CONFIDENTIAL

Florida Public Service Commission

Supplemental Data Request

(Complete Submittal)

Florida Power Corporation's

1999 Ten-Year Site Plan

DECLASSIFIED

See order PSC-99-1795-CFO-EI

July, 1999

1. **Provide all data requested on the attached forms. If any of the requested data is already included in FPC's Ten-Year Site Plan, state so on the appropriate form.**

Information from FPC's 1999 Ten-Year Site Plan was used to complete the attached requested data forms.

HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
HIGH CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1989	6,045	623	4,633	276	300	34	N/A	46	133	5,256
1990	6,166	641	4,733	230	342	35	N/A	49	136	5,374
1991	6,128	684	4,699	207	313	36	N/A	53	136	5,383
1992	6,465	827	4,927	186	287	39	N/A	58	141	5,754
1993	6,913	848	5,016	274	502	48	N/A	70	155	5,864
1994	6,880	801	5,003	262	527	52	N/A	81	154	5,804
1995	7,510	886	5,522	284	502	55	N/A	101	160	6,408
1996	7,464	824	5,416	309	528	67	37	116	167	6,240
1997	7,786	872	5,696	285	509	78	46	130	170	6,568
1998	8,367	941	6,276	291	453	95	43	144	124	7,217
1999	8,609	1,458	6,250	324	457	108	44	159	76	7,708
2000	8,500	1,197	6,417	313	450	118	47	160	76	7,614
2001	8,767	1,276	6,662	301	402	129	50	162	76	7,938
2002	8,531	854	6,910	298	341	142	53	162	75	7,764
2003	8,125	289	7,108	300	297	155	56	163	75	7,397
2004	8,255	219	7,343	297	262	169	59	164	75	7,562
2005	8,482	265	7,550	299	231	184	62	164	75	7,815
2006	8,728	325	7,758	301	204	198	65	166	75	8,083
2007	8,966	388	7,952	303	180	212	68	167	75	8,340
2008	9,246	451	8,185	305	159	226	71	167	75	8,636

NOTE : COLUMN (OTH) INCLUDES DEMAND REDUCTIONS FOR LOAD CONTROL PROGRAMS (HEATWORKS AND VOLTAGE REDUCTION) AND CUSTOMER-OWNED SELF-SERVICE COGENERATION.

HISTORY AND FORECAST OF SUMMER PEAK DEMAND (MW)
LOW CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1989	6,045	623	4,633	276	300	34	N/A	46	133	5,256
1990	6,166	641	4,733	230	342	35	N/A	49	136	5,374
1991	6,128	684	4,699	207	313	36	N/A	53	136	5,383
1992	6,465	827	4,927	186	287	39	N/A	58	141	5,754
1993	6,913	848	5,016	274	502	48	N/A	70	155	5,864
1994	6,880	801	5,003	262	527	52	N/A	81	154	5,804
1995	7,510	886	5,522	284	502	55	N/A	101	160	6,408
1996	7,464	824	5,416	309	528	67	37	116	167	6,240
1997	7,786	872	5,696	285	509	78	46	130	170	6,568
1998	7,577	941	5,486	291	453	95	43	144	124	6,427
1999	8,313	1,458	5,954	324	457	108	44	159	76	7,412
2000	8,170	1,197	6,087	313	450	118	47	160	76	7,284
2001	8,383	1,276	6,278	301	402	129	50	162	76	7,554
2002	8,084	854	6,463	298	341	142	53	162	75	7,317
2003	7,643	289	6,626	300	297	155	56	163	75	6,915
2004	7,685	219	6,773	297	262	169	59	164	75	6,992
2005	7,853	265	6,921	299	231	184	62	164	75	7,186
2006	8,018	325	7,048	301	204	198	65	166	75	7,373
2007	8,204	388	7,190	303	180	212	68	167	75	7,578
2008	8,351	451	7,290	305	159	226	71	167	75	7,741

NOTE : COLUMN (OTH) INCLUDES DEMAND REDUCTIONS FOR LOAD CONTROL PROGRAMS (HEATWORKS AND VOLTAGE REDUCTION) AND CUSTOMER-OWNED SELF-SERVICE COGENERATION.

HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
HIGH CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1988/89	6,873	639	5,261	237	493	52	N/A	44	147	5,900
1989/90	7,366	958	5,656	0	503	52	N/A	47	150	6,614
1990/91	6,312	796	4,574	196	490	51	N/A	52	153	5,370
1991/92	7,159	1,005	5,063	210	611	60	N/A	55	155	6,068
1992/93	6,516	876	4,608	150	599	67	N/A	57	159	5,484
1993/94	7,185	1,004	4,901	199	759	90	N/A	67	165	5,905
1994/95	8,975	1,169	6,223	280	997	101	N/A	74	131	7,392
1995/96	10,350	1,486	7,263	45	1,146	105	10	94	201	8,749
1996/97	8,486	1,228	5,624	290	901	133	16	104	190	6,852
1997/98	7,717	908	5,419	318	645	119	18	122	168	6,327
1998/99	9,594	1,527	6,663	322	874	183	18	120	190	8,190
1999/00	9,785	1,575	6,820	312	865	204	21	120	192	8,395
2000/01	10,058	1,668	7,012	300	859	228	24	121	195	8,680
2001/02	9,832	1,266	7,262	297	790	254	27	121	190	8,528
2002/03	9,430	720	7,453	299	743	281	30	122	185	8,173
2003/04	9,567	666	7,673	296	713	310	33	123	186	8,339
2004/05	9,795	728	7,854	298	690	339	36	124	189	8,582
2005/06	10,044	806	8,037	300	670	369	39	125	192	8,843
2006/07	10,280	883	8,206	302	652	399	42	125	195	9,089
2007/08	10,566	963	8,419	304	637	428	45	125	198	9,382

NOTE : COLUMN (OTH) INCLUDES DEMAND REDUCTIONS FOR LOAD CONTROL PROGRAMS (HEATWORKS AND VOLTAGE REDUCTION) AND CUSTOMER-OWNED SELF-SERVICE COGENERATION.

HISTORY AND FORECAST OF WINTER PEAK DEMAND (MW)
LOW CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(OTH)	(10)
YEAR	TOTAL	WHOLESALE	RETAIL	INTERRUPTIBLE	RESIDENTIAL LOAD MANAGEMENT	RESIDENTIAL CONSERVATION	COMM. / IND. LOAD MANAGEMENT	COMM. / IND. CONSERVATION	OTHER DEMAND REDUCTIONS	NET FIRM DEMAND
1988/89	6,873	639	5,261	237	493	52	N/A	44	147	5,900
1989/90	7,366	958	5,656	0	503	52	N/A	47	150	6,614
1990/91	6,312	796	4,574	196	490	51	N/A	52	153	5,370
1991/92	7,159	1,005	5,063	210	611	60	N/A	55	155	6,068
1992/93	6,516	876	4,608	150	599	67	N/A	57	159	5,484
1993/94	7,185	1,004	4,901	199	759	90	N/A	67	165	5,905
1994/95	8,975	1,169	6,223	280	997	101	N/A	74	131	7,392
1995/96	10,350	1,486	7,263	45	1,146	105	10	94	201	8,749
1996/97	8,486	1,228	5,624	290	901	133	16	104	190	6,852
1997/98	7,717	908	5,419	318	645	119	18	122	168	6,327
1998/99	9,259	1,527	6,328	322	874	183	18	120	190	7,855
1999/00	9,414	1,575	6,449	312	865	204	21	120	192	8,024
2000/01	9,627	1,668	6,581	300	859	228	24	121	195	8,249
2001/02	9,332	1,266	6,762	297	790	254	27	121	190	8,028
2002/03	8,894	720	6,917	299	743	281	30	122	185	7,637
2003/04	8,934	666	7,040	296	713	310	33	123	186	7,706
2004/05	9,100	728	7,159	298	690	339	36	124	189	7,887
2005/06	9,263	806	7,256	300	670	369	39	125	192	8,062
2006/07	9,445	883	7,371	302	652	399	42	125	195	8,254
2007/08	9,588	963	7,441	304	637	428	45	125	198	8,404

NOTE : COLUMN (OTH) INCLUDES DEMAND REDUCTIONS FOR LOAD CONTROL PROGRAMS (HEATWORKS AND VOLTAGE REDUCTION) AND CUSTOMER-OWNED SELF-SERVICE COGENERATION.

HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)
HIGH CASE

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR %
1989	28,606	165	131	463	24,123	1,529	2,195	27,847	51.8
1990	28,629	173	145	506	24,880	1,548	1,377	27,805	46.6
1991	29,219	166	156	509	25,179	1,411	1,799	28,389	53.5
1992	29,561	174	170	516	25,414	1,471	1,817	28,702	46.8
1993	31,150	188	195	524	26,528	1,695	2,020	30,243	55.5
1994	32,135	205	220	536	27,675	1,819	1,680	31,174	51.2
1995	34,682	219	246	549	29,499	1,846	2,322	33,667	49.8
1996	35,797	235	285	562	30,785	2,089	1,841	34,715	44.9
1997	35,739	254	317	563	30,850	1,758	1,997	34,605	57.7
1998	38,936	275	333	565	33,387	2,340	2,036	37,763	68.1
1999	40,381	297	344	568	33,779	2,975	2,419	39,173	54.6
2000	41,253	313	345	570	34,730	2,913	2,382	40,024	54.3
2001	42,626	329	347	569	35,849	3,083	2,449	41,381	54.4
2002	41,966	347	348	569	36,961	1,582	2,160	40,702	54.5
2003	42,553	366	350	569	37,941	924	2,402	41,268	57.6
2004	43,772	385	351	572	39,084	891	2,489	42,464	58.0
2005	44,900	405	353	570	40,165	864	2,544	43,572	58.0
2006	46,054	425	354	571	41,222	881	2,603	44,705	57.7
2007	47,147	444	356	571	42,206	900	2,669	45,776	57.5
2008	48,443	463	357	573	43,393	919	2,738	47,049	57.1

NOTE : COLUMN (OTH) INCLUDES CONSERVATION ENERGY FOR LIGHTING AND PUBLIC AUTHORITY CUSTOMERS, CUSTOMER-OWNED SELF-SERVICE COGENERATION AND LOAD CONTROL PROGRAMS.

HISTORY AND FORECAST OF ANNUAL NET ENERGY FOR LOAD (GWh)
LOW CASE

(1) YEAR	(2) TOTAL	(3) RESIDENTIAL CONSERVATION	(4) COMM. / IND. CONSERVATION	(OTH) OTHER ENERGY REDUCTIONS	(5) RETAIL	(6) WHOLESALE	(7) UTILITY USE & LOSSES	(8) NET ENERGY FOR LOAD	(9) LOAD FACTOR %
1989	28,606	165	131	463	24,123	1,529	2,195	27,847	51.8
1990	28,629	173	145	506	24,880	1,548	1,377	27,805	46.6
1991	29,219	166	156	509	25,179	1,411	1,799	28,389	53.5
1992	29,561	174	170	516	25,414	1,471	1,817	28,702	46.8
1993	31,150	188	195	524	26,528	1,695	2,020	30,243	55.5
1994	32,135	205	220	536	27,675	1,819	1,680	31,174	51.2
1995	34,682	219	246	549	29,499	1,846	2,322	33,667	49.8
1996	35,797	235	285	562	30,785	2,089	1,841	34,715	44.9
1997	35,739	254	317	563	30,850	1,758	1,997	34,605	57.7
1998	38,936	275	333	565	33,387	2,340	2,036	37,763	68.1
1999	38,874	297	344	568	32,363	2,975	2,328	37,665	54.7
2000	39,563	313	345	570	33,144	2,913	2,278	38,335	54.4
2001	40,648	329	347	569	33,992	3,083	2,328	39,403	54.5
2002	39,672	347	348	569	34,787	1,582	2,038	38,407	54.6
2003	40,042	366	350	569	35,584	924	2,248	38,757	57.9
2004	40,800	385	351	572	36,284	891	2,316	39,492	58.3
2005	41,600	405	353	570	37,059	864	2,349	40,272	58.3
2006	42,332	425	354	571	37,709	881	2,393	40,982	58.0
2007	43,121	444	356	571	38,427	900	2,423	41,751	57.7
2008	43,715	463	357	573	38,940	919	2,463	42,321	57.3

NOTE : COLUMN (OTH) INCLUDES CONSERVATION ENERGY FOR LIGHTING AND PUBLIC AUTHORITY CUSTOMERS, CUSTOMER-OWNED SELF-SERVICE COGENERATION AND LOAD CONTROL PROGRAMS.

EXISTING GENERATING UNIT OPERATING PERFORMANCE

(1)	(2)	(3)		(4)		(5)		(6)	
		PLANNED OUTAGE FACTOR (POF) %		FORCED OUTAGE FACTOR (FOF) %		EQUIVALENT AVAILABILITY FACTOR (EAF) %		AVERAGE NET OPERATING HEAT RATE (ANOHR) BTU/KWH	
PLANT NAME	UNIT NO.	HISTORICAL	PROJECTED	HISTORICAL	PROJECTED	HISTORICAL	PROJECTED	HISTORICAL	PROJECTED
ANCLOTE	1	7.13	6.38	0.87	0.99	88.37	88.13	9,985	10,120
	2	14.52	11.28	0.50	0.34	79.05	83.56	9,989	10,094
AVON PARK	P1-P2	4.62	2.34	10.46	5.25	85.00	92.32	16,734	16,726
BARTOW	1	8.36	4.87	1.57	0.63	84.80	90.06	10,664	10,910
	2	5.15	5.93	2.49	1.46	88.80	90.16	10,542	10,489
	3	9.62	6.91	3.65	6.09	82.09	81.97	9,965	10,054
BARTOW	P1-P4	5.15	1.54	3.18	7.54	90.72	90.51	14,855	14,677
BAYBORO	P1-P4	4.01	0.00	0.92	0.63	94.95	95.72	13,402	13,272
CRYSTAL	1	7.05	10.89	1.56	1.04	84.41	81.47	9,838	9,868
RIVER	2	3.73	8.66	5.34	2.73	84.67	80.30	9,791	9,820
	3	8.28	4.16	50.13	5.27	40.04	90.53	10,468	10,451
	4	7.97	3.77	3.58	3.68	84.37	88.83	9,405	9,382
	5	3.00	7.30	0.86	0.69	94.16	90.14	9,374	9,339
DEBARY	P1-P10	2.28	1.17	0.40	0.37	95.20	96.08	13,944	14,151
HIGGINS	P1-P4	5.52	3.15	2.91	2.21	90.97	91.52	16,386	16,195
INTERCESSION CITY	P1-P11	3.31	2.02	2.90	2.20	92.53	92.29	13,273	13,306
RIO PINAR	P1	0.62	0.62	2.06	0.13	97.27	99.40	18,071	17,863
SUWANNEE	1	0.00	0.00	0.19	0.00	99.81	100.00	12,871	13,079
	2	0.00	0.00	0.00	0.00	99.98	99.98	12,953	13,165
	3	0.00	1.99	0.18	0.26	99.76	97.69	11,122	11,172
SUWANNEE	P1-P3	6.51	3.98	1.59	1.59	84.63	88.19	14,388	13,484
TIGER BAY	1	1.52	0.00	2.35	0.36	94.56	99.64	7,769	7,738
TURNER	P1-P4	4.51	1.73	1.64	1.20	92.99	96.14	16,554	16,870
UNIV. OF FLA.	P1	2.26	1.63	15.82	2.49	78.42	94.11	8,798	9,486

NOTE : HISTORICAL - AVERAGE OF PAST THREE YEARS
PROJECTED - AVERAGE OF NEXT TEN YEARS

NOMINAL, DELIVERED RESIDUAL OIL PRICES
BASE CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	RESIDUAL OIL (BY SULFUR CONTENT)								
	LESS THAN 0.7%		ESCALATION	0.7 - 2.0%		ESCALATION	GREATER THAN 2.0%		ESCALATION
YEAR	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
				1 /	1 /				
1996		DATA		17.02	266.00			DATA	
1997		NOT		16.13	252.00	-5.26		NOT	
1998		AVAILABLE		12.61	194.00	-23.02		AVAILABLE	
				2 /	2 /		3 /	3 /	
1999				14.50	223.00	14.95	12.87	198.00	
2000				14.95	230.00	3.14	13.33	205.00	3.54
2001				15.93	245.00	6.52	13.98	215.00	4.88
2002				16.58	255.00	4.08	14.63	225.00	4.65
2003		NOT		16.90	260.00	1.96	14.95	230.00	2.22
2004		APPLICABLE		16.90	260.00	0.00	14.95	230.00	0.00
2005				16.90	260.00	0.00	14.95	230.00	0.00
2006				17.10	263.00	1.15	15.15	233.00	1.30
2007				17.23	265.00	0.76	15.28	235.00	0.86
2008				17.42	268.00	1.13	15.47	238.00	1.28

HEAT CONTENT < 0.7% RESIDUAL OIL = N/A MBTU/BBL
HEAT CONTENT 0.7 - 2.0% RESIDUAL OIL = 6.50 MBTU/BBL
HEAT CONTENT > 2.0% RESIDUAL OIL = 6.50 MBTU/BBL

ASH CONTENT < 0.7% RESIDUAL OIL = N/A PERCENT
ASH CONTENT 0.7 - 2.0% RESIDUAL OIL = 0.10 PERCENT
ASH CONTENT > 2.0% RESIDUAL OIL = 0.10 PERCENT

NOTES: 1 / TOTAL RESIDUAL OIL AS BURNED - APPROXIMATE
2 / 1.0% SULFUR
3 / 2.5% SULFUR

NOMINAL, DELIVERED RESIDUAL OIL PRICES
HIGH CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	RESIDUAL OIL (BY SULFUR CONTENT)								
	LESS THAN 0.7%		ESCALATION	0.7 - 2.0%		ESCALATION	GREATER THAN 2.0%		ESCALATION
YEAR	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
1996		DATA			SEE			DATA	
1997		NOT			BASE			NOT	
1998		AVAILABLE			CASE			AVAILABLE	
				1 /	1 /		2 /	2 /	
1999				15.60	240.00		13.65	210.00	
2000				16.25	250.00	4.17	14.30	220.00	4.76
2001				16.90	260.00	4.00	14.95	230.00	4.55
2002				17.55	270.00	3.85	15.60	240.00	4.35
2003		NOT		18.20	280.00	3.70	16.25	250.00	4.17
2004		APPLICABLE		18.85	290.00	3.57	16.90	260.00	4.00
2005				19.50	300.00	3.45	17.55	270.00	3.85
2006				20.15	310.00	3.33	18.20	280.00	3.70
2007				20.80	320.00	3.23	18.85	290.00	3.57
2008				21.45	330.00	3.13	19.50	300.00	3.45

HEAT CONTENT < 0.7% RESIDUAL OIL = N/A MBTU/BBL
HEAT CONTENT 0.7 - 2.0% RESIDUAL OIL = 6.50 MBTU/BBL
HEAT CONTENT > 2.0% RESIDUAL OIL = 6.50 MBTU/BBL

ASH CONTENT < 0.7% RESIDUAL OIL = N/A PERCENT
ASH CONTENT 0.7 - 2.0% RESIDUAL OIL = 0.10 PERCENT
ASH CONTENT > 2.0% RESIDUAL OIL = 0.10 PERCENT

NOTES: 1 / 1.0% SULFUR
2 / 2.5% SULFUR

NOMINAL, DELIVERED RESIDUAL OIL PRICES
LOW CASE

RESIDUAL OIL (BY SULFUR CONTENT)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	LESS THAN 0.7%			0.7 - 2.0%			GREATER THAN 2.0%		
YEAR	$/BBL	c/MBTU	ESCALATION %	$/BBL	c/MBTU	ESCALATION %	$/BBL	c/MBTU	ESCALATION %
1996		DATA			SEE			DATA	
1997		NOT			BASE			NOT	
1998		AVAILABLE			CASE			AVAILABLE	
				1 /	1 /		2 /	2 /	
1999				12.87	198.00		11.77	181.00	
2000				12.81	197.00	-0.51	11.83	182.00	0.55
2001				12.94	199.00	1.02	11.96	184.00	1.10
2002				13.07	201.00	1.01	12.09	186.00	1.09
2003		NOT		13.20	203.00	1.00	12.22	188.00	1.08
2004		APPLICABLE		13.33	205.00	0.99	12.35	190.00	1.06
2005				13.46	207.00	0.98	12.48	192.00	1.05
2006				13.59	209.00	0.97	12.61	194.00	1.04
2007				13.72	211.00	0.96	12.74	196.00	1.03
2008				13.85	213.00	0.95	12.87	198.00	1.02

HEAT CONTENT < 0.7% RESIDUAL OIL = N/A MBTU/BBL
HEAT CONTENT 0.7 - 2.0% RESIDUAL OIL = 6.50 MBTU/BBL
HEAT CONTENT > 2.0% RESIDUAL OIL = 6.50 MBTU/BBL

ASH CONTENT < 0.7% RESIDUAL OIL = N/A PERCENT
ASH CONTENT 0.7 - 2.0% RESIDUAL OIL = 0.10 PERCENT
ASH CONTENT > 2.0% RESIDUAL OIL = 0.10 PERCENT

NOTES: 1 / 1.0% SULFUR
2 / 2.5% SULFUR

NOMINAL, DELIVERED DISTILLATE OIL and NATURAL GAS PRICES
BASE CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	DISTILLATE OIL			NATURAL GAS		
			ESCALATION			ESCALATION
YEAR	$/BBL	c/MBTU	%	c/MBTU	c/THERM	%
	1 /	1 /				
1996	26.39	455.00		278.00	27.80	
1997	27.55	475.00	4.40	287.00	28.70	3.24
1998	21.52	371.00	-21.89	291.00	29.10	1.39
	2 /	2 /		3 /	3 /	
1999	21.92	378.00	1.89	238.00	23.80	-18.21
2000	24.36	420.00	11.11	240.00	24.00	0.84
2001	26.10	450.00	7.14	240.00	24.00	0.00
2002	26.97	465.00	3.33	240.00	24.00	0.00
2003	27.26	470.00	1.08	245.00	24.50	2.08
2004	27.55	475.00	1.06	245.00	24.50	0.00
2005	28.13	485.00	2.11	245.00	24.50	0.00
2006	28.42	490.00	1.03	248.00	24.80	1.22
2007	28.71	495.00	1.02	248.00	24.80	0.00
2008	29.00	500.00	1.01	248.00	24.80	0.00

HEAT CONTENT DISTILLATE OIL = 5.80 MBTU/BBL

ASH CONTENT DISTILLATE OIL = 0.00 PERCENT

NOTES: 1 / AS BURNED DATA - APPROXIMATE
2 / WITHOUT INLAND FREIGHT - 0.5% SULFUR
3 / SUPPLY COST ONLY

NOMINAL, DELIVERED DISTILLATE OIL and NATURAL GAS PRICES
HIGH CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	DISTILLATE OIL			NATURAL GAS		
			ESCALATION			ESCALATION
YEAR	$/BBL	c/MBTU	%	c/MBTU	c/THERM	%
1996		SEE			SEE	
1997		BASE			BASE	
1998		CASE			CASE	
	1 /	1 /		2 /	2 /	
1999	23.08	398.00		250.00	25.00	
2000	25.52	440.00	10.55	260.00	26.00	4.00
2001	27.26	470.00	6.82	270.00	27.00	3.85
2002	28.13	485.00	3.19	280.00	28.00	3.70
2003	28.42	490.00	1.03	290.00	29.00	3.57
2004	28.71	495.00	1.02	300.00	30.00	3.45
2005	29.29	505.00	2.02	320.00	32.00	6.67
2006	29.58	510.00	0.99	330.00	33.00	3.13
2007	29.87	515.00	0.98	340.00	34.00	3.03
2008	30.16	520.00	0.97	350.00	35.00	2.94

HEAT CONTENT DISTILLATE OIL = 5.80 MBTU/BBL

ASH CONTENT DISTILLATE OIL = 0.00 PERCENT

NOTES: 1 / WITHOUT INLAND FREIGHT - 0.5% SULFUR
2 / SUPPLY COST ONLY

NOMINAL, DELIVERED DISTILLATE OIL and NATURAL GAS PRICES
LOW CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	DISTILLATE OIL			NATURAL GAS		
YEAR	$/BBL	c/MBTU	ESCALATION %	c/MBTU	c/THERM	ESCALATION %
1996		SEE			SEE	
1997		BASE			BASE	
1998		CASE			CASE	
	1 /	1 /		2 /	2 /	
1999	18.73	323.00		200.00	20.00	
2000	19.02	328.00	1.55	202.00	20.20	1.00
2001	19.14	330.00	0.61	204.00	20.40	0.99
2002	19.31	333.00	0.91	206.00	20.60	0.98
2003	19.43	335.00	0.60	208.00	20.80	0.97
2004	19.60	338.00	0.90	210.00	21.00	0.96
2005	19.78	341.00	0.89	212.00	21.20	0.95
2006	20.01	345.00	1.17	214.00	21.40	0.94
2007	20.18	348.00	0.87	216.00	21.60	0.93
2008	20.30	350.00	0.57	218.00	21.80	0.93

HEAT CONTENT DISTILLATE OIL = 5.80 MBTU/BBL

ASH CONTENT DISTILLATE OIL = 0.00 PERCENT

NOTES: 1 / WITHOUT INLAND FREIGHT - 0.5% SULFUR
2 / SUPPLY COST ONLY

NOMINAL, DELIVERED COAL PRICES
BASE CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	LOW SULFUR COAL (< 1.0%)				MEDIUM SULFUR COAL (1.0 - 2.0%)				HIGH SULFUR COAL (> 2.0%)			
YEAR	$/TON	c/MBTU	ESCALATION %	% SPOT PURCHASE	$/TON	c/MBTU	ESCALATION %	% SPOT PURCHASE	$/TON	c/MBTU	ESCALATION %	% SPOT PURCHASE
					1 /	1 /		4 /				
1996		DATA			47.00	188.00		0.00		DATA		
1997		NOT			47.25	189.00	0.53	0.00		NOT		
1998		AVAILABLE			47.00	188.00	-0.53	0.00		AVAILABLE		
	2 /	2 /		4 /	3 /	3 /		4 /				
1999	49.75	199.00		0.00	41.50	166.00		0.00				
2000	50.00	200.00	0.50	0.00	42.25	169.00	1.81	0.00				
2001	50.75	203.00	1.50	0.00	42.75	171.00	1.18	0.00				
2002	49.25	197.00	-2.96	0.00	43.25	173.00	1.17	0.00				
2003	50.00	200.00	1.52	0.00	43.50	174.00	0.58	0.00		NOT		
2004	51.25	205.00	2.50	0.00	44.25	177.00	1.72	0.00		APPLICABLE		
2005	49.75	199.00	-2.93	0.00	44.75	179.00	1.13	0.00				
2006	50.75	203.00	2.01	0.00	45.25	181.00	1.12	0.00				
2007	52.00	208.00	2.46	0.00	46.00	184.00	1.66	0.00				
2008	53.25	213.00	2.40	0.00	46.50	186.00	1.09	0.00				

HEAT CONTENT < 1.0% LOW SULFUR COAL = 25.00 MBTU/TON
HEAT CONTENT 1.0 - 2.0% MED. SULFUR COAL = 25.00 MBTU/TON
HEAT CONTENT > 2.0% HIGH SULFUR COAL = N/A MBTU/TON

ASH CONTENT < 1.0% LOW SULFUR COAL = 8.36 PERCENT
ASH CONTENT 1.0 - 2.0% MED. SULFUR COAL = 8.89 PERCENT
ASH CONTENT > 2.0% HIGH SULFUR COAL = N/A PERCENT

NOTES: 1 / TOTAL COAL - $/TON ARE APPROXIMATE - AS BURNED DATA
2 / LIMITED TO 1.2 lb SO2/MBTU
3 / LIMITED TO 2.1 lb SO2/MBTU
4 / 100% CONTRACT

NOMINAL, DELIVERED COAL PRICES
HIGH CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	LOW SULFUR COAL (< 1.0%)				MEDIUM SULFUR COAL (1.0 - 2.0%)				HIGH SULFUR COAL (> 2.0%)			
YEAR	$/TON	c/MBTU	ESCALATION %	% SPOT PURCHASE	$/TON	c/MBTU	ESCALATION %	% SPOT PURCHASE	$/TON	c/MBTU	ESCALATION %	% SPOT PURCHASE
1996		DATA				SEE				DATA		
1997		NOT				BASE				NOT		
1998		AVAILABLE				CASE				AVAILABLE		
	1 /	1 /		3 /	2 /	2 /		3 /				
1999	50.25	201.00		0.00	42.25	169.00		0.00				
2000	50.75	203.00	1.00	0.00	43.00	172.00	1.78	0.00				
2001	51.75	207.00	1.97	0.00	43.75	175.00	1.74	0.00				
2002	50.50	202.00	-2.42	0.00	44.50	178.00	1.71	0.00				
2003	51.50	206.00	1.98	0.00	45.00	180.00	1.12	0.00		NOT		
2004	53.00	212.00	2.91	0.00	45.50	182.00	1.11	0.00		APPLICABLE		
2005	50.75	203.00	-4.25	0.00	46.25	185.00	1.65	0.00				
2006	52.00	208.00	2.46	0.00	46.75	187.00	1.08	0.00				
2007	53.00	212.00	1.92	0.00	47.50	190.00	1.60	0.00				
2008	54.25	217.00	2.36	0.00	48.00	192.00	1.05	0.00				

HEAT CONTENT < 1.0% LOW SULFUR COAL = 25.00 MBTU/TON
HEAT CONTENT 1.0 - 2.0% MED. SULFUR COAL = 25.00 MBTU/TON
HEAT CONTENT > 2.0% HIGH SULFUR COAL = N/A MBTU/TON

ASH CONTENT < 1.0% LOW SULFUR COAL = 8.36 PERCENT
ASH CONTENT 1.0 - 2.0% MED. SULFUR COAL = 8.89 PERCENT
ASH CONTENT > 2.0% HIGH SULFUR COAL = N/A PERCENT

NOTES: 1 / LIMITED TO 1.2 lb SO_2/MBTU
2 / LIMITED TO 2.1 lb SO_2/MBTU
3 / 100% CONTRACT

NOMINAL, DELIVERED COAL PRICES
LOW CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	LOW SULFUR COAL (< 1.0%)				MEDIUM SULFUR COAL (1.0 - 2.0%)				HIGH SULFUR COAL (> 2.0%)			
YEAR	$/TON	c/MBTU	ESCALATION %	% SPOT PURCHASE	$/TON	c/MBTU	ESCALATION %	% SPOT PURCHASE	$/TON	c/MBTU	ESCALATION %	% SPOT PURCHASE
1996		DATA				SEE				DATA		
1997		NOT				BASE				NOT		
1998		AVAILABLE				CASE				AVAILABLE		
	1 /	1 /		3 /	2 /	2 /		3 /				
1999	49.25	197.00		0.00	41.25	165.00		0.00				
2000	49.50	198.00	0.51	0.00	41.75	167.00	1.21	0.00				
2001	50.00	200.00	1.01	0.00	42.25	169.00	1.20	0.00				
2002	48.75	195.00	-2.50	0.00	42.50	170.00	0.59	0.00				
2003	49.25	197.00	1.03	0.00	43.00	172.00	1.18	0.00		NOT		
2004	50.50	202.00	2.54	0.00	43.50	174.00	1.16	0.00		APPLICABLE		
2005	49.50	198.00	-1.98	0.00	44.00	176.00	1.15	0.00				
2006	50.25	201.00	1.52	0.00	44.50	178.00	1.14	0.00				
2007	51.25	205.00	1.99	0.00	45.25	181.00	1.69	0.00				
2008	52.25	209.00	1.95	0.00	45.75	183.00	1.10	0.00				

HEAT CONTENT < 1.0% LOW SULFUR COAL = 25.00 MBTU/TON
HEAT CONTENT 1.0 - 2.0% MED. SULFUR COAL = 25.00 MBTU/TON
HEAT CONTENT > 2.0% HIGH SULFUR COAL = N/A MBTU/TON

ASH CONTENT < 1.0% LOW SULFUR COAL = 8.36 PERCENT
ASH CONTENT 1.0 - 2.0% MED. SULFUR COAL = 8.89 PERCENT
ASH CONTENT > 2.0% HIGH SULFUR COAL = N/A PERCENT

NOTES: 1 / LIMITED TO 1.2 lb SO2/MBTU
2 / LIMITED TO 2.1 lb SO2/MBTU
3 / 100% CONTRACT

NOMINAL, DELIVERED NUCLEAR FUEL AND FIRM PURCHASES

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	NUCLEAR		FIRM PURCHASES		QF PURCHASES	
YEAR	c/MBTU	ESCALATION %	$/MWh	ESCALATION %	$/MWh	ESCALATION %
			1 /		2 /	
1996	35.00		53.25		20.87	
1997	32.00	-8.57	57.12	7.27	19.72	-5.51
1998	34.00	6.25	57.65	0.93	19.00	-3.65
			3 /			
1999	32.40	-4.71	14.00		19.53	2.79
2000	35.20	8.64	13.90	-0.71	19.73	1.02
2001	35.20	0.00	14.10	1.44	20.20	2.38
2002	34.70	-1.42	14.40	2.13	20.42	1.09
2003	34.70	0.00	14.60	1.39	20.95	2.60
2004	38.30	10.37	14.70	0.68	21.34	1.86
2005	38.70	1.04	14.60	-0.68	21.12	-1.03
2006	42.70	10.34	14.90	2.05	21.58	2.18
2007	43.20	1.17	15.20	2.01	21.84	1.20
2008	45.20	4.63	15.40	1.32	22.37	2.43

NOTES: 1 / PURCHASED POWER - INVOICE COST (INCLUDING ANY DEMAND CHARGES)
2 / QF CONTRACTS WITH FIRM DELIVERIES - ENERGY COST ONLY
3 / ENERGY COST ONLY

FINANCIAL ASSUMPTIONS
BASE CASE

AFUDC RATE		8.53 %
CAPITALIZATION RATIOS:		
	DEBT	45.00 %
	PREFERRED	0.00 %
	EQUITY	55.00 %
RATE OF RETURN:		
	DEBT	7.00 %
	PREFERRED	8.00 %
	EQUITY	12.00 %
INCOME TAX RATE:		
	STATE	5.50 %
	FEDERAL	35.00 %
	EFFECTIVE	38.58 %
OTHER TAX RATE:		NOT USED %
DISCOUNT RATE:		8.53 %
TAX DEPRECIATION RATE:		15 YEAR, 150% TO SL

FINANCIAL ESCALATION ASSUMPTIONS

(1) YEAR	(2) GENERAL INFLATION %	(3) PLANT CONSTRUCTION COST %	(4) FIXED O & M COST %	(5) VARIABLE O & M COST %
1999	3.10	3.10	2.50	2.50
2000	3.10	3.10	2.50	2.50
2001	3.10	3.10	2.50	2.50
2002	3.10	3.10	2.50	2.50
2003	3.10	3.10	2.50	2.50
2004	3.10	3.10	2.50	2.50
2005	3.10	3.10	2.50	2.50
2006	3.10	3.10	2.50	2.50
2007	3.10	3.10	2.50	2.50
2008	3.10	3.10	2.50	2.50

LOSS OF LOAD PROBABILITY, RESERVE MARGIN,
AND EXPECTED UNSERVED ENERGY
BASE CASE LOAD FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ANNUAL ISOLATED			ANNUAL ASSISTED		
YEAR	LOSS OF LOAD PROBABILITY (DAYS/YR)	RESERVE MARGIN % (INCLUDING FIRM PURCH.)	EXPECTED UNSERVED ENERGY (MWh)	LOSS OF LOAD PROBABILITY (DAYS/YR)	RESERVE MARGIN (%)	EXPECTED UNSERVED ENERGY (MWh)
1999	1.327	19	1397.8	0.045	19	36.9
2000	1.365	16	1491.1	0.049	16	39.4
2001	0.538	17	480.2	0.010	17	7.2
2002	0.910	18	988.7	0.028	18	23.1
2003	0.329	24	345.4	0.007	24	5.5
2004	0.386	20	382.2	0.006	20	4.9
2005	0.502	22	565.6	0.013	22	11.6
2006	0.458	19	465.0	0.009	19	7.4
2007	0.426	23	496.0	0.012	23	11.7
2008	0.413	20	457.8	0.009	20	8.5

LOSS OF LOAD PROBABILITY, RESERVE MARGIN,
AND EXPECTED UNSERVED ENERGY
HIGH CASE LOAD FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ANNUAL ISOLATED			ANNUAL ASSISTED		
YEAR	LOSS OF LOAD PROBABILITY (DAYS/YR)	RESERVE MARGIN % (INCLUDING FIRM PURCH.)	EXPECTED UNSERVED ENERGY (MWh)	LOSS OF LOAD PROBABILITY (DAYS/YR)	RESERVE MARGIN (%)	EXPECTED UNSERVED ENERGY (MWh)
1999						
2000						
2001						
2002						
2003			**SENSITIVITY NOT PERFORMED**			
2004						
2005						
2006						
2007						
2008						

LOSS OF LOAD PROBABILITY, RESERVE MARGIN,
AND EXPECTED UNSERVED ENERGY
LOW CASE LOAD FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ANNUAL ISOLATED			ANNUAL ASSISTED		
YEAR	LOSS OF LOAD PROBABILITY (DAYS/YR)	RESERVE MARGIN % (INCLUDING FIRM PURCH.)	EXPECTED UNSERVED ENERGY (MWh)	LOSS OF LOAD PROBABILITY (DAYS/YR)	RESERVE MARGIN (%)	EXPECTED UNSERVED ENERGY (MWh)
1999						
2000						
2001						
2002						
2003			**SENSITIVITY NOT PERFORMED**			
2004						
2005						
2006						
2007						
2008						

Demand Side Management Annual Report

Utility: FLORIDA POWER CORPORATION
Program Name: **Home Energy Check**
Program Start Date: January 1991 with revision approved April 1996
Reporting Period: 1998

a	b	c	d	e	f	g	h	i
Year	Total Number of Customers	Total Number of Eligible Customers	Projected Cumulative Number of Program Participants	Projected Cumulative Penetration Level % [(d/c)x100]	Actual Annual Number of Program Participants	Actual Cumulative Number of Program Participants	Actual Cumulative Penetration Level % [(g/c)x100]	Actual Participation Over (Under) Projected Participants (g-d)
1994	1,100,537	1,100,537	120,000	11%	22,673	115,585	11%	-4,415
1995	1,124,679	1,124,679	150,000	13%	30,437	146,022	13%	-3,978
1996	1,141,671	1,141,671	175,010	15%	34,749	180,771	16%	5,761
1997	1,160,611	1,160,611	202,020	17%	39,621	220,392	19%	18,372
1998	1,182,786	1,182,786	230,030	19%	28,488	248,880	21%	18,850
1999								
2000								
2001								
2002								
2003								

Annual Demand & Energy Savings (during the reporting period)	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Summer kW Reduction	0.1	0.1	2,552.1	2,746.3
Winter kW Reduction	0.1	0.1	2,550.0	2,700.7
Annual kWh Reduction	297.1	317.5	8,464,663.0	9,044,407.8

Utility Cost per Installation: 75.5
Total Program Cost of the Utility ($000): 2,149.7
Net Benefits of Measures Installed During Reporting Period ($000): N/A

Demand Side Management Annual Report

Utility: FLORIDA POWER CORPORATION
Program Name: **Home Energy Improvement**
Program Start Date: April 1996
Reporting Period: 1998

a	b	c	d	e	f	g	h	i
Year	Total Number of Customers	Total Number of Eligible Customers	Projected Cumulative Number of Program Participants	Projected Cumulative Penetration Level % [(d/c)x100]	Actual Annual Number of Program Participants	Actual Cumulative Number of Program Participants	Actual Cumulative Penetration Level % [(g/c)x100]	Actual Participation Over (Under) Projected Participants (g-d)
1996	1,141,671	1,141,671	11,794	1%	13,246	13,246	1%	1,452
1997	1,160,611	1,160,611	25,967	2%	21,447	34,693	3%	8,726
1998	1,182,786	1,182,786	42,427	4%	24,276	58,969	5%	16,542
1999								
2000								
2001								
2002								
2003								

Annual Demand & Energy Savings (during the reporting period)	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Summer kW Reduction	0.3	0.3	7,678.9	8,263.2
Winter kW Reduction	0.9	1.0	22,284.1	23,601.1
Annual kWh Reduction	459.9	491.2	11,164,535.0	11,925,453.9

Utility Cost per Installation:	130.5
Total Program Cost of the Utility ($000):	3,168.5
Net Benefits of Measures Installed During Reporting Period ($000):	1,124.2

Demand Side Management Annual Report

Utility: FLORIDA POWER CORPORATION
Program Name: **Residential New Construction**
Program Start Date: April 1996
Reporting Period: 1998

a	b	c	d	e	f	g	h	i
Year	Total Number of Customers	Total Number of Eligible Customers	Projected Cumulative Number of Program Participants	Projected Cumulative Penetration Level % [(d/c)x100]	Actual Annual Number of Program Participants	Actual Cumulative Number of Program Participants	Actual Cumulative Penetration Level % [(g/c)x100]	Actual Participation Over (Under) Projected Participants (g-d)
1996	1,141,671	1,141,671	1,520	0%	5,409	5,409	0%	3,889
1997	1,160,611	1,160,611	4,420	0%	5,676	11,085	1%	6,665
1998	1,182,786	1,182,786	9,191	1%	6,567	17,652	1%	8,461
1999								
2000								
2001								
2002								
2003								

Annual Demand & Energy Savings (during the reporting period)	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Summer kW Reduction	0.5	0.5	3,317.4	3,569.8
Winter kW Reduction	1.0	1.0	6,490.2	6,873.8
Annual kWh Reduction	524.8	561.0	3,446,610.0	3,684,243.4

Utility Cost per Installation: 104.6
Total Program Cost of the Utility ($000): 687.1
Net Benefits of Measures Installed During Reporting Period ($000): 3,369.6

Demand Side Management Annual Report

Utility: FLORIDA POWER CORPORATION
Program Name: **Residential Load Management**
Program Start Date: January 1981 with revision approved April 1996
Reporting Period: 1998

a	b	c	d	e	f	g	h	i
Year	Total Number of Customers	Total Number of Eligible Customers	Projected Cumulative Number of Program Participants	Projected Cumulative Penetration Level % [(d/c)x100]	Actual Annual Number of Program Participants	Actual Cumulative Number of Program Participants	Actual Cumulative Penetration Level % [(g/c)x100]	Actual Participation Over (Under) Projected Participants (g-d)
1994	1,100,537	1,100,537	523,650	48%	17,430	523,736	48%	86
1995	1,124,679	1,124,679	563,650	50%	12,989	536,725	48%	-26,925
1996	1,141,671	1,141,671	580,951	51%	17,982	554,707	49%	-26,244
1997	1,160,611	1,160,611	599,197	52%	18998	573,705	49%	-25,492
1998	1,182,786	1,182,786	616,679	52%	12963	586,668	50%	-30,011
1999								
2000								
2001								
2002								
2003								

Annual Demand & Energy Savings (during the reporting period)	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Summer kW Reduction	1.0	1.0	12,314.9	13,252.0
Winter kW Reduction	1.9	2.0	24,012.2	25,431.4
Annual kWh Reduction	0.0	0.0	0.0	0.0

Utility Cost per Installation: 2,943.2
Total Program Cost of the Utility ($000): 38,152.7
Net Benefits of Measures Installed During Reporting Period ($000): 355.3

Demand Side Management Annual Report

Utility: FLORIDA POWER CORPORATION
Program Name: **Business Energy Check**
Program Start Date: January 1991 with revision approved April 1996
Reporting Period: 1998

a	b	c	d	e	f	g	h	i
Year	Total Number of Customers	Total Number of Eligible Customers	Projected Cumulative Number of Program Participants	Projected Cumulative Penetration Level % [(d/c)x100]	Actual Annual Number of Program Participants	Actual Cumulative Number of Program Participants	Actual Cumulative Penetration Level % [(g/c)x100]	Actual Participation Over (Under) Projected Participants (g-d)
1994	122,987	122,987	20,040	16%	1,308	11,795	10%	-8,245
1995	126,189	126,189	25,050	20%	1,194	12,989	10%	-12,061
1996	129,440	129,440	27,550	21%	720	13,709	11%	-13,841
1997	132,504	132,504	30,050	23%	604	14,313	11%	-15,737
1998	136,345	136,345	32,550	24%	544	14,857	11%	-17,693
1999								
2000								
2001								
2002								
2003								

Annual Demand & Energy Savings (during the reporting period)	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Summer kW Reduction	0.1	0.2	76.2	81.8
Winter kW Reduction	0.1	0.1	76.2	80.5
Annual kWh Reduction	300.0	320.7	163,200.0	174,452.2

Utility Cost per Installation:	255.6
Total Program Cost of the Utility ($000):	139.0
Net Benefits of Measures Installed During Reporting Period ($000):	N/A

Demand Side Management Annual Report

Utility: FLORIDA POWER CORPORATION
Program Name: **Better Business**
Program Start Date: April 1996
Reporting Period: 1998

a	b	c	d	e	f	g	h	i
Year	Total Number of Customers	Total Number of Eligible Customers	Projected Cumulative Number of Program Participants	Projected Cumulative Penetration Level % [(d/c)x100]	Actual Annual Number of Program Participants	Actual Cumulative Number of Program Participants	Actual Cumulative Penetration Level % [(g/c)x100]	Actual Participation Over (Under) Projected Participants (g-d)
1996	129,440	129,440	72,077	56%	63	63	0%	-72,014
1997	132,504	132,504	116,830	88%	215	278	0%	-116,552
1998	136,345	136,345	171,394	126%	174	452	0%	-170,942
1999								
2000								
2001								
2002								
2003								

Annual Demand & Energy Savings (during the reporting period)	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Summer kW Reduction	28.6	30.8	4,983.7	5,352.5
Winter kW Reduction	19.0	20.1	3,309.3	3,497.9
Annual kWh Reduction	61,276.2	65,480.0	10,662,056.0	11,393,515.7

Utility Cost per Installation:	2,240.7
Total Program Cost of the Utility ($000):	389.9
Net Benefits of Measures Installed During Reporting Period ($000):	16.3

Demand Side Management Annual Report

Utility: FLORIDA POWER CORPORATION
Program Name: **C/I New Construction**
Program Start Date: April 1996
Reporting Period: 1998

a	b	c	d	e	f	g	h	i
Year	Total Number of Customers	Total Number of Eligible Customers	Projected Cumulative Number of Program Participants	Projected Cumulative Penetration Level % [(d/c)x100]	Actual Annual Number of Program Participants	Actual Cumulative Number of Program Participants	Actual Cumulative Penetration Level % [(g/c)x100]	Actual Participation Over (Under) Projected Participants (g-d)
1996	129,440	129,440	8,391	6%	2	2	0%	-8,389
1997	132,504	132,504	15,867	12%	7	9	0%	-15,858
1998	136,345	136,345	23,120	17%	1	10	0%	-23,110
1999								
2000								
2001								
2002								
2003								

Annual Demand & Energy Savings (during the reporting period)	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Summer kW Reduction	44.4	47.7	44.4	47.7
Winter kW Reduction	88.0	93.0	88.0	93.0
Annual kWh Reduction	43,200.0	46,220.5	43,200.0	46,220.5

Utility Cost per Installation:	1,822.3
Total Program Cost of the Utility ($000):	1.8
Net Benefits of Measures Installed During Reporting Period ($000):	0.7

Demand Side Management Annual Report

Utility:	FLORIDA POWER CORPORATION
Program Name:	**Energy Monitor**
Program Start Date:	April 1996
Reporting Period:	1998

a	b	c	d	e	f	g	h	i
Year	Total Number of Customers	Total Number of Eligible Customers	Projected Cumulative Number of Program Participants	Projected Cumulative Penetration Level % [(d/c)x100]	Actual Annual Number of Program Participants	Actual Cumulative Number of Program Participants	Actual Cumulative Penetration Level % [(g/c)x100]	Actual Participation Over (Under) Projected Participants (g-d)
1996	129,440	129,440	69	0%	28	28	0%	-41
1997	132,504	132,504	141	0%	6	34	0%	-107
1998	136,345	136,345	207	0%	0	34	0%	-173
1999								
2000								
2001								
2002								
2003								

Annual Demand & Energy Savings (during the reporting period)	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Summer kW Reduction	---	---	---	---
Winter kW Reduction	---	---	---	---
Annual kWh Reduction	---	---	---	---

Utility Cost per Installation: ---

Total Program Cost of the Utility ($000): 0.1

Net Benefits of Measures Installed During Reporting Period ($000): ---

Demand Side Management Annual Report

Utility: FLORIDA POWER CORPORATION
Program Name: **Innovation Incentive**
Program Start Date: January 1991 with revision approved April 1996
Reporting Period: 1998

a Year	b Total Number of Customers	c Total Number of Eligible Customers	d Projected Cumulative Number of Program Participants	e Projected Cumulative Penetration Level % [(d/c)x100]	f Actual Annual Number of Program Participants	g Actual Cumulative Number of Program Participants	h Actual Cumulative Penetration Level % [(g/c)x100]	i Actual Participation Over (Under) Projected Participants (g-d)
1994	122,987	122,987	30	0%	37	81	0%	51
1995	126,189	126,189	40	0%	41	122	0%	82
1996	129,440	129,440	48	0%	19	141	0%	93
1997	132,504	132,504	56	0%	4	145	0%	89
1998	136,345	136,345	64	0%	2	147	0%	83
1999								
2000								
2001								
2002								
2003								

Annual Demand & Energy Savings (during the reporting period)	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Summer kW Reduction	455.0	488.7	910.0	977.3
Winter kW Reduction	295.0	311.8	590.0	623.6
Annual kWh Reduction	0.0	0.0	0.0	0.0

Utility Cost per Installation: 68,346.2
Total Program Cost of the Utility ($000): 136.7
Net Benefits of Measures Installed During Reporting Period ($000): 5.4

Demand Side Management Annual Report

Utility: FLORIDA POWER CORPORATION
Program Name: **Commercial Load Management**
Program Start Date: April 1996
Reporting Period: 1998

a	b	c	d	e	f	g	h	i
Year	Total Number of Customers	Total Number of Eligible Customers	Projected Cumulative Number of Program Participants	Projected Cumulative Penetration Level % [(d/c)x100]	Actual Annual Number of Program Participants	Actual Cumulative Number of Program Participants	Actual Cumulative Penetration Level % [(g/c)x100]	Actual Participation Over (Under) Projected Participants (g-d)
1996	129,440	129,440	43	0%	9	9	0%	-34
1997	132,504	132,504	86	0%	0	9	0%	-77
1998	136,345	136,345	129	0%	0	9	0%	-120
1999								
2000								
2001								
2002								
2003								

Annual Demand & Energy Savings (during the reporting period)	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Summer kW Reduction	---	---	---	---
Winter kW Reduction	---	---	---	---
Annual kWh Reduction	---	---	---	---

Utility Cost per Installation: ---
Total Program Cost of the Utility ($000): 706.0
Net Benefits of Measures Installed During Reporting Period ($000): ---

Demand Side Management Annual Report

Utility: FLORIDA POWER CORPORATION
Program Name: **Standby Generation**
Program Start Date: April 1993 with revision approved April 1996
Reporting Period: 1998

a	b	c	d	e	f	g	h	i
Year	Total Number of Customers	Total Number of Eligible Customers	Projected Cumulative Number of Program Participants	Projected Cumulative Penetration Level % [(d/c)x100]	Actual Annual Number of Program Participants	Actual Cumulative Number of Program Participants	Actual Cumulative Penetration Level % [(g/c)x100]	Actual Participation Over (Under) Projected Participants (g-d)
1994	122,987	2,576	80	3%	7	12	0%	-68
1995	126,189	2,601	120	5%	21	33	1%	-87
1996	129,440	543	121	22%	2	35	6%	-86
1997	132,504	553	122	22%	0	35	6%	-87
1998	136,345	565	123	22%	10	45	8%	-78
1999								
2000								
2001								
2002								
2003								

Annual Demand & Energy Savings (during the reporting period)	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Summer kW Reduction	208.6	224.0	2,086.0	2,240.4
Winter kW Reduction	208.6	220.5	2,086.0	2,204.9
Annual kWh Reduction	0.0	0.0	0.0	0.0

Utility Cost per Installation:	45
Total Program Cost of the Utility ($000):	454
Net Benefits of Measures Installed During Reporting Period ($000):	168

Demand Side Management Annual Report

Utility: FLORIDA POWER CORPORATION
Program Name: **Interruptible Service - IS-1**
Program Start Date: November 1992 - program closed to new customers as of April 1996
Reporting Period: 1998

a Year	b Total Number of Customers	c Total Number of Eligible Customers	d Projected Cumulative Number of Program Participants	e Projected Cumulative Penetration Level % [(d/c)x100]	f Actual Annual Number of Program Participants	g Actual Cumulative Number of Program Participants	h Actual Cumulative Penetration Level % [(g/c)x100]	i Actual Participation Over (Under) Projected Participants (g-d)
1994	122,987	122,987	96	0%	4	100	0%	4
1995	126,189	126,189	96	0%	16	116	0%	20
1996	129,440	129,440	96	0%	14	130	0%	34
1997	132,504	132,504	96	0%	2	132	0%	36
1998	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Annual Demand & Energy Savings (during the reporting period)	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Summer kW Reduction	---	---	---	---
Winter kW Reduction	---	---	---	---
Annual kWh Reduction	---	---	---	---

Utility Cost per Installation:	---
Total Program Cost of the Utility ($000):	20,678.0
Net Benefits of Measures Installed During Reporting Period ($000):	---

Demand Side Management Annual Report

Utility: FLORIDA POWER CORPORATION
Program Name: **Interruptible Service - IS-2**
Program Start Date: November 1992 with revision approved June 1996
Reporting Period: 1998

a Year	b Total Number of Customers	c Total Number of Eligible Customers	d Projected Cumulative Number of Program Participants	e Projected Cumulative Penetration Level % [(d/c)x100]	f Actual Annual Number of Program Participants	g Actual Cumulative Number of Program Participants	h Actual Cumulative Penetration Level % [(g/c)x100]	i Actual Participation Over (Under) Projected Participants (g-d)
1994								
1995								
1996								
1997	132,504	132,504	96	0%	1	1	0%	-95
1998	136,345	136,345	192	0%	0	1	0%	-191
1999								
2000								
2001								
2002								
2003								

Annual Demand & Energy Savings (during the reporting period)	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Summer kW Reduction	---	---	---	---
Winter kW Reduction	---	---	---	---
Annual kWh Reduction	---	---	---	---

Utility Cost per Installation: ---
Total Program Cost of the Utility ($000): 59.1
Net Benefits of Measures Installed During Reporting Period ($000): ---

Demand Side Management Annual Report

Utility: FLORIDA POWER CORPORATION
Program Name: **Curtailable Service - CS-1**
Program Start Date: November 1992 - program closed to new customers as of April 1996
Reporting Period: 1998

a	b	c	d	e	f	g	h	i
Year	Total Number of Customers	Total Number of Eligible Customers	Projected Cumulative Number of Program Participants	Projected Cumulative Penetration Level % [(d/c)x100]	Actual Annual Number of Program Participants	Actual Cumulative Number of Program Participants	Actual Cumulative Penetration Level % [(g/c)x100]	Actual Participation Over (Under) Projected Participants (g-d)
1994	122,987	122,987	11	0%	4	12	0%	1
1995	126,189	126,189	11	0%	0	12	0%	1
1996	129,440	129,440	11	0%	1	13	0%	2
1997	132,504	132,504	11	0%	0	13	0%	2
1998	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Annual Demand & Energy Savings (during the reporting period)	Per Installation @ Meter	Per Installation @ Generator	Program Total @ Meter	Program Total @ Generator
Summer kW Reduction	---	---	---	---
Winter kW Reduction	---	---	---	---
Annual kWh Reduction	---	---	---	---

Utility Cost per Installation: ---
Total Program Cost of the Utility ($000): 629.0
Net Benefits of Measures Installed During Reporting Period ($000): ---

Demand Side Management Annual Report

Utility: FLORIDA POWER CORPORATION
Program Name: **Curtailable Service -CS-2**
Program Start Date: November 1992 with revision approved June 1996
Reporting Period: 1998

a	b	c	d	e	f	g	h	i
Year	Total Number of Customers	Total Number of Eligible Customers	Projected Cumulative Number of Program Participants	Projected Cumulative Penetration Level % [(d/c)x100]	Actual Annual Number of Program Participants	Actual Cumulative Number of Program Participants	Actual Cumulative Penetration Level % [(g/c)x100]	Actual Participation Over (Under) Projected Participants (g-d)
1994								
1995								
1996								
1997	132,504	132,504	11	0%	0	0	0%	-11
1998	136,345	136,345	22	0%	0	0	0%	-22
1999								
2000								
2001								
2002								
2003								

Annual Demand & Energy Savings (during the reporting period)	Per Installation		Program Total	
	@ Meter	@ Generator	@ Meter	@ Generator
Summer kW Reduction	---	---	---	---
Winter kW Reduction	---	---	---	---
Annual kWh Reduction	---	---	---	---

Utility Cost per Installation: ---
Total Program Cost of the Utility ($000): 0.0
Net Benefits of Measures Installed During Reporting Period ($000): ---

2. Illustrate what FPC's generation expansion plan would be as a result of each of the demand forecast sensitivities discussed in FPC's Ten-Year Site Plan. Include the cumulative present worth revenue requirements (CPWRR) of each sensitivity.

The economic results of each of the above sensitivities are provided below.
The CPWRR from the #1 ranked plan for each sensitivity are included.
The CPWRR for resource plans other than the #1 ranked plan are special report runs and have not been included or reviewed in detail.

	BASE CASE FUEL PRICE FORECAST			
	High Demand		Low Demand	
Year	Unit(s)	CPWRR ($000)	Unit(s)	CPWRR ($000)
1999	Hines Energy Complex CC 1	1,033,511	Hines Energy Complex CC 1	991,164
2000		2,022,419		1,935,334
2001	Inter. City P12-14 & CT 1-3	3,035,557		2,859,849
2002		3,935,791		3,679,514
2003		4,783,579		4,446,643
2004		5,614,553		5,182,525
2005	Hines Energy Complex CC 2	6,404,358		5,878,871
2006		7,171,552	Hines Energy Complex CC 2	6,561,800
2007	Hines Energy Complex CC 3	7,914,642		7,213,483
2008		8,632,185		7,833,797
2009	CT 4-5	9,302,073	Inter. City P12-14	8,407,489

3. Provide a table of annual and cumulative present worth revenue requirements (CPWRR) for all combinations of units that were evaluated in order to arrive at FPC's base case generation expansion plan. Include the type and timing of the unit or units that comprise each alternative, and the impact of these unit additions on the system loss of load probability (LOLP) and seasonal reserve margins.

FPC's 1999 Ten-Year Site Plan expansion review analyzed hundreds of possible expansion alternatives. In order to simplify the data collection for this question, FPC selected five expansion alternatives that related to various types of technology and produced the CPWRR for these alternatives. The types of technology selected are shown below.

Expansion Alternative

1) Current Combined Cycle Technology (Base Plan)
2) Combined Cycle & Combustion Turbines
3) Advanced Combustion Turbine Technology
4) Advanced Combined Cycle Technology
5) Syngas (IGCC) & Pulverized Coal Technology

The data requested has been attached for the above technologies:

Expansion Alternative # 1

Current Combined Cycle Technology (Base Plan)

Year	Unit(s)	Annual PWRR ($000)	CPWRR ($000)	LOLP	Reserve Margin (%)	
					Summer	Winter
1999	Hines Energy Complex CC 1	1,010,355	1,010,355	0.045		19
2000		967,639	1,977,994	0.049		16
2001	Inter. City P12-14	967,625	2,945,619	0.010		17
2002		858,509	3,804,128	0.028		18
2003		807,135	4,611,263	0.007		24
2004		777,536	5,388,798	0.006		20
2005	Hines Energy Complex CC 2	749,577	6,138,375	0.013		22
2006		721,481	6,859,856	0.009		19
2007	Hines Energy Complex CC 3	705,232	7,565,088	0.012		23
2008		674,338	8,239,426	0.009		20
2009		614,978	8,854,404			

Expansion Alternative # 2

Combined Cycle & Combustion Turbines

Year	Unit(s)	Annual PWRR ($000)	CPWRR ($000)	LOLP	Reserve Margin (%)	
					Summer	Winter
1999	Hines Energy Complex CC 1	1,010,355	1,010,355			19
2000		967,639	1,977,994			16
2001	Inter. City P12-14	967,625	2,945,619			17
2002		858,509	3,804,128	LOLP		18
2003		807,135	4,611,263	SENSITIVITY		24
2004		777,536	5,388,798	NOT		20
2005	Hines Energy Complex CC 2	749,577	6,138,375	PERFORMED		22
2006		721,481	6,859,856			19
2007	CT 1-2	701,351	7,561,206			20
2008		673,794	8,235,000			17
2009	CT 3-4	625,209	8,860,208			

Expansion Alternative # 3

Advanced Combustion Turbine Technology

Year	Unit(s)	Annual PWRR ($000)	CPWRR ($000)	LOLP	Reserve Margin (%)	
					Summer	Winter
1999	Hines Energy Complex CC 1	1,010,355	1,010,355			19
2000		967,639	1,977,994			16
2001	Inter. City P12-14	967,625	2,945,619			17
2002		858,509	3,804,128	LOLP		18
2003		807,135	4,611,263	SENSITIVITY		24
2004		777,536	5,388,798	NOT		20
2005	CT 1-2	751,310	6,140,109	PERFORMED		20
2006		734,710	6,874,819			16
2007	CT 3-4	715,645	7,590,464			17
2008	CT 5-6	698,767	8,289,230			18
2009	Hines Energy Complex CC 2	636,834	8,926,064			

Expansion Alternative # 4

Advanced Combined Cycle Technology

Year	Unit(s)	Annual PWRR ($000)	CPWRR ($000)	LOLP	Reserve Margin (%)	
					Summer	Winter
1999	Hines Energy Complex CC 1	1,010,355	1,010,355			19
2000		967,639	1,977,994			16
2001	Inter. City P12-14	967,625	2,945,619			17
2002		858,509	3,804,128	LOLP		18
2003		807,135	4,611,263	SENSITIVITY		24
2004		777,536	5,388,798	NOT		20
2005	Hines Energy Complex CC 2	749,577	6,138,375	PERFORMED		22
2006		721,481	6,859,856			19
2007	Hines Energy Complex CC 3	703,549	7,563,404			20
2008		673,746	8,237,150			17
2009	Hines Energy Complex CC 4	627,608	8,864,758			

Expansion Alternative # 5

Syngas (IGCC) & Pulverized Coal Technology

Year	Unit(s)	Annual PWRR ($000)	CPWRR ($000)	LOLP	Reserve Margin (%)	
					Summer	Winter
1999	Hines Energy Complex CC 1	1,010,355	1,010,355			19
2000		967,639	1,977,994			16
2001	Inter. City P12-14	967,625	2,945,619			17
2002		858,509	3,804,128	LOLP		18
2003		807,135	4,611,263	SENSITIVITY		24
2004		777,536	5,388,798	NOT		20
2005	Pulverized Coal 1	807,402	6,196,200	PERFORMED		25
2006		770,095	6,966,295			22
2007		732,697	7,698,991			18
2008	IGCC 1	767,368	8,466,359			22
2009		697,652	9,164,011			

4. Discuss in greater detail how elements of risk (such as a changing regulatory environment, heavy reliance on natural gas, transmission system constraints, inadequate fuel diversity, evolving environmental regulations, or unusually high or low forecasts of load and fuel price) are addressed in FPC's generation expansion plan. Explain how FPC will adapt to such contingencies.

Risk in the planning process is handled first and foremost through a careful evaluation of the utility's current resources and a qualitative assessment of the future competitive and regulatory environment. Although a full range of future resources should be considered in the IRP process, cost-effectiveness is not the sole criteria under which they should be evaluated for addition to the utility's system. Each resource must also be evaluated for its contribution to the utility's fuel mix, environmental compliance, ability to be sited (including transmission impacts), and other non-cost related considerations.

Futures different from the IRP's resulting final optimal case are considered in the scenario analysis process that is part of FPC's IRP process. Scenario analysis examines which available resources would be selected in an optimal plan for a given set of future circumstances that is different from the base case. The optimal plans for a variety of futures are scrutinized to determine whether the resources selected in the final optimal case are similarly selected under the new set of assumptions. A robust final optimal plan is one that contains resources that are picked under many, if not all, possible future scenarios. Adding resources that are selected under a variety of future scenarios minimizes risk to the utility and its ratepayers.

5. Estimate annual emissions in tons for SO2, NOx, particulates, VOCs, CO2 and mercury using base case generation expansion planning assumptions. If sensitivities to the base case demand and/or fuel price forecast were performed and provided in FPC's Ten-Year Site Plan or in response to Question #1 above, estimate annual emissions for expansion plans resulting from each sensitivity.

The following emissions data are estimates that are provided for informational purposes only. Estimates are subject to change in the future as emission factors and predictive emissions models are refined. Sensitivities to emission data were not performed.

	BASE CASE DEMAND FORECAST					
	Base Case Fuel Price Forecast					
Year	SO2	NOx	PM	VOC	CO2	Hg
1999	139,014	57,525	8,565	956	23,472,358	0.632
2000	129,600	56,200	8,210	950	23,147,520	0.613
2001	137,543	58,931	8,653	1,042	24,387,060	0.629
2002	132,014	56,859	8,294	965	23,379,620	0.617
2003	136,852	57,815	8,573	941	23,783,964	0.626
2004	139,601	59,274	8,751	1,039	24,572,676	0.635
2005	130,452	56,478	8,291	1,117	24,123,818	0.616
2006	135,843	58,260	8,641	1,198	25,040,380	0.626
2007	124,657	55,246	8,089	1,308	24,513,116	0.602
2008	132,902	57,548	8,580	1,361	25,551,872	0.617

6. Discuss how FPC's Clean Air Act Compliance plan is integrated into the generation expansion plan.

FPC's generation expansion plan is developed with the criterion that FPC will operate within the specifications of the Clean Air Act. The Base Expansion Plan utilizes natural gas and high efficiency combined cycle generation to help meet the requirements of the 1990 Clean Air Act Amendments. Fuel switching, SO_2 emission allowance purchases, re-dispatching of generation, and technology changes are other options available to FPC to insure compliance with the 1990 Clean Air Act Amendments.

7. Identify and discuss all proposed or reasonably expected State and Federal environmental regulations or legislation that impacted FPC's generation expansion plan.

The key environmental legislation and resulting regulations affecting or expected to affect FPC's generation expansion plan are:

The Clean Air Act Amendments (CAAA): FPC is in the process of developing the most cost-effective plan to maintain compliance with the Title IV SO_2 allowance allocations beginning in the year 2000. In addition, as prescribed by Title III of the CAAA, EPA is continuing to evaluate the emissions of air toxics from electric utilities and whether to regulate those emissions. In February, 1998 EPA determined that further regulation of air toxic emissions from electric utilities is not appropriate at the present time, but additional study is needed. Potential future regulation could have a significant impact on FPC's generation plan.

Regional Haze Rule: EPA is in the process of finalizing a regional haze regulation that requires all states to improve visibility to background conditions over the next several decades. This regulation could cause FPC to add costly emissions controls, especially on its coal-fired units.

Ambient Air Quality: Recent high ground-level ozone readings in Florida may cause several areas, including the Tampa Bay area, to become non-attainment for this pollutant. This change will make it more difficult and costly to build new generating capacity and could also result in a requirement to decrease emissions from current facilities.

New Source Review Reform: EPA has proposed changes to the rules that regulate the air emissions from construction of new units or modification of existing units. If EPA were successful, routine activities that are currently exempt from New Source Review would be

7. (continued)

subject to it in the future. This could result in the installation of costly state-of-the-art pollution control equipment at many of FPC's facilities. EPA and the Utility Air Regulatory Group are currently negotiating a potential alternative New Source Review program that would achieve emissions reductions with more flexibility and less cost.

The Kyoto Climate Change Agreement: The Kyoto climate change agreement was developed in December 1997. If ratification of the protocol is successful, implementation will have a profound impact on FPC's operations and planning.

The reauthorization of the Clean Water Act (CWA): Congress has begun the process to reauthorize the CWA. Any changes to the CWA, particularly any changes related to intake structures or cooling water systems, may have an effect on the generation plan.

State consumptive use requirements: Because of increased pressure on a limited resource, the state's water management districts have begun restricting and/or denying new consumptive use water permits. Such changes in water use policy will increase reliance on alternative water supplies such as treated effluent and stormwater to support new generation expansion. Many changes are either being considered or have been enacted by the legislature that affect how water is allocated in Florida.

State industrial wastewater permits: The State of Florida has received delegation of the federal NPDES program. Current state industrial wastewater permits have been consolidated into the NPDES permits. However, no new limitations to wastewater discharges that would restrict generation expansion are anticipated from this delegation.

7. (continued)

Wetlands permitting: The Environmental Resource Permitting program requires applicants to address cumulative and secondary impacts to wetlands, wildlife and water quality. These predictive analyses can affect expansion plans.

Power Plant Siting Act (PPSA): Florida's current PPSA is designed to be a "one-stop" environmental permitting process. The extensive lead times for the necessary studies, permit application preparation, processing, and approval must be accounted for in generation planning.

8. Identify and discuss FPC's environmental research activities in the various areas of public concern such as air toxics, EMF, heavy metals and greenhouse gases.

FPC, through research being conducted by the utility industry at the national level and in Florida, is studying the emissions of air toxics, including heavy metals, from utility boilers. The national study was used by EPA to report to Congress on utility emissions in 1998. In Florida, the Florida Electric Power Coordinating Group and the Florida Department of Environmental Protection participated in a joint study of mercury emissions from utility boilers. FPC is not studying greenhouse gas emissions, but is participating in the U.S. Department of Energy's Climate Challenge Program, which is a voluntary effort to reduce emissions of greenhouse gases.

9. Discuss how FPC incorporates public concern over air toxic emissions, EMF exposure, heavy metals emissions and greenhouse gases into the generation expansion plan as well as plans for transmission and distribution additions.

In order to minimize emissions of air toxics, including heavy metals, FPC incorporates into its new generation facilities clean-burning fuels, such as distillate oil and natural gas. In addition, the best available control technology is incorporated into the design of each new generating unit to help control the appropriate air pollutant. Power line configurations which are effective at reducing EMF levels are incorporated into FPC's transmission and distribution additions.

FPC continues to monitor EMF research, and to up-date its customers and its employees with the latest information on the EMF issue. In addition, FPC holds open houses on virtually all new substation and transmission projects to both inform the public about the planned facilities as well as solicit feedback from the public as to the planned location of said facilities. In the design of all new substation and transmission projects, FPC adheres to current State of Florida EMF Standards. FPC continues, as it has since 1991, to provide customers with the latest information on the EMF issue and to offer free home and business EMF measurements.

Emissions of greenhouse gases, including carbon dioxide (CO_2), have been linked by some scientists to the hypothesis of a gradual warming of the earth's atmosphere. Although evidence to support or reject the hypothesis is inconclusive, FPC is voluntarily reducing its emissions of CO_2 and other greenhouse gases through a variety of methods as generation expansion decisions are made. FPC is a signatory to the President's voluntary Climate Challenge and will continue to reduce emissions of greenhouse gases over the next several years. Generation expansion will include a combination of lower emitting fuel (primarily natural gas), continuance of the state's leading demand side management program, improvements in efficiency at the nuclear power station and other generating sites, and a variety of other methods. However, it is important to note that the aggressive CO_2 reduction targets included

9. (continued)

in the Kyoto Protocol cannot be achieved in Florida or nationally without a fundamental change in methods of generating electricity.

10. Identify and discuss any firm power purchases that FPC expects to make from other utilities over the planning horizon. If some unidentified or unconfirmed future power purchase is part of FPC's generation expansion plan, explain the nature of that purchase.

FPC has long-term contracts for about 469 MW of purchased power with other utilities, including a contract with Southern Company for approximately 409 MW of purchased power annually through May 2010. This represents about 5 percent of FPC's total current system capacity. FPC has an option to lower the UPS purchases by approximately 200 MW given a three-year notice.

The other 60 MW of purchased power is a partial requirements contract between Tampa Electric Company (TECO) and FPC. This was originally a full requirements contract between TECO and the Sebring Utilities Commission (SUC). The contract was assumed by FPC and converted to partial requirements after FPC purchased the SUC electric distribution system in 1993. The terms of this contract with TECO change to 70 MW from 2005 through February, 2011. This contract expires in March, 2011.

11. Discuss FPC's historic, existing, and proposed activities regarding renewable energy resources.

In 1988, FPC and Sandia National Laboratory installed a utility connected solar photovoltaic array at the Econ substation near Orlando. The Solar Progress system is rated at 15 kilowatts of peak electrical output. The purpose of the project was to develop operational experience with grid-connected photovoltaic arrays and to test new photovoltaic cell technologies.

FPC investigated the addition of a solar water heating pilot program to its portfolio of demand-side management programs. This study began in November 1990 and ended in July 1992. The study found that the program did not pass the Commission's cost-effectiveness criteria, and was disbanded.

A cooperative effort was undertaken in 1992 between FPC, Kentucky Fried Chicken, the Florida Energy Extension Service, New Thermal Technologies, Inc., and ECU Inc. to demonstrate the use of a Solar-Electric Air Conditioning System. This system uses desiccant-based latent heat removal with conventional roof-mounted air conditioning. The heat from the solar system is used to drive the collected moisture from the desiccant material. The conclusion derived from the cost and operating data gathered is that the system is not cost-effective for the participant or the utility.

Sunworks is a cooperative project between FPC and the Florida Energy Extension Service at the University of Florida in Gainesville. This project uses desiccant cooling technology to cool a residential size building. Solar energy is used to recharge the desiccant. The equipment is in-service and is being monitored for collection of operational data.

11. (continued)

FPC is also involved in a project to demonstrate the feasibility of using solar power to charge an electric bus. This is a joint effort between the Pinellas Suncoast Transit Authority and FPC. The photovoltaic charging station is currently under review.

Currently, FPC is conducting market research to test customers acceptance and willingness to purchase electric energy from renewable resources such as, solar, wind, biomass and landfill methane. FPC will investigate and, if determined by FPC to be feasible, implement a Green Energy Program under which FPC would purchase electric energy generated from new renewable resources and offer to sell such energy to its customers who elect to participate in the program.

Beginning third quarter 2000, FPC will conduct a research and development project to standardize pre-packaged, roof mounted photovoltaic (PV) systems for manufactured buildings. The main objective of this project is to streamline processes in the factory environment, thereby reducing labor cost in the field. FPC plans to monitor the impact from solar PV systems installed on the grid.

12. Provide, on a system-wide basis, historical heating degree day (HDD) data for the period from 1989-1998 and forecasted HDD data for the period from 1999-2008.

Year	HDD
1989	445.3
1990	445.5
1991	421.2
1992	585.2
1993	508.1
1994	515.0
1995	601.0
1996	859.1
1997	442.7
1998	557.2
Forecast:	
1999-2008	551

13. Provide, on a system-wide basis, historical cooling degree day (CDD) data for the period from 1989-1998 and forecasted CDD data for the period from 1999-2008.

Year	CDD
1989	3992.1
1990	4209.8
1991	3948.0
1992	3327.0
1993	3396.0
1994	3345.3
1995	3928.5
1996	3682.1
1997	3434.1
1998	4159.0
Forecast:	
1999-2008	3691

14. Provide, on a system-wide basis, the historical real retail price of electricity within FPC's service territory for the period 1989-1998. Also, provide the forecasted real retail price of electricity within FPC's service territory for the period 1999-2008. Indicate the type of price deflator used to calculate the historical prices and forecasted real retail prices.

The following table lists FPC's historical and projected average billed cents per kWh to the retail sector. The deflator used is the Consumer Price Index - All Urban Consumers.

Year	AVG. RETAIL PRICE (Cents /kWh)	CPI-U (1982-84=100)	REAL AVG. RETAIL PRICE (Cents /kWh)
1989	5.831	124.0	4.702
1990	6.147	130.7	4.703
1991	6.169	136.2	4.529
1992	6.017	140.3	4.289
1993	6.461	144.5	4.471
1994	6.631	148.2	4.474
1995	6.830	152.4	4.482
1996	6.865	156.9	4.375
1997	6.970	160.5	4.343
1998	6.995	163.0	4.291
Forecast:			
1999	7.009	166.6	4.207
2000	7.020	171.3	4.099
2001	7.073	176.1	4.016
2002	7.052	181.1	3.895
2003	7.119	186.2	3.823
2004	7.260	191.8	3.785
2005	7.404	197.6	3.747
2006	7.566	204.0	3.709
2007	7.744	210.9	3.672
2008	7.926	218.0	3.636

15. Provide the following data to support Schedule 4 of FPC's Ten-Year Site Plan: the 12 monthly peak demands for the years 1996, 1997, and 1998; and the date on which these monthly peaks occurred.

MONTHLY PEAK DEMAND

	1996		1997		1998	
Month	Date	MW	Date	MW	Date	MW
Jan	9	8,668	19	8,066	1	6,097
Feb	5	8,807	12	5,794	10	6,156
Mar	9	7,246	5	5,028	13	6,885
Apr	29	5,614	27	5,085	2	5,630
May	23	6,360	27	6,798	21	7,066
Jun	25	6,768	19	6,964	19	7,906
Jul	22	7,164	3	7,462	2	8,004
Aug	28	6,802	12	7,300	12	7,808
Sep	3	7,052	16	6,932	1	7,235
Oct	1	5,508	1	6,426	7	7,034
Nov	1	5,190	17	5,239	19	5,387
Dec	20	7,286	15	6,608	18	5,948

16. Provide estimated dates when FPC plans to file for a determination of need for the proposed Hines Units 2 and 3. Discuss FPC's plans to issue an RFP for this capacity, and whether such RFP will consider the availability and cost of purchased power options.

FPC's April 1999 TYSP projects an in-service date of November 2004 and November 2006 for HEC#2 and #3, respectively. Given the current increase in market activity for combustion turbines, FPC anticipates a 48-month window for developing a combined cycle power plant. The 48-month construction window would anticipate a RFP in November 2001 followed by a determination of need filing in May 2002 for the second power block at the Hines Energy Complex.

17. Provide planning and construction time lines for the proposed Hines Units 2 and 3. Discuss when FPC plans to place an order with a vendor to meet this time line, and include the "drop-dead" date for a decision by FPC on whether to install the combined cycle units.

FPC's April 1999 TYSP projects an in-service date of November 2004 and November 2006 for HEC#2 and #3, respectively. Given the current increase in market activity for combustion turbines, FPC would anticipate a 48-month window for developing a combined cycle power plant. Vendor equipment lead times are approximately 30 months. FPC would typically proceed with placing equipment orders within the first year of the 48-month installation schedule. A decision date to proceed with HEC#2 and #3 would typically occur 36-42 months before their in-service dates. The major components of the 48-month schedule are shown below:

Evaluations/RFP Considerations/ FPSC preparations	xxx (6 months)
Determination of Need (FPSC)	xxx (6 months)
Licensing and Permitting	xxxxxxxxx (18 months)
Engineer/Procure/Construct	xxxxxxxxxxxxxxxxxxxxx(42 months)
Total (48 months)	

18. Identify and describe FPC's next avoided unit for purposes of cogeneration, including unit performance and cost parameters.

FPC is currently preparing a Standard Offer contract for the FPSC's review. As part of this preparation, the identity and description of the next avoided unit are being developed and will be available when the Standard Offer is complete.

19. Provide a detailed description of the changes necessary to produce the planned capacity upgrades to the existing Crystal River units. Include a time line describing the critical path of the necessary changes.

Capacity upgrades to Crystal River Units #4 & #5 include replacing the high pressure (HP) turbine rotor, inner shells, blades & diaphragms during their planned turbine outages in the spring of 2000 and spring of 1999, respectively. The engineering phase of this project is complete. The bid/selection of the vendor is complete. Crystal River #5 installation was completed May 19, 1999. Crystal River #4 delivery is on schedule for a spring 2000 installation. The outage time scheduled for unit #4 is approximately 2 months. The critical path of this schedule is delivering and installing the equipment for Unit #4's outage in the spring of 2000.

Capacity upgrades to Crystal River Units #1 & #2 include replacing the high pressure (HP)/intermediate pressure (IP) turbine rotors, inner shells, blades & diaphragms during their planned turbine outages in the fall of 2001 and spring of 2000, respectively. The engineering phase of this project is approaching completion. The bid and selection of the vendor was completed this summer. Approximately 1 year is required to manufacture and deliver equipment. The outage time scheduled for these units is approximately 2 months for each unit. The critical path of this schedule is delivering and installing the equipment for Unit #2's outage in the spring of 2000.

20. Discuss all efforts FPC has made to secure natural gas supplies for the proposed unit additions and fuel changes to existing units. Include a discussion of available gas transportation. Discuss any contingency plans made by FPC in the event that adequate natural gas supplies are unavailable.

FPC's wellhead purchases are made under market based contracts. Supplies are expected to continue to be available in sufficient quantities at market prices. Natural gas transportation to FPC's plants is provided by two interstate pipeline companies. FPC's Suwannee plant is served by South Georgia Natural Gas Company and all other FPC plants are served by Florida Gas Transmission Company. FPC utilizes firm, secondary firm, and interruptible transportation contracts. Sufficient firm gas transportation capacity can be made available to buyers who are willing to contract with interstate pipelines for expansion capacity and/or other pipeline customers willing to resell capacity. Several new pipeline projects have been proposed to serve the state of Florida's expanding gas demand, including expansion projects by Florida Gas Transmission Company. FPC will give each proposal consideration that represents an opportunity for it to provide its customers with lower costs and greater reliability.

- Hines 1 and Debary P8 are expected to utilize natural gas as the primary fuel from FPC's existing portfolio of wellhead supply and gas transportation.
- Anclote 1 is expected to utilize natural gas when it is available at prices lower than its primary fuel (#6 fuel oil).
- Intercession City P12-14 are expected to utilize natural gas from FPC's then-existing portfolio of wellhead supply and gas transportation, including FGT's Phase IV capacity.
- Hines 2 & 3 are expected to utilize natural gas as the primary fuel from FPC's then-existing portfolio of wellhead supply and gas transportation. FPC's capacity will likely include additional capacity from FGT and/or a new interstate pipeline.

21. Discuss what actions, if any, FPC has taken to increase the supply-side portion of its reserve margin.

FPC's supply-side expansion plan consists mainly of three generation expansion phases. The first expansion phase was just recently completed with the commercial operation of the Hines Energy Complex (HEC) combined cycle Unit #1 in April 1999. The second phase is the construction of three combustion turbine units at the Intercession City (IC) Site by December 2000. The third phase is the projected expansion of the Hines Energy Complex Unit #2 & #3 by 2004 and 2006, respectively.

22. Provide monthly participation data for FPC's residential load management program for the period 1997 to date. Include the number of participants at the beginning of each month, the number who signed on to the program each month, and the number who dropped off the program each month.

Number of Participants at the Beginning of each Month	1997	1998	1999
January	532,319	540,503	493,129
February	534,761	543,676	493,414
March	536,345	545,205	493,069
April	537,203	546,398	491,963
May	532,730	542,483	488,333
June	528,120	541,265	480,023
July	526,983	518,213	477,608
August	527,403	502,479	
September	528,116	492,344	
October	529,748	490,958	
November	532,281	490,253	
December	537,448	492,726	

Number of LM Installations	1997	1998	1999
January	1,605	1,636	221
February	1,311	1,935	243
March	1,646	1,980	286
April	2,018	1,986	204
May	1,508	1,393	222
June	1,695	485	424
July	1,392	582	
August	1,204	792	
September	1,408	541	
October	2,072	411	
November	1,510	344	
December	1,632	878	

22. (continued)

Number of LM Cancellations	1997	1998	1999
January	703	808	1,023
February	387	726	1,166
March	519	760	1,093
April	1,027	765	1,466
May	1,373	705	5,315
June	1,443	610	1,173
July	1,517	6,743	
August	1,371	18,255	
September	947	6,185	
October	963	4,125	
November	398	2,311	
December	659	1,153	

23. Discuss the assumptions and calculation methodology on which FPC's load management demand reduction estimates are based.

FPC's Load Management reduction estimates are based upon participation by appliance type, the month of control, the time-of-day of control, the duration of control, temperature conditions during the control period, and a set of monthly time-temperature matrices, by appliance, that contain per-participant impact estimates for any given time-of-day and temperature. Historical estimates of Load Management reductions apply actual monthly participation to the fraction of the hour load control was actually used times the time-temperature matrix estimate of savings during the actual month of control, hour of control, and actual temperature conditions. This is performed separately for each appliance type, and the results are then summed by appliance type to estimate the total amount of load reduction. The forecast of Load Management reductions are also developed in this manner, however, the calculation is based upon forecasted rather than actual conditions. In particular, the forecast assumes normal temperature conditions at the time of winter and summer peak.

24. Explain how the Residential and Commercial/Industrial Conservation data (columns 7 and 9) in Schedules 3.1 and 3.2 were derived from FPC's Commission approved DSM goals.

The Residential and Commercial/Industrial Conservation data presented in columns 7 and 9 of Schedules 3.1 and 3.2 were derived from FPC's proposed conservation goals that were submitted for Commission approval as required in docket 971005-EG. The Commission will be establishing new conservation goals in 1999, and FPC's proposed goals reflect the most recent planning estimates of the total amount of savings that is cost-effective and reasonably achievable through Demand-Side Management (DSM) for the 2000-2009 period. While the proposed goals are segmented by the Residential and Commercial/Industrial market segments, the conservation information contained in Schedules 3.1 and 3.2 is segmented by dispatchable DSM (columns 6 and 8) and non-dispatchable DSM (columns 7 and 9), as well as by market segment. It is, therefore, necessary to combine columns 6, 7, 8 and 9 to estimate the total amount of conservation savings reflected in FPC's proposed conservation goals.

25. Explain how FPC has exceeded its Commission approved DSM goals. Have program participation rates and/or average savings exceeded expectations?

Regarding the new residential programs contained in FPC's current DSM Plan, participation in both the Home Energy Improvement and Residential New Construction Programs have been running ahead of expectations since their implementation in mid-1996. Also, Commission approved modifications were made to both of these programs in mid-1997 that were designed to yield both higher participation rates and higher average program savings. Finally, favorable economic conditions have stimulated a high level of building activity throughout the FPC service territory, which has increased the potential market for FPC's residential new construction program.

In the commercial/industrial market segment, FPC's DSM Plan originally projected that actual DSM achievements would significantly exceed the Commission approved goals during the first half of the ten-year goals period. In addition, actual DSM achievements have exceeded the DSM Plan's expectations primarily due to greater than expected participation in the Innovation Incentive and Standby Generation Programs.

26. Identify the fixed and variable costs of the transportation component in the delivered price for natural gas from 1996 to 1998 (actual) and 1999 to 2008 (forecast). State whether FPC has excluded any charge, fee, tax, levy, or any other consideration from the actual and forecasted delivered natural gas prices.

FPC's actual fuel prices are reported on a total delivered cost basis, not by individual price component in schedule A-4. The transportation component prices are therefore not readily available. The forecasted (1999-2008) fixed and variable costs of the transportation component for natural gas are shown in the following two tables. FPC does not exclude any charges, fees, taxes, levies, or any other consideration from the actual or forecasted delivered natural gas prices.

NATURAL GAS FIXED TRANSPORTATION COST
($/MMBTU)

FT DEMAND RATES

	FGT FTS-1	FGT FTS-2	FGT Short Term	FGT Tiger Bay	Sonat Short Term
1999	$0.38	$0.80	$0.13	$1.41	$0.00
2000	$0.38	$0.78	$0.00	$1.43	$0.00
2001	$0.38	$0.78	$0.00	$1.46	$0.00
2002	$0.38	$0.78	$0.00	$1.49	$0.00
2003	$0.38	$0.78	$0.00	$1.53	$0.00
2004	$0.38	$0.78	$0.00	$1.56	$0.00
2005	$0.38	$0.78	$0.00	$1.60	$0.00
2006	$0.38	$0.78	$0.00	$1.64	$0.00
2007	$0.38	$0.78	$0.00	$1.67	$0.00
2008	$0.38	$0.78	$0.00	$1.71	$0.00

26. (continued)

NATURAL GAS VARIABLE TRANSPORTATION COST
($/MMBTU)

FT DEMAND RATES

	FGT U of F	FGT IC	FGT O-FGT	Sonat Suwan
1999	$0.21	$0.21	$0.11	$0.18
2000	$0.22	$0.22	$0.12	$0.18
2001	$0.22	$0.22	$0.12	$0.18
2002	$0.22	$0.22	$0.12	$0.19
2003	$0.22	$0.22	$0.12	$0.19
2004	$0.22	$0.22	$0.12	$0.19
2005	$0.22	$0.22	$0.12	$0.19
2006	$0.22	$0.22	$0.12	$0.19
2007	$0.22	$0.22	$0.12	$0.19
2008	$0.22	$0.22	$0.12	$0.19

27. If applicable, provide the forecast for delivered prices of any other fuel not included in response to question #1. Provide the data from 1999 to 2008 in dollars per million BTU ($/MMBtu) and dollars per unit ($/unit). Also, include the following assumptions: type of fuel, heat content, ash content, and sulfur content.

N/A. All fuel forecasts were included in response to Question #1.

28. If applicable, provide the following information from 1996 to 1998 for any fuel forecast provided in response to the previous question: type of fuel, heat content, ash content, and sulfur content.

N/A. All fuel forecasts were included in response to Question #1.

29. For each fuel price forecast, indicate the percentage of total fuel purchases made through long term contracts.

Long term contracts are generally defined as having a duration of over one year. Much of FPC's fuel is procured with long term contracts using market pricing. For forecasting purposes the prices are assumed to be market prices with the exception of certain coal contracts and gas contracts for Tiger Bay. The percentage of actual fuel that is procured by long term contracts depends upon vendor deliveries, spot prices and availability, and system requirements.

30. For each fuel price forecast produced by or for FPC, compare the 2007 price forecast in FPC's 1998 and 1999 Ten-Year Site Plans. If the 2007 price forecast has changed by more than ten percent from 1998 to 1999, provide the reasons for the change.

Residual Oil, >2%, Base Forecast - Due to the very low oil prices experienced in 1998, expectations for future oil prices were lowered by 11.4%.

Residual Oil, 0.7-2%, Low Forecast - Due to the very low oil prices experienced in 1998, expectations for future oil prices were lowered by 12.3%.

Natural Gas, High Forecast – A possible sharp increase in the use of natural gas by the power generation market segment could result in higher prices than those forecasted previously. This was represented by a 19.3% increase in the 1999 forecast.

Distillate Oil, Low Forecast - Due to the very low oil prices experienced in 1998, expectations for future oil prices were lowered by 20.8%.

Low Sulfur Coal, High Forecast – Actual prices for low sulfur coal have continued to trend downward, resulting in an expectation of lower future prices by 10.7%.

31. Describe how the specific characteristics of FPC's generating units affect the characteristics of the fuels that FPC burns for electric generation.

Each individual generating unit is designed to utilize a specific type of primary fuel, while some are also capable of utilizing one or more secondary fuels as detailed in Schedules 1 and 8. Environmental and plant location parameters also contribute to each unit's unique set of operating and fuel characteristics.

32. Refer to Schedule 6.1 of FPC's 1998 and 1999 Ten-Year Site Plans. Please respond to the following:

A) In the 1998 Ten-Year Site Plan, FPC forecasted the amount of annual energy interchange for 1998 at 104 GWH. In the 1999 Ten-Year Site Plan, FPC reported the actual amount of annual energy interchange for 1998 at - 422 GWH. Describe the reasons for the 526 GWH difference.

B) In the 1998 Ten-Year Site Plan, FPC forecasted the amount of nuclear-derived generation for 1998 at 5,548 GWH. In the 1999 Ten-Year Site Plan, FPC reported the actual amount of nuclear-derived generation for 1998 at 5,863 GWH. Describe the reasons for the 315 GWH difference.

C) In the 1998 Ten-Year Site Plan, FPC forecasted the amount of coal-fired generation for 1998 at 15,094 GWH. In the 1999 Ten-Year Site Plan, FPC reported the actual amount of coal-fired generation for 1998 at 14,892 GWH. Describe the reasons for the 202 GWH difference.

D) In the 1998 Ten-Year Site Plan, FPC forecasted the amount of residual oil-fired generation for 1998 at 3,922 GWH. In the 1999 Ten-Year Site Plan, FPC reported the actual amount of residual oil-fired generation for 1998 at 7,031 GWH. Describe the reasons for the 3,109 GWH difference.

E) In the 1998 Ten-Year Site Plan, FPC forecasted the amount of distillate oil-fired generation for 1998 at 211 GWH. In the 1999 Ten-Year Site Plan, FPC reported the actual amount of distillate oil-fired generation for 1998 at 762 GWH. Describe the reasons for the 551 GWH difference.

32. (continued)

F) In the 1998 Ten-Year Site Plan, FPC forecasted the amount of natural gas-fired generation for 1998 at 3,713 GWH. In the 1999 Ten-Year Site Plan, FPC reported the actual amount of natural gas-fired generation for 1998 at 2,498 GWH. Describe the reasons for the 1,215 GWH difference.

G) In the 1998 Ten-Year Site Plan, FPC forecasted the amount of generation from other sources for 1998 at 7,954 GWH. In the 1999 Ten-Year Site Plan, FPC reported the actual amount of generation from other sources for 1998 at 7,139 GWH. Describe the reasons for the 815 GWH difference.

The actual amount of energy generated from FPC's resources may differ from projected amounts for a multitude of reasons. These reasons may range from modeling assumptions to hourly/long-term market behavior to operational and customer issues. FPC is responding to question 32A-G in an aggregate planning overview perspective versus a detailed hourly or daily dispatch perspective.

A) FPC projected to receive 104 GWh of firm net purchases from other utilities. Additional net interchange transactions of 526 GWh above projections resulted in a net impact of 422 GWh of net interchange sales. Increased interchange sales could be attributed to above normal demands for other utilities as well as unavailability of other utility units.

B) Nuclear Generation exceeded projections by 315 GWh due to the increase in availability of the unit.

32. (continued)

C) Coal Generation was within 1.3% of projections. The differences could be attributed to a combination of the availability of lower cost generation as well as the need for additional coal maintenance.

D) Residual Oil generation increased by 3,109 GWh over projections. This increase could be attributed to a decrease in oil prices relative to gas and coal, unavailability of natural gas generation, as well as supplying generation for additional off system sales.

E) The Distillate Oil generation increased by 551 GWh over projections. This increase could be attributed to increased base sales, a decrease in distillate oil prices, unavailability of steam generation, as well as contributing to additional off system sales.

F) Natural Gas generation decreased by 1,215 GWh over projections. This decrease could be attributed to an increase in natural gas prices relative to oil and coal as well as additional unavailability of natural gas units.

G) Other generation decreased by 815 GWh over projections. This decrease could be attributed to the Tiger Bay facility being included in the actual Natural Gas projections while Tiger Bay was originally projected to be in Other generation.

FPC aggregate generation exceeded planning projections by a total of 2,095 GWh. The increase in actual generation was accounted to 985 GWh of additional off system sales as well as 1,110 GWh of additional base sales.

33. Quantify the annual incremental natural gas and distillate oil requirements (MCF and barrels, respectively) that FPC has forecasted for Hines Unit 1 for the period 1999-2008, Intercession City Units P12 - P14 for the period 2000-2008, Hines Unit 2 for the period 2004-2008, and Hines Unit 3 for the period 2006-2008.

UNIT	FUEL	FUEL UNITS	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Hines Unit 1	Natural Gas	1,000 MCF	15,067	19,201	19,660	19,935	19,774	19,831	18,456	17,777	15,445	15,776
Hines Unit 1	Distillate Oil	1,000 BBL	0	0	0	0	0	0	0	0	0	0
Int. City Units P12-P14	Natural Gas	1,000 MCF		68	4,025	2,660	2,339	3,255	1,589	2,456	1,266	1,725
Int. City Units P12-P14	Distillate Oil	1,000 BBL		0	0	0	0	0	0	0	0	0
Hines Unit 2	Natural Gas	1,000 MCF						3,034	22,619	22,592	23,184	22,842
Hines Unit 2	Distillate Oil	1,000 BBL						0	0	0	0	0
Hines Unit 3	Natural Gas	1,000 MCF								2,857	21,674	21,612
Hines Unit 3	Distillate Oil	1,000 BBL								0	0	0