notarized certificate by an officer of the QF certifying that the Facility has continuously maintained qualifying status on a calendar year basis since the commencement of the term of this Agreement.

ii. QF contemplates installing and operating a __________ MVA generator located at ______________________________________ which shall be and remain the specific site of the QF throughout the term of this Agreement. The generator is designed to produce a maximum of ______ megawatts (MW) of electric power designed, operated and controlled to provide reactive power requirements from 0.95 lagging to 0.95 leading power factor at the point of interconnection with the Company, such equipment being hereinafter referred to as the "Facility".

c. Evaluation Procedure: Each eligible Standard Offer Contract received by the Company will be evaluated as to its technical reliability, viability and financial stability, as well as other relevant information, in accordance with FPSC Rule 25-17.0832, F.A.C., and the Company's Procedure for Processing Standard Offer Contracts as defined in Rate Schedule COG-2 (COG-2). The criteria and procedure used to evaluate Standard Offer Contracts are attached to the Standard Offer Contract as Appendix A.

2. Term of the Agreement: This Agreement shall begin immediately upon its execution by the parties and shall end at 12:01 a.m., _____________, 20___.

Continued to Sheet No. 8.485

RESERVED FOR FUTURE USE

Continued from Sheet No. 8.480

Notwithstanding the foregoing if the QF does not meet the Construction Commencement Date or its Commercial In-Service Date as defined in COG-2 in accordance with the terms and conditions of this Agreement, then this Agreement shall be rendered of no force and effect. This Agreement shall consist of the Company's Rate Schedule COG-2 and all attached appendices thereto attached hereto and made a part hereof as Appendix B. For the purpose of this Agreement, "Construction Commencement Date" shall mean the date on which QF's on site activity is coordinated and continuous and active construction efforts are undertaken and ongoing relative to the actual construction of major project features other than site preparation work, which shall occur no later than January 1, 2001.

3. <u>Sale of Electricity by QF.</u> The Company agrees to purchase all of the Actual Contracted Capacity and associated energy generated at the Facility and transmitted to the Company by the QF pursuant to this tariff, less the amount of electric power consumed by the QF's generator auxiliaries. The Facility shall be fully dispatchable in the manner set forth in COG-2, Appendix C. The purchase and sale of electricity pursuant to this Agreement shall be construed as a: (   ) Net Billing Arrangement or: (   ) Simulteneous Purchase and Sale Arrangement. Once made, the selection of a billing methodology may only be changed in accordance with FPSC Rule 25-17.082, F.A.C., and shall be in accordance with the following provisions:

a. upon at least thirty (30) days advance written notice to the Company; and

b. upon the installation by the Company of any additional metering equipment reasonably required to effect the change in billing methodology and upon payment by the QF for such metering equipment and its installation; and

c. upon completion and approval by the Company of any alterations to the interconnection reasonably required to effect the change in billing methodology and upon payment by the QF for such alterations.

Continued to Sheet No. 8.490

Continued from Sheet No. 8.485

The parties agree that QF's obligation to generate and sell electricity from the Facility is subject to both scheduled and unscheduled outages of the Facility. Neither party shall be required to compensate the other party for electrical energy which from time to time may not be generated and sold by QF or received and purchased by the Company as a result of such scheduled and unscheduled outages. The parties agree to use best efforts to minimize the duration of any scheduled or unscheduled outages which from time to time may interrupt the purchase and sale of electricity under this Agreement.

4. <u>Payment for Electricity Produced by QF</u>:

a. <u>Energy:</u> The Company agrees to pay the QF for energy produced by the Facility and delivered to the Company in accordance with the rates and procedures contained in Rate Schedule COG-2 attached hereto as Appendix B. Prior to January 1, 2003, QF will receive energy payments based on the Company's actual avoided energy costs. Starting January 1, 2003, to the extent that the Designated Avoided Unit would have been operated had it been installed by the Company, the QF's energy payments will be based on the Company's Designated Avoided Unit's energy costs, otherwise QF's energy payment will be based on the Company's actual avoided energy costs as defined in COG-2, Appendix D, such determination to be made hourly.

b. <u>Capacity:</u>

i. <u>Anticipated Contracted Capacity:</u> QF intends to sell ________ MW of Firm Capacity and achieve commercial in-service status, beginning on or before January 1, 2003, the in-service date of the Designated Avoided Unit.

After initial Facility testing and on one occasion only, QF may finalize, increase or decrease its Anticipated Contracted Capacity by no more than 10% of the Anticipated Contracted Capacity and specify when capacity payments are to begin, by completing Paragraph 4.b.ii at a later time. However, QF must complete Paragraph 4.b.ii. by January 1, 2003 in order to be entitled to any capacity payments pursuant to this Agreement.

Continued to Sheet No. 8.495

Continued from Sheet No. 8.490

ii. <u>Actual Contracted Capacity:</u> The Firm Capacity committed by QF for purposes of this Agreement is ________ MW. To the extent that the Company pays for but declines to take all of the Actual Contracted Capacity (Non-dispatched Capacity) in any given hour, such Non-dispatched Capacity and Associated Energy shall not be sold by the QF or otherwise used in any way or disposed of without the Company's prior written consent. QF elects to receive, and the Company agrees to commence calculating, capacity payments in accordance with this Agreement starting with the first Monthly Period following ____________, 20____.

iii. <u>Firm Capacity Payment Options:</u> The following options are available to the QF for payment for Firm Capacity delivered by the QF:

1) Value of Deferral Capacity Payments;
2) Early Capacity Payments;
3) Levelized Capacity Payments;
4) Early Levelized Capacity Payments.

QF chooses to receive firm capacity payments from the Company under Option: ____________. Each of these options is further defined in and subject to the provisions of the Company's Rate Schedule COG-2, Appendix A.

At the end of each Monthly Period, beginning with the Monthly Period specified in Paragraph 4.b.ii, the Company will calculate QF's Monthly Availability and Capacity Factor. During the term of this Agreement, if the QF's Monthly Availability and Capacity Factor equals or exceeds the Minimum Performance Standards (MPS), attached hereto as Appendix C in Rate Schedule COG-2, then the Company agrees to pay QF a Monthly Capacity Payment as calculated in the Section entitles Basis for Monthly Capacity Payment Calculation, Paragraph 5 of COG-2, Appendix C.

The capacity payment for a given month will be added to the energy payment for such month and tendered by the Company to QF as a single payment as promptly as possible, normally by the twentieth business day following the day the meter is read.

Continued to Sheet No. 8.500

Continued from Sheet No. 8.495

iv. <u>Security Guarantees:</u> The Company requires certain security deposits to ensure the completion of construction and performance under this Agreement in order to protect its ratepayers in the event the QF fails to deliver Firm Capacity and Energy in the amount and times specified in this Agreement, which shall be in form and substance as described herein. Such security may be refunded in the manner described in Paragraphs 4.b.iv.(1) and 4.b.iv.(2). Pursuant to FPSC Rule 25-17.091, F.A.C., a utility may not require security guarantees from a municipal solid waste facility as required in FPSC Rule 25-17.0832(2)(d) and (3)(f)(1), F.A.C. However, at its option, a municipal solid waste facility may provide such risk-related guarantees.

(1) <u>Completion Security:</u> The QF shall pay to the Company a security deposit equal to $10.00 per kilowatt ($10.00/kW) of Anticipated Contracted Capacity as described herein as security for QF's completion of the Facility by the in-service date of the Designated Avoided Unit. Such security will be required within 60 days of contract execution. Such security shall be in the form of cash deposited in an interest bearing escrow account mutually acceptable to the Company and the QF; an unconditional and irrevocable direct pay letter of credit in form and substance satisfactory to the Company; or a performance bond in form and substance satisfactory to the Company. The form of security required will be in the sole discretion of the Company and will be in such form as to allow the Company immediate access to the funds in the event that the QF fails to complete the construction and achieve commercial in-service status by the in-service date of the Designated Avoided Unit.

If the QF achieves commercial in-service status by the in-service date of the Designated Avoided Unit then the entire deposit and any interest therein, if applicable, shall be refunded to the QF upon payment by the QF of the Performance Security as required in Paragraph 4.b.iv.(2).

Continued to Sheet No. 8.505

Continued from Sheet No. 8.500

If the QF's Commercial In-Service Date is delayed beyond the in-service date of the Designated Avoided Unit, the Company may, upon the request of the QF, extend such date for a period not to exceed five (5) months, in which case the Company shall be entitled to retain or draw down on an amount equal to 20% of the original deposit amount for each month (or portion thereof) that the completion of the project is delayed. If the QF's Commercial In-Service Date is delayed and an extension has not been granted or such date is delayed beyond the extended completion date, then the Company shall retain all of the deposit and terminate this Agreement.

(2) Performance Security: Within sixty (60) days after the later of the QF's Commercial In-Service Date or the in-service date of the Designated Avoided Unit, the QF shall pay the Company a deposit in the amount of $10.00/kW of Actual Contracted Capacity as security for QF's performance under this Agreement. Such security deposit shall be provided in the same manner as the completion security deposit as described in Paragraph 4.b.iv.(1). Such performance security shall be retained by the Company for twelve (12) months from the later of the QF's Commercial In-Service Date or the in-service date of the Designated Avoided Unit.

If, at the end of the twelve month period so described, the QF's 12-month average of each month's numerical value for both the Monthly Availability Factor and the Monthly Capacity Factor meet the Minimum Performance Standards (MPS) as set forth in Rate Schedule COG-2, then QF shall be entitled to a refund of such deposit. However, if at the end of the first twelve month period, the QF's 12-month average of each month's numerical value for both the Monthly Availability Factor and the Monthly Capacity Factor fail to meet the MPS, then the Company shall be entitled to retain or draw down 50% of such deposit and retain the remainder of the security for an additional twelve month period.

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Continued from Sheet No. 8.505

If, at the end of the twenty fourth month, the QF's 12-month average of each month's numerical value for both the Monthly Availability Factor and the Monthly Capacity Factor again fail to achieve the MPS, for the most recent 12-month period, then the Company shall be entitled to retain the remainder of the security and to terminate the contract. However, if at the end of the twenty fourth month, the QF's 12-month average of each month's numerical value for both the Monthly Availability Factor and the Monthly Capacity Factor meet the MPS, for the most recent 12-month period, then the QF shall be entitled to a refund of the remaining deposit.

For the purpose of this calculation, the 12-month average of a parameter shall be defined to equal the sum of each month's average numerical value for that parameter, for the most recent 12-month period, divided by twelve (12).

(3) Liquidated Damages: The parties hereto agree that the Company would be substantially damaged in amounts that would be difficult or impossible to ascertain in the event that QF fails to complete the Facility by the in-service date of the Designated Avoided Unit or to provide a Facility which meets the MPS. In the event that the Company terminates this Agreement for the QF's failure to achieve commercial in-service status by the in-service date of the Designated Avoided Unit or achieve the MPS once in service, the Company may retain all of the completion or performance security as liquidated damages, not as penalty, in lieu of actual damages and the QF hereby waives any defenses as to the validity of any such liquidated damages. In the event the QF defaults, it forfeits the aforesaid Completion or Performance Security. In addition thereto, the Company shall be entitled to pursue such equitable remedies against the QF as may be available.

5. Electricity Production Schedule: During the term of this Agreement, the QF agrees to the following:

Continued to Sheet No. 8.515

Continued from Sheet No. 8.510

a. QF shall provide the Company in writing prior to April 1 of each calendar year an estimate of the amount of electricity to be generated by the QF and delivered to the Company for each month of the following calendar year, including the time, duration and magnitude of any planned outages or reductions in capacity;

b. By July 1 of each calendar year, the Company shall notify the QF in writing whether the requested scheduled maintenance period(s) are acceptable. If the Company cannot accept any of the requested period(s), the Company shall advise the QF of the time period closest to the requested period(s) when the outage(s) can be scheduled. QF shall only schedule outages during periods approved by the Company and such approval shall not be unreasonably withheld. Once the schedule has been established and approved, either party requesting a subsequent change in such schedule, except when such event is due to Force Majeure, must obtain approval for such change from the other party. Such approval shall not be unreasonably withheld or delayed.

c. During the term of this Agreement, the QF shall employ qualified personnel for managing, operating and maintaining the Facility and for coordinating such with the Company. The QF shall ensure that operating personnel are on duty at all times, twenty-four hours a calendar day and seven calendar days a week. Additionally, during the term of this Agreement, the QF shall operate and maintain the Facility in such a manner as to ensure compliance with its obligations hereunder.

d. The Company shall not be obligated to purchase and may require curtailed or reduced deliveries of energy, to the extent necessary to maintain the reliability and integrity of any part of the Company's system, or if the Company determines that a failure to do so is likely to endanger life or property, or is likely to result in significant disruption of electric service to the Company's Customers. The Company shall give QF prior notice, if practicable, of its intent to refuse, curtail or reduce the Company's acceptance of energy pursuant to this Section and will act to minimize the frequency and duration of such occurrences.

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Continued from Sheet No. 8.515

e. The Company shall not be required to accept or purchase energy during any period in which, due to operational circumstances, acceptance or purchase of such energy would result in the Company's incurring costs greater than those which it would incur by generating an equal additional amount of energy with its own resources. The Company shall give the QF as much prior notice as practicable of its intent not to accept energy pursuant to this Section.

f. QF shall promptly update the yearly generation schedule and maintenance schedule as and when any changes may be determined necessary;

g. QF shall comply with reasonable requirements of the Company regarding day-to-day or hour-by-hour communications between the parties relative to the performance of this Agreement.

6. QF's Obligation If QF Receives Early, Levelized, or Early Levelized Capacity Payments: The parties recognize that Rule 25-17.0832, F. A. C., may require the repayment by the QF of all one portion of any payments made to it pursuant to Option 2, 3, or 4 of Section 4.2.3 if the QF fails to perform pursuant to the terms and conditions of this Agreement. To ensure that the QF will satisfy its obligation to make any such repayments, the following provisions will apply:

The Company shall establish a Repayment Account to accrue the sum of the capacity payments that may have to be repaid by the QF to the Company. Amounts shall be added to the Repayment Account each month through December 2002, in the amount of the Company's payments to the QF for capacity delivered prior to January 1, 2003.

Beginning on January 1, 2003, the difference between the capacity payment made to the QF and the "normal" capacity payment calculated pursuant to Option 1 in COG-2 will also be added each month to the Repayment Account, so long as the payment made to the QF is greater than the monthly payment the QF would have received if it had selected Option 1 in Paragraph 4.b.iii. The annual balance in the Repayment Account shall accrue interest at an annual rate of 9.37%.

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Continued from Sheet No. 8.520

Also beginning on January 1, 2003, at such time that the monthly capacity payment made to the QF, pursuant to the Capacity Payment Option selected, is less than the "normal" monthly capacity payment in Option 1 in COG-2, there shall be debited from the Repayment Account an Early Payment Offset Amount to reduce the balance in the Repayment Account. Such Early Payment Offset Amount shall be equal to the amount which the Company would have paid for capacity in that month if capacity payments had been calculated pursuant to Option 1 in COG-2 and the QF had elected to begin receiving capacity payments on January 1, 2003, minus the monthly capacity payment the Company makes to the QF (assuming the MPS are met or exceeded), pursuant to the Capacity Payment Option chosen by the QF in Paragraph 4.b.iii.

QF shall owe the Company and be liable for the current balance in the Repayment Account. The Company agrees to notify the QF monthly as to the current Repayment Account balance.

In the event of default by the QF, the total Repayment Account balance shall become due and payable within twenty (20) business days of receipt of written notice, as reimbursement for the early capacity payments made to the QF by the Company. The QF's obligation to reimburse the Company in the amount of the balance in the Repayment Account shall survive the termination of the QF's Standard Offer Contract with the Company. Such reimbursement shall not be construed to constitute liquidated damages and shall in no way limit the right of the Company to pursue all its remedies at law or in equity against the QF.

Prior to receipt of Early Levelized or Early-Levelized Capacity Payments, the QF shall secure its obligation to repay any balance in the Repayment Account in the event QF defaults pursuant to this Agreement. Such security shall be in the form of cash deposited in an interest bearing escrow account mutually acceptable to the Company and the QF; an unconditional and irrevocable direct pay letter of credit in form and substance satisfactory to the Company; or a performance bond in form and substance satisfactory to the Company. The form of security required will be in the sole discretion of the Company and will be in such form as to allow the Company immediate access to the funds in the event of default by the QF. Florida Statute 377.709(4) requires the local government to refund early capacity payments should a Municipal Solid Waste Facility owned, operated by or on the behalf of a local government be abandoned, closed down or rendered illegal. Therefore a utility may not require risk-related guarantees from a Municipal Solid Waste Facility as required in FPSC Rule 25-17.0832(2)(c) and (3)(e)(8), F.A.C. However, at its option, a Municipal Solid Waste Facility may provide such risk-related guarantees.

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Continued from Sheet No. 8.525

7. **Nonperformance Provisions:** QF shall not receive a capacity payment during any month in which the QF fails to meet the MPS for Monthly Availability and Monthly Capacity Factor of the Company's Designated Avoided Unit as defined in Appendix C in COG-2. In addition, if for any month starting January 1, 2003, the QF fails to achieve the MPS and the monthly capacity payment that would have been made to the QF pursuant to the capacity payment option selected is less than the "normal" monthly capacity payment had the QF selected Option 1, then the QF shall be liable for and shall pay the Company an amount equal to the Early Payment Offset Amount for the month; provided, however, that such calculation shall assume that the QF satisfied the MPS. Any payments thus required of QF shall be separately invoiced by the Company to QF after each month for which such payment is due and shall be paid by QF within twenty (20) business days after receipt of such invoice by QF. Such payment shall be debited from the Capacity Account as an Early Payment Offset Amount provided that any such payment will not exceed the current balance in the Capacity Account.

8. **Default**

a. **Mandatory Default:** QF shall be in default under this Agreement if:

i. QF voluntarily declares bankruptcy; or

ii. QF fails to achieve, on both accounts, a minimum Monthly Availability Factor of 25% and fails to achieve a minimum Monthly Capacity Factor of 25%, during the same month, for 12 consecutive months starting January 1, 2003; or

iii. QF fails to maintain its status as a QF as required herein; or

iv. QF fails to perform in accordance with Section 4.b.iv.(2).

b. **Optional Default:** The Company may declare the QF to be in default:

i. If at any time prior to January 1, 2003, and after Monthly Capacity Payments have begun, the Company has sufficient reason to believe that the QF is unable to deliver its Actual Contracted Capacity; or

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RESERVED FOR FUTURE USE

RESERVED FOR FUTURE USE

Continued from Sheet No. 8.530

iii. after Monthly Capacity Payments have begun, the QF fails each month, for 24 consecutive months, to meet the MPS; or

iv. QF refuses, is unable or anticipatorily breaches its obligation to deliver its Actual Contracted Capacity after January 1, 2003.

c. Default Remedy: In the event of default by the QF, the total Repayment Account balance shall become due and payable within twenty (20) business days of receipt of written notice, as reimbursement for the early capacity payments made to the QF by the Company. The QF's obligation to reimburse the Company in the amount of the balance in the Repayment Account shall survive the termination of the QF's Standard Offer Contract with the Company. Such reimbursement shall not be construed to constitute liquidated damages and shall in no way limit the right of the Company to pursue all its remedies at law or in equity against the QF.

9. General Provisions:

a. Permits: QF hereby agrees to seek to obtain any and all governmental permits, certifications, or other authority QF is required to obtain as a prerequisite to engaging in the activities provided for in this Agreement. The Company hereby agrees to seek to obtain at QF's expense any and all governmental permits, certifications or other authority the Company is required to obtain as a prerequisite to engaging in the activities provided for in this Agreement.

b. Indemnification: The Company and QF shall each be responsible for its own facilities. The Company and the QF shall each be responsible for its own facilities in ensuring adequate safeguards for other Company Customers, the Company and QF personnel and equipment, and for the protection of its own generating system. The Company and the QF shall each indemnify and save the other harmless from any and all claims, demands, costs, or expense for loss, damage, or injury to persons or property of the other caused by, arising out of, or resulting from:

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i. any act or omission by a party or that party's contractors, agents, servants and employees in connection with the installation or operation of that party's generation system or the operation thereof in connection with the other party's system; and

ii. any defect in, failure of, or fault related to a party's generation system; and

iii. the negligence of a party or negligence of that party's contractors, agents servants and employees; and

iv. any other event or act that is the result of, or proximately caused by a party.

For the purpose of this subsection, the term party shall mean either the Company or QF, as the case may be.

c. <u>Insurance:</u> The QF shall deliver to the Company, at least fifteen (15) days prior to the start of any interconnection work, a certificate of insurance certifying the QF's coverage under a liability insurance policy issued by a reputable insurance company authorized to do business in the state of Florida naming the QF as named insured, and the Company as an additional named insured, which policy shall contain a broad form contractual endorsement specifically covering the liabilities accepted under this Agreement arising out of the interconnection to the QF, or caused by operation of any of the QF's equipment or by the QF's failure to maintain its equipment in satisfactory and safe operating condition.

i. In subsequent years, a certificate of insurance renewal must be provided annually to the Company indicating the QF's continued coverage as described herein. Renewal certification shall be sent to:

Tampa Electric Company
c/o Director of Risk Management
P. O. Box 111
Tampa, FL 33601

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ii. The policy providing such coverage shall provide public liability insurance, including coverage for personal injury, death and property damage, in an amount not less than $1,000,000 for each occurrence; provided however, if QF has insurance with limits greater than the minimum limits required herein, the QF shall set any amount higher than the minimum limits required by the Company to satisfy the insurance requirements of this Agreement.

iii. The above required policy shall be endorsed with a provision whereby the insurance company to notify the Company thirty (30) days prior to the effective date of any cancellation or material change in said policy.

iv. QF shall pay all premiums and other charges due on said policy and keep said policy in force during the entire period of interconnection with the Company.

d. <u>Force Majeure:</u> If either party shall be unable, by reason of force majeure, to carry out its obligations under this Agreement, either wholly or in part, the party so failing shall give written notice and full particulars of such cause or causes to the other party as soon as possible after the occurrence of any such cause; and such obligations shall be suspended during the continuance of such hindrance, which, however, shall be remedied with all possible dispatch; and the obligations, terms and conditions of this Agreement shall be extended for such period as may be necessary for the purpose of making good any suspension so caused. The term "force majeure" shall be taken to mean all acts of God, strikes, lockouts or other industrial disturbances at the manufacturing site of the major equipment components or the construction site, wars, blockades, insurrections, riots, arrests and restraints of rules and people, explosions, fires, floods, lightning, wind, perils of the sea, accidents to equipment or machinery or similar occurrences; provided, however that no occurrence may be claimed to be a force majeure occurrence if it is caused by the negligence or lack of due diligence on the part of the party attempting to make such claim and specifically does not include interruption in fuel supply. QF agrees to pay the costs necessary to reactivate the Facility and/or the interconnection with the Company's system if the same are rendered inoperable due to actions of QF, its agents, or force majeure events affecting the Facility or the interconnection with the Company.

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Continued from Sheet No. 8.545

The Company agrees to reactivate at its own cost the interconnection with the Facility in circumstances where any interruptions to such interconnections are caused by the Company or its agents.

e. <u>Conditions Precedent:</u> Notwithstanding any other provisions of this Agreement including the provisions of Paragraph 9.d, the Company shall have the right to terminate this Agreement by notice to the QF, without cause, liability or obligation, if one or more of the following conditions, after reasonable effort by QF, shall not have been or cannot be satisfied in the Company's good faith judgement, and in the time periods described below. The Company in its sole discretion may extend QF's time for satisfying these conditions if one or more of the events described below is pending as of such date and it is reasonable to expect that such event will be accomplished within sixty (60) days:

i. QF meets the Construction Commencement Date;

ii. On or before the QF's Commercial In-Service Date: QF secures certification of the facility as a QF as defined herein and as certified by the FERC;

iii. On or before January 1, 2001: QF secures any and all land use and zoning approvals reasonably necessary to obtain construction financing and authorizes the commencement of construction of the facility on a basis not substantially adverse to the Company;

iv. On or before January 1, 2001: QF has secured all other environmental and construction permits and other governmental approvals reasonably necessary to obtain construction financing and to begin construction of the facility on a basis not substantially adverse to the Company;

v. On or before January 1, 2001: QF achieves closing of financing for construction of the facility;

vi. On or before January 1, 2002: QF provides to the Company written evidence of the rights to adequate fuel supply for the facility in a form satisfactory to the Company;

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Continued from Sheet No. 8.550

vii. Within 6 months after the effective date of this Agreement: QF provides evidence in writing in a form satisfactory to the Company indicating and substantiating the ownership of or the right to use the real property as the specific site upon which the facility will be located; and

viii. On or before January 1, 2001: Sufficient information satisfactory to the Company has been provided to the Company describing the technical capability and experience of the Facility's technology, including its environmental performance of the facility.

f. Assignment: The QF shall have the right to assign its benefits under this Agreement, but the QF shall not have the right to assign its obligations and duties without the Company's prior written consent and such consent shall not be unreasonably withheld.

g. Disclaimer: In executing this Agreement, the Company does not, nor should it be construed, to extend its credit or financial support for the benefit of any third parties lending money to or having other transactions with QF or any assignee of this Agreement.

h. Notification: For purposes of making any and all non-emergency oral and written notices, payments or the like required under the provisions of this Agreement, the parties designate the following to be notified or to whom payment shall be sent until such time as either party furnishes the other party written instructions changing such designate.

For: QF	For: Tampa Electric Company manager-Industrial/Governmental Marketing & Sales Tampa Electric Company P.O. Box 111 Tampa, Florida 33601

i. Applicable Law: This Agreement shall be governed by and construed and enforced in accordance with the laws, rules, and regulations of the State of Florida and the Company's Tariff as may be modified, changed, or amended from time to time.

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j. <u>Severability:</u> If any part of this Agreement, for any reason, be declared invalid, or unenforceable by a court or public authority of appropriate jurisdiction then such decision shall not affect the validity of the remainder of the Agreement, which remainder shall remain in force and effect as if this Agreement had been executed without the invalid or unenforceable portion.

k. <u>Complete Agreement and Amendments:</u> All previous communications or agreements between the parties, whether verbal or written, with reference to the subject matter of this Agreement are hereby abrogated. No amendment or modification to this Agreement shall be binding unless it shall be set forth in writing and duly executed by both parties to this Agreement.

l. <u>Incorporation of Rate Schedule:</u> The parties agree that this Agreement shall be subject to all of the provisions contained in the Company's published Rate Schedule COG-2 as approved and on file with the FPSC. The Rate Schedule is incorporated herein by reference.

m. <u>Survival of Agreement:</u> This Agreement, as it may be amended from time to time, shall be binding and inure to the benefit of the Parties' respective successors-in-interest and legal representatives.

IN WITNESS WHEREOF, QF and the Company have executed this Agreement the day and year first above written.

WITNESSES:	Qualifying Facility
______________________	By:______________________
______________________	Its:______________________
WITNESSES:	Tampa Electric Company
______________________	By:______________________
______________________	Its:______________________

EVALUATION PROCEDURE
FOR STANDARD OFFER CONTRACTS
APPENDIX A
STANDARD OFFER CONTRACT

The Company believes that Standard Offer Contracts should be evaluated and then accepted based on meeting specific criteria rather than ranking them entirely on the timing of their receipt. This Evaluation Procedure will insure the acceptance of Standard Offer Contracts that meet the Company's needs and are in the best interest of Customers.

Each eligible Standard Offer Contract received by the Company will be evaluated as to its technical reliability, viability and financial stability, as well as other relevant information, in accordance with FPSC Rule 25-17.0832, F.A.C., and the Company's Procedure for Processing Standard Offer Contracts as defined in Rate Schedule COG-2.

QFs submitting Standard Offer Contracts to the Company should, at the same time, provide considerable detail regarding their projects by submitting specific information for each of the following evaluation criteria. Failure to provide this information may result in a determination of non-viability by the Company. Each eligible Standard Offer Contract received will be evaluated based upon the information provided in response to the following list of parameters:

EVALUATION PARAMETERS:

1. **Technical Viability:**

   a. What is the technology being proposed?

   b. Has the technology been demonstrated or commercially applied? Please explain.

   c. Has the QF previously utilized this technology elsewhere?

Construction:	Please provide performance record and experience with project technology.
Operations:	Please provide operator's experience and performance record in comparable facilities.

   d. Has a project feasibility study been conducted by an Independent Engineer to assess project technology and its potential effect on the project's financial results? Please explain.

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e. What thermal efficiency must be maintained by the unit(s) in order to retain status as a QF?

2. <u>Fuel Supply:</u>

a. What is the primary fuel type?

b. What are the annual fuel requirements? (primary/alternate)

c. Has primary fuel supply been secured? Is the fuel supply domestic, cross-border or foreign? Is the term of the fuel supply agreement equal to the debt term?

d. Is an alternate fuel required?

e. Has an alternate fuel supply been secured?

f. Have transportation arrangements for both primary and alternate fuels been secured (firm/interruptible, provide detail)?

g. Are the pricing terms of the fuel supply agreement(s) directly tied to the corresponding energy payments?

3. <u>Reliability:</u>

a. Dispatchability: Will the facility be dispatched on request or will it be base loaded? Please explain.

b. QF Status: Has project obtained FERC certification as a QF? Has application been made for FERC certification? Please explain.

c. Operations and Maintenance: Who will provide O & M for the facility: (a) developer; or (b) third party?

d. Steam Host:
- Please explain the importance of the thermal energy (steam), taken by the steam host, to the overall operations of the steam host.
- Are there adequate alternative candidates in close proximity to the facility that could serve as a potential steam host replacement?
- What is the minimum "steam take" necessary for the project to maintain QF status?

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- Has a steam host been secured?
- Is the steam host already in existence?
- Is it a new steam host? (Is it identifiable?)
- What are the steam host's operating hours?
- Is steam host's business cycle or thermal requirements seasonal? If so explain.

e. Permits: What permits or licenses will be required for the project? Have the necessary permits or licenses been secured? What specific environmental considerations must the project meet?

f. Construction Schedule: Has a construction schedule including milestones been formulated? Please provide detail.

g. Site Control: Has the project's location been identified? Has the site been secured? Does the site require specific environmental considerations, i.e. wetlands, etc.? Please explain.

4. <u>Developer's Qualifications:</u>

a. Project's Financial Stability: Does the project Developer's credit rating qualify for Investment-Grade Status? Please provide detail.

b. Developer's Experience: Has developer any projects in operation? Has developer any other projects under construction? Please provide details for each previous IPP or QF projects undertaken by the Developer, including but not limited to:

- Financial arrangements and Institutions,
- Fuel contracts,
- Scheduling/project control information,
- Regulatory treatment,
- Ownership structure, i.e. partnership, limited partnership, contract buy-outs, etc., and
- Total operating experience and performance.

c. Project Financing: Has project financing been secured? Will ownership equity in project be 15% or greater? Will the project be structured as a nonrecourse financing project? Please provide detail.

Continued to Sheet No. 8.580

Continued from Sheet No. 8.575

d. Working Capital: Has long-term working capital been secured? Are sufficient reserves available to fund six-months of debt service? Are sufficient funds available to cover six-months of O&M expenses? Does project have warranties for key operating equipment during the first year of operations? Please provide detail.

<u>EVALUATION CRITERIA AND SCORING:</u> The QF will receive a score of 2, 1, or 0 in each of the categories listed below. A score of "2" indicates that the project fully meets or exceeds the specific requirements that the Company has established for that parameter. A score of "1" indicates that the project may only marginally meet some portion of the established requirements. And, a score of "0" indicates that a sufficient number of the established requirements have not been satisfactorily met.

The Company will accept Standard Offer Contracts on the basis of the information provided in response to the evaluation criteria and upon its judgement of other relevant factors. The Standard Offer Contract receiving the most points and which has convincingly demonstrated that the project is financially and technically viable and that the committed capacity would be available by the date specified in the Standard Offer Contract will be accepted first. The Company will continue to accept successive Standard Offer Contracts until further acceptance of a Standard Offer Contract would cause the subscription limit to be exceeded. Points for each category will be given as follows:

<u>Technical Viability</u>

2 Technology has been proven through commercial application.
1 Technology has been satisfactorily demonstrated in a pilot project (more than two years).
0 Technology has not been satisfactorily demonstrated or proven.

<u>Fuel Availability</u>

2 Primary fuel supply has been secured.
1 Letter of intent to supply primary fuel is in-hand.
0 Primary fuel supply is unsecured.

<u>Fuel Diversity</u>

2 An alternate fuel supply has been secured.
1 Letter of intent to supply alternate fuel is in-hand.
0 Alternate fuel supply is unsecured.

Continued to Sheet No. 8.585

Continued from Sheet No. 8.580

<u>Fuel Transportation</u>

- 2 Transportation agreement for both primary and alternate fuels has been secured.
- 1 Transportation agreement appears likely.
- 0 Transportation agreement is uncertain.

<u>Dispatchability</u>

- 2 Unit(s) is completely dispatchable or base loaded.
- 1 Unit(s) is somewhat dispatchable.
- 0 Unit(s) is not dispatchable.

<u>QF Status</u>

- 2 QF status has been certified by FERC or the FPSC and has been provided.
- 1 Application for FERC Certification has been made and has been provided.
- 0 Application for FERC Certification has not been made.

<u>Operations and Maintenance</u>

- 2 A long-term O&M agreement (five years or more) has been reached.
- 1 A long-term O&M agreement appears likely or a short-term O&M agreement (less than five years) has been reached.
- 0 No decision has been made toward achieving an O&M agreement.

<u>Steam Host</u>

- 2 A letter of intent with a steam host has been provided.
- 1 The steam host exists and has been identified, but a letter of intent has not been provided.
- 0 Steam Host does not exist and/or is unidentified.

<u>Permits</u>

- 2 Permits and licenses are in-hand.
- 1 Permits and licenses are not yet secured but no permitting or zoning problems are apparent.
- 0 Significant doubts exist regarding environmental considerations, permitting and/or zoning.

Continued to Sheet No. 8.590

Continued from Sheet No. 8.585

<u>Construction Schedule and Milestones</u>

2 A Construction schedule exists and Milestones are appropriate for timely completion.

1 Timely completion of project appears likely.

0 Timely completion appears doubtful.

<u>Site Control</u>

2 Site has been secured and does not require specific environmental considerations.

1 Site is identified and is sufficiently secured.

0 Site is uncertain or it requires specific environmental considerations, i.e. wetlands, etc.

<u>Developer's Financial Stability</u>

2 Project developer has a credit rating comparable to Investment-Grade Status.

1 Project developer has a credit rating that is less favorable than Investment-Grade Status.

0 Project developer's credit rating is considered too risky.

<u>Developer's Experience</u>

2 Developer has proven experience developing cogeneration projects.

1 Developer has marginal experience developing cogeneration projects.

0 Developer has no experience developing cogeneration projects.

<u>Project Financing</u>

2 Project financing has been secured.

1 Project financing appears likely.

0 Project financing is uncertain.

<u>Working Capital</u>

2 Working capital has been secured.

1 Working capital appears likely.

0 Working capital is uncertain.

Continued to Sheet No. 8.595

RESERVED FOR FUTURE USE

Continued from Sheet No. 8.590

Please provide the following general information to assist the Company in evaluating your Standard Offer Contract

- Standard Offer Committed Capacity (MW):
- Size and type of generation:
- Any existing or planned capacity commitments or energy sales to other utilities, if so provide detail:
- Will the project directly interconnect into the Company's transmission grid? Please explain:
- If the project is located external to the Company's retail service area, how will the power be delivered to the Company? Please explain:
- Will steam host use a portion of electric generation, if so provide detail:
- Please provide developer's ownership structure for this project:
- Developer's Insurance Carrier:
    - Property damage insurance:
    - Business interruption insurance:
    - Rating of insurance carrier:
- Please provide estimates of the following:
    - Expected annual metered electric output,
    - Expected annual metered useful thermal output, in Btu/hr X operating hours/year,
    - Expected annual metered fuel input, in Btu/hr X operating hours/year.
- Other:

~~TAMPA ELECTRIC COMPANY'S~~ INTERCONNECTION AGREEMENT

This agreement is made and entered into this _______ day of _____________, ~~19~~____ by and between ____________________, hereinafter referred to as "QF" and Tampa Electric Company, a private utility corporation organized under the laws of the State of Florida, hereinafter referred to as the "Company". The QF and the Company ~~Tampa Electric~~ shall collectively be referred to herein as the "Parties."

1. <u>Facility:</u> The QF's generating facility, hereinafter referred to as "Facility," is located at ______________________, within the Company's ~~Tampa Electric~~ service territory. QF intends to have its Facility installed and operational on or about _____________, ~~19~~____. QF shall provide the Company ~~Tampa Electric~~ reasonable prior notice of the Facility's initial operation, and it shall cooperate with the Company ~~Tampa Electric~~ to arrange initial deliveries of power to the Company's system.

The Facility has been or will be certified as a Qualifying Facility pursuant to the rules and regulations of the Florida Public Service Commission (FPSC) or the Federal Energy Regulatory Commission (FERC). The QF shall maintain the qualifying status of the Facility throughout the terms of the Interconnection Agreement. By the end of the first quarter of each year, QF shall furnish the Company ~~Tampa Electric~~ a notarized certificate by an officer of QF certifying that the Facility has continuously maintained qualifying status on a calendar year basis since the commencement of the contract term.

2. <u>Construction Activities:</u> QF shall provide the Company ~~Tampa Electric~~ with written instructions to proceed with construction of the interconnection facilities as described in this Agreement at least 24 months prior to the date on which the facilities shall be completed.

The Company ~~Tampa Electric~~ agrees to complete the interconnection facilities as described in this Agreement within 24 months of receipt of written instructions to proceed.

Upon the parties' agreement as to the appropriate interconnection design requirements and receipt of written instructions to proceed delivered by QF, the Company ~~Tampa Electric~~ shall design and perform or cause to be performed all of the work necessary to interconnect the Facility with the Company's ~~Tampa Electric~~ system.

Continued to Sheet No. 8.605

Continued from Sheet No. 8.600

Prior to any work being done by the Company ~~Tampa Electric Company~~, the Company ~~Tampa Electric~~ shall supply QF with a written cost estimate of all required materials and labor and an estimate of the date by which construction of the interconnection will be completed. This estimate shall be provided to QF within 60 days after QF provides the Company ~~Tampa Electric~~ with its final electrical one-line diagrams. The Company ~~Tampa Electric~~ shall also provide project timing and feasibility information to the QF.

QF agrees to pay the Company ~~Tampa Electric~~ all expenses incurred by the Company ~~Tampa Electric~~ necessary for integration of the Facility into the Company's ~~Tampa Electric~~ electrical system, including but not limited to the design, construction, operation, maintenance and repair of the interconnection facilities described in Exhibit A. Exhibit A shall contain a complete description of the interconnection facilities including the final electrical on-line diagram. Such interconnection costs shall not include any interconnection costs which the Company ~~Tampa Electric~~ would otherwise incur if it were not engaged in interconnected operations with QF but instead provided through its own generation facilities the electric power required by the Facility.

QF agrees to pay the costs for complete interconnection work ($___ dollars): (   ) within 30 days after the Company ~~Tampa Electric~~ notifies QF that such interconnection work has been completed; or (   ) payable in (up to 36) _____ monthly installments, plus interest on the outstanding balance calculated at the 30-day highest grade commercial paper rate in effect 30 days prior to the date each payment is due, such rate to be determined by the Company ~~Tampa Electric~~, with the first such installment payment being due 30 days after the Company ~~Tampa Electric~~ notifies QF that such interconnection work has been completed.

In the event QF notifies the Company ~~Tampa Electric~~ in writing to cease interconnection work before its completion, QF shall be obligated to reimburse the Company ~~Tampa Electric~~ for the interconnection costs incurred up to the date such notification is received. The payment terms shall be in accordance with the payment option selected by the QF in the proceeding paragraph.

3. **Cost Estimates:** Attached hereto as Exhibit B and incorporated herein by this reference is a document entitled, "QF Interconnection Cost Estimates." The parties agree that the cost of the interconnection work contained in Exhibit B is a good faith estimate of the actual cost to be incurred.

Continued to Sheet No. 8.610

Continued from Sheet No. 8.605

4. <u>Technical Requirements and Operations:</u> The parties agree that QF's interconnection with, and delivery of electricity into, the Company's ~~Tampa Electric~~ system must be accomplished in accordance with the provisions of the Company's ~~Tampa Electric~~ "General Standards for Safety and Interconnection of Cogeneration and Small Power Production Facilities to the Electric Utility System," "NERC Planning Standards," September 1997, [Copyright @ 1997 by the North American Electric Reliability Council] attached hereto as Exhibit C, that are applicable to generation and transmission facilities which are connected to, or are being planned to be connected to the Company's transmission system (document provided upon request).

In the event that changes in the engineering or operating standards or practices in the utility industry, and the Company's ~~Tampa Electric Company's~~ corresponding standards or practices or changes in regulatory requirements, affect the design or operation of the Company's ~~Tampa Electric's~~ electrical system, and this in turn necessitates additions to or modifications of the equipment or facilities utilized in order to ensure the continued safe and reliable operations contemplated by this Agreement, as well as the continued compatibility of the Facility with the Company's ~~Tampa Electric's~~ system, QF agrees to bear the cost of such additions or modifications which are directly attributable to the Facility. The costs of such additions or modifications shall not include any costs which the Company ~~Tampa Electric~~ would otherwise incur if it were not engaged in interconnected operations with the Facility, but instead provided through its own generation facilities the electrical power required by the Facility.

In addition, QF agrees to require that the Facility operator immediately notify the Company's ~~Tampa Electric's~~ System Dispatcher by telephone in the event hazardous or unsafe conditions associated with the parties' parallel operations are discovered. If such conditions are detected by the Company ~~Tampa Electric~~, then the Company ~~Tampa Electric~~ will likewise immediately contact the operator of the Facility by telephone. Each party agrees to immediately take whatever appropriate corrective action is necessary to correct the hazardous or unsafe conditions.

To the extent the Company ~~Tampa Electric~~ reasonably determines the same to be necessary to ensure the safe operation of the Facility or to protect the integrity of the Company's ~~Tampa Electric's~~ system, QF agrees to reduce power generation or take other appropriate actions.

Continued to Sheet No. 8.615

Continued from Sheet No. 8.610

5. **Interconnection Facilities:** The interconnection facilities shall include the items listed in Exhibit A. Interconnection facilities on the Company's ~~Tampa Electric's~~ side of the ownership line with QF shall be owned, operated, maintained and repaired by the Company ~~Tampa Electric~~. QF shall be responsible for the cost of designing, installing, operating and maintaining the interconnection facilities on QF's side of the ownership line as indicated in Exhibit A. The QF shall be responsible for establishing and maintaining controlled access by third parties to the interconnection facilities owned by the QF.

6. **Maintenance and Repair Payments:** The Company ~~Tampa Electric~~ will separately invoice QF monthly for all costs associated with the operation, maintenance and repair of the interconnection facilities. QF agrees to pay the Company ~~Tampa Electric~~ within 20 business days of receipt of each such invoice.

7. **Site Access:** In order to help ensure the continuous, safe, reliable and compatible operation of the Facility with the Company's ~~Tampa Electric~~ system, QF hereby grants to the Company ~~Tampa Electric~~ for the period of interconnection the reasonable right of ingress and egress, consistent with the safe operation of the Facility, over property owned or controlled by QF to the extent the Company ~~Tampa Electric~~ deems such ingress and egress necessary in order to examine, test, calibrate, coordinate, operate, maintain or repair any interconnection equipment involved in the parallel operation of the Facility and the Company's ~~Tampa Electric's~~ system, including the Company's ~~Tampa Electric's~~ metering equipment.

8. **Construction Responsibility:** In no event shall any the Company ~~Tampa Electric~~ statement, representation, or lack thereof, either express or implied, relieve QF of its exclusive responsibility for the Facility. Specifically, any the Company ~~Tampa Electric~~ inspection of the Facility shall not be construed as confirming or endorsing the Facility's design or its operating or maintenance procedures nor as a warranty or guarantee as to the safety, reliability, or durability of the Facility's equipment. The Company's ~~Tampa Electric's~~ inspection, acceptance, or its failure to inspect shall not be deemed an endorsement of any Facility equipment or procedure.

Continued to Sheet No. 8.620

Continued from Sheet No. 8.615

9. <u>Insurance:</u> The QF shall deliver to the Company ~~Tampa Electric~~, at least fifteen (15) days prior to the start of any interconnection work, a certificate of insurance certifying the QF's coverage under a liability insurance policy issued by a reputable insurance company authorized to do business in the State of Florida naming the QF as named insured, and the Company ~~Tampa Electric~~ as an additional named insured, which policy shall contain a broad form contractual endorsement specifically covering the liabilities accepted under this Agreement arising out of the interconnection to the QF, or caused by operation of any of the QF's equipment or by the QF's failure to maintain its equipment in satisfactory and safe operating condition.

a~~1~~. In subsequent years, a certificate of insurance renewal must be provided annually to the Company ~~Tampa Electric~~ indicating the QF's continued coverage as described herein. Renewal certification shall be sent to:

Tampa Electric Company
Risk Management Department
P. O. Box 111
Tampa, FL 33601

b~~2~~. The policy providing such coverage for a Standard Offer Contract shall provide public liability insurance, including coverage for personal injury, death and property damage, in an amount not less than $1,000,000 for each occurrence; provided however, if QF has insurance with limits greater than the minimum limits required herein, the QF shall set any amount higher than the minimum limits required by the Company to satisfy the insurance requirements of this Agreement.

c~~3~~. The policy providing such coverage for a Negotiated Contract shall provide public liability insurance, including coverage for personal injury, death and property damage, in an amount not less than $1,000,000 for each occurrence. The Parties may negotiate the amount of insurance over $1,000,000.

d~~4~~. The above required policy shall be endorsed with a provision requiring the insurance company to notify the Company ~~Tampa Electric~~ thirty (30) days prior to the effective date of any cancellation or material change in said policy.

Continued to Sheet No. 8.625

Continued from Sheet No. 8.620

~~e~~5. The QF shall pay all premiums and other charges due on said policy and keep said policy in force during the entire period of interconnection with the Company ~~Tampa Electric~~.

10. Electric Service to QF: The Company ~~Tampa Electric~~ will provide the class or classes of electric service requested by QF, to the extent that they are consistent with applicable tariffs; provided, however, that interruptible service will not be available under circumstances where interruptions would impair QF's ability to generate and deliver Firm Capacity and Energy to the Company ~~Tampa Electric~~ under the terms of the Company's ~~Tampa Electric's~~ Standard Offer Contract.

11. Assignment: The QF shall have the right to assign its benefits under this Agreement, but the QF shall not have the right to assign its obligations and duties without the Company's ~~Tampa Electric's~~ prior written consent and such consent shall not be unreasonably withheld.

12. Disclaimer: In executing this Agreement, the Company ~~Tampa Electric~~ does not, nor should it be construed to extend its credit or financial support for the benefit of any third parties lending money to or having other transactions with QF or any assignee of this Agreement.

13. Applicable Law: This Agreement shall be governed by and construed and enforced in accordance with the laws, rules and regulations of the State of Florida and the Company's ~~Tampa Electric's~~ Tariff as may be modified, changed or amended from time to time.

14. Severability: If any part of this Agreement, for any reason, be declared invalid, or unenforceable by a court or public authority of appropriate jurisdiction, then such decision shall not affect the validity of the remainder of the Agreement, which remainder shall remain in force and effect as if this Agreement had been executed without the invalid or unenforceable portion.

Continued to Sheet No. 8.630

Continued from Sheet No. 8.625

15. <u>Complete Agreement and Amendments:</u> All previous communications or agreements between parties, whether verbal or written, with reference to the subject matter of this Agreement are hereby abrogated. No amendment or modification to this Agreement shall be binding unless it shall be set forth in writing and duly executed by both parties to this Agreement.

16. <u>Incorporation of Rate Schedule:</u> The parties agree that this Agreement shall be subject to all of the provisions contained in the Company's ~~Tampa Electric's~~ published Rate Schedule COG-1 or COG-2 as approved and on file with the FPSC. The Rate Schedule is incorporated herein by reference.

17. <u>Survival of Agreement:</u> This Agreement, as it may be amended from time to time, shall be binding and inure to the benefit of the Parties' respective successors-in-interest and legal representatives.

18. <u>Notification:</u> For purpose of making emergency or any communications relating to the operation of the Facility, under the provisions of this Agreement, the parties designate the following persons for notification:

For QF:

________________ ______________

________________ Phone: ______________

For Tampa Electric:

Dispatcher

Palm River Phone: (813) 621-2929

Continued to Sheet No. 8.635

Continued from Sheet No. 8.630

For purposes of making any and all non-emergency oral and written notices, payments or the like required under the provisions of this Agreement, the parties designate the following to be notified or to whom payment shall be sent until such time as either party furnishes the other written instructions changing such designate.

For QF:

For Tampa Electric:
~~Assistant Director, Cogeneration~~
Tampa Electric Company
manager-Industrial/Governmental Marketing & Sales
P.O. Box 111
Tampa, Florida 33601

IN WITNESS WHEREOF, QF and the Company ~~Tampa Electric~~ have executed this Agreement the day and year first above written.

WITNESSES:

____

____

Qualifying Facility

By:____________________________

Its:____________________________

WITNESSES:

____

____

Tampa Electric Company

By:____________________________

Its:____________________________

RESERVED FOR FUTURE USE

RESERVED FOR FUTURE USE

RESERVED FOR FUTURE USE

RESERVED FOR FUTURE USE

~~TAMPA ELECTRIC COMPANY'S~~
GENERAL STANDARDS FOR SAFETY AND INTERCONNECTION OF COGENERATION AND SMALL POWER PRODUCTION FACILITIES TO THE ELECTRIC UTILITY SYSTEM

The following section is based on Florida Public Service Commission (FPSC) Rule 25-17.87, Florida Administrative Code, (F.A.C.), Interconnection and Standards and is applicable throughout Tampa Electric Company's (the Company's) service area:
~~25-17.87 Interconnection and Standards~~

1. The Company ~~Each utility~~ shall interconnect with any qualifying facility (qf) which:

   a. is in its service area;

   b. requests interconnection;

   c. agrees to meet system standards specified in this Rule;

   d. agrees to pay the cost of interconnection; and

   e. signs an interconnection agreement.

2. Nothing in this rule shall be construed to preclude the Company ~~a utility~~ from evaluating each request for interconnection on its own merits and modifying the general standards specified in this Rule to reflect the result of such an evaluation.

3. Where the Company ~~a utility~~ refuses to interconnect with a qf ~~qualify facility~~ or attempts to impose unreasonable standards pursuant to subsection (2) of this rule, the qf ~~qualifying facility~~ may petition the FPSC for relief. The Company ~~utility~~ shall have the burden of demonstrating to the FPSC why interconnection with the qfs ~~qualifying facility~~ should not be required or that the standards the Company ~~utility~~ seeks to impose on the qfs ~~qualifying facility~~ pursuant to subsection (2) are reasonable.

4. Upon a showing of credit worthiness, the qfs ~~qualifying facility~~ shall have the option of making monthly installment payments over a period no longer than 36 months toward the full cost of interconnection. However, where the qfs ~~qualifying facility~~ exercises that option, the Company ~~utility~~ shall charge interest on the amount owing. The Company ~~utility~~ shall charge such interest at the 30 day highest grade commercial paper rate. In any event, no the Company ~~utility~~ may not bear the cost of interconnection.

Continued to Sheet No. 8.705

Continued from Sheet No. 8.700

5. <u>Application for Interconnection:</u> A qf ~~qualifying facility~~ shall not operate electric generating equipment in parallel with the Company's ~~utility's~~ electric system without the prior written consent of the Company ~~utility~~. Formal application for interconnection shall be made by the qf ~~qualifying facility~~ prior to the installation of any generation related equipment. This application shall be accompanied by the following:

a. Physical layout drawings, including dimensions;

b. All associated equipment specifications and characteristics including technical parameters, ratings, basic impulse levels, electrical main one-line diagrams, schematic diagrams, system protections, frequency, voltage, current and interconnection distance;

c. Functional and logic diagrams, control and meter diagrams, conductor sizes and length, and any other relevant data which might be necessary to understand the proposed system and to be able to make a coordinated system;

d. Power characteristics in watts and vars;

e. Expected radio-noise, harmonic generation and telephone interference factor;

f. Synchronizing methods; and

g. Operating/instruction manuals.

Any subsequent change in the system must also be submitted for review and written approval prior to actual modification. The above mentioned review, recommendations and approval by the Company ~~utility~~ do not relieve the qf ~~qualifying facility~~ from complete responsibility for the adequate engineering design, construction and operation of the qf ~~qualifying facility~~ equipment and for any liability for injuries to property or persons associated with any failure to perform in a proper and safe manner for any reason.

Continued to Sheet No. 8.710

Continued from Sheet No. 8.705

6. **Personnel Safety:** Adequate protection and safe operational procedures must be developed and followed by the joint system. These operating procedures must be approved by both the Company ~~utility~~ and the qf ~~qualifying facility~~. The qf ~~qualifying facility~~ shall be required to furnish, install, operate and maintain in good order and repair, and be solely responsible for, without cost to the Company ~~utility~~, all facilities required for the safe operation of the generation system in parallel with the Company's ~~utility's~~ system.

The qf ~~qualifying facility~~ shall permit the Company's ~~utility~~ employees to enter upon its property at any reasonable time for the purpose of inspection and/or testing the qf's ~~qualifying facility's~~ equipment, facilities, or apparatus. Such inspections shall not relieve the qf ~~qualifying facility~~ from its obligation to maintain its equipment in safe and satisfactory operating condition.

The Company's ~~utility's~~ approval of isolating devices used by the qf ~~qualifying facility~~ will be required to ensure that these will comply with the Company's ~~utility's~~ switching and tagging procedure for safe working clearances.

a. **Disconnect switch:** A manual disconnect switch, of the visible load break type, to provide a separation point between the qf's ~~qualifying facility's~~ generation system and the Company's ~~utility's~~ system, shall be required. The Company ~~utility~~ will specify the location of the disconnect switch. The switch shall be mounted separate from the meter socket and shall be readily accessible to the Company ~~utility~~ and be capable of being locked in the open position with a Company ~~utility~~ padlock. The Company ~~utility~~ may reserve the right to open the switch (i.e., isolating the qf's ~~qualifying facility's~~ generation system) without prior notice to the qf ~~qualifying facility~~. To the extent practicable, however, prior notice shall be given.

Continued to Sheet No. 8.715

Continued from Sheet No. 8.710

Any of the following conditions shall be cause for disconnection:

i. The Company's ~~Utility~~ system emergencies and/or maintenance requirements; Hazardous conditions existing on the qf's generating or protective equipment as determined by the Company;

ii. Adverse effects of the qf's ~~qualifying facility's~~ generation to the Company's ~~utility's~~ other electric consumers and/or system as determined by the Company ~~utility~~;

iii. Failure of the qf ~~qualifying facility~~ to maintain any required insurance; or

iv. Failure of the qf ~~qualifying facility~~ to comply with any existing or future regulations, rules, orders or decisions of any governmental or regulatory authority having jurisdiction over the qf's ~~qualifying facility's~~ electric generating equipment or the operation of such equipment.

b. Responsibility and Liability: The Company ~~Tampa Electric~~ and the qf shall each be responsible for its own facilities. The Company ~~Tampa Electric~~ and the qf shall each be responsible for ensuring adequate safeguards for other Company ~~Tampa Electric~~ customers, the Company ~~Tampa Electric~~ and qf personnel and equipment, and for the protection of its own generating system. The Company ~~Tampa Electric~~ and the qf shall each indemnify and save the other harmless from any and all claims, demands, costs, or expense for loss, damage, or injury to persons or property of the other caused by, arising out of, or resulting from:

i. Any act or omission by a party, or that party's contractors, agents, servants and employees in connection with the installation or operation of that party's generation system or the operation thereof in connection with the other party's system;

ii. Any defect in, failure of, or fault related to a party's generation system;

iii. The negligence of a party or negligence of that party's contractors, agents, servants or employees; or

Continued to Sheet No. 8.720

Continued from Sheet No. 8.715

iv. Any other event or act that is the result of, or proximately caused by a party.

For the purpose of this paragraph, the term party shall mean either the Company or qf, as the case may be.

c. Insurance: The qf shall deliver to the Company ~~Tampa Electric~~, at least fifteen (15) days prior to the start of any interconnection work, a certificate of insurance certifying the qf's coverage under a liability insurance policy issued by a reputable insurance company authorized to do business in the State of Florida naming the qf as named insured, and the Company ~~Tampa Electric~~ as an additional named insured, which policy shall contain a broad form contractual endorsement specifically covering the liabilities accepted under this agreement arising out of the interconnection to the qf, or caused by operation of any of the qf's equipment or by the qf's failure to maintain its equipment in satisfactory and safe operating condition.

i. In subsequent years, a certificate of insurance renewal must be provided annually to the Company ~~Tampa Electric~~ indicating the qf's continued coverage as described herein. Renewal certification shall be sent to:

Tampa Electric Company
Risk Management Department
P. O. Box 111
Tampa, FL 33601

ii. The policy providing such coverage for a Standard Offer Contract shall provide public liability insurance, including coverage for personal injury, death and property damage, in an amount not less than $1,000,000 for each occurrence; provided however, if qf has insurance with limits greater than the minimum limits required herein, the qf shall set any amount higher than the minimum limits required by the Company ~~Tampa Electric~~ to satisfy the insurance requirements of this Agreement.

Continued to Sheet No. 8.725

Continued from Sheet No. 8.720

iii. The policy providing such coverage for a Negotiated Contract shall provide public liability insurance, including coverage for personal injury, death and property damage, in an amount not less than $1,000,000 for each occurrence. The Parties may negotiate the amount of insurance over $1,000,000.

iv. The above required policy shall be endorsed with a provision requiring the insurance company will notify the Company ~~Tampa Electric~~ thirty (30) days prior to the effective date of cancellation or material change in said policy.

v. The qf shall pay all premiums and other charges due on said policy and keep said policy in force during the entire period of interconnection with the Company ~~Tampa Electric~~.

7. <u>Protection and Operation:</u> It will be the responsibility of the qf ~~qualifying facility~~ to provide all devices necessary to protect the qf's ~~qualifying facility's~~ equipment from damage by the abnormal conditions and operations which occur on the Company ~~utility~~ system that result from interruptions and restorations of service by the Company's ~~utility's~~ equipment and personnel. The qf ~~qualifying facility~~ shall protect its generator and associated equipment from overvoltage, undervoltage, overload, short circuits (including ground fault condition), open circuits, phase unbalance and reversal, over or under frequency condition, and other injurious electrical conditions that may arise on the Company's ~~utility's~~ system and any reclose attempt by the Company ~~utility~~.

The Company ~~utility~~ may reserve the right to perform such tests as it deems necessary to ensure safe and efficient protection and operation of the qf's ~~qualifying facility's~~ equipment.

Continued to Sheet No. 8.730

Continued from Sheet No. 8.725

a. <u>Loss of source:</u> The qf ~~qualifying facility~~ shall provide, or the Company ~~utility~~ will provide at the qf's ~~qualifying facility's~~ expense, approved protective equipment necessary to immediately, completely, and automatically disconnect the qf's ~~qualifying facility's~~ generation from the Company's ~~utility's~~ system in the event of a fault on the qf's ~~qualifying facility's~~ system, a fault on the Company's ~~utility's~~ system, or loss of source on the Company's ~~utility's~~ system. Disconnection must be completed within the time specified by the Company ~~utility~~ in its standard operating procedure for its electric system for loss of a source on the Company's ~~utility's~~ system.

This automatic disconnecting device may be of the manual or automatic reclose type and shall not be capable of reclosing until after service is restored by the Company ~~utility~~. The type and size of the device shall be approved by the Company ~~utility~~ depending upon the installation. Adequate test data or technical proof that the device meets the above criteria must be supplied by the qf ~~qualifying facility~~ to the Company ~~utility~~. The Company ~~utility~~ shall approve a device that will perform the above functions at minimal capital and operating costs to the qf ~~qualifying facility~~.

b. <u>Coordination and Synchronization:</u> The qf ~~qualifying facility~~ shall be responsible for coordination and synchronization of the qf's ~~qualifying facility's~~ equipment with the Company's ~~utility's~~ electrical system, and assumes all responsibility for damage that may occur from improper coordination or synchronization of the generator with the Company's ~~utility's~~ system.

c. <u>Electrical characteristics:</u> Single phase generator interconnections with the Company ~~utility~~ are permitted at power levels up to 20 KW. For power levels exceeding 20 KW, a three phase balanced interconnection will normally be required. For the purpose of calculating connected generation, 1 horsepower equals 1 kilowatt. The qf ~~qualifying facility~~ shall interconnect with the Company ~~utility~~ at the voltage of the available distribution or transmission line of the Company ~~utility~~ for the locality of the interconnection, and shall utilize one of the standard connections (single phase, three phase, wye, delta) as approved by the Company ~~utility~~.

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The Company ~~utility~~ may reserve the right to require a separate transformation and/or service for a qf's ~~qualifying facility's~~ generation system, at the qf's ~~qualifying facility's~~ expense. The qf ~~qualifying facility~~ shall bond all neutrals of the qf's ~~qualifying facility's~~ system to the Company's ~~utility's~~ neutral, and shall install a separate driven ground with a resistance value which shall be determined by the Company ~~utility~~ and bond this ground to the qf's ~~qualifying facility's~~ system neutral.

d. <u>Exceptions</u> A qf's ~~qualifying facility's~~ generator having a capacity rating that can:

i. Produce power in excess of one half of the minimum Company ~~utility~~ customer requirements of the interconnected distribution or transmission circuit; or

ii. produce power flows approaching or exceeding the thermal capacity of the connected Company ~~utility~~ distribution or transmission lines or transformers; or

iii. adversely affect the operation of the Company ~~utility~~ or other Company ~~utility~~ customer's voltage, frequency or overcurrent control and protection devices; or

iv. adversely affect the quality of service to other Company ~~utility~~ customers; or

v. interconnect at voltage levels greater than distribution voltages, will require more complex interconnection facilities as deemed necessary by the Company ~~utility~~.

8. <u>Quality of Service:</u> The qf's ~~qualifying facility's~~ generated electricity shall meet the following minimum guidelines:

a. <u>Frequency:</u> The governor control on the prime mover shall be capable of maintaining the generator output frequency within limits for loads from no-load up to rated output. The limits for frequency shall be 60 hertz (cycles per second), plus or minus an instantaneous variation of less than 1%.

b. <u>Voltage:</u> The regulator control shall be capable of maintaining the generator output voltage within limits for loads from no-load up to rated output. The limits for voltage shall be the nominal operating voltage level, plus or minus 5%.

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c. Harmonics: The output sine wave distortion shall be deemed acceptable when it does not have a higher content (root mean square) of harmonics than the Company's ~~utility's~~ normal harmonic content at the interconnection point.

d. Power Factor: The qf's ~~qualifying facility's~~ generation system shall be designed, operated and controlled to provide reactive power requirements from 0.95 lagging to 0.95 leading power factor at the point of interconnection with Company ~~utility~~. Induction generators shall have static capacitors that provide at least 95% of the magnetizing current requirements of the induction generator field. (Capacitors shall not be so large as to permit self-excitation of the qf's ~~qualifying facility's~~ generator field).

e. DC Generators: Direct current generators may be operated in parallel with the Company's ~~utility's~~ system through a synchronous invertor. The invertor must meet all criteria in these rules.

9. Metering: The actual metering equipment required, its voltage rating, number of phases, size, current transformers, potential transformers, number of inputs and associated memory is dependent on the type, size and location of the electric service provided. In situations where power may flow both in and out of the qf's ~~qualifying facility's~~ system, power flowing into the qf's ~~qualifying facility's~~ system will be measured separately from power flowing out of the qf's ~~qualifying facility's~~ system.

The Company ~~utility~~ will provide, at no additional cost to the qf ~~qualifying facility~~, the metering equipment necessary to measure capacity and energy deliveries to the qf ~~qualifying facility~~. The Company ~~utility~~ will provide, at the qf's ~~qualifying facility's~~ expense, the necessary additional metering equipment to measure capacity and energy deliveries by the qf ~~qualifying facility~~ to the Company ~~utility~~.

10. Cost Responsibility: The qf ~~qualifying facility~~ is required to bear all costs associated with the change-out, upgrading or addition of protective devices, transformers,

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lines, services, meters, switches, and associated equipment and devices beyond that which would be required to provide normal service to the qf ~~qualifying facility~~ if the qf were a non-generating customer. These costs shall be paid by the qf ~~qualifying facility~~ to the Company ~~utility~~ for all material and labor that is required. Prior to any work being done by the Company ~~utility~~, the Company ~~utility~~ shall supply the qf ~~qualifying facility~~ with a written cost estimate of all its required materials and labor and an estimate of the date by which construction of the interconnection will be completed. This estimate shall be provided to the qf within 60 days after the qf provides the Company ~~utility~~ with its final electrical plans. The Company ~~utility~~ shall also provide project timing and feasibility information to the qf ~~qualifying facility~~.

11. The Company ~~utility~~ shall submit, to the FPSC, a standard agreement for the interconnection by qfs as part of their Standard Offer contract or contracts required by FPSC Rule 25-17.0832(3), F.A.C.