Need Study for Electrical Power Plant 2007

040206-EI

FPL

APPENDICES
E - P

Appendix E

FPL's Forecast of Peak Demand, Net Energy for Load (NEL) and Results of Summer Peak and Winter Peak Runs

Year	Annual Peaks Jan (Winter) MW	Annual Peaks Aug (Summer) MW	Annual Net Energy For Load GWH
2004	20,081	20,297	109,525
2005	20,583	20,799	112,565
2006	21,100	21,331	115,942
2007	21,605	21,851	118,430
2008	22,046	22,289	120,899
2009	22,539	22,784	123,115
2010	23,026	23,294	125,811
2011	23,522	23,783	128,327
2012	24,024	24,279	130,724
2013	24,535	24,784	133,274
2014	25,057	25,300	135,903
2015	25,589	25,828	138,467
2016	26,109	26,369	141,150
2017	26,644	26,928	143,802
2018	27,193	27,503	146,335
2019	27,758	28,094	148,972
2020	28,336	28,702	151,697
2021	28,930	29,326	154,275
2022	29,543	29,972	156,944
2023	30,178	30,641	159,777
2024	30,834	31,334	162,796
2025	31,511	32,051	165,826

Appendix E

SUMMER PEAK FORECAST INPUTS

Year	SPKperCust	FLINCfix	RPRIfix	MAXTMP
1969	3.68		4.93	93.30
1970	3.99	97.90	4.64	93.50
1971	4.01	105.10	4.63	92.60
1972	4.16	116.98	4.70	89.90
1973	4.40	130.19	4.92	91.10
1974	4.32	132.98	5.82	90.50
1975	4.07	132.47	6.36	90.00
1976	4.23	138.31	5.90	92.70
1977	4.18	145.77	6.36	92.00
1978	4.24	157.93	6.17	90.80
1979	4.17	168.67	6.25	91.90
1980	4.40	179.02	6.30	94.80
1981	4.26	189.89	7.18	95.70
1982	4.18	194.45	6.71	92.50
1983	4.39	205.19	6.64	95.90
1984	4.07	221.37	7.63	93.60
1985	4.07	235.09	7.67	94.50
1986	4.05	247.43	6.84	93.20
1987	4.36	260.80	6.55	95.80
1988	4.19	275.97	6.47	93.50
1989	4.38	293.99	5.94	95.40
1990	4.35	301.86	5.63	95.00
1991	4.38	301.78	5.56	92.90
1992	4.47	304.51	5.22	95.40
1993	4.55	316.52	5.11	94.30
1994	4.44	325.88	4.62	91.60
1995	4.64	340.67	4.57	94.20
1996	4.52	355.12	4.71	91.30
1997	4.59	370.45	4.72	92.60
1998	4.86	392.76	4.37	94.94
1999	4.80	399.06	4.10	94.31
2000	4.70	416.33	3.97	92.30
2001	4.77	431.83	4.54	92.10
2002	4.78	439.47	4.07	92.00
2003		457.82	3.89	92.00
2004		477.68	3.69	92.00
2005		496.37	3.58	92.00
2006		517.47	3.48	92.00
2007		538.46	3.37	92.00
2008		560.18	3.32	92.00
2009		581.30	3.26	92.00
2010		603.04	3.18	92.00
2011		625.59	3.18	92.00
2012		648.99	3.18	92.00
2013		673.26	3.18	92.00
2014		698.44	3.18	92.00
2015		724.57	3.18	92.00
2016		751.66	3.18	92.00
2017		779.78	3.18	92.00
2018		808.94	3.18	92.00
2019		839.19	3.18	92.00
2020		870.58	3.18	92.00
2021		903.14	3.18	92.00
2022		936.92	3.18	92.00
2023		971.96	3.18	92.00
2024		1,008.31	3.18	92.00
2025		1,046.02	3.18	92.00

Appendix E

SUMMER PEAK FORECAST

Year	Actual Summer Peak/Customer	Pred		Resid	%Resid	StdResid
1965	2.663					
1966	2.827					
1967	3.006					
1968	3.608					
1969	3.677					
1970	3.991	4.225		-0.234	-5.87%	-2.096
1971	4.012	4.141		-0.129	-3.21%	-1.153
1972	4.157	4.122		0.035	0.84%	0.312
1973	4.398	4.200		0.198	4.50%	1.772
1974	4.317	4.195		0.122	2.83%	1.092
1975	4.071	4.140		-0.068	-1.68%	-0.612
1976	4.231	4.161		0.070	1.65%	0.623
1977	4.180	4.147		0.033	0.79%	0.296
1978	4.242	4.160		0.082	1.93%	0.731
1979	4.170	4.201		-0.031	-0.74%	-0.276
1980	4.404	4.220		0.184	4.18%	1 645
1981	4.261	4.235		0.026	0.61%	0.232
1982	4.182	4.203		-0.021	-0.51%	-0.189
1983	4.394	4.246		0.147	3.36%	1.319
1984	4.075	4.200		-0.125	-3.07%	-1.118
1985	4.070	4.151		-0.081	-2.00%	-0.727
1986	4.047	4.211		-0.164	-4.06%	-1.468
1987	4.364	4.261		0.103	2.36%	0.919
1988	4.192	4.338		-0.146	-3.49%	-1.309
1989	4.381	4.381		0.000	-0.01%	-0.002
1990	4.354	4.445		-0.091	-2.08%	-0.810
1991	4.377	4.400		-0.022	-0.51%	-0.201
1992	4.468	4.486		-0.018	-0.41%	-0.164
1993	4.549	4.505		0.044	0.97%	0.394
1994	4.435	4.547		-0.111	-2.51%	-0.997
1995	4.635	4.565		0.070	1.52%	0.630
1996	4.524	4.580		-0.055	-1.23%	-0.496
1997	4.595	4.593		0.002	0.05%	0.019
1998	4.863	4.701		0.162	3.32%	1.445
1999	4.803	4.785		0.018	0.38%	0.164
2000	4.700	4.763		-0.063	-1.34%	-0.565
2001	4.766	4.694		0.072	1.50%	0.641
2002	4.781	4.779		0.002	0.05%	0.020

Year	Predicted Summer Peak/Customer	Total Customers	Predicted Peak	FMPA	Peak Forecast	Absolute Growth	% Growth
2003	4.809	**4,095,628**	**19,698**	75	**19,773**	554	2.9%
2004	4.851	**4,168,421**	**20,222**	75	**20,297**	524	2.7%
2005	4.886	**4,241,326**	**20,724**	75	**20,799**	502	2.5%
2006	4.926	**4,315,007**	**21,256**	75	**21,331**	533	2.6%
2007	4.966	**4,385,245**	**21,776**	75	**21,851**	520	2.4%
2008	5.002	**4,455,713**	**22,289**		**22,289**	438	2.0%
2009	5.039	**4,521,322**	**22,784**		**22,784**	495	2.2%
2010	5.078	**4,587,137**	**23,294**		**23,294**	510	2.2%
2011	5.111	**4,652,864**	**23,783**		**23,783**	489	2.1%
2012	5.146	**4,717,877**	**24,279**		**24,279**	495	2.1%
2013	5.182	**4,782,747**	**24,784**		**24,784**	505	2.08%
2014	5.219	**4,847,471**	**25,300**		**25,300**	516	2.08%
2015	5.258	**4,912,254**	**25,828**		**25,828**	528	2.09%
2016	5.298	**4,977,356**	**26,369**		**26,369**	542	2.10%
2017	5.339	**5,043,209**	**26,928**		**26,928**	558	2.12%
2018	5.383	**5,109,600**	**27,503**		**27,503**	575	2.13%
2019	5.427	**5,176,482**	**28,094**		**28,094**	592	2.15%
2020	5.474	**5,243,591**	**28,702**		**28,702**	608	2.16%
2021	5.522	**5,310,978**	**29,326**		**29,326**	624	2.18%
2022	5.572	**5,379,289**	**29,972**		**29,972**	646	2.20%
2023	5.624	**5,448,751**	**30,641**		**30,641**	669	2.23%
2024	5.677	**5,519,305**	**31,334**		**31,334**	693	2.26%
2025	5.733	**5,590,820**	**32,051**		**32,051**	717	2.29%

Appendix E

SUMMER PEAK MODEL STATISTICS

Regression Statistics	
Iterations	1
Adjusted Observations	33
Deg. of Freedom for Error	28
R-Squared	0.819
Adjusted R-Squared	0.794
Durbin-Watson Statistic	1.858
AIC	-4.243
BIC	-4.016
F-Statistic	31.751
Prob (F-Statistic)	0
Log-Likelihood	27.33
Model Sum of Squares	2
Sum of Squared Errors	0
Mean Squared Error	0.01
Std. Error of Regression	0.11
Mean Abs. Dev. (MAD)	0.08
Mean Abs. % Err. (MAPE)	1.93%
Ljung-Box Statistic	1
Prob (Ljung-Box)	0.963

Variable	Coefficient	StdErr	T-Stat	P-Value	Units	Definition
CONST	3.12475	1.189	2.628	1.42%		Constant term
FLINCfix	0.00148	0.000	4.623	0.01%		Real FL Income
RPRIfix	-0.08784	0.033	-2.673	1.28%		Real Price
MAXTMP	0.01458	0.013	1.083	28.86%		Max Summer Temp
AR(1)	0.351005	0.195	1.796	8.42%		

Variable	Coefficient	Mean	Elast	Units	Definition
FLINCfix	0.00	252.295	0.0887073		Real FL Income
RPRIfix	-0.09	5.61	-0.12		Real Price
MAXTMP	0.01	92.84	0.32		Max Summer Temp

Appendix E

WINTER PEAK FORECAST INPUTS

Year	WPERCUST	RELINCfix	MINWDTMP2	PRIORAM	RatTmpSald2	DUMTMP36
1970	3.76	97.90	35.64	812.37	1.20	0.0
1971	3.77	105.10	33.02	458.84	1.39	0.0
1972	3.33	116.98	43.18	535.86	1.12	0.0
1973	3.73	130.19	40.30	407.05	1.26	0.0
1974	3.73	132.98	42.43	568.65	1.26	0.0
1975	3.34	132.47	46.01	535.84	1.21	0.0
1976	4.06	138.31	39.60	711.13	1.47	0.0
1977	4.65	145.77	33.16	755.01	1.83	0.0
1978	4.38	157.93	35.01	674.82	1.80	0.0
1979	4.24	168.67	38.83	675.59	1.68	0.0
1980	4.45	179.02	31.04	489.84	2.19	31.0
1981	4.97	189.89	30.58	855.00	2.30	30.6
1982	4.81	194.45	30.87	778.89	2.33	30.9
1983	3.82	205.19	40.22	460.66	1.84	40.2
1984	4.38	221.37	30.05	939.30	2.52	30.0
1985	4.79	235.09	28.77	926.92	2.69	28.8
1986	4.46	247.43	32.70	615.55	2.42	32.7
1987	3.80	260.80	40.08	525.61	2.02	40.1
1988	4.19	275.97	42.40	599.65	1.93	42.4
1989	4.20	293.99	35.30	737.67	2.33	35.3
1990	5.08	301.86	28.42	789.66	2.92	28.4
1991	3.68	301.78	38.58	300.24	2.20	38.6
1992	4.06	304.51	42.73	557.77	2.03	42.7
1993	3.85	316.52	40.77	601.13	2.14	40.8
1994	3.68	325.88	48.23	445.27	1.81	48.2
1995	4.75	340.67	36.02	503.51	2.44	36.0
1996	5.14	355.12	33.46	669.67	2.64	33.5
1997	4.78	370.45	35.26	742.88	2.51	35.3
1998	3.55	392.76	48.22	425.17	1.84	48.2
1999	4.47	399.06	40.00	674.00	2.22	40.0
2000	4.43	416.33	38.80	512.00	2.30	38.8
2001	4.62	431.83	35.80	654.00	2.50	35.8
2002	4.38	439.47	40.10	629.00	2.22	40.1
2003	4.97	457.82	33.10	670.00	2.72	33.1
2004		477.68	36.00	684.21	2.52	36.0
2005		496.37	36.00	684.21	2.54	36.0
2006		517.47	36.00	684.21	2.55	36.0
2007		538.46	36.00	684.21	2.57	36.0
2008		560.18	36.00	684.21	2.59	36.0
2009		581.30	36.00	684.21	2.60	36.0
2010		603.04	36.00	684.21	2.61	36.0
2011		625.59	36.00	684.21	2.63	36.0
2012		648.99	36.00	684.21	2.64	36.0
2013		673.26	36.00	684.21	2.65	36.0
2014		698.44	36.00	684.21	2.66	36.0
2015		724.57	36.00	684.21	2.67	36.0
2016		751.66	36.00	684.21	2.67	36.0
2017		779.78	36.00	684.21	2.68	36.0
2018		808.94	36.00	684.21	2.68	36.0
2019		839.19	36.00	684.21	2.68	36.0
2020		870.58	36.00	684.21	2.68	36.0
2021		903.14	36.00	684.21	2.69	36.0
2022		936.92	36.00	684.21	2.69	36.0
2023		971.96	36.00	684.21	2.69	36.0
2024		1,008.31	36.00	684.21	2.69	36.0
2025		1,046.02	36.00	684.21	2.70	36.0

Appendix E

WINTER PEAK FORECAST

Year	Actual Winter Peak/Customer	Pred	[illegible]	Resid	% Resid	StdResid
1970	3.763	3.910		-0.146	-3.89%	-0.653
1971	3.774	3.928		-0.154	-4.07%	-0.686
1972	3.330	3.514		-0.184	-5.53%	-0.822
1973	3.734	3.634		0.099	2.66%	0.444
1974	3.734	3.658		0.076	2.03%	0.338
1975	3.341	3.506		-0.165	-4.95%	-0.738
1976	4.058	3.959		0.099	2.44%	0.442
1977	4.650	4.406		0.244	5.25%	1.090
1978	4.380	4.306		0.074	1.69%	0.331
1979	4.238	4.135		0.103	2.43%	0.460
1980	4.454	4.302		0.152	3.41%	0.679
1981	4.971	4.600		0.371	7.46%	1.657
1982	4.811	4.576		0.235	4.88%	1.048
1983	3.819	3.745		0.075	1.95%	0.333
1984	4.384	4.844		-0.460	-10.48%	-2.052
1985	4.788	5.013		-0.225	-4.70%	-1.004
1986	4.457	4.540		-0.083	-1.86%	-0.370
1987	3.795	3.971		-0.176	-4.64%	-0.786
1988	4.189	3.881		0.308	7.35%	1.375
1989	4.202	4.508		-0.306	-7.28%	-1.367
1990	5.080	5.179		-0.099	-1.95%	-0.442
1991	3.678	4.070		-0.392	-10.65%	-1.749
1992	4.059	3.943		0.116	2.85%	0.517
1993	3.854	4.126		-0.273	-7.08%	-1.218
1994	3.680	3.563		0.117	3.19%	0.524
1995	4.747	4.480		0.268	5.64%	1.195
1996	5.140	4.811		0.330	6.42%	1.473
1997	4.784	4.719		0.065	1.36%	0.291
1998	3.548	3.654		-0.105	-2.97%	-0.470
1999	4.473	4.355		0.119	2.66%	0.530
2000	4.432	4.382		0.050	1.13%	0.223
2001	4.625	4.720		-0.095	-2.05%	-0.423
2002	4.378	4.379		-0.002	-0.04%	-0.007
2003	4.968	5.006		-0.037	-0.75%	-0.166

	Predicted Winter Peak/Customer	Total Customers	Predicted Peak	FMPA	Peak Forecast	Absolute Growth	% Growth
2004	4.799	4,168,421	**20,006**	75	**20,081**	-109	-0.5%
2005	4.835	4,241,326	**20,508**	75	**20,583**	502	2.5%
2006	4.873	4,315,007	**21,025**	75	**21,100**	517	2.5%
2007	4.910	4,385,245	**21,530**	75	**21,605**	505	2.4%
2008	4.948	4,455,713	**22,046**		**22,046**	441	2.0%
2009	4.985	4,521,322	**22,539**		**22,539**	493	2.2%
2010	5.020	4,587,137	**23,026**		**23,026**	487	2.2%
2011	5.055	4,652,864	**23,522**		**23,522**	496	2.2%
2012	5.092	4,717,877	**24,024**		**24,024**	502	2.1%
2013	5.130	4,782,747	**24,535**		**24,535**	511	2.13%
2014	5.169	4,847,471	**25,057**		**25,057**	521	2.12%
2015	5.209	4,912,254	**25,589**		**25,589**	532	2.12%
2016	5.245	4,977,356	**26,109**		**26,109**	520	2.03%
2017	5.283	5,043,209	**26,644**		**26,644**	535	2.05%
2018	5.322	5,109,600	**27,193**		**27,193**	550	2.06%
2019	5.362	5,176,482	**27,758**		**27,758**	565	2.08%
2020	5.404	5,243,591	**28,336**		**28,336**	579	2.08%
2021	5.447	5,310,978	**28,930**		**28,930**	594	2.10%
2022	5.492	5,379,289	**29,543**		**29,543**	613	2.12%
2023	5.538	5,448,751	**30,178**		**30,178**	634	2.15%
2024	5.587	5,519,305	**30,834**		**30,834**	656	2.17%
2025	5.636	5,590,620	**31,511**		**31,511**	677	2.20%

Appendix E

WINTER PEAK MODEL STATISTICS

Regression Statistics	
Iterations	1
Adjusted Observations	34
Deg. of Freedom for Error	28
R-Squared	0.837
Adjusted R-Squared	0.808
Durbin-Watson Statistic	1.592
AIC	-2.834
BIC	-2.565
F-Statistic	28.75
Prob (F-Statistic)	0
Log-Likelihood	5.93
Model Sum of Squares	7
Sum of Squared Errors	1
Mean Squared Error	0.05
Std. Error of Regression	0.22
Mean Abs. Dev. (MAD)	0.17
Mean Abs. % Err. (MAPE)	4.05%
Ljung-Box Statistic	4
Prob (Ljung-Box)	0.55

Variable	Coefficient	StdErr	T-Stat	P-Value	Units	Definition
CONST	3.664	1.125	3.258	0.31%		Constant term
RFLINCfix	0.001	0.001	1.461	15.61%		Real FL Income
MINWDTMP2	-0.030	0.020	-1.490	14.84%		Min Winter day Temp
PRIORAM	0.001	0.000	1.538	13.61%		HDD the day before until 9:00 AM day of the peak
RatTmpSatd2	0.622	0.321	1.936	6.38%		Ratio: Temp divided by Heat Saturation
DUMTMP36	-0.009	0.005	-1.866	7.34%		Dummy times Temp

Variable	Coefficient	Mean	Elast
RFLINCfix	0.001	258.340	0.078
MINWDTMP2	-0.030	37.314	-0.261
PRIORAM	0.001	624.663	0.079
RatTmpSatd2	0.622	2.038	0.298
DUMTMP36	-0.009	25.93	-0.057

Appendix F

FPL Fuel Forecast
for New Gas-Fired Capacity Options and Existing FPL Units
(Nominal $/mmBTU)

	Firm Transportation Gas (1)		Non-Firm (2) Transportation	Existing Firm (3) Transportation Gas
Year	Variable (Dispatch) Price	Demand (Sunk) Price	Variable (Dispatch) Price	Variable (Dispatch) Price
2003	----	----	6.00	5.76
2004	----	----	5.52	5.27
2005	5.00	0.55	5.31	5.06
2006	4.96	0.55	5.26	5.00
2007	4.98	0.55	5.28	5.02
2008	4.99	0.55	5.30	5.04
2009	5.13	0.55	5.44	5.18
2010	5.27	0.55	5.58	5.32
2011	5.41	0.55	5.74	5.47
2012	5.57	0.55	5.90	5.63
2013	5.74	0.55	6.07	5.79
2014	5.91	0.55	6.25	5.97
2015	6.09	0.55	6.44	6.37
2016	6.28	0.55	6.64	6.69
2017	6.49	0.55	6.85	6.89
2018	6.71	0.55	7.08	7.11
2019	6.93	0.55	7.31	7.34
2020	7.16	0.55	7.55	7.58
2021	7.40	0.55	7.80	7.82
2022	7.65	0.55	8.06	8.27
2023	7.91	0.55	8.33	8.61
2024	8.18	0.55	8.61	8.88
2025	8.47	0.55	8.90	9.17
2026	8.76	0.55	9.21	9.47
2027	9.07	0.55	9.53	9.78
2028	9.39	0.55	9.86	10.11
2029	9.73	0.55	10.21	10.45
2030	10.07	0.55	10.56	10.79
2031	10.42	0.55	10.92	11.14

Notes:

(1) Forecasted prices to be used in the 2003 RFP evaluation of: a) FPL next planned generating unit (4x1 CC unit at Turkey Point), b) tolling proposals and non-tolling firm for gas-fired baseload capacity proposals (i.e., such as CC Capacity) to be served by either Gulfstream and FGT received in response to FPL's RFP (unless Proposer-guaranteed gas prices are submitted as part of the proposal, c) RFP CC filler units, and d) FPL's new CC units Martin #8 and Manatee #3 that come in-service in 2005.

(2) Forecasted prices to be used for: a) FPL's alternate (4 CT's at Turkey Point) option, b) tolling/non-tolling non-firm gas-fired capacity peaking proposals (i.e., CT Capacity) received in response to FPL's RFP (unless Proposer-guaranteed gas prices are submitted as part of the proposal), c) RFP CT filler units, and d) existing FPL CT's at Martin and Ft. Myers.

(3) Forecasted prices will be used for modeling existing FPL dual fuel units and existing FPL CC units.

Appendix F

FPL Fuel Forecast
for New Coal-Fired and Coke-Fired Capacity Options and Existing FPL Units[1][2]
(Nominal $/mmBTU)

Year	Scherer Plant	Martin Plant: 1% Sulfur Coal	St.Johns River Power Park	Petroleum Coke[3]
2003	1.92	1.75	1.51	0.53
2004	1.57	1.76	1.63	0.53
2005	1.59	1.79	1.65	0.53
2006	1.62	1.82	1.67	0.54
2007	1.65	1.85	1.70	0.56
2008	1.68	1.88	1.68	0.59
2009	1.70	1.91	1.62	0.62
2010	1.73	1.94	1.65	0.65
2011	1.76	1.98	1.68	0.67
2012	1.79	2.01	1.71	0.70
2013	1.83	2.05	1.74	0.71
2014	1.86	2.09	1.78	0.73
2015	1.90	2.12	1.81	0.76
2016	1.94	2.17	1.85	0.77
2017	1.98	2.21	1.89	0.78
2018	2.02	2.26	1.93	0.79
2019	2.06	2.30	1.97	0.81
2020	2.11	2.35	2.01	0.82
2021	2.15	2.40	2.05	0.83
2022	2.20	2.45	2.10	0.84
2023	2.25	2.50	2.14	0.86
2024	2.30	2.56	2.19	0.87
2025	2.35	2.61	2.24	0.89
2026	2.40	2.67	2.29	0.90
2027	2.46	2.73	2.34	0.91
2028	2.51	2.79	2.40	0.93
2029	2.57	2.85	2.45	0.95
2030	2.63	2.91	2.51	0.96
2031	2.69	2.97	2.57	0.97

Notes:

(1) Forecasted prices will be used for coal- and petroleum coke-based capacity proposals received in response to FPL's RFP by geographic location (unless Proposer-guaranteed coal/petroleum coke prices are submitted as part of the proposal.)

(2) Forecasted prices will be also used for modeling existing FPL solid fuel-based units as indicated.

(3) Petroleum Coke forecasted prices are as delivered FOB Florida Port; not to a specific location in Florida.

Appendix F

FPL Residual Oil Price Forecast [(1)]
(Nominal $/mmBTU)

Year	Martin [(2)]	Everglades	Manatee	Turkey Point	Canaveral	Sanford	Riviera
2003	4.68	4.65	4.60	4.75	4.64	4.97	4.68
2004	4.14	4.11	4.07	4.22	4.10	4.44	4.14
2005	3.84	3.81	3.77	3.92	3.80	4.14	3.84
2006	3.75	3.72	3.67	3.83	3.71	4.05	3.75
2007	3.76	3.73	3.68	3.84	3.72	4.06	3.76
2008	3.87	3.83	3.79	3.94	3.82	4.17	3.87
2009	3.98	3.94	3.90	4.06	3.93	4.29	3.98
2010	4.09	4.06	4.01	4.17	4.05	4.41	4.09
2011	4.22	4.19	4.14	4.30	4.18	4.54	4.22
2012	4.36	4.33	4.28	4.44	4.32	4.69	4.36
2013	4.51	4.48	4.43	4.59	4.46	4.84	4.51
2014	4.67	4.63	4.58	4.75	4.62	5.00	4.67
2015	4.83	4.79	4.74	4.91	4.78	5.17	4.83
2016	5.00	4.97	4.92	5.09	4.96	5.34	5.00
2017	5.19	5.15	5.10	5.28	5.14	5.53	5.19
2018	5.38	5.35	5.29	5.47	5.33	5.74	5.38
2019	5.57	5.53	5.48	5.66	5.52	5.93	5.57
2020	5.78	5.74	5.69	5.88	5.73	6.15	5.78
2021	6.00	5.96	5.91	6.09	5.95	6.37	6.00
2022	6.23	6.19	6.13	6.33	6.18	6.61	6.23
2023	6.47	6.43	6.37	6.57	6.42	6.85	6.47
2024	6.72	6.68	6.62	6.82	6.66	7.11	6.72
2025	6.98	6.94	6.88	7.08	6.93	7.38	6.98
2026	7.26	7.22	7.15	7.36	7.20	7.67	7.26
2027	7.55	7.50	7.44	7.65	7.49	7.96	7.55
2028	7.85	7.80	7.74	7.96	7.79	8.27	7.85
2029	8.16	8.12	8.05	8.27	8.10	8.59	8.16
2030	8.51	8.46	8.40	8.62	8.45	8.95	8.51
2031	8.88	8.81	8.77	8.98	8.82	9.33	8.88

Note:

(1) Forecasted prices will be used for modeling existing FPL steam units as indicated or proposed units as applicable.

(2) Martin steam units require co-fire ratio of 70% residual oil and 30% natural gas.

Appendix F

FPL Distillate Oil Price Forecast[1]
(Nominal $/mmBTU)

Year	Gas Turbines at Everglades	Gas Turbines at Lauderdale	Gas Turbines & New CT's at Ft. Myers	Combined Cycles at Putnam	Combined Cycles at Lauderdale	New CT's at Martin/Martin #8
2003	6.36	6.36	6.91	6.40	6.36	6.77
2004	5.65	5.65	6.21	5.69	5.65	6.07
2005	5.39	5.39	5.95	5.43	5.39	5.81
2006	5.31	5.31	5.88	5.35	5.31	5.74
2007	5.33	5.33	5.90	5.37	5.33	5.76
2008	5.48	5.48	6.06	5.52	5.48	5.91
2009	5.63	5.63	6.22	5.67	5.63	6.07
2010	5.79	5.79	6.39	5.84	5.79	6.24
2011	5.98	5.98	6.58	6.02	5.98	6.43
2012	6.17	6.17	6.79	6.22	6.17	6.63
2013	6.38	6.38	7.00	6.42	6.38	6.85
2014	6.60	6.60	7.23	6.64	6.60	7.07
2015	6.83	6.83	7.47	6.87	6.83	7.31
2016	7.07	7.07	7.72	7.12	7.07	7.56
2017	7.33	7.33	7.99	7.38	7.33	7.82
2018	7.61	7.61	8.28	7.65	7.61	8.11
2019	7.89	7.89	8.57	7.94	7.89	8.40
2020	8.19	8.19	8.88	8.24	8.19	8.70
2021	8.49	8.49	9.20	8.54	8.49	9.02
2022	8.81	8.81	9.53	8.87	8.81	9.35
2023	9.15	9.15	9.88	9.20	9.15	9.70
2024	9.50	9.50	10.25	9.56	9.50	10.06
2025	9.87	9.87	10.63	9.92	9.87	10.44
2026	10.26	10.26	11.03	10.32	10.26	10.84
2027	10.67	10.67	11.45	10.72	10.67	11.26
2028	11.09	11.09	11.89	11.15	11.09	11.69
2029	11.53	11.53	12.35	11.59	11.53	12.14
2030	11.99	11.99	12.83	12.05	11.99	12.62
2031	12.47	12.47	13.33	12.53	12.47	13.12

Note:
(1) Forecasted prices will be used for modeling backup fuel at existing FPL units as indicated or proposed units as applicable.

Appendix F

FPL Nuclear Fuel Price Forecast
(Nominal $/mmBTU)

Year	Port St. Lucie Plant 1	Port St. Lucie Plant 2	Turkey Point Plant 3	Turkey Point Plant 4
2003	0.36	0.37	0.39	0.36
2004	0.38	0.38	0.38	0.38
2005	0.38	0.41	0.40	0.40
2006	0.38	0.40	0.40	0.38
2007	0.37	0.39	0.37	0.37
2008	0.38	0.39	0.38	0.38
2009	0.39	0.40	0.39	0.39
2010	0.40	0.41	0.39	0.39
2011	0.41	0.41	0.40	0.40
2012	0.41	0.42	0.40	0.40
2013	0.42	0.43	0.41	0.41
2014	0.43	0.43	0.41	0.42
2015	0.43	0.44	0.42	0.42
2016	0.44	0.44	0.43	0.43
2017	0.45	0.45	0.43	0.44
2018	0.45	0.46	0.44	0.44
2019	0.46	0.46	0.45	0.45
2020	0.47	0.47	0.45	0.46
2021	0.47	0.48	0.46	0.46
2022	0.48	0.48	0.46	0.47
2023	0.49	0.49	0.47	0.47
2024	0.50	0.50	0.48	0.48
2025	0.50	0.50	0.48	0.48
2026	0.51	0.51	0.49	0.49
2027	0.51	0.52	0.50	0.50
2028	0.52	0.52	0.50	0.50
2029	0.53	0.53	0.51	0.51
2030	0.53	0.54	0.51	0.51
2031	0.54	0.54	0.52	0.52

Appendix F

Delivered Solid Fuel Price Forecast for Bid 1
(Nominal $/mmBTU)

YEAR	HIGH SULFUR COAL	PETROLEUM COKE	80%/20% BLEND
2003	$1.73	$1.01	$1.59
2004	$1.77	$1.09	$1.64
2005	$1.75	$0.83	$1.57
2006	$1.79	$0.84	$1.60
2007	$1.84	$0.87	$1.64
2008	$1.90	$0.90	$1.70
2009	$1.93	$0.94	$1.73
2010	$1.96	$0.97	$1.76
2011	$1.99	$0.99	$1.79
2012	$2.01	$1.02	$1.81
2013	$2.03	$1.04	$1.83
2014	$2.03	$1.06	$1.84
2015	$2.04	$1.10	$1.85
2016	$2.05	$1.12	$1.86
2017	$2.07	$1.13	$1.88
2018	$2.09	$1.15	$1.90
2019	$2.11	$1.17	$1.92
2020	$2.13	$1.19	$1.94
2021	$2.15	$1.21	$1.96
2022	$2.17	$1.23	$1.98
2023	$2.18	$1.25	$1.99
2024	$2.20	$1.27	$2.01
2025	$2.21	$1.29	$2.02
2026	$2.22	$1.31	$2.04
2027	$2.23	$1.33	$2.05
2028	$2.25	$1.35	$2.07
2029	$2.26	$1.37	$2.08
2030	$2.27	$1.40	$2.09
2031	$2.28	$1.43	$2.11

Appendix G
Financial and Economic Assumptions

Projected Capitalization Ratios		Projected Cost of Capital
Debt = 45%		Debt = 6.4%
Preferred = 0%		Preferred = 0%
Equity = 55%		Equity = 11.0%
	Discount Rate = 7.82%	
	AFUDC Rate = 7.84%	

Tax Assumptions

Rates:		Book Life
Composite Income Tax = 38.575%		Combustion Turbines = 25 Years
(Includes Federal and State Tax)		Combined Cycle = 25 Years
	Tax Depreciation Life = 20 Years	

Annual Escalation Assumptions
(In Percent)

Year	Generator Capital	Generator Fixed O&M	Generator Variable O&M
2003	1.70%	4.3%	3.0%
2004	1.70%	4.1%	0.2%
2005	1.70%	4.2%	0.8%
2006	1.70%	3.9%	1.0%
2007	1.70%	4.0%	1.2%
2008	1.70%	4.3%	1.2%
2009	1.70%	4.5%	1.2%
2010	1.70%	4.4%	1.3%
2011	1.70%	4.5%	1.3%
2012	1.70%	4.5%	1.3%
2013	1.70%	4.5%	1.4%
2014	1.70%	4.7%	1.4%
2015	1.70%	4.5%	1.1%
2016	1.70%	4.4%	1.1%
2017	1.70%	4.3%	1.4%
2018	1.70%	4.5%	1.7%
2019	1.70%	4.5%	1.9%
2020	1.70%	4.6%	1.9%
2021	1.70%	4.5%	1.8%
2022	1.70%	4.3%	1.9%
2023	1.70%	4.4%	1.9%
2024	1.70%	4.4%	1.9%
2025	1.70%	4.5%	2.0%
2026	1.70%	4.6%	2.1%
2027	1.70%	4.6%	2.1%
2028	1.70%	4.6%	2.1%
2029	1.70%	4.6%	2.1%
2030	1.70%	4.6%	2.1%
2031	1.70%	4.6%	2.1%
2032	1.70%	4.6%	2.1%

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Request for Proposals

Florida Power & Light Company (FPL) is soliciting proposals of firm capacity and energy to satisfy a need for approximately 1,066 megawatts (MW) starting June 1, 2007.

Parties interested in submitting proposals in response to this request may obtain further information and register for receipt of the RFP by visiting our website at www.FPL.com/2003rfp, or you may contact Steven Scroggs, RFP Contact Person, Florida Power & Light Company, Resource Assessment and Planning Department, PO Box 029100, Miami, FL 33102-9100, (305) 552-4199, Steven_Scroggs@FPL.com. Copies of the RFP will be available on August 25, 2003. Proposals must be submitted by 4:00 pm EDT by October 24, 2003 to the RFP Contact Person. After initial screening and evaluation, it is anticipated that a short list of proposers will be announced on or about January 15, 2004 with initial negotiations to follow. FPL expects to announce the final selection to fulfill the need on or about May 13, 2004.

Proposals will compete against FPL's next planned generating unit, a nominal 1,100 MW natural gas-fired combined cycle combustion turbine facility at FPL's Turkey Point Site. A nominal 600 MW facility located at FPL's Turkey Point Site will also be available for potential combination with proposals that partially fulfill the 2007 need.

An RFP Pre-Release Meeting will be held August 21, 2003 in Miami, FL to discuss the requirements of the RFP. A Pre-Bid Workshop will be held on September 2, 2003 in Miami, FL to discuss the RFP data requirements and assist potential proposers in understanding the RFP submittal process. Parties interested in attending either meeting in person or by teleconference may register by contacting the RFP Contact Person.

FPL reserves the right to reject all proposals and to modify or cancel the RFP.

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Request for Proposals

Florida Power & Light Company (FPL) is soliciting proposals of firm capacity and energy to satisfy a need for approximately 1,066 megawatts (MW) starting June 1, 2007.

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Request for Proposals

Florida Power & Light Company (FPL) is soliciting proposals of firm capacity and energy to satisfy a need for approximately 1,066 megawatts (MW) starting June 1, 2007.

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Request for Proposals

Florida Power & Light Company (FPL) is soliciting proposals of firm capacity and energy to satisfy a need for approximately 1,066 megawatts (MW) starting June 1, 2007.

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FPL

Florida Power & Light Company
Corporate Communications
Media Line: 305-552-3888
Aug. 14, 2003

FOR IMMEDIATE RELEASE

FPL announces power resources needed in 2007 to meet growth in South Florida; issues a "request for proposals"

JUNO BEACH, Fla. – Florida Power & Light Company today announced the need to increase its power resources in 2007 to respond to significant growth occurring in Florida, particularly in South Florida.

The company said it plans to add capacity by either building its own plant or purchasing power from other companies, selecting whichever is the best and most cost-effective way to meet customers' needs. A notice of FPL's "request for proposals" was issued today outlining the company's power needs, as well as identifying FPL's proposed project, in accordance with Florida Public Service Commission rules.

FPL's self-build option involves adding a new, natural gas-fired plant capable of serving approximately 230,000 customers to its existing 11,000-acre Turkey Point plant site near Florida City. Using a competitive bidding process that complies with the PSC's bid rule, FPL is seeking purchased-power proposals from other companies to evaluate against the Turkey Point option in order to arrive at a final selection no later than spring 2004.

"Responding to growth by selecting the best and most cost-effective power resources for customers continues to be a priority for our company," said FPL President Armando Olivera. "We have recently completed new plants in southwest and northern Florida and are building additional plants in Manatee and Martin counties.

"Now, our attention must turn to meeting the increased demand for electricity that comes from the significant growth that is occurring in Miami-Dade and southeast Florida."

According to FPL, 45 percent of the electricity that its customers use in Broward and 40 percent in Miami-Dade are imported from FPL plants and other resources outside the region. While the system is designed for power plants to deliver electricity to FPL's large electric grid – and power lines to then supply electricity wherever and whenever customers want it – it is still important to ensure the system is reasonably balanced. Additional generation in South Florida would begin to restore this imbalance and improve our system's overall reliability.

The FPL Turkey Point option

If selected as the best and most cost-effective option to meet customers' electricity needs, FPL's new Turkey Point unit would be among the cleanest, most

(more)

environmentally advanced and efficient power plants in the nation. By placing new generation where growth is occurring, the proposed natural gas-fired generating unit also would improve system reliability.

The new unit would join four existing generating units at the site, including two 400-megawatt oil/gas-fired units and two 700-megawatt nuclear units.

FPL analyzed a number of other potential FPL projects and sites before concluding that Turkey Point is its best and most cost-effective project self-build option. New construction at Turkey Point would be able to make use of plant infrastructure already in place. Additionally, the site is already served by a natural gas pipeline for fuel deliveries and by transmission power lines that deliver electricity to customers, though some upgrades may be needed.

"We believe the Turkey Point option offers customers the opportunity for reliable energy, using a cleaner-burning fuel at a site specifically established for power generating facilities. That's cost conscious and helps conserve Florida's land resources," Olivera said.

"In the months ahead, we are committed to continuing our dialogue with our Turkey Point and South Miami-Dade neighbors. By doing so, we believe we can better align the benefits of this option with the interests and priorities of the communities we serve."

The Turkey Point option would:

- Add a nominal 1,100 megawatt, state-of-the-art, natural gas-fired combined-cycle plant capable of producing enough power to serve approximately 230,000 new homes and businesses.
- Utilize 65 acres designed for future power plant expansion at an existing 11,000-acre power plant property.
- Help balance the FPL system grid by adding power in a region where current customer demand is the greatest and where demand growth is forecasted to continue.
- Increase output at the Turkey Point site from 2,200 to 3,300 megawatts, which is enough energy to serve a total of approximately 690,000 homes and businesses.
- Improve system reliability by placing generation where growth is occurring.
- Provide additional power in an environmentally responsible and highly efficient manner.
- Represent a total project cost of approximately $600 million.

Combined-cycle generating technology produces electricity from two stages of production instead of one. In the first stage, energy is produced through fuel combustion in a turbine similar to a jet engine. In the second stage, hot exhaust from the turbines is used to make steam. Energy from both stages then drives turbines and electric generators to produce electricity. In all, this method of generating electricity is about 30 percent more efficient than methods relying on a traditional steam plant.

Olivera said FPL will continue its commitment to conservation programs as well as load

(more)

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management programs that help meet peak periods of high electricity use. FPL customers have helped defer the need for 10 power plants over the past two decades by adopting cost-effective conservation measures and by participating in voluntary programs where power to certain appliances can be automatically reduced at peak periods in return for a credit or discount on monthly bills. Additionally, FPL is developing future "green power" options for its customers.

The utility also said that for future capacity requirements beyond 2007, it expects to consider projects using other fuels, such as coal, to enhance fuel diversity and system reliability.

Miami-Dade residents are invited in the coming weeks to learn more about the proposed Turkey Point expansion project, share your interests and priorities, request a presentation or sign up to be on a mailing list for future updates by visiting www.FPL.com/turkeypoint, by contacting Ramon_Ferrer@FPL.com or by calling 1-866-362-4888.

The FPL "request for proposals"
In the interest of making sure customers get the best and most cost-effective new sources of future electricity, Olivera said the utility also welcomes and will thoroughly evaluate alternative third-party offers for better and more cost-effective proposals than Turkey Point.

In its "request for proposals" (RFP) notice issued today, FPL said the company is soliciting proposals for firm capacity and energy to satisfy a need for approximately 1,066 megawatts starting June 1, 2007. This is the amount of power FPL forecasts it will need to serve customer growth, including the 20 percent reserve margin required by the Florida Public Service Commission.

FPL will be conducting its RFP under a revised PSC bid rule put in place last year to provide bidders with more project information and more insight into FPL's evaluation process.

Proposals in response to the RFP are due no later than Oct. 24. Following a first round of evaluation, FPL plans to announce a short list of proposals in mid-January with a final selection planned for no later than mid-May 2004.

Under the requirements of Florida's Power Plant Siting Act, most proposed capacity additions also must undergo about 18-months of multi-agency review coordinated by the Florida Department of Environmental Protection and a PSC review and hearing. In a PSC hearing, the commission rules on the need for the project and determines whether the best and most cost-effective generation option has been selected for customers.

Potential bidders interested in submitting proposals in response to FPL's RFP may obtain further information by visiting FPL's Web site at www.FPL.com/2003rfp, by contacting FPL's RFP contact person Steven_Scroggs@fpl.com or by calling 305-552-4199.

(more)

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Florida Power & Light Company is the principal subsidiary of FPL Group, Inc. (NYSE: FPL), nationally known as a high quality, efficient and customer-driven organization focused on energy-related products and services. With annual revenues of more than $8 billion and a growing presence in 24 states, FPL Group is widely recognized as one of the country's premier power companies. Florida Power & Light Company serves more than 4 million customer accounts in Florida. FPL Energy, Inc., FPL Group's energy-generating subsidiary, is a leader in producing electricity from clean and renewable fuels. Additional information is available on the Internet at www.FPL.com, www.FPLGroup.com and www.FPLEnergy.com.

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FPL's 2003 Request for Proposals
Questions and Answers

Questions 1 - 94 were submitted at the RFP Workshop on September 2, 2003.

1. ***Will FPL scale back (or increase) the capacity of the CT option to allow greater flexibility in developing lower cost portfolios?***

   No.

2. ***Language re (pg.21): "Commit all facility output, including Ancillary service products "What is included within definition of "Ancillary service products"?***

   Ancillary Services is defined on page 1 of the Draft Purchase Power Agreement, Appendix A to FPL's 2003 RFP.

3. ***Step 4 of the economic evaluation states that "FPL may conduct sensitivity analysis" as part of the evaluation. Please clarify what sensitivities will be conducted.***

   Please see the discussion of the Sensitivity Analysis on page B-7 of Appendix B. The results of any sensitivity analysis that is conducted will be considered as a part of a portfolio's risk profile in the non-economic evaluation.

4. ***Do CC proposals (Greenfield) all get the Fuel Switching Credit (FSC) since dual fuel is a threshold requirement or is there some difference between the two?***

   The Fuel Switching Credit (Section II.E) applies only to those assets that can choose to operate on natural gas or residual fuel oil. The dual fuel capability requirement (Section III.E. 11)) is a requirement based on backup fuel capability using light oil or two independent and redundant natural gas pipelines (See Addendum Two). It is assumed that new gas-fired generation will employ combustion turbine technology requiring distillate quality fuel oil and therefore not be eligible for a Fuel Switching Credit. No significant arbitrage opportunity is offered by light oil oil versus natural gas, therefore no FSC will be applied. This applies to FPL's next planned generating unit, as well.

5. ***Will any benefit be given to proposals that make capacity available prior to 2007?***

No. FPL's 2003 RFP seeks firm capacity and energy to meet its projected need in the summer of 2007. Capacity available prior to June 1, 2007 would most likely add to system costs.

6. ***Will the fuel switching credit be calculated based on the heat rate in a given proposal or on the 11,000 heat rate stated in the RFP?***

An estimated value was provided in Section II.E using the 11,000 Btu/kWh heat rate. The actual value of the credit for eligible proposals will be calculated using the September 1, 2003 Fuels Forecast and the proposal specific capacity and performance information.

7. ***Will you develop a short list? Will there be a minimum number of proposers on the short list? Will you negotiate with those bidders on the short list?***

A short list will be developed based on the number of competitive proposals identified during the evaluation period. No minimum or maximum number of proposals is pre-supposed. The process identifies (page B-9) that during the Initial Negotiating period selected Proposers will be asked to provide a Best and Final Offer and answer questions that may be developed.

8. ***More clearly explain what is meant by the "minimum experience of proposer" requirement in the minimum requirements.***

The "Minimum Experience of Proposer" requirement is a minimum criterion established to qualify Proposers for consideration based on their previously demonstrated experience in undertaking the complex and difficult tasks necessary to successfully develop, permit, design, procure, construct and commission a utility-grade electrical generation facility. FPL is requiring that a Proposer have successfully accomplished (successfully developed, permitted, designed, procured, constructed, and commissioned) one similar project previously to be considered a credible entity for the purpose of this RFP. In that the final responsibility lies with the Proposer, this cannot be assuaged by the experience of employees or of related contractors or sub-partners whose relationship is defined by contracts to which FPL has no, nor desires, access. If a Proposer consists of a Special Purpose Entity (SPE) backed by a parent Guarantor, the experience of the parent Guarantor may be considered if it is demonstrated that the parent Guarantor commits to providing material support to the SPE. Material support exceeds a financial arms-length relationship (as that of a Lender) and necessarily includes access to the personnel, processes, experience and relevant resources of the parent Guarantor. Under such an arrangement, the experience of the parent Guarantor would be reviewed consistent with Section III.E 10).

The five-year operating experience requirement applies to the "operating entity". The operating entity does not have to be the Proposer.

9. Is the 1100mw a "SE Florida" need or an FP&L system need? How much does "SE Florida" need in 2007?

FPL develops its annual need on the basis of maintaining a reserve margin of 20% above the forecasted FPL system summer peak firm load. For the year 2007, the incremental need to satisfy this standard is 1066 MW. Recognizing transmission limitations and the imbalance of load to generation in the Southeast region, FPL has further identified the system cost advantages of locating all or a portion of this need in the Southeast.

10. Does FPL intend to quantify the risks (identified in your second quarter earning report) relative to self build/next generation's unit operation?

Reviews of risks are a part of the non-economic evaluation. As discussed in the RFP, these risks will not be quantified.

11. Please define "greatest value" if it is not otherwise defined as the lowest price.

The objectives of FPL's 2003 RFP are to minimize system costs to FPL customers, minimize risk to FPL customers and maintain FPL's reliability standards. The generation alternative that best satisfies these three objectives will provide the "greatest value."

12. Clarify how FPL will include the implementation of an RTO/ISO in its evaluation.

The economic evaluation is conducted under the best information available today, so FPL assumes that the current regulatory environment continues throughout the evaluation term. Therefore, in that section of the evaluation, the implementation of an RTO/ISO is not included. Proposers may take exception to portions of the RFP (that are not Minimum

Requirements of Section III.E) or a clause in the PPA that relates to language contemplating actions that govern under the scenario of a transition to a RTO/ISO environment. The non-economic evaluation will review the exception(s) and the proposed alternative language to assess the resulting impact to the portfolio's risk profile. This assessment will be considered in the final selection.

13. ***The RFP question cut-off date is September 23rd, one month prior to the proposal due date. Will FPL be providing any material information to potential bidders after the September 23rd date?***

FPL has decided to extend the question cut-off date until September 30th. Replies to questions received up to that date, and any other pertinent information for Proposers that FPL deems relevant after that date, will be posted on the RFP website (www.FPL.com/2003rfp) or distributed electronically to the contact name on file with FPL.

14. ***Is FPL considering the PPA terms to be accepted by a bidder if an exception is not indicated in responding to the RFP? If so, what will be negotiated if the PPA terms are deemed accepted and the proposal pricing is firm?***

If an exception is not indicated by a Proposer FPL will rely on this as the Proposer's indication that there are no exceptions and the Proposer is incorporating the PPA as part of its offer. This will enable FPL to more effectively compare proposals to one another, as well as, fairly anticipate what can be expected in completing negotiations in its evaluation and subsequent selection process. There are a few placeholders in the PPA that would need to be filled in with proposal specific information in conjunction with the Proposer. No additional negotiations would be necessary. FPL considers that there may be exceptions and proposed language that better tailor the FPL draft PPA to a Proposer's specific project, or help clarify a creative pricing proposal.

15. ***Why is the fuel switching credit not applied to Purchase Power Agreements?***

The Fuel Switching Credit recognizes the value of fuel optionality that could benefit FPL customers. This is achieved in a Tolling Agreement or a Sale of an existing asset, but not in a standard Purchased Power Agreement relationship.

16. ***Is the FPL self-build option going to be evaluated against outside proposals on an apple-to-apples basis?***

Yes. The proposals received in response to the RFP will be evaluated in a fair comparison to FPL's next planned generating unit.

17. ***Site certification filed by April 1, 2004- Contract negotiations completed by May 13, 2004. Is this an inconsistency?***

No. FPL views the milestone requirement of April 1, 2004 consistent with the statutory time periods that support a successful commercial operation date of June 1, 2007 for assets requiring a determination of need under the PPSA. Proposers are expected to be making significant progress towards the success of their proposed projects, as is required of FPL's self-build options.

18. ***Please explain the non-economic criteria being used to evaluate a project's financial viability.***

Form # 3 in Appendix D (pgs D-14, D-15) lists the information that will be evaluated. The evaluation will focus on the ability of the Proposer (and guarantor, if different) to successfully build the project and post the required security. The evaluation will also assess risks associated with the exceptions taken to the RFP and PPA terms.

19. ***Is the amount of performance security allowed to be reduced during the term of the contract? If so, what schedule of reduction is FPL going to require?***

No, the security amount doesn't change during period of the PPA. However, the form of the security may change based on the financial strength of the bidder.

20. ***Does FPL have in place a PPA that contains the terms and conditions set forth in the draft PPA?***

A response to this question is not required in order to develop a proposal to the RFP.

21. ***For an existing plant, what is the PPA assumption associated with a subordinated lien/mortgage?***

The draft PPA included in the RFP assumes a new facility and makes no assumptions regarding an existing plant. However, Section 5.2.1 of the PPA establishes that FPL shall have a lien against the facility to secure the obligation of the Sellers. Note that the lien is subordinated to any project lenders.

22. ***If a proposer has no Standard & Poor's or Moody's rating, or the rating is less than BBB or BAA2 respectively, will the proposal be evaluated? Why was this level of debt rating selected? Will FPL look to a corporate parent if a bidder proposes a single purpose corporate entity to own the project?***

Yes. All proposals will be evaluated; however, part of the evaluation is verifying that proposals meet the Financial Viability requirements of Section III.E 5). If the proposal is supported by newly built generation, and thereby includes significant completion risks, there is a minimum credit rating requirement. A non–rated supplier can either obtain the necessary rating, or partner with an appropriately rated entity, to guarantee their performance. Failure to meet the requirements, either by the Supplier or in combination with its Guarantor, will result in the Proposal being evaluated as not meeting the minimum required financial viability, and the Proposal will not be further evaluated. Proposals that are not supported by newly built generation are not subject to this minimum credit rating requirement.

Single purpose corporate entities are evaluated under the same criteria as any other entity. The relevant information is the financial strength of the entity and, if appropriate, its Guarantor. Note in particular, Appendix D page 4; "If a Proposer will be relying on any parent/affiliate guarantees, the Proposer shall also include a description of the corporate relationship between the Proposer and the guarantor and provide a description regarding the proposed guarantor's willingness to guarantee the Proposer's obligations and the terms of the guarantee."

23. ***FPL seeks "completion & performance" guarantees from bidders. Does FPL offer consumers similar guarantees relative to the self-build next generating unit option?***

A response to this question is not required in order to develop a proposal to the RFP.

24. ***Will a proposal be penalized if exceptions to the draft PPA are noted?***

No. The non-economic evaluation will assess the risks and benefits presented by various proposals. Exceptions may be minor, inconsequential, beneficial, clarifying, major or insurmountable. No penalties or bonuses are awarded in the non-economic evaluation; rather the nature and impact of the associated exceptions and proposed alternate language in the proposals are assessed to develop a risk profile.

25. ***Why are "upstream" gas pipeline costs estimates for the evaluated portfolios evaluated if those costs are supposed to be included in the proposals submitted?***

These are not the same cost categories. Proposals are to include the capital costs of constructing and connecting and the O&M costs for natural gas pipeline <u>laterals</u> that connect the delivery point to the facility. "Upstream" costs that will be developed by FPL (or a specialty consultant) relate to those capital improvements that are required for portfolios on the natural gas pipeline <u>mainline</u> in order to provide the proper pressure and volumetric flow required of the new facility at the designated delivery point. Lateral costs are a part of the proposal and development of these costs are the responsibility of the Proposer; the development of an estimate of mainline costs to be used in the economic evaluation is the responsibility of FPL.

26. ***Is FPL requesting a fixed price yearly figure for all FOM and VOM charges, rather than CPI or some other index?***

Addendum One to FPL's 2003 RFP clarifies the requirements for providing annual values for FOM and VOM, and the application of approved indices.

27. ***How will the combustion turbines be used in creating candidate portfolios? Are the combustion turbine options FPL's next planned generating unit? If yes, please explain.***

The EGEAS model will develop portfolios based upon the constraints of FPL's need, and available generation alternative sizes and costs. The 4x0 CT self-build alternative will be treated as another generation alternative in the economic evaluation. The alternative will be available to be combined into a portfolio with partial need proposals that, in combination, satisfies the total need. Each portfolio that satisfies the need, whether it includes the 4x0 CT self-build option or not, will be evaluated for its impact on system costs and compared with other portfolios. The CT self-build alternative is <u>not</u> FPL's next planned generating unit.

28. ***Will the next planned generating unit have residual value at the end of the evaluation period?***

As a direct answer to the question, yes, the next planned generating unit, if built, will undoubtedly have some residual value at the end of the evaluation period. A more germane question might be "will any residual value credit be given to the next planned generating unit, or any other unit in FPL's economic evaluation?" The answer to this question is, no. This is a conservative factor built into FPL's economic evaluation that provides an advantage to Proposers.

29. ***What are the escalation rates used for in the next planned unit? Please make these available.***

Addendum One to the FPL 2003 RFP clarifies the methodology and indices applied by FPL.

30. ***What pipeline is assumed to supply the next generation unit?***

FPL assumes that gas will be physically supplied to FPL's next planned generating unit via the FGT pipeline as discussed in the Pre-Bid workshop. The forecast price of the gas that is supplied to this Turkey Point unit is based on FPL's September 1, 2003 Fuel Forecast promulgated as a part of Addendum Two.

31. ***What is the rationale for a 30 year evaluation when the maximum term of a PPA is 25 years?***

The economic evaluation will be a 29 year evaluation beginning in 2003 and continuing through 2031, with the 2003 through 2006 economics the same for all combinations and portfolios. Therefore, a 25-year term PPA, from 2007 through 2031, would in fact be evaluated for the full 29 years of the analysis.

32. ***The next planned generating unit fixed O&M is $3.57/kw-yr. Why is this so much less than fixed O&M listed in ten year site plan?***

There are at least three reasons for these differences. First, the Fixed O&M value listed in FPL's Ten Year Site Plan is for an un-sited greenfield unit, not for a unit located at a specific existing site such as Turkey Point.

Second the estimates presented in the Ten Year Site Plan were developed in late 2002/early 2003 while the costs presented in the RFP represent a later and more refined estimate. Third, the value shown in the Ten Year Site Plan for fixed O&M includes the cost for capital replacement, which is provided separately in Table V-2 and V-3 of the RFP.

33. ***How much gas FT (firm transportation) is being purchased in the model to support the 4x1 CCGT at Turkey Point?***

In the economic evaluation, FPL will include the cost of firm gas transportation sufficient to deliver 75% of the total annual gas needed for the <u>base operation</u> mode of the 4x1 CC at Turkey Point. This same approach will be used in evaluating all other CC unit-based proposals received in response to FPL's RFP.

34. ***Is Fixed O&M and Capital (Replacement) Expenditure included in revenue requirements in tables V-4 & V-1?***

The Fixed O&M and Capital Replacement Expenditures are not included in the revenue requirement values shown in Tables V-1 and V-4 in item nos. 5, 6, and 7. The Fixed O&M and Capital Replacement Expenditures are shown separately on pages 33 and 37 in Tables V-2 and V-5.

35. ***How much import ATC is opened up from outside SE from 1100 MW at Turkey Point? What about 600 MW at Turkey Point?***

A response to this question is not required in order to develop a proposal to the RFP.

36. ***Is it anticipated that the capacity sought in the RFP will serve only SE Florida load?***

No. The capacity solicited in the RFP is based on satisfying a 20% reserve margin planning standard for the FPL system during the summer of 2007. Therefore the capacity sought is based on a system standard.

37. ***Is this the first time that FPL has used system transmission losses as part of evaluating responses to a RFP?***

A response to this question is not required in order to develop a proposal to the RFP.

38. ***Other than the land, is there infrastructure at the existing Turkey Point facilities that will be utilized by the Next Planned Unit? If so how is that infrastructure cost allocated to the Next Planned Unit?***

Yes. Virtually any plant that will be built upon a site at which one or more operating generating units already exist will make use of the existing infrastructure to some degree (for example, use of an existing administration building, etc.). Such existing infrastructure represents sunk, not incremental costs. All projected incremental costs that will be incurred due to the potential addition and operation of the next planned generating unit at Turkey Point have been captured in the costs provided for that unit in FPL's RFP.

39. ***In the Non-Economic Evaluation process, does FPL anticipate any reliability concerns with having such a large portion of FPL's total system capacity at one site?***

No.

40. ***Clarify the definition of "Southeastern Florida" – what are the substations included in that area.***

Please refer to the following tables, which contain a listing of the substations by FPL Transmission area. This shows the substations included within the Southeastern Florida area along with the other areas discussed in the document entitled "General Information Regarding FPL's Transmission System Capability" which is available on the Florida OASIS website located at "http: \\floasis.siemens-asp.com\OASIS\FPL\INFO.HTM"

FPL cautions against efforts to be too precise in defining southeast Florida or relying upon loss factors shown in the RFP. Actual losses in a portfolio will depend upon as yet to be performed load flow analyses which will differ based on the alternatives in the portfolio, their location, size and integration facilities.

Table 40.1 Substation List by FPL Transmission Areas

Southeast						East	Midway
137 AVE	CORAL RF	GREENFRG	LAUDRDLO	NW6THST	SAWGRASS	ACREAGE	ADAMSPMT
40TH ST	CORBETT	GRENACRE	LAWRENCE	OAKLNDPK	SEABOARD	ALEXANDR	BABCOCK
40TH ST	COURT	GREYNOLD	LE JEUNE	OJUS	SEAGULL	BEE LINE	BRIGHTON
62 AVE	CROSSBOW	GRIFFIN	LEMON CT	OLYM HTS	SEMINOLA	BRIDGE	CITRUS
ABERDEEN	CRYSTAL	HACIENDA	LEVEE	OPA LOCA	SHERIDAN	COVE	DAIRY
ACME	CULLUM	HAINLIN	LEVEEDST	ORCHID	SIMPSON	FLASTEEL	EDEN
AIR PORT	CUTLER	HALNDALE	LINDGREN	OSBORNE	SISTRUNK	GATLIN	EMERSON
ALTON	CYPRESS	HAMLET	LINTON	OSCEMILL	SLVRLAKE	HILLS	F PIERCE
ANDREWS	DADE	HARMONY	LITTLE R	OVERTOWN	SNAKE CK	HOBE	GLENDALE
ANDYTOWN	DADE-CGC	HAULOVER	LOXAHATC	PALM AIR	SNAP CK	INDN TWN	GRANT
ANHINGA	DADELNDN	HAWKINS	LRIV SUB	PALMETO	SO MIAMI	JUNO	HARRIS
ARCH CK	DADELNDS	HIA ALT	LUCY	PANTHER	SOUTHSDE	JUPITER	HARTMAN
ASHMONT	DANIA	HIALEAH	LUMMUS	PARKLAND	SOUTHWST	LK PARK	HIBISCUS
ATLANTIC	DATURA	HIATUS	LYONS	PEMBROKE	SPANGLER	MARTIN	HIELD
AVENTURA	DAVIE	HIGHLNDS	MALLARD	PENNSUCO	SPOONBIL	MONET	HOLND PK
AVOCADO	DAVIS	HILSBORO	MARATHON	PERRINE	SPRINGTR	MONTEREY	INDIALAN
BASSCRK	DEAUVILE	HLLCREST	MARGATE	PERRY	STIRLING	OAKES	INDRIO
BAUER	DEERFLD	HNTINGTN	MARION	PHOENIX	STONE BR	OLYMPIA	JENSEN
BEACON	DEERSUB	HOLLYWOD	MARKET	PINEHRST	SUNNY IS	P & W	MALABAR
BELL	DELMAR	HOLLYWTP	MARLIN	PINEWOOD	SUNNYLND	P MAYACA	MELBOURN
BELVEDER	DELTRAIL	HOLMBERG	MARYMNT	PLANTATN	SWEETWTR	PLUMOSUS	MICCO
BEVERLY	DILLARD	HOLYBROK	MASTER	PLAYLAND	TAMIAMI	PT SEWEL	MIDWAY
BIRD	DORAL	HOLYCROS	MASTERTP	POMPANO	TARTAN	RIO	OKECHOBE
BISCAYNE	DOUGLAS	HOMELAND	MAULE	PORT	TAVRNIER	ROSS	OSLO
BLUE LGN	DRIFTWD	HOMESTED	MCARTHUR	PORTSAID	TERMINAL	RYDER	PALM BAY
BOCA TCA	DUMFLDNG	HYPERNAP	MCGREGOR	POWERLIN	TIMBLKE	SHERMAN	PLAZA
BOCARAT	EARHART	HYPOLUXO	MEMORIAL	PRINCTON	TRACE	SQR LAKE	PRIMAVST
BOCATAP	ELY	I B M	MERCHAND	PROGRESO	TRADWNDS	STUART	SABAL
BOULEVRD	EUREKA	IMAGINTN	MIA BCH	PT EVGLD	TRAIN	TRIGAS	SANPIPER
BOULEVTP	FAIRMONT	INDIAN C	MIA EAST	PURDY LN	TROPICAL	WARFIELD	SAVANNAH
BOYNTON	FASHION	INDIANCS	MIA LAKE	QUANTUM	TURKEY P		ST LUCIE
BRANDON	FIREHSE	INDUSTFL	MIA SH	QUIETWAT	TWINLAKE		SWEATT
BROADMOR	FLACITY	INTRNTNL	MIA WEST	RAILWAY	ULETA		TURNPIKE
BROWARD	FLAGAMI	ISLMRADA	MIAMI	RAINBERY	UNIVRSTY		WEST
BUEN VST	FLAMINGO	IVES	MIASHSUB	RANCH	URBAN		WH CITY
BUTTS	FOUNTAIN	JACARAND	MIL TRL	RAVENSWD	VALENCIA		WYOMING
CALDWELL	FRON TP	JASMINE	MILAM	RECWAY	VENETIAN		
CARL TP	FRONTON	JOG	MILLER	RED ROAD	VERENA		
CATCHMNT	FULFORD	JWFISHCK	MIRAMAR	REMSBURG	VIL GRN		
CEDAR	G GLADES	KENDALL	MITCHELL	RESERVTN	VIRG KEY		
CHAPEL	GALLOWAY	KEY BISC	MOFFETT	RINKER	W PM BCH		
CLINTMRE	GALTAP	KEYLARGO	MONTGMRY	RIV.DIST	WATKINS		
CNSR DIS	GARDEN	KILLIAN	MOTOROLA	RIVERSDE	WELLEBY		
CNTRY CL	GERMNTWN	KIMBERLY	NATLBRDG	RIVIERA	WESTNGHS		
CNTYLINE	GLADVIEW	KNOWLTON	NATOMA	ROCK ISL	WESTON V		
CNTYLITP	GOLF	KOGER	NEWTON	ROEBUCK	WESTWARD		
COCO GRV	GOOLESBY	LAKE IDA	NOBHILL	ROHAN	WHISP PN		
COLLINS	GOULDS	LAKEVIEW	NORMANDY	RONEY	WILCOX		
COMMERCE	GRAMERCY	LANTANA	NORMNDFL	ROSELAWN	WILLIAMS		
CONGRESS	GRAPLAND	LATN QTR	NORTHWD	SAGA	WINDMILL		
CONSRVTN	GRAT230	LAUDANIA	NORTHWES	SAMPLE	WOLFSON		
COPANS	GRATIGNY	LAUDRDLI	NORTON	SANDFOOT	WOODLAND		
					WSGABLES		
					YAMATO		

Table 40.2 Substation Listing by FPL Transmission Area

Southwest	Cent-West		North			
ALICO	ARCADIA	PNTA GOR	624-A	EDGEWATR	MELROSTP	SATSUMTP
ALLIGATR	ARCADTP	POLO	AURORA	ELKTON	MERRITT	SCOTSMOR
ALVA	AUBURN	PROCTOR	BALDWIN	FLEMING	MILLCREK	SEBSTIAN
BONI SPG	BEKER	RATLSNAK	BALDWIN	FLGR BCH	MILLCREK	SLAG
CALUSA	BEKERIND	RINGLING	BANANA R	FLOMICH	MILLS	SN PLANT
CAPRI	BELMDTAP	ROTONDA	BARBTP	FORGROVE	MIMS	SO CAPE
COLLIER	BENEVA	RUBONIA	BARNA	FPL120G1	MINING	SOCAPEFL
COLONIAL	BRDENTON	RYE	BARNA	FRANCSTP	MINUTMN	SPRUCE
CORKSCRW	BUCK MTR	S VENICE	BARWICK	FRONTNAC	MOULTRIE	ST AUG
EDISON	BUCKEYE	SARASOTA	BARWIKTP	FTMCYTFL	N RIV TP	ST JOHNS
ESTERO	CARLSTRM	SHADE	BRADFORD	GATOR	NASH	ST JOHNS
F MY SUB	CASTLE	SORRENTO	BRADFORD	GCS-FPL	NEW RVR	ST.JOE
FT MYERS	CHARLOTE	TUTTLE	BRADFORD	GEN ELEC	NEW RVR	STARKE
GATEWAY	CLARK	VAMO	BREVARD	GENEVA	NO CAPE	SUNTREE
GLADOLUS	CLEVLAND	VENICE	BREVARD	GENEVTP	NORRIS	SYKES CK
GOLD GTE	COAST	VENICSUB	BRNADST	GEORGIAP	NORRIS	SYLVAN
IMPERIAL	COCOPLUM	WALKER	BULOW	GERONA	NORRISDS	TAYLOR
IONA	CORTEZ	WHIDDEN	BUNNELL	GRANVIEW	NOVA	TITANIUM
JETPORT	CORTEZ	WHITFILD	BUNNELL	GRIFFSTP	NRIVGOAB	TITUSVIL
LABELLE	CRAWLYTP	WOODS	C-5	GRISSOM	ONEIL	TOCOI
LAZYACRE	DEEPCRK		CAPE K	HAMMONTP	ORANGEDL	TOLOMATO
LIVNGSTN	DOORFLD		CAPE K	HAMPTON	ORMOND	TOMOKA
METRO	ENGLEWOD		CELERY	HASTINGS	ORMOND	TRLRIDGE
NAPLES	FRANKLIN		CHULUOTA	HAWTHTFL	ORSINO	TROPCANA
ORANGE R	FRT INDS		CITY PT2	HIRIDGE	OSTEEN	TULSA
ORTIZ	FRTVILLE		CITY-PT1	HOLLY HL	P ORANGE	TUSTGOAB
P.RIDGE	GRANADA		CITYTAP1	HOLLYTP	PACETTI	VIERA
SAN CARL	HARBOR		CLEAR LK	HUDSNTFL	PACIFIC	VOLUSIA
SOLANA	HOWARD		COCO BCH	HUDSONFL	PALATKA	VOLUSIA
TERRY	HOWARD		COCOA	IND HRBR	PATRICK	WABASSO
TICE	HYDE PK		COLLEGE	INDIAN R	PELICAN	WABASSO
VANDRBLT	INTERSTE		COLUMALT	INTRLCHN	PIONEER	WELBRN
WINKLER	IXORA		COLUMBIA	INTRLCTP	POINSETT	WELBRNTP
	JOHNSON		COLUMDST	KACIE	POINSETT	WILLOW
	KEENTOWN		COMO	LAUREL	POMONATP	WINDOVER
	LAURELWD		COMOTAP	LAWTEY	PRICE	WIREMILL
	MANATEE		COQUINA	LEWIS	PUTNAM	WIREMLTP
	MCCALL		COURTENY	LEWISTAP	PUTNAM	WNASAUTP
	MURDOCK		COX	LINDE	REED	YORKE
	MYAKKA		CRES CTY	LIVE OAK	REGIS	YULEE
	NOTRDAME		CRILL SW	LK BUTLR	RICE	
	ONECO		CRILL TP	LPGA	RICE	
	ORNGTREE		CRISAFUL	LVOAKTAP	RINEHART	
	OSPREY		DAYT BCH	MACDONTP	RIVERTON	
	PALM SOL		DELAND	MACLENNY	ROCKLDGE	
	PANACEA		DELTA	MADISNFL	S DAYTON	
	PARK		DELTONA	MANVILTP	SANDERTP	
	PARRISH		DURBIN	MATANZAS	SANFORD	
	PAYNE		DUVAL	MATEO	SANFORDI	
	PAYNETAP		DUVAL	MAXVILTP	SANFORDO	
	PEACHLND		EAU GALL	MCDONELL	SARNO	
	PHILLIPI		EAUGLDS	MCMEEKIN	SATELITE	

41. ***How will annual system transmission related costs calculated for a portfolio be allocated amongst the individual projects in the portfolio?***

The system related transmission costs calculated for a portfolio to meet FPL's need will not be allocated to the individual projects in the portfolio. Portfolios are assessed costs in aggregate and not as individual projects. The impact on the transmission system is that resulting from a specific portfolio and not that resulting from each individual project comprising a portfolio. Please see Appendix E.

42. ***Would you elaborate on how the $58 deferral value will be used in the Evaluation Process? Is there any information available on how the "Value of Deferral" ($58.85/kw-yr) is developed?***

The $58 value of deferral value shown in the RFP document on item 7 is presented due to a requirement in the Bid-Rule that such information be included in an RFP. This value will not be used in the FPL's economic evaluation, as that analysis will be based on a 25-year revenue requirement approach. The formula for determining the value of deferral is set forth in Rule 25-17.0832, Florida Administrative Code.

43. ***What is the forecast capacity factor for the Turkey Point 4x1 self-build option?***

As stated in the footnote to Table V-2, 85% was the assumed annual capacity factor used to develop the cost values. Actual forecast values will be dependent on the specific analysis conducted and may change in the economic evaluation.

44. ***What is the forecast capacity factor for the Turkey Point (4) simple cycle self-build alternative, if chosen?***

As corrected at the September 2, 2003 RFP Workshop, the footnote to Table V-5, 15% is the assumed annual capacity factor. Actual forecast values will be dependent on the specific analysis conducted and may change in the economic evaluation.

45. ***Will FPL include a 2x1 self-build option? (To match with < 1100 MW bids from a bidder)***

No.

46. ***Are non-economic factors that will be evaluated limited to those set forth in Appendix B. If not, what are the other non-economic factors that will be used in evaluating bids?***

FPL has indicated in significant detail the areas and specific topics that we anticipate will be of interest in our non-economic review. Without a full knowledge of all of the proposals that will be received in response to the RFP, it would be imprudent for FPL to rule out any other factors that have yet to be identified. If FPL determines that it is necessary to employ other non-economic factors, FPL will comply with the Bid Rule.

47. ***Clarify the mitigation applied in the equity penalty calculation as it related to Performance Security.***

The Performance Security required of a Seller provides funds that, under a Seller Event of Default, FPL may draw upon to compensate for damages created by Seller's underperformance. FPL's access to this security would come only through a failure to perform by the Seller (Event of Default) such as; Seller abandons operation, Seller fails to maintain a 64% Capacity Billing Factor, Facility fails three successive Capacity Demonstration Tests, etc. These events have evidentiary requirements and cure periods that lengthen the time between an under-performance event and potential recovery. In spite of these factors, FPL can conceive of certain situations (however unlikely) where, under a PPA, the Performance Security funds would mitigate losses that FPL would be solely financially responsible for in an FPL self-build option. In FPL's calculation, the mitigation afforded by the PPA is not based on the risk presented by an external generation alternative, but is based on the risk FPL avoids by not having to operate its own unit.

48. ***Please explain the Review Panel, its process and function.***

Proposals that exhibit strong potential in the economic evaluation, but require clarification in non-economic areas, may be considered for a Review Panel. The Review Panel would allow for an interview-style exchange between FPL personnel representing the areas of review and Proposers to clarify proposal features ensuring an accurate understanding is obtained for the non-economic evaluation.

49. ***Page 1 – the first paragraph of your RFP states that "Low price alone will not necessarily result in a successful proposal." Does this mean that an IPP proposal that is not necessarily the lowest price may be selected by FPL?***

The objectives of FPL's 2003 RFP are to minimize system costs to FPL customers, minimize risk to FPL customers and maintain FPL's reliability standards. The generation alternative that best satisfies these three objectives will provide the "greatest value". The process allows for an IPP proposal, that is not necessarily the lowest price, to be selected by FPL.

50. ***Would you accept a proposal from an existing unit that steps in say 100 MW in 2007, 400 MW in 2008 and full unit in 2009?***

Minimum requirement 3) requires that the firm capacity and energy of the proposals commence by June 1, 2007. Therefore FPL would be able to evaluate the 100 MW offer in 2007 as an eligible proposal, with later additions not available to be considered in this RFP.

51. ***Page 20 discussed the proposal minimum term. If a plant doesn't have a need determination, 1 year is the minimum term. A project that has its steam capacity limited to 74.9 MW and that has received all of its DEP permits and local approvals viewed by FPL as not requiring a need determination?***

More facts would be necessary to answer this question. If the Proposer plans on operating the subject plant such that its steam cycle was 75 MW or greater, FPL understands that the plant would require a determination of need.

The decision as to whether a specific plant does or does not require a need determination is not the responsibility of FPL. A Proposer is responsible for the status of any facility being used to support a proposal, and the acquisition of necessary approvals for such facilities, new or existing. The minimum term requirements are self-evident as provided in the RFP.

52. ***Will the FPL self-build at Turkey Point need to prepare an environmental impact statement?***

A response to this question is not required in order to develop a proposal to the RFP.

53. ***Who are the members of the FPL Management Review Team? What are the processes it will use to determine the selected proposal?***

A response to the first question is not required in order to develop a proposal to the RFP. The evaluation processes are described in Appendix B, Evaluation Methodology.

54. ***Does the current schedule set forth in the RFP contemplate a Proposer acquiring a site in South Florida from which to propose?***

Please see Question and Answer # 58.

55. ***Will the costs associated with the next planned generating unit be modified after the Proposal Due date (i.e. during the evaluation process) prior to "Best and Final" offers being submitted?***

If costs or performance parameters associated with the next planned generating unit are to be modified, the requirements of the Revised Bid Rule (section 14) will be observed.

56. ***Page 3 of the RFP states "Projects that contribute to FPL's system fuel diversity and lower the system average costs will have an advantage during FPL's economic and non-economic evaluation of the proposal". Does this mean that a proposal that offers fuel diversity will receive an advantage during FPL's economic and non-economic evaluation of a proposal? In other words, please explain how a proposal that offers fuel diversity will be evaluated?***

The statement described in the question is intended to identify that the attribute that enables a proposal to offer lower system average rates through fuel diversity will be the attribute that provides that proposal an advantage. No arbitrary or additional quantitative value will be applied to a proposal offering fuel diversity.

57. ***The Southeast import penalty presumes a new plant outside of the Southeast. What fuel and location are presumed? (Page 6 of RFP)***

The question is based on a misunderstanding of the discussion provided in Section I. There is no "Southeast import penalty". The discussion on page 6 of the RFP provides the background behind the system's economic preference for a geographic siting in the Southeast. No specific fuel or location is necessary to discuss the issues cited in this section.

The evaluation discussion (Section IV.D) discusses a methodology for a cost adjustment recognizing the impact each portfolio will have on the efficiency of Southeastern regional dispatch. This analysis will be specifically developed for each portfolio that completes the final economic evaluation step.

58. ***FPL has a preference for a site in southeast Florida. Given that Turkey Point is not available to outside bidders, does the RFP contemplate bidders locating and securing site elsewhere in southeast Florida?***

No. The RFP does not contemplate any specific actions on the part of Proposers. The RFP communicates the fact that a project sited in the southeast Florida region will likely have an economic advantage over non-Southeastern sited projects in the analysis based on the transmission related components in the economic evaluation. Recognizing this fact, it would seem logical that Proposers desiring to maximize the competitiveness of their projects would site them in the Southeast region. However, the locational advantage may be offset in part by lower Proposer pricing for units located outside of southeast Florida.

59. ***Does FPL evaluate the fuel switching credit so as to allow arbitrage opportunities in the fuel markets? Does FPL's self-build contemplate taking advantage of pricing differences between natural gas and fuel oil?***

FPL applies standard option pricing methodology to the opportunity offered by assets that can burn natural gas or residual fuel oil and pass that benefit to FPL customers. FPL's self-build option will not be able to burn residual fuel oil, and therefore will not be eligible for the credit.

60. ***Has the "regulatory out" provision of the PPA been used by FPL in any other contract to which it is a party?***

A response to this question is not required in order to develop a proposal in response to the RFP.

61. ***You described a process in which proposals are combined with others to meet a system need. Assume proposals A, B, and C are combined and make the short list. How will negotiations be conducted if all 3 Proposers have been combined and are from different companies?***

FPL will negotiate individually with all parties with the objective of completing a set of contracts that support the portfolio selected in the evaluation.

62. ***Will FPL perform an illustrative analysis for a fee? Refers to a request for an additional case analysis for transmission loss estimates specified by a potential Proposer.***

FPL asserts that it has provided the best available information that can be communicated prior to receiving specific proposals in response to the RFP. Undertaking specific analysis for individual parties would only result in information with limited value and unknown relevance to the final determining circumstances. No analysis can currently be performed that Proposers could rely upon to conclusively represent the impact to the transmission system for their specific facility, since it may be combined with a number of other unknown proposals and/or alternatives.

63. ***Is there a requirement that a "Guarantor" be related / affiliated to a bidder? i.e. is a third party guarantor acceptable?***

A third party Guarantor is acceptable. In the case of an un-affiliated Guarantor, FPL will pay particular attention to the requirement that the Proposer "provide a description regarding the proposed guarantor's willingness to guarantee the Proposer's obligations and the terms of the guarantee." The Guarantor will be evaluated using the Financial Viability criteria stated in the RFP.

64. ***Will FPL consider proposals from Bidders for capacity at the Turkey Point site?***

No. Minimum requirement 12) requires that "For newly built generation, the Proposer shall be responsible for the location, development and permitting of the proposed facility site.

65. ***Will FPL consider competing bids at the Turkey Point site? If not, why not?***

No. Minimum requirement 12) requires that "For newly built generation, the Proposer shall be responsible for the location, development and permitting of the proposed facility site.

66. ***Page 22 of FPL's RFP requires a Proposer to guarantee all O&M costs and demonstrate credit support for the guarantee that is satisfactory to FPL. What type of credit support will FPL be seeking? Is this in addition to the performance security requirements? Is FPL's self build represented by guaranteed O&M costs? (In other words, is FPL guaranteeing O&M at its Turkey Point facility?)***

The question refers to the section of the RFP that identifies that a guarantee is required if a Proposer chooses to submit its own <u>fuel commodity and transportation forecast</u> and desires that the proposal be evaluated on the basis of this forecast. In this case, FPL requires a Proposer to provide a sufficient guarantee that specifically supports this aspect. This guarantee is in addition to the performance and security requirements. The O&M costs may be bid as indexed or firm values (as further described in Addendum One) and require no additional guarantee.

67. ***This question relates to FPL's security requirements found on pages 15 and 16 of the RFP. Assume that a Proposer offers 500 MW of new gas fired construction. To assure completion security, the Proposer will have to post 94 million in completion security (500 MW x 188,000 per MW = 94 million). Additionally, the Proposer will have to pose 47.5 million in performance security (500 MW x 95,000 = 47.5 million). The total of these two sums is 141.5 million. Using the chart of page 16, how much of this 141.5 million would be in the form of cash or letter of credit, assuming the Proposer has an AAA+/Aaa to AA-/Aa3 unsecured debt rating?***

There is an apparent misunderstanding in the statement of the question. Completion Security and the Performance Security are not concurrent, and need not be posted simultaneously. Completion Security must be posted "not later than the Commencement Date" (PPA, Section 4.1), and Performance Security must be posted "not later than Capacity Delivery Date, and as a condition thereto"(PPA, Section 4.2).

In order to fully answer the hypothetical situation posited one must recognize the Supplier's Tangible Net Worth (Net Worth per the most recent audited financial statements less goodwill and intangible assets), which influences the amount of cash or letter of credit required. The example in Table 67.1 illustrates the calculation of the Completion Security Liquid Amount under two different Tangible Net Worth scenarios. In the first scenario the Supplier Tangible Net Worth is $700 million, in the second scenario the Tangible Net Worth is $500 million.

Table 67.1 Example Calculation of Completion Security Liquid Amount

Hypothetical Information		
Capacity Bid	500	MW
Supplier's Credit Rating	AAA+	
Percentage of Tangible Net Worth	15%	Definition of Credit Limit, PPA page 4 or page 16 of the RFP.
Completion Security Amount:	94,000	$188.00/kW x 500,000 kw, RFP page 15 or PPA definition of Completion Security Amount
Scenario 1		
Supplier Tangible Net Worth	700,000	
Supplier Credit Limit:	105,000	15% of Tangible Net Worth
Completion Security Liquid Amount	9,400	The greater of the Completion Security Amount minus the Supplier Credit Limit, or 10% of the Completion Security Amount.
Scenario 2		
Supplier Tangible Net Worth	500,000	
Supplier Credit Limit	75,000	15% of Tangible Net Worth
Completion Security Liquid Amount	19,000	The greater of the Completion Security Amount minus the Supplier Credit Limit, or 10% of the Completion Security Amount.

68. ***Does the Turkey Point site already have in place facilities at which residual fuel oil can be stored that can supply FPL's proposed self build? If so, are any costs of these existing facilities being assigned to FPL's self-build proposal? Why or why not?***

No. The capital costs for the next planned generating unit include the cost of installing facilities to provide the required dual fuel capability without reliance on any currently installed systems.

69. ***In FPL's Manatee-Martin RFP, a bidder was allowed to submit a couple of variations of its bid and not incur an additional $10,000 fee. This RFP apparently does not allow a bidder to offer any variation or alternative pricing without having to pay another $10,000 fee. Is this reading of the RFP correct? If so, why was this change made? How much did it cost FPL to evaluate an alternative pricing proposal contained with a bid during the Manatee – Martin RFP process?***

Yes, this is a correct reading. The change was made so that the fee is cost-based. The cost estimate per proposal is based on the costs FPL incurred in the analysis of the above mentioned RFP. The evaluation fee was developed using the total incremental costs experienced in the past RFP divided by all eligible proposals evaluated. As described in the RFP and at the Discussion Meeting and Workshops, the evaluation process treats each proposal as a stand-alone proposal for analytical purposes. This requires that each proposal be set up and modeled as an independent proposal to be considered in comparison with (or potentially in combination with) other proposals and alternatives. In this manner, each proposal is given the full analytical deference and credibility provided to all other proposals.

70. ***Does your Turkey Point facility need a gas lateral to feed your self-build option? If so, what is the cost of the gas lateral? Is that figure set forth in the RFP and if so, where?***

The Turkey Point facility needs gas transportation expansion (including a lateral) with a cost estimated at $29.9 million (in 2007$), and this separate cost breakout can be found in the RFP document on page 32, Table V-1, item no. 11. This value is also accounted for in the values presented in items 5, 6, and 7 on that same page.

71. *On page 22 of the RPF contains a section entitled Permit and Authorization Feasibility. What will FPL be looking for in the way of a "demonstration that there are no significant barriers to obtaining the necessary regulatory and govt. permits authorizations to execute or implement the proposed project on a schedule that meets the June 1,2007 date" Has FPL already concluded that its Turkey Point self-build proposal meets this permit and authorization feasibility requirement. If not, will that be part of the evaluation process of FPL's self-build option?*

FPL has requested Proposers provide certain specific information delineated in Form #7 of Appendix D. This will be the information used to determine the feasibility of the proposed project. The criteria stated will be reviewed for all alternatives.

72. *The geographic preference contained on pages 3-5 of the RFP is not listed as one of the non-price evaluation factors contained in Appendix B entitled Evaluation Methodology. Does that mean the geographic preference will not be evaluated during Step 5 of the evaluation process? If the geographic preference is a non-price factor that will be used by FPL in evaluating proposals, how will the geographic preference be evaluated?*

The geographic preference discussion provides important background and best available information to Proposers. The economic evaluation will quantitatively address the transmission-related costs, they are not non-price factors.

73. *Would FPL consider a system sale from an IPP with multiple plants?*

No. When FPL mentioned system sales, it was contemplating a utility system as the provider of the sale. When contemplating a system sale, FPL applies different requirements regarding the specific nature of the source of firm capacity and energy and level of control FPL has on the total output of a specific facility. These requirements differ because FPL can rely upon certain assumptions regarding the nature and obligations of the Seller, who is assumed to be another regulated generation utility. There are three key assumptions that are made by FPL regarding the actions and obligations of a Seller in a system sale:

- Reserve Margin. Generation utilities are required to maintain certain reserve margins which provides assurance to purchasers that the selling utility has rights to sufficient physical reserves to cover their load obligations.

- Accountability. Generation utilities are held accountable to performance and reliability standards such as "prudent utility practices" and other industry standards through regulatory oversight by the Public Service Commission.

- Transparency. Through the regulatory reporting requirements observed by generation utilities, buyers have the ability to satisfy themselves that the obligation made by the Seller can indeed be met.

FPL considers that these key assumptions, that represent the underlying foundation upon which system sales with other regulated utilities may be executed, are fundamentally necessary to facilitate a system sale. IPP's do not have the same attributes as utilities do, regarding their generating units. IPP's are not required to maintain reserve margins, they are not held accountable by a regulatory body, and they do not have transparent reporting requirements. Moreover, FPL has specified protections in its RFP and PPA for contractual arrangements with IPP's which could be circumvented if it were to consider a system sale from IPP's. So FPL will not consider a system sale from an IPP.

74. ***Can you please indicate a 600mw Southeast, 600mw outside Southeast analysis?***

No. Such analysis might prove as misleading as it might be helpful because the results would depend on the sites chosen and their associated transmission integration requirements.

75. ***FPL is has a fuel switching credit in this RFP. Such a credit was not in the FPL Manatee-Martin RFP? Why is this fuel switching credit now part of FPL's RFP when it was not contained in FPL's recent Manatee-Martin RFP?***

A response to this question is not required in order to develop a proposal in response to the RFP.

76. ***Page 26 of RFP – Condition precedent. Need determination proceeding and Final Order that includes language "which order includes a finding that FPL is entitled to recover from its customers all payments for capacity and energy, which orders are no longer subject to appeal." Has this language been part of a need determination order that has even been granted in the past? If the need determination order has this language, isn't the need for the regulatory out language eliminated or at least***

A response to this question is not required in order to develop a proposal in response to the RFP.

77. ***Does FPL have a preference for its next planned generating unit at Turkey Point, all things otherwise being equal?***

FPL prefers its next planned generating unit over other self-build options because its economic analysis showed it to be FPL's most cost-effective

self build option to meet customer needs. FPL cannot determine, without receiving and evaluating proposals, whether it prefers its next planned generating unit over some other portfolio of generating alternatives. For that reason FPL is encouraging and soliciting competitive proposals. FPL unequivocally states that it is not predisposed to select its next planned generating unit as a result of this RFP.

78. ***Given the requirements for completion and performance security – project level financing will be difficult. Is it the intent of FPL to limit proposals from project level respondents?***

No. It is FPL's intent to protect its customers adequately.

79. ***Explain the rationale behind the level of completion and performance security.***

It is what FPL considers necessary and appropriate to protect its customers.

80. ***FPL has a "Reg-Out" clause which allows FPL to reduce capacity payments to an IPP if laws or regulations change. In the evaluation process, does FPL assume recovery of capital costs for the self-build option is similarly at risk if laws or regulations change?***

In the economic evaluation, it is assumed that there will be no change in laws or regulations that would trigger the regulatory modifications provision or recovery of FPL's costs.

90. ***In the evaluation process, does FPL assign any risk to the Next Generation Unit option, which results in approximately 14% of all FPL system generation at one site?***

No.

91. ***At last meeting, you said FPL would not consider bids at the Turkey Point Site. What assessment did FPL do to determine competing bids at the same site was not a good idea?***

A response to this question is not required in order to develop a proposal in response to the RFP.

92. ***Completion and Performance Security requirements are higher than recent RFP's by FPL. Why is it so much higher?***

A response to this question is not required in order to develop a proposal in response to the RFP.

93. ***Has FPL estimated the cost of upgrading transmission into Corbett Substation that would eliminate the "geographic preference" of South of Corbett Substation?***

A response to this question is not required in order to develop a proposal in response to the RFP.

94. ***How will grandfathering of the TSA/Network Reservation be treated post RTO from a Receipt Point perspective?***

A response to this question is not required in order to develop a proposal in response to the RFP.

Questions 95 - 118 were submitted on September 5, 2003

95. ***Is Appendix A the contract? Just fill it in? How do you accommodate other options?***

Appendix A is a draft, it is not intended to be filled in and submitted. The draft PPA represents FPL's desired commercial framework. It is based upon the assumption that the subject facility is a newly built natural gas-fired CC. While it does not represent every possible contemplated arrangement, it should be sufficient to communicate FPL's perspective. Proposers are directed to note exceptions and provide alternative language to these terms if a Proposer objects to any terms.

96. ***Primary fuel is a pipeline natural gas planned through 2031. We have reason to believe we will not have gas then. We will be nearly out of gas and oil in the US. Is this the reason for "fuel diversity" in the proposal? How important is this factor in your evaluation?***

Fuel diversity refers to the economic diversity of fuel source that assists in managing the risk associated with a large percentage of generation dependent on one fuel type. This attribute will be considered in the non-economic analysis for its risk mitigating impact.

97. ***What are the percentage weighting of factors for each major consideration in your evaluation? Do you have a formula? Can we have it?***

The economic evaluation is a quantitative result with the components explained. The non-economic evaluation is a review of risks, but no "weighting factors" are used.

98. ***Do you really want a "turn-key" plant? Is this negative or positive in your evaluation of proposals?***

The Revised Bid Rule mentions "turnkey offerings" in its definition of potential participants. Turnkey offerings present somewhat different risk profiles and this will be addressed in the risk assessment in the non-economic evaluation. See Appendix F for details.

99. ***Do you want to own power plants or only receive power? What % weighting do you give to each case?***

FPL is indifferent to the own/purchase prospect. The evaluation is conducted on economics and risk.

100. ***Do you have a list of acronyms definitions used in this RFP? (The PPA does not cover all acronyms).***

Most acronyms were defined in their first appearance in the document. Please contact FPL for clarification of specific items.

101. ***The contract seems to be all penalty related. Are there any incentives for the Proposer, such as early meeting the schedule, or exceeding the power output, or exceeding the "up-time" of the facility, etc.?***

The contract is not all penalty related. There are contractual incentives for the Proposer, including scalable compensation that rewards high performing facilities. Such provisions work to the customers' advantage. Similarly, there are other provisions that protect customers by giving Proposers incentives to perform by avoiding "penalty" provisions. All these provisions protect the customer. Additionally, unless the contract term is a minimum requirement, a Proposer may propose alternative terms.

102 ***When do we learn what voltage(s) to deliver? Is there a table of substations or entry points, and entry voltages?***

This would depend on the Proposer's sited location, proximity to the FPL system and unit capability. The OASIS website contains much of the information requested.

103. ***Fuel diversity encourages other fuels: solid, LNG, etc., but the Contract (PPA) calls for #2 low S fuel oil, what do you want? And how will other selections affect the proposal evaluation?***

The question confuses two aspects of the RFP, fuel diversity and dual fuel capability. Dual fuel capability (based on continuity of generation – not diversity) requires alternative fuel sources for newly constructed gas fired generation. The draft PPA considers a gas-fired combined cycle unit using light oil oil as its alternate fuel satisfying the dual fuel requirement. Fuel diversity is also an important aspect FPL will consider.

104. ***Where is Appendix E, Section 3?***

The section heading was changed. The section referred to is Paragraph C) of Appendix E.

105. ***How much does Southeast siting affect the evaluation rankings?***

The siting will impact the transmission cost components in the economic evaluation. The magnitude will depend on the location, the location of other alternatives in the portfolio and the related integration facilities. How much these factors will affect portfolio economics cannot be quantified until proposals are received and evaluated.

106. ***Rule 25-22.082 of the Florida Adm. Code – Can we have a copy? (Note the "must comply", page 20)***

The rule may be viewed on-line at www.psc.state.fl.us/rules/Chap22.pdf

107. ***What is a "brownfield", etc.?***

This refers to the development of a new construction project on an existing industrial site.

108. ***Do you have diagrams of FPL transmission lines? And preferred connect points?, and voltages?***

Please refer to the OASIS website for transmission connection information at http://floasis.siemens-asp.com\OASIS\FPL\INFO.HTM

109. ***Are these (Completion and Performance) "securities" additive?***

No, the Performance Security and Completion Security are not additive. (See Section II.H).

110. Contract "Terms" ---; There are 4 options here, yet the PPA only has 2, Explain.

It was impractical to draft alternative contracts for every conceivable option, so FPL drafted a contract for the most common option submitted in FPL's previous RFP. In addition, FPL outlines specific considerations for potential turnkey options. The PPA is a draft document representing FPL's desired commercial framework. It is based upon the assumption that the subject facility is a newly built natural gas-fired CC. While it does not represent every possible contemplated arrangement, it should be sufficient to communicate FPL's perspective. Specific negotiations would be undertaken with Finalists.

*111. **Dual Fuel Capability - - - permitting for 500 hours operation on secondary fuel ---. Is this requirement in the PPA contract? What weight does this have in the proposal evaluation?***

All newly built gas-fired generation proposals must satisfy the dual fuel capability requirement (Section III.E. 11, also Addendum Two, Section B.) This requirement is not identified in the PPA, because it is a proposal eligibility criterion. However, there is no requirement that the secondary fuel be permitted, since that process cannot be guaranteed by a Proposer. FPL asks that a Proposer commit to making "commercially reasonable efforts" to attain the needed permits and authorizations. There is no weighting factor, as it is pass or fail.

*112. **What does "Distributed Generation sources" mean? It is not in the PPA!?***

The term is taken from the Revised Bid Rule.

*113. **In the "evaluation process", what is the % weighting for each of the subsections of the proposal evaluation?***

FPL's evaluation process is explained in Section 4 and Appendices B, C and E. In summary, the process contains an economic and a non-economic evaluation. The economic evaluation is an explicit quantitative analysis. The non-economic evaluation is a non-quantitative assessment of the risk profile presented by a proposal in three defined areas. The selection process will be a business judgment made considering the information provided by these two approaches. No weighting factors are utilized, nor required to accomplish the selection process we have described.

114. Where can we get copy of EGEAS generation planning software?

The software may be obtained from EPRI in Palo Alto, CA.

115. TableV-2 Where do you expect to get gas in 2032? There are studies that show the US totally runs out of gas in 2034. So the projected price for gas seems to be largely understated. How can our proposals be compared to Turkey Point that does not project a change of fuel?

FPL develops its generation plan consistent with the best information available. This information supports the continued viability of natural gas as an available fuel source beyond the present planning horizon. The assumption regarding the availability of natural gas is the same for all assets and the analysis concludes in 2031.

116. Does "capacity factor" of 85% conflict with the 20% Rule? Explain.

Capacity Factor refers to the ratio of capacity delivered versus total unit capacity, and represents a measure of the unit's dispatch or "on-line" time. If the "20% Rule" refers to the 20% reserve margin planning standard, the two do not conflict. The 20% reserve margin refers to the amount of available capacity above the forecasted summer firm peak.

117. Doesn't the (PPA's) limitation to two "terms" in Section 2.4 conflict with the RFP's multi-terms? App A, P 17, 2.4

No. The minimum and maximum contract terms set forth in the RFP control, as they are minimum requirements. However, the contract term set forth in Section 2.4 of the PPA is consistent with the minimum and maximum contract terms set forth in the RFP. Also, please see Question and Answer # 89.

118. "Purchase Obligation Excused" – What does this section mean? Under what circumstances these would be invoked? App A, P26, 6.3

Section 6.3 of the draft PPA attempts to capture the real-time nature of operating a power system. Operating requirements may fluctuate significantly and instantaneously. This provision allows the FPL system operator to react to any system condition and treat the Facility no differently that any other generating unit in the FPL system that is under FPL's control.

Questions 119 – 177 were submitted on September 10, 2003.

119. ***Please define "greatest value" if it is not otherwise defined as the lowest price result. [p. 1]***

Please see Question and Answer # 11.

120. ***FPL states that it retains the right to refine its cost estimates. Will FPL commit to adhering to those cost estimates for the Next planned Generating Unit after the Need Determination hearing should that unit be selected in this RFP process? [p1]***

A response to this question is not required in order to develop a proposal in response to the RFP.

121. ***FPL clearly will use estimates of costs for its Next Planned Generating Unit. Will Bidders be allowed to use estimates and then modify those costs, upward or downward, if selected in this RFP process and not be penalized by FPL?***

Proposers must stand behind estimates used in their proposals to enable proposal pricing to be firm, as required in Section III.E (8) Binding Nature of Proposals. However, if during the RFP process, FPL changes its cost estimates for its next planned generating unit, the remaining Proposers will, consistent with the Bid Rule, be allowed to revise their proposals. Also, Proposers selected as finalists will be allowed to modify their proposed prices when submitting their Best and Final Offer. Such price changes will not be "penalized", they will be incorporated into the RFP economic evaluation. However, once a proposal is selected for negotiation, the proposal prices upon which the selection were made will be firm.

122. ***Define "firm offers of fixed duration" [p 1]***

"Firm offers" are offers with definite, discernible terms and conditions which the Proposer extends to FPL for 120 days, with the only opportunity to change being either in response to a change in FPL's cost estimate for its next planned generating unit or when formulating a solicited Best and Final Offer after having been selected as a finalist. "Fixed duration" offers will commence between January 1, 2007 and June 1, 2007 and continue for a term at least as long as the minimum term required in the RFP, but no later than May 31, 2032.

123. ***If further changes to the capacity need are identified prior to the Proposal Due date, will potential Bidders be notified of the change in capacity need? [p. 2]***

If FPL were to make a change to the capacity need for summer 2007, and FPL chose to fill that need with an additional next planned generating unit that required a determination of need, FPL may consider expanding the current RFP process to satisfy the increased need. If FPL makes such a decision to expand the current RFP, participants would be notified.

124. ***Did FPL evaluate a self-build option using solid fuels? Liquid fuels? LNG? Which fuels were evaluated? [p. 3]***

A response to this question is not required in order to develop a proposal in response to the RFP. FPL puts forth its next planned generating unit (a 4x1 CC at Turkey Point) as the most cost-effective alternative.

125. ***What were the results of any evaluations done by FPL of an FPL self-build unit using other than natural gas? Will FPL provide the analysis?***

A response to this question is not required in order to develop a proposal in response to the RFP.

126. ***Please clarify the definition of "southeastern Florida"; What are all the substations included in the defined area?***

Please see Question and Answer # 40.

127. ***What is the assumed voltage level associated with the transmission loss factors? [p, 5]***

The connection voltages vary between 69 kV and 500 kV based on the specific voltage of the substation utilized in the model. However, for the illustrative purpose of the diagram, the loss factors would not change appreciably (within the accuracy of the analysis) under a step-up or down in transmission voltage.

128. ***Provide a list of the loss factors associated with each substation. [p 5]***

Please see Question and Answer # 62.

129. ***Why does it appear that there are different transmission loss factors within the "southeastern Florida" region and that only the immediate area around Turkey Point as a 1.0 factor? [p. 5]***

The question refers to Figure I.1, the illustrative loss factors for various areas of peninsular Florida. This information was developed using the same methodology that FPL will apply to evaluate the transmission loss associated with each specific portfolio in the final economic evaluation. The information, while indicative, cannot represent the specific analysis that will be conducted with individual portfolios. The loss factors are necessarily relative, as each area is compared to a reference point (further described in Appendix E). Any location that is different than the reference point used in an analysis will have a finite loss factor. The illustration shows a 1.0 factor near the region FPL has identified as it's load center (nominally South Palm Beach County, North Broward County), which was used as the reference for the illustration. This may or may not be the reference point used in the analysis of portfolios. Any location that is different from the reference point will have some amount of loss.

130. FPL is requiring all Bidders to secure all transmission on a "firm long-term basis for the entire term of the proposal". Does this include transmission service on the FPL system? [p. 13]

No. The requirement refers only to delivery involving third-party transmission systems if required. Assets on the FPL system will be treated as a system asset for the purposes of transmission reservation.

131. Why isn't the Fuel Switching Credit applied to Power Purchase Agreement proposals that also offer oil-firing capability and provide operational control to Florida Power & Light? [p. 11]

Please see Question and Answer # 15.

132. Why is an 11,000 (HHV) heat rate used in calculating the Fuel Switching Credit? Wouldn't it be more appropriate to use the heat rate associated with an individual proposal? [p. 11]

Please see Question and Answer # 6.

133. Explain what is meant by FPL will "not bear any price or cost risks". [p. 12]

Section II.F. is entitled "Proposer Obligations". The statement in subsection 3) expands on this general heading to identify that cost increases that may be the result of changes are necessarily the risk of the Proposer upon whom FPL and its customers rely. FPL believes this is balanced by the recognition that cost savings that may be the result of these same changes would be to the benefit of the Proposer.

134. ***The cut-off date for the RFP questions is September 23rd, one month before the Proposal Due date. Why is the question cut-off date so early when there is apparently information, such as the FPL Fuel Forecast, that will be provided to potential Bidders by FPL as late as the end of September and to which potential Bidders may have questions? [p. 14]***

Please see Question and Answer # 13 and Addendum Two.

135. ***Why did the completion security requirements increase from the 2002 RFP and isn't $188,000 per MW excessive security that is substantially higher than the industry norm? [p. 15]***

A response to this question is not required in order to develop a proposal in response to the RFP.

136. ***Will FPL allow the Performance Security of $95,000 per MW to be reduced as the term of the agreement decreases? If so, please provide a schedule or should such reduction be assumed on a straight-line basis? [p. 15]***

No. The Performance Security amount remains the same throughout the term of the agreement. The form of the Performance Security may change in relation to the credit rating and Tangible Net Worth of the Seller/Guarantor.

137. ***Will FPL be placing an amount equivalent to Completion Security and Performance Security into some form of escrow account to be used to protect FPL customers in the event FPL's Next Planned Generating Unit is selected and is not completed or does not perform as expected? If the Public Service Commission were to suggest such an arrangement, what would FPL's position be?***

A response to this question is not required in order to develop a proposal in response to the RFP.

138. ***The requirements surrounding Completion and Performance Security, basically that any proposal made at the project level will require this security to be in the form of cash, impedes the ability of a Bidder to proposal project level responses to the RFP. Is this the intent? [p. 16]***

The stated question is an inaccurate representation of the RFP requirements. A response to this question is not required in order to develop a proposal in response to the RFP.

139. ***If the maximum term of a proposal is 25 years, why is the evaluation performed over a 30-year period?***

Please see Question and Answer # 31

140. ***Will the FPL Next Planned Generating Unit be evaluated on a 25-year basis?***

The economic evaluation will be conducted on the same term for all portfolios.

141. ***Will the Next Planned Generating Unit have residual value at the end of the evaluation period?***

Please see Question and Answer # 28.

142. ***The June 1, 2007 commencement date is clear. Are there any benefits which will be accorded to proposals that can be available prior to that date? [p 21]***

Please see Question and Answer # 5.

143. ***How did FPL determine the maximum block size of 1,225 MW? Is this a high growth scenario under the Ten Year Site Plan? [p 21]***

The upper limit of the block size to be considered was based on 1) a block size sufficient to satisfy the 2007 need, and 2) a maximum block size that would potentially accommodate a broad range of reasonable proposal combinations and technologies, and 3) a block size that would, consistent with the Need Determination process, focus on the need for 2007.

144. ***Clarify how FPL is planning to include the implementation of an RTO/ISO in its evaluation. [p 22]***

Please see Question and Answer # 12.

145. ***More clearly explain what is meant by the "minimum experience of Proposer" requirement in the Minimum Requirements. Same question with respect to the other functions described (construction, procurement, commissioning). [p 23]***

Please see Question and Answer # 8.

146. ***Is the dual fuel requirement for a new gas-fired plant applicable if a project is already through the development process or substantially through the development process? Why does this requirement not apply to a solid or liquid fuel proposal? [p 24]***

Section III.E (11) of the RFP indicates that the dual fuel requirement applies to newly-built gas-fired generation, which FPL intends to mean that which is not in commercial operation in the form proposed. The purpose of the dual fuel requirement is to satisfy reliability and continuity concerns related to the dependency of a project on a single natural gas source and to support the determination of need process. Solid and liquid fuel facilities generally consist of significant on-site storage which satisfies FPL's concerns in this area. Please see Addendum Two for additional information on Dual Fuel Capability.

147. ***Define "newly built" in the context of the Minimum requirements with respect to the dual fuel requirement. [p 24]***

Please see Question and Answer # 146.

148. ***Clarify – are the milestones listed to be considered only as applicable to a proposal? [p 24]***

The Request for Proposal document is developed to solicit and screen competitive proposals for supply-side alternatives to the next planned generating unit. Assuming the question intends to elicit the applicability of these milestones to FPL's self-build options, FPL considers that meeting these dates is necessary for any alternative requiring PPSA licensing to satisfy a commercial operation date of June 1, 2007.

149. ***Clarify what the goal of the regulatory modification requirement is from FPL's standpoint. [p 25]***

A response to this question is not required in order to develop a proposal in response to the RFP.

150. ***In the Final Economic Evaluation, why is it conducted for the years 2003- 2031? If a proposal begins on June 1, 2007 for a term of twenty-five years, the evaluation must conclude in June 2032. [p 29]***

Please see Question and Answer # 31. Proposals that begin between January 1, 2007 and June 1, 2007 will be evaluated as beginning on January 1, 2007 and continuing 25 years to December 31, 2031 in the economic evaluation.

151. ***What are the estimates of the electric transmission and fuel system interconnection costs that will be used in the final economic evaluation?***

The electric transmission and fuel system interconnection costs are to be provided by Proposers with their proposals, and necessarily will be project specific.

152. ***Explain how the efficiency of the Southeastern area will be determined and utilized in the final economic evaluation.***

Appendix E, Section E provides a description and an example of the method to be applied to each portfolio.

153. ***What are the additional costs related to fuel infrastructure enhancement in the Final Economic Evaluation?***

Please see Question and Answer # 25.

154. ***What are the "mitigating factors" in the Final economic Evaluation?***

Please see Appendix C, Section B for a full discussion of mitigating factors. Also, see Question and Answer # 47.

155. ***Please explain the Review Panel, its process and function. [p 30]***

Please see Question and Answer # 48.

156. ***Will ground rules be established prior to the commencement of the non-economic evaluation or will the Review Panel be free to use criteria individual to each separate proposal? [p 30]***

The non-economic evaluation process and criteria are described in Step 5 of Appendix B. The purpose of the Review Panel is to amplify and clarify specifics related to a proposal.

157. ***Will Bidders be able to comment on the summary report of the Review Panel prior to the summary report being finalized to ensure that no misinterpretation of the non-economic factors of the proposal occurred? If not why not? [p 30]***

No. The non-economic review is a component of the evaluation process and is not open to negotiation or debate during the process. The Review Panel was developed specifically to provide reviewers with the capability to fairly interact with selected Proposers if necessary to clarify components of their proposals. The evaluation process will be conducted by Resource Assessment and Planning department and may be monitored by FPSC staff.

158. ***Does FPL plan to issue a summary report of the risk areas for the FPL Next Planned Generating Unit? If not, does FPL assume there are no risks associated with this unit? [p 30]***

No. No.

159. ***Who are the members of the FPL Management review Team? What are the processes they will be using to make the final selection in the RFP?***

Please see Question and Answer # 53.

160. ***The estimate of fuel transportation for the Next Planned Generating unit is $0.55/MMBtu. Is this a current agreement that FPL has on the gas pipeline that will serve the unit? What is that gas pipeline that will serve the unit? Will this same transportation rate be assumed for all proposals reviewed and located on the same pipeline as the Next Planned Generating Unit? [p 32]***

Please see Question and Answer # 30 and Addendum Two.

161. ***Why is the estimate of fuel cost for the Next Planned Generating Unit and for the FPL CT option different? Does FPL utilize two separate fuel forecasts for these two potential units? [p 32 and 36]***

Please see Addendum Two.

162. ***What are the escalation rates used by FPL for the Next Planned Generating Unit and the CT option? [p 34 and 36]***

Please see Addendum One.

163. ***Will the Next Planned Generating Unit be evaluated with "transmission related increase costs"? [p B3]***

Yes. The evaluation methodology described in Appendix B is applicable to all the generation alternatives considered in the RFP process.

164. ***Clarify that both the economic and non-economic evaluations will be overseen by the FPL Resource Assessment & Planning Department. [p B4]***

Yes. Please see Question and Answer # 53.

165. ***Explain what, if any, barriers have been erected to prevent the FPL Resource Assessment & Planning Department and the FPL department responsible for developing cost estimates for the Next Planned Generating Unit and/or the CT Option from communicating during the evaluation process. Will there be any communication between these departments during the evaluation period prior to the Short List Announcement?***

A response to this question is not required in order to develop a proposal to the RFP.

166. ***Will information regarding the 'Filler units" be provided to potential Bidders before the Bid Due date? [p B4]***

The economic analysis will utilize filler units consisting of Combined Cycle and Simple Cycle Combustion Turbine facilities, as well as solid fuel capacity replacing expiring solid fuel PPA's. The CC and CT units will be consistent with the data provided for the FPL self-build units. The replacement solid fuel capacity will be available in 2010.

167. ***Will information regarding the "Filler units" be provided to potential Bidders before the Cut-off Date for RFP Questions? [p B4]***

See Question and Answer # 166.

168. ***On carrying finalist proposals from Step 3 to Step 4 in the economic evaluation process, how do you know the estimated incremental costs in Step 4 – the stated criteria for determining what finalist proposals make it to Step 4 – unless Step 4 is actually performed? [p B5]***

Depending on the number of proposals received, this screening step may be unnecessary. If it is necessary, an estimate would be made and subsequently verified upon completion of Step 4. If the estimate was in error, and should rightfully have included additional proposals, those proposals would be incorporated in Step 4.

169. ***What sensitivity analysis may be run in the economic evaluation? Please explain how they will be used. [p B5]***

Please see the discussion of the Sensitivity Analysis on page B-7 of Appendix B and Question and Answer # 3.

170. ***In what circumstances would the ability to fuel switch not be to the benefit of FPL's customers for the purpose of applying the Fuel Switching Credit? [p B6]***

Please see Question and Answer # 15. The draft PPA offers an energy payment that compensates a Seller based on a fixed schedule. The schedule is indifferent to the Seller's choice of fuel, therefore leaving the arbitrage benefit exclusively to the Seller. Proposers may offer alternative language that would provide the benefit to the customer, under which terms the fuel switching credit may be applicable.

171. ***Explain the non-economic analysis criteria related to a "proposer's ability to complete". [p B7]***

The "ability to complete"... is an assessment of many aspects solicited in the Appendix D forms that allow reviewers to determine how well prepared and capable a Proposer is to conduct the proposed project.

172. ***Explain the non-economic criteria regarding a project's financial viability. [p B8]***

The financial viability criteria are described in Section II.H (4) and Section III.E. (5) of the RFP.

173. ***Explain the non-economic criteria regarding "Florida permitting experience" [p B8]***

Form 7 of Appendix D describes the information that will be reviewed to develop an assessment of this area.

174. ***Clarify what is meant by "impact to Risk profile" in Step 5 of the Review Panel process. [p B9]***

Step 5 is the Non-Economic Evaluation, of which the Review Panel may be a part. An example regarding financial viability demonstrates the concept of impact to risk profile. The financial viability of different proposers will vary with the specifics of the proposer and/or its guarantor. FPL would assess that a proposal with strong financial viability (e.g. high Supplier Credit Limit) will present a lower impact to the portfolio's risk profile than that presented by a proposal with a weak financial viability (low Supplier Credit Limit). Demonstrated market actions, such as the Proposer's history of contract fulfillment will also be considered.

175. ***Clarify the intent of the experience parameters for development, design/construction, and operational, as used by the review Panel. [p B9]***

The intent is to ensure that FPL focus its evaluation on Proposers that have demonstrated experience in the identified areas.

176. ***Explain the justification of a 30% risk factor in the equity penalty.***

Please see Section A of Appendix C and Attachment Two to the RFP.

177. ***Why isn't the mitigation associated with the Performance Security calculated annually since it is in place for the term of any agreement? [p C8]***

A response to this question is not required in order to develop a proposal to the RFP.

Questions 178 to 193 were submitted on September 19, 2003.

178. ***Does the Turkey Point 4x1 Self Build have the ability to operate the CTs without the steam turbine in operation? In other words can FPL operate the CTs in simple cycle mode?***

Yes. In most scenarios the facility would be able to sustain simple cycle operation for an indefinite time period via use of the steam path for excess heat dissipation. In the unlikely event of a failure of the steam turbine, the design of the Turkey Point facility will enable the unit to transition from a combined cycle mode, through a simple cycle mode, before requiring a shutdown of the facility. This transition will be able to be accomplished with sufficient time to allow a controlled replacement of capacity using FPL system reserves.

179. ***Table E-6 specifies the "Increased Operating Cost of a 4x0 CT (600 MW/10,000 heat rate block) addition at Turkey Point", would a 2x1 Combined Cycle (600 MW/7000 heat rate block nominal) addition at Turkey Point with 600 MWs coming from outside southeast Florida have the same results?***

Yes, the NPV of the increased operating costs shown in Table E-6 would be estimated as the same value ($22.258 MM) for a portfolio with 600 MW of any type of capacity located in the Southeastern region with the balance of the portfolio capacity outside the region. The method FPL will employ to determine the impact of the increased operating costs in the Southeast region created by a portfolio is based solely on the capacity in the Southeast region. Net plant heat rate is not used in the development of this estimate. The information provided in Tables E-5, E-6 and E-7 are indicative estimates of one facet of the economic evaluation, actual results will vary based on the specific nature of any actual proposals or portfolios evaluated.

FPL's RFP process does allow for a combination (as described by the questioner) to be made, if qualifying proposals for a 2x1 combined cycle facility in the Southeast region are received. The resulting portfolio would be compared to other portfolios and the FPL next planned generating unit, a 4x1 combined cycle unit at Turkey Point.

180. ***In regard to the 3 types of costs shown on Table V-2 and Table V-5, which costs will be used in determining the "dispatch costs" for modeling the two FPL self-build options in the economic evaluation? How will the remaining costs on these pages be used in the economic evaluation?***

The projected Variable O&M expenditures, plus the energy cost determined by heat rate and fuel cost, will be added together to form the dispatch cost for the FPL self-build options in the economic evaluation. The two remaining costs, projected Fixed O&M and Capital Replacement expenditures, will be added together and modeled as an annual fixed cost.

181. ***If a proposal is submitted with natural gas as its primary fuel and residual oil as its secondary fuel, and it is the intent of the Proposer that the proposal receive the Fuel Switching Credit, what additional information must be provided?***

The proposal should clearly state, as a comment in Section 4 b) of Form #4, that the proposal is made with the intent of passing the benefit of the fuel switching capability of the facility to FPL's customers and that the Proposer requests the proposal be evaluated with the Fuel Switching Credit.. Only then would the proposal receive the Fuel Switching Credit. (Please see Q & A # 170 for additional discussion of this item).

182. ***On page E-3 of Appendix E of FPL's RFP, the last paragraph requires specific information. However, there is no specific response line indicated on Form # 5 where this information is to be supplied. How should a proposal indicate that a GIS application has been filed? Also, is it acceptable to file a GIS application either concurrently with, or subsequent to, submitting the proposal?***

FPL inadvertently omitted this response line on page 3 of 3 of Form # 5. FPL requests that each applicable proposal address this item either at the bottom of page 3 of 3 of Form # 5 or by adding a separate page after page

3 of 3 in the hard copies of their proposal. FPL requests that this issue be addressed by a statement that a GIS application was filed with the appropriate utility (which is named in the statement) and provide the date on which the application was filed.

In regard to the timing of when FPL expects such a GIS application to be filed, FPL expects that most, if not all, of the proposals submitted in response to this RFP will have a valid application already on file with the appropriate utility. However, FPL will accept proposals that state that a GIS application is being filed concurrently with the submission of the proposal on the Proposal Due Date of October 24, 2003. FPL will deem proposals as ineligible/non-responsive if an associated GIS application is not filed with the appropriate utility by October 24, 2003.

183. Will FPL agree to provide the Seller similar security requirements as it is requesting of the Seller? If not, what protection does the Seller have in the event FPL's credit is downgraded or its financial condition deteriorates?

The RFP and draft PPA do not envision FPL providing similar security to the Seller. However, nothing in the RFP precludes respondents from submitting proposals that are contingent upon FPL agreeing to certain minimum security requirements; the risks, terms and costs of which FPL would assess in the context of the evaluation.

184. Are there any limits on the extent to which the Seller is able to upgrade the facility or make improvements that increase the Committed Capacity during the term of the agreement? If there are limits, what are they? If upgrades are allowed, would FPL pay the same amount for the upgraded capacity?

A PPA entered into as a result of this RFP will address the firm capacity and energy needs identified in FPL's 2003 RFP. The Seller cannot unilaterally modify the facility except as provided in the PPA as it is executed. In the future, the Seller may propose modifications and FPL will consider such a proposal. However, FPL will not be obligated or required to accept or agree to such modifications. To the extent that FPL agrees to the proposed modifications, the PPA would be amended to reflect the agreement and the payment for any modification would be addressed in the amendment.

185. Why is it necessary to deposit Liquid Security into the "security account", especially if it is in the form of a letter of credit?

The minimum bid requirements refer to Section II.H. of the RFP for Security Package Requirements. Section II.H.4) specifies, in part :

"Completion Security and Performance Security in excess of the Supplier Credit Limit shall be in the form of cash in U.S. Dollars or U.S. Government Bonds deposited with an Issuer acceptable to FPL or an irrevocable standby LOC drawn on an Issuer acceptable to FPL."

Letters of credit are not required to be placed in a security account. Other Liquid Security (cash or bonds) are to be deposited with a bank. Note that Section 4.3 of the PPA has proposed language governing this account.

186. Are the FPL lien and the security account requirements of the draft PPA considered minimum requirements of the RFP?

The Financial Viability and Security Requirements listed in Section III. E.5 of the RFP (and incorporated by reference, Section II.H of the RFP) are minimum requirements of the RFP. The specific discussion regarding the Form of Security, as a part of Section II.H of the RFP, is also a minimum requirement. Proposers may state exceptions and alternative language only to those portions of Section 4.3 of the draft PPA not addressed in the sections referenced above.

187. In section 10.4 of the draft PPA, FPL's suggested language states that "FPL shall, at Seller's expense, design, own, purchase, install, and maintain such metering equipments unless FPL agrees in writing to allow another party to design, own, install, and maintain the metering equipment." How can the Seller manage these costs? What costs would FPL suggest the Seller include for this expense since FPL shall design, own, purchase, install, and maintain metering equipment unless FPL decides to allow a third party to perform such tasks?

Metering requirements are included in the transmission interconnection cost estimates FPL will use to evaluate the proposals. The transmission interconnection cost estimates may be developed by the Proposer or by FPL, as described in Appendix D, Section F.4.a). The language in Section 10.4 of the draft PPA sets forth FPL's preferred approach in terms of all aspects of metering. The Proposer may take an exception to this language and suggest alternative language for FPL's consideration.

The actual costs of transmission interconnection will be the responsibility of the Seller in the execution of a Transmission Interconnection Agreement with FPL or a third-party system. The draft PPA discusses the metering requirements that are a part of the FPL Transmission Interconnection Agreement, as these meters are what are presumed in the draft PPA as the revenue meters associated with PPA payments. In any event, it is in the interest of both Proposer and FPL to use cost estimates that are as accurate as possible in this area.

In the absence of an existing study conducted by FPL, the Proposer is given the first opportunity to develop the estimate. FPL will check this cost estimate for reasonableness. If FPL determines that the transmission interconnection cost estimate is materially incorrect, FPL will notify the Proposer regarding the source (if identifiable) and amount of the discrepancy. The Proposer will be allowed to choose whether or not the Proposer will make a correction to the proposed guaranteed capacity payments (Form #5, item 1) consistent with the identified discrepancy. FPL will then use the re-submitted guaranteed capacity payments during the evaluation process. No other proposals will be allowed to be altered, including FPL's next planned generating unit, during this preliminary reasonableness review.

188. Will FPL purchase all start-up energy from the Facility at 90% of its avoided cost?

Yes. Consistent with Section 6.0 and Section 7.0 of the draft PPA, energy delivered by the Facility at the Receipt Point commencing with the Initial Synchronization Date until the Capacity Delivery Date would be paid for at 90% of FPL's Avoided Cost. The Proposer may take an exception to this language and suggest alternative language for FPL's consideration.

189. What are the reference conditions under which the 1225 MW maximum capacity is to be calculated (95 °F, 45% relative humidity)? Is this 1225 MW an absolute maximum or would FPL consider a slightly higher number (i.e. 1250 MW)?

The reference conditions should match that of the proposed Capacity and Heat Rate identified on Form # 4, items 5) and 6). The reference condition is 95 °F and 50% relative humidity. Proposers are further directed to items 4) c and 4) d of Form #4, for a discussion of fuel heat content and ambient pressure values to be used in specifying generator unit performance values.

The maximum block size for consideration in response to this RFP is identified in Section III. E. 4 as 1225 MW. FPL does not pre-suppose that proposals must offer the upper limit of this block size definition. Capacity in excess of this block size will not be considered or evaluated. Moreover, the upper limit of 1225 MW is a minimum requirement proposals must meet to be further evaluated.

190. ***When will FPL determine if it will allow a third party, namely the Seller or a contractor of the Seller, to perform the tasks listed in 5 (a). In section 10.4.6 of the draft PPA, what is the cost of FPL's metering equipment tests?***

Please see Question & Answer # 187.

191. ***Will the Seller be allowed to update pricing once an estimate of electric interconnection and metering costs are obtained from FPL?***

Only in the event that FPL determines a proposal transmission interconnection estimate is materially incorrect. Please see Question & Answer # 187.

192. ***In section 13.17 of the draft PPA, what is intended by the words "make technical references available."***

The draft PPA includes these words with the intent of having Seller make available to FPL the manufacturer's recommendations and designer's estimates associated with the relevant operating capabilities of the Facility.

193. ***Section III.E.6 (Minimum Requirements). Is it the intent of FPL to shift, from the Buyer to the Seller, the congestion costs risk upon implementation of an RTO?***

Yes. It is the intent that, in the event of the implementation of a RTO, certain risks and costs of congestion are assigned as the responsibility of the Seller. This is more fully discussed in Sections 10.2.2 and 10.5 of the draft PPA. The intent and purpose of these sections, and their incorporation as minimum requirements in the RFP, are to protect FPL's customers from uncertain and potentially volatile congestion costs.

Questions 194 to 201 were submitted on September 25, 2003

194. ***With respect to Item 6 of the Minimum Requirements of the RFP, is the phrase "maintaining compliance with current environmental regulations" intended to include changes to such regulations following the Commencement Date?***

Yes, with respect to Item 6 of the Minimum Requirements of the RFP, the phrase, "maintaining compliance with current environmental regulations" is intended to include those environmental regulations that may become effective after the Commencement Date but on or before the Capacity Delivery Date.

195. ***Is it possible that FPL might change the schedule requirements referred to in Section II G of the RFP after proposals have been submitted? If so, will Proposer's be permitted to modify their proposals to account for any burdens imposed on Proposer's from such changes?***

Proposals are to be made with firm binding prices based on the requirements and schedule set forth in the RFP. As noted, the "dates are subject to change to accommodate unforeseen delays or required procedural actions." Any such changes deemed necessary by FPL, will be evaluated by FPL for their impact on all Proposers. The need to allow modifications will be considered at that time.

196. ***It is our understanding that there is an inconsistency between the minimum requirement of the RFP that states the "Site Certification Application" be filed on April 1, 2004 on the one hand, and Section II G of the RFP which states that the latest date to file for the "Need Determination" is June 23, 2004 on the other hand? Please clarify.***

There is no inconsistency. FPL requires that Proposers agree to file the Site Certification application, if selected as a Finalist, by April 1, 2004. FPL will file the request for a Determination of Need (with or without a co-applicant) by June 23, 2004. These dates are necessary to satisfy the statutory time periods of the process supporting a June 1, 2007 COD. A Site Certification application may be filed prior to a request for a Determination of Need.

197. ***In a non-project financed deal (i.e. corporate facility) there will not be a financial closing. Is there a minimum requirement with respect to this type of financing?***

In a non-project financed deal, a Seller who individually meets the minimum financial viability standards required under the RFP and can demonstrate adequate cash available (through available lines of credit or cash on hand) to fund construction may be deemed as satisfying this requirement. The Seller will be required to submit sufficient documentation, including updated financial statements, which in FPL's sole opinion demonstrate the necessary level of funding adequacy. Upon such a review and satisfactory determination, FPL will accept the Full Notice to Proceed to the contractor as meeting the requirements of this milestone.

If the Seller is relying upon a guarantee from another entity, parent company, affiliate, or unaffiliated third party, we would require a "closing equivalent". This would require legal binding commitments of cash adequate to fund construction of the project from the guarantor, in addition to the Full Notice to Proceed.

198. ***Why would it be necessary for FP&L to have both a Plant RTU (Section 14.1 of the DRAFT PPA) and a Switchyard RTU (Section 14.3 of the DRAFT PPA)?***

The Remote Terminal Units (RTUs)identified, perform two different and necessary functions. The Plant RTU is necessary to support Automatic Generation Control and dispatch control data requirements. The Switchyard RTU is required to support transmission system management information systems and switching control system requirements.

199. ***Are ad-valorem tax expenses included in the FP&L Turkey Point generation alternative estimates? If so, what is the amount of the expense?***

Yes. Ad-valorem taxes are included in items 6 (estimated annual levelized capital revenue requirement) and 7 (estimated annual value of deferral with AFUDC) on Table V–1 and Table V–4 of the RFP. A separate breakout of the estimated ad-valorem tax costs is not available. FPL used a property tax rate of 2.06 % in its calculation of these cost items and will use the same property tax rate for FPL generating alternatives, including filler units, in the RFP economic evaluation of capacity options.

200. ***Are major maintenance expenses included in the estimates provided for the FP&L Turkey Point CC estimates? If so, what is the amount of the expense?***

Yes. Table V–2 provides all of the projected annual operating and maintenance expenditures (both fixed and variable), plus the projected annual capital replacement expenditures, for the unit. These projected expenditures include what FPL considers to be "major maintenance." A separate categorization of "major maintenance expenses" is not available.

201. ***Are start expenses included in the estimates provided for the FP&L Turkey Point CT estimates? If so, what is amount of the expense?***

No. FPL estimates the "cold" (greater than 48 hours off-line) start up costs for the Turkey Point CT Alternative Generating Unit to be $12,000 per start. FPL will use only "cold" start up costs in the RFP economic evaluation of capacity options.

Questions 202 – 233 were received on or before September 30, 2003.

202. ***Should a proposer's capacity pricing, expressed in \$/kW-month, be based on a facility's summer capacity or winter capacity?***

Capacity Payments are based on the Committed Capacity in the Draft PPA. The Committed Capacity should be based on the summer capacity of the Facility. The reference conditions are 95°F, 50% RH, at the appropriate barometric pressure for the facility elevation and based on the fuel characteristics provided in Form #4.

203. ***In FPL's PPA, what are the differences between Scheduled Outage Hours, Maintenance Outage Hours, and Planned Outage Hours?***

Section 13.12 of the Draft PPA addresses "Outages" and defines "Schedule Outages" and "Maintenance Outages". Section 13.12 also states the relationship between the Scheduled and Maintenance Outages and the Projected Annual Planned Outage Hours and Projected Annual Forced Outage Hours submitted by Bidders in Form 4, page 2 of 9.

204. ***In FPL's PPA, the capacity payments are based on a facility's "capacity factor" (by way of the Hourly Capacity Factor and Hourly Peak Capacity Factor). Is this terminology supposed to represent the actual dispatch of the facility by FPL or the availability for dispatch provided by the proposer?***

Capacity Payments in the Draft PPA are based on the "Capacity Billing Factor". In the context of the PPA's capacity payment provisions, the term "capacity factor" should be viewed as "availability factor" (i.e., it is based to the Available Capacity of the Facility).

205. ***In the RFP's Appendix D, on page D-6, the discussion concerning variable O&M payments instructs the proposer to assume 85% and 15% annual capacity factors for baseload and peaking resources, respectively. Is FPL guaranteeing this level of utilization for such resources?***

No. The stated capacity factors are simply guidelines and are the bases upon which the variable O&M costs for FPL's next planned generating unit (Turkey Point CC unit) and alternative generating unit (Turkey Point CT Option) were based. FPL is not guaranteeing any particular level of dispatch or utilization of contracted resources.

206. ***In the RFP's Appendix D, on page D-17, is the sentence in the asterisk footnote that reads "Do not include Maintenance Outage Hours in these projections" meant to apply to both columns of requested information (i.e., Planned and Forced Outage Hours)?***

Yes.

207. ***Has the value of the Fuel Switching Credit, estimated on page 11 of the RFP, changed with the publication of the Fuel Forecast in Addendum Two?***

Yes. The Fuel Switching Credit has changed because the spread between the forecasted natural gas cost and the forecasted residual fuel oil cost has changed. This has reduced the frequency with which the model estimates a change will be beneficial, and results in a reduction of the Fuel Switching Credit amount when compared to the earlier estimate. The following table provides an estimate of the Fuel Switching Credit for various heat rate levels.

Table 207.1 Revised Estimate of Fuel Switching Credit

Heat Rate	Estimated Fuel Switching Credit	Units
9,000	$0.093	$/kW-mo.
9,500	$0.098	$/kW-mo.
10,000	$0.103	$/kW-mo.
10,500	$0.108	$/kW-mo.
11,000	$0.113	$/kW-mo.
11,500	$0.119	$/kW-mo.
12,000	$0.124	$/kW-mo.
12,500	$0.129	$/kW-mo.
13,000	$0.134	$/kW-mo.
13,500	$0.139	$/kW-mo.
14,000	$0.144	$/kW-mo.

208. ***Does the FP&L self-build costs (for construction and operation) presented in the RFP include the costs of environmental pollution liability insurance coverage? If so, what is that cost?***

Yes. FPL retains an umbrella liability coverage policy for all FPL facilities. Liability coverage for the clean-up and remediation of environmental spills is an event covered under this policy. The pro-rated cost of this policy for any individual generating unit, including the next planned generating unit, is not available.

209. ***Please explain what is meant by "industry standards" in the last sentence of Section 16.1 of the draft PPA. For example, does it refer to the insurance industry or the electric utility industry? Does it mean blackout/brownout insurance coverage available on reasonable terms and conditions for the resulting bodily injury or property damage that occurs?***

The term "industry standards" in Section 16.1 of the draft PPA refers to insurance industry standards, specifically to the proper use of Florida standard commercial liability insurance documents. The intent is to identify coverage consistent with normal practice that is reasonably available.

210. ***(a) If FPL obtains the need determination but the site certification application is not approved or unreasonably conditioned through no fault of Seller, is Seller relieved of its obligations under the PPA by operation of either the condition precedent clause or the force majeure clause? (b) If your answer provides that Seller is at risk under this scenario, please explain whether acceptance of this risk is a minimum requirement of the RFP.***

(a) Neither clause in the draft PPA would provide relief to a Seller under the scenario described. Specifically, the Condition Precedent clause of the draft PPA offers no relief, while the Force Majeure clause of the draft PPA specifically identifies that such a scenario "....shall not be considered Force Majeure". Neither clause in the draft PPA is a minimum requirement, so a Proposer may take exception and offer alternative language. (b) Acceptance of the risk implied by the specific wording in the above question is not a minimum requirement of the RFP. This does not mean to imply, however, that FPL would accept the alternative language implied by the question in a PPA. Please refer to the following paragraph for a general discussion of the possible impact of exceptions and alternative language to the draft PPA on minimum requirements in the RFP.

FPL included the draft PPA to communicate the clauses and provisions FPL considers are necessary and appropriate to protect the interests of FPL's customers should it be determined to enter into a PPA between FPL and the Proposer. Proposers are allowed to take exception and propose alternative language to provisions in the draft PPA and the RFP, except for those provisions that are minimum requirements (Section III.E of the RFP). In general, as has been previously stated, exceptions to the draft PPA would not result in a proposal being eliminated from further evaluation. However, FPL recognizes that it is possible that a Proposer's exception and alternative language could also result in non-compliance with one or more of the RFP minimum requirements. In that situation, such exception and alternative language to the draft PPA would be judged by FPL to represent a violation of a minimum requirement. If such a situation occurs, where FPL determines that the effect of the exception or alternative language to the draft PPA constitutes a violation of a minimum requirement, FPL will communicate this to the Proposer and offer that Proposer an opportunity to revise the proposal so as to avoid a minimum requirement violation and subsequent disqualification from further evaluation.

211. ***Is the Seller required to assume the risk of a significant delay in the approval of the site certification application through no fault of its own? For example, if due to such a delay, Seller is unable to achieve the Scheduled Capacity Delivery Date, is Seller liable for liquidated damages. Under the same circumstances, if Seller is unable to achieve the Final Capacity Delivery Date, is Seller subject to termination and liable for liquidated damages? If your answer provides that Seller is at risk under either scenario, please explain whether this is a minimum requirement of the RFP.***

The Seller, by submitting the proposal, agrees to comply with meeting the initial delivery date of June 1, 2007 and the Milestone dates found in Sections III.E.2) and III.E.13) respectively, both of which are minimum requirements. Further the draft PPA communicates how FPL would intend to manage the contract in the event of "a significant delay" and what would constitute an excusable "significant delay". Please see Question and Answer # 210 for a discussion of how FPL intends to handle exceptions and alternative language relating to minimum requirements.

212. ***Would Seller be in violation of the minimum requirements if Seller proposed changes to the PPA such that a delay in the approval of a site certification application beyond twelve months (from filing of the application) would constitute a force majeure and the dates for each Major Milestone would be extended by one day for each day delay in receipt of the approval beyond such twelve-month period.***

No, stating exceptions and proposing alternative language to the draft PPA or to the RFP (other than Section III.E, Minimum Requirements) is not, in itself, a violation of the minimum requirements. FPL is unable to answer the question as stated, without reviewing the proposed alternative language in its full context. Please see Question and Answer # 210 for a discussion of how FPL intends to handle exceptions and alternative language relating to minimum requirements.

213. ***Are the figures labeled "Martin Plant 1% Sulfur" referring to the Indiantown Cogeneration, L.P. PPA fuel charge forecast? If not, to what plant/unit do these prices relate?***

No. The prices are estimated as if they were to be delivered to FPL's Martin facility.

214. ***Are the coal prices shown just the coal commodity price, or are they the delivered coal price (i.e. commodity and transportation)?***

The coal prices are the delivered price (commodity and transportation) to the identified location.

215. ***If the coal rates do not include transportation/shipping cost, what is the applicable rate for southeast Florida and/or the "Martin Plant 1% Sulfur"; please distinguish between fixed and variable transportation charges?***

The values include transportation costs. The forecasts are estimates, and are not based upon currently negotiated or committed prices from transportation providers. The values will only be used as representative values for the purpose of the economic evaluation of applicable units.

216. ***Similarly, what is the intrastate shipping cost for petroleum coke to be used in the evaluation and to which location; please distinguish between fixed and variable shipping costs?***

The forecast value is FOB Florida port. No intrastate transportation cost is included. If a Proposer chooses a locale that is not at a Florida port, the proposal should include the costs of transportation from the nearest port to the chosen location.

217. ***Do the prices include all applicable State taxes on the respective fuel commodity or shipping charges? If not, what is the tax assumption(s) per the locations to be used in the evaluation?***

There are no applicable state taxes on fuel consumed for the purpose of electrical generation.

218. ***Are the coal costs for Plants Sherer (Georgia), St. Johns and Martin to be grossed up for electric transmission losses (Figure I.1 on page 5 of the RFP) in the evaluation?***

No. The coal costs represent what is to be applied for the purposes of the economic evaluation.

219. ***Are any of these prices supported by an investment grade entity or guarantor, or are they simply the fuel estimates to be used in the evaluation of solid fueled plants/proposals?***

The fuel costs provided in Addendum Two to FPL's 2003 RFP will be used in the economic evaluation of FPL and proposed facilities. They represent FPL's best available estimates for fuel commodity and transportation costs and are not supported by a guarantee.

220. ***Is a proposal made in respect of a specific portion of a facility acceptable, where that portion in all respects is dedicated to serving FPL and complies with, inter alia, the same PPA terms as would apply to a whole facility?***

No. Minimum requirement #3 fully describes the expectations of FPL in this RFP solicitation. Partial output capacity proposals are not acceptable for this solicitation. It would be acceptable, however, for a proposal to offer full output in compliance with the minimum requirements from specified units at a site that may have additional units under other arrangements.

221. ***If the foregoing is not acceptable, please provide a rationale as the situation described is the same as the existing FPL plant examples and there does not appear to be any impediments in the draft PPA.***

A response to this question is not required to develop a proposal to the RFP.

222. ***Please identify what "Governmental Authority" (other than FPSC or FERC) could be expected to have jurisdiction over a PPA with FPL.***

The language refers to any possible future entity that may assume such jurisdiction.

223. ***Please explain why a company, absent any employees of suitable skill/experience, mitigates the issue about representative experience? Are you not ultimately relying on the experience base, which supported prior successes, is still there today or has been met by new hires with suitable experience?***

Employees are not guarantors of performance. The responsibility and therefore the experience requirements are appropriately assigned to the firm and/or partnership undertaking the guarantee.

224. ***Please explain how completion risks (or other financial risks) are not already satisfied via the terms of the draft PPA?***

A response to this question is not required to develop a proposal to the RFP. Proposers are encouraged to state exceptions and alternative language to the RFP and draft PPA terms that are not minimum requirements in Section III.E of the RFP.

225. ***Is there any sanction from the FPSC or FERC statue, which requires that, in respect of a proposal submission, an investment grade rating is necessary?***

A response to this question is not required to develop a proposal to the RFP.

226. ***Isn't it the case that the "4-on-1 CC self build" proposal isn't actionable until the plant is certified by the FPSC for rate recovery, or absent such recovery order, FPL's debt rating could be impaired? Similarly, would not the debt rating of a SPE proposal be related (via the PPA) to FPL's debt rating?***

A response to this question is not required to develop a proposal to the RFP.

227. ***What monetary consideration is there at the time of submission of a proposal up to signing a PPA, which requires an investment grade rating?***

A response to this question is not required to develop a proposal to the RFP.

228. ***Please explain the comments on page 6 of the RFP: "Specifically, the most likely site for a future solid fuel facility in Florida would be outside the Southeast area." Wouldn't such a plant (or any plant, regardless of fuel) face the same loss of capacity value as indicated in Figure I.1?***

In answer to your question, yes any proposed plant that is sited outside the Southeast will be subject to the same transmission loss methodology described in detail in Appendix E to the RFP.

229. ***For who's future solid fueled plant is transmission capacity being set aside so it does not "carry a larger burden of transmission costs"?***

Please see Question and Answer # 57. No transmission capacity is being set aside. It is not necessary to assume a specific plant or owner to discuss the potential future impact of present day generation siting decisions.

230. ***Are all suppliers to FPL to be treated as a network resource for transmission planning?***

Yes. All suppliers would be treated as a network resource for the RFP transmission planning evaluation.

231. ***Aside from line losses, how are stability issues priced and apportioned, for example in affecting the value/pricing of a proposal?***

The transmission integration analysis, conducted for each candidate portfolio, will include the development of system upgrades necessary to interconnect the candidate portfolio and satisfy system stability requirements. The development of transmission-related costs is described in detail in Appendix E. These portfolio based costs are considered when determining the overall system costs presented by the candidate portfolio. They are not further apportioned or assigned to the pricing of an individual proposal that is a part of the candidate portfolio.

232. ***Why isn't a 2-on-1 combined cycle unit at Turkey Point used for the candidate portfolios?***

A response to this question is not required to develop a proposal to the RFP.

233. ***May Proposers withdraw their proposals in full at any time, regardless of whether or not FPL makes modifications to its Next Planned Generating Unit?***
Yes.

Appendix J
FPL's Self Build Construction Option

	New Generation Alternatives	1
	Alternatives:	4 x 1 CC Moderate Duct Fired **PTF**
	I. CONSTRUCTION (1000) (2007 $)	
A	Permit/Eng/Fab (months)	24
B	Construction Phase (months)	24
C	Project Total (months)	48
D	Total Direct Cost	$408,000
E	Total Indirect Cost	$54,200
F	Dual Fuel Adder	$10,000
G	Fuel Expansion/Handling	$29,900
H	Transmission Expansion Interconnection	$22,900
I	Transmission Integration	$3,500
J	AFUDC (excludes item I on Alternative 2)	$51,800
K	Total Other Cost	$118,100
L	**Grand Total Cost (1000) (2007 $)**	**$580,300**
	II. PLANT CHARACTERISTICS (Unit Average)	
M	Net Sum 95FCapability (mw) - Base	984
N	Net Win 35F Capability (mw) - Base	1086
O	Heat Rate btu/kwh 75F100% -Base	6,835
P	Heat Rate btu/kwh 75F 75% -Base	7,130
Q	Heat Rate btu/kwh 75F 50% -Base	7,720
R	Duct Firing-Incremental from Base Sum MW 95F	96
S	Duct Firing-Incremental from Base Win MW 35F	95
T	Duct Firing-Incremental from Base Ann Avg Heat Rate 75F	8,700
U	Peak Firing- Incremental from Base Sum MW 95F	64
V	Peak Firing- Incremental from Base Win MW 35F	n/a
W	Peak Firing- Incremental from Base Sum Heat Rate 75F	11,500
X	Base Operation- Planned Outage Hours/Year	148
Y	Base Operation- Forced Outage Hours/Year	88
Z	Duct Firing Operation- Planned Outage Hours/Year	n/a
AA	Duct Firing Operation- Forced Outage Hours/Year	n/a
BB	Peak Firing Operation- Planned Outage Hours/Year	8672
CC	Peak Firing Operation- Forced Outage Hours/Year	0
DD	Ramp Rate (MW/Minute)	30
EE	Minimum Load	300
	III. OPERATION COSTS (2007 $)	
FF	Fixed O&M ($/kw - yr) (Summer Peak Output)	3.57
GG	Variable (excl. fuel) ($/mwh) (Summer Peak Output @ 85% CF)	0.13
HH	Capital Replacement ($/kw-yr) (Summer Peak Output)	6.49
II	Cold Startup Cost (greater than 48 hours off-line)($/startup)	$20,000
	IV. EMISSION RATES	
JJ	NOx Emission Rates (lb/mmbtu)	0.010
KK	CO Emission Rates (lb/mmbtu)	0.031
LL	SO2 Emission Rates (lb/mmbtu)	0.006
MM	PM10 (lb/mmbtu)	0.007
	IV. SPENDING CURVES	
NN	See Attached Monthly Cash Flows	
	Equipment	GE 7241FA 4CT/HRSG&1ST
	Cooling	Tower
	SCR's	Yes
		Foggers

Appendix K

Summary of Requirements and Cost for Upgrades or New construction

Portfolio capacity options			Summer peak capability for capacity options in portfolio (MW) Portfolio 1	Portfolio 2	Portfolio 3/4	Portfolio 6	Portfolio 7/8	Portfolio 10
FPL CC @ Turkey PT			**1144**					
FPL 4 CTs @ Turkey PT				**648**		**648**		**648**
BID 1 CFB @ HST Lucy 230 kV bus						**50**	**50**	
Bid 2/3 CC @ Midway-Martin 500kV line					**1220**		**1220**	
BID 4 CTs @ Whidden 230 kV bus				**447**		**447**		**447**
BID 5 CC @ Malabar-Midway/Emerson 230 kV lines								**252**
Total MW for portfolio			**1144**	**1095**	**1220**	**1145**	**1270**	**1347**
Transmission facility	**kV**	**Upgrade or new facility**	**Integration cost by facility required to meet reliability criteria ($,000)**					
Turkey Pt - Galloway Tap	230	Upgrade	2,196					
Turkey Pt - McGregor - Fla City	230	Upgrade	101	101				101
Turkey Pt-Killian	230	Upgrade	2,178					
Killian - Miller	230	Upgrade	59					
Charlotte - Orange Rv	230	New Line		22,963		22,963		22,963
Orange Rv - Alva - Corbett	230	Upgrade		21,554		21,554		21,554
Riviera - Roebuck	138	Upgrade			1,436		1,436	
W. Palm Bch-Westward	138	Upgrade			74		74	
Westward-Roebuck	138	Upgrade			263		263	
Laudania-Pt. Everglades	230	Upgrade			14		14	
55 MVAR Cap at Arch Creek	138	Cap. Bank			751		751	
55 MVAR Cap at Biscayne	138	Cap. Bank			751		751	
55 MVAR Cap at Miami Shores	138	Cap. Bank			707		707	
55 MVAR Cap at Opa Locka	138	Cap. Bank			697		697	
55 MVAR Cap at Hallandale	138	Cap. Bank			697			
Total Integration Cost ($,000)			**4,534**	**44,618**	**5,390**	**44,517**	**4,693**	**44,618**

Appendix L

Transmission losses calculated for the year 2007

Portfolio	Transmission losses in MW relative to Portfolio 1	
	2007 Peak Load Level	2007 Average Load Level
Portfolio 2	27	19
Portfolio 3/4	32	6
Portfolio 6	17	15
Portfolio 7/8	29	2
Portfolio 10	21	10

Appendix M
Calculation of Costs for Annual Energy Losses:

Portfolio Description: **FPL CC**

On-Peak Hours =	876
Off-Peak Hours =	7,884
Discount Factor =	0.07819

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
					= (4)*On-Peak Hours	= (1)*(5)/1000		= (7)*Off-Peak Hours	= (2)*(8)/1000	= (6) + (9)	= (3)*(10)
Year	On-Peak Marginal Energy Cost ($/mwh)	Off-Peak Marginal Energy Cost ($/mwh)	Discount Factor	Peak Load Loss (MW)	On - Peak Hours Annual Energy Loss (MWH)	On - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	Average Load Loss (MW)	Off - Peak Hours Annual Energy Loss (MWH)	Off - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	Total Annual Energy Loss Cost Nominal ($ 000)	Total Annual Energy Loss Cost NPV ($ 000)
2003	0	0	1.000	0	0	$0	0	0	$0	$0	$0
2004	0	0	0.927	0	0	$0	0	0	$0	$0	$0
2005	0	0	0.860	0	0	$0	0	0	$0	$0	$0
2006	0	0	0.798	0	0	$0	0	0	$0	$0	$0
2007	$46.92	$39.15	0.740	0	0	$0	0	0	$0	$0	$0
2008	$45.77	$38.49	0.686	0	0	$0	0	0	$0	$0	$0
2009	$47.31	$39.94	0.637	0	0	$0	0	0	$0	$0	$0
2010	$47.82	$40.13	0.590	0	0	$0	0	0	$0	$0	$0
2011	$50.00	$41.91	0.548	0	0	$0	0	0	$0	$0	$0
2012	$50.26	$42.68	0.508	0	0	$0	0	0	$0	$0	$0
2013	$53.33	$44.79	0.471	0	0	$0	0	0	$0	$0	$0
2014	$55.90	$44.73	0.437	0	0	$0	0	0	$0	$0	$0
2015	$56.67	$46.05	0.405	0	0	$0	0	0	$0	$0	$0
2016	$58.97	$48.44	0.376	0	0	$0	0	0	$0	$0	$0
2017	$60.77	$49.38	0.349	0	0	$0	0	0	$0	$0	$0
2018	$62.69	$51.47	0.323	0	0	$0	0	0	$0	$0	$0
2019	$63.08	$52.28	0.300	0	0	$0	0	0	$0	$0	$0
2020	$63.59	$53.21	0.278	0	0	$0	0	0	$0	$0	$0
2021	$66.15	$55.35	0.258	0	0	$0	0	0	$0	$0	$0
2022	$68.21	$57.24	0.239	0	0	$0	0	0	$0	$0	$0
2023	$68.85	$58.71	0.222	0	0	$0	0	0	$0	$0	$0
2024	$72.56	$61.38	0.206	0	0	$0	0	0	$0	$0	$0
2025	$73.97	$63.40	0.191	0	0	$0	0	0	$0	$0	$0
2026	$76.54	$65.68	0.177	0	0	$0	0	0	$0	$0	$0
2027	$79.49	$67.82	0.164	0	0	$0	0	0	$0	$0	$0
2028	$81.41	$70.21	0.152	0	0	$0	0	0	$0	$0	$0
2029	$84.10	$72.75	0.141	0	0	$0	0	0	$0	$0	$0
2030	$86.92	$75.34	0.131	0	0	$0	0	0	$0	$0	$0
2031	$90.90	$77.88	0.121	0	0	$0	0	0	$0	$0	$0
										NPV Total ($000) =	$0

Appendix M
Calculation of Costs for Annual Energy Losses:

Portfolio Description: **FPL 4 CT & Bid 4**

On-Peak Hours =	876
Off-Peak Hours =	7,884
Discount Factor =	0.07819

	(1)	(2)	(3)	(4)	(5) = (4)*On-Peak Hours	(6) = (1)*(5)/1000	(7)	(8) = (7)*Off-Peak Hours	(9) = (2)*(8)/1000	(10) = (6) + (9)	(11) = (3)*(10)
Year	On-Peak Marginal Energy Cost ($/mwh)	Off-Peak Marginal Energy Cost ($/mwh)	Discount Factor	Peak Load Loss (MW)	On - Peak Hours Annual Energy Loss (MWH)	On - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	Average Load Loss (MW)	Off - Peak Hours Annual Energy Loss (MWH)	Off - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	Total Annual Energy Loss Cost Nominal ($ 000)	Total Annual Energy Loss Cost NPV ($ 000)
2003	0	0	1.000	0	0	$0	0	0	$0	$0	$0
2004	0	0	0.927	0	0	$0	0	0	$0	$0	$0
2005	0	0	0.860	0	0	$0	0	0	$0	$0	$0
2006	0	0	0.798	0	0	$0	0	0	$0	$0	$0
2007	$46.92	$39.15	0.740	[redacted]	23,652	$1,110	[redacted]	149,796	$5,865	$6,974	$5,161
2008	$45.77	$38.49	0.686	[redacted]	23,652	$1,083	[redacted]	149,796	$5,766	$6,848	$4,700
2009	$47.31	$39.94	0.637	[redacted]	23,652	$1,119	[redacted]	149,796	$5,983	$7,102	$4,521
2010	$47.82	$40.13	0.590	[redacted]	23,652	$1,131	[redacted]	149,796	$6,011	$7,142	$4,217
2011	$50.00	$41.91	0.548	[redacted]	23,652	$1,183	[redacted]	149,796	$6,278	$7,461	$4,085
2012	$50.26	$42.68	0.508	[redacted]	23,652	$1,189	[redacted]	149,796	$6,393	$7,582	$3,851
2013	$53.33	$44.79	0.471	[redacted]	23,652	$1,261	[redacted]	149,796	$6,709	$7,971	$3,754
2014	$55.90	$44.73	0.437	[redacted]	23,652	$1,322	[redacted]	149,796	$6,700	$8,023	$3,505
2015	$56.67	$46.05	0.405	[redacted]	23,652	$1,340	[redacted]	149,796	$6,898	$8,238	$3,338
2016	$58.97	$48.44	0.376	[redacted]	23,652	$1,395	[redacted]	149,796	$7,256	$8,651	$3,251
2017	$60.77	$49.38	0.349	[redacted]	23,652	$1,437	[redacted]	149,796	$7,397	$8,834	$3,079
2018	$62.69	$51.47	0.323	[redacted]	23,652	$1,483	[redacted]	149,796	$7,710	$9,193	$2,972
2019	$63.08	$52.28	0.300	[redacted]	23,652	$1,492	[redacted]	149,796	$7,831	$9,323	$2,795
2020	$63.59	$53.21	0.278	[redacted]	23,652	$1,504	[redacted]	149,796	$7,971	$9,475	$2,635
2021	$66.15	$55.35	0.258	[redacted]	23,652	$1,565	[redacted]	149,796	$8,291	$9,856	$2,542
2022	$68.21	$57.24	0.239	[redacted]	6,132	$418	[redacted]	78,840	$4,513	$4,931	$1,180
2023	$68.85	$58.71	0.222	[redacted]	6,132	$422	[redacted]	78,840	$4,629	$5,051	$1,121
2024	$72.56	$61.38	0.206	[redacted]	6,132	$445	[redacted]	78,840	$4,839	$5,284	$1,087
2025	$73.97	$63.40	0.191	[redacted]	6,132	$454	[redacted]	78,840	$4,998	$5,452	$1,041
2026	$76.54	$65.68	0.177	[redacted]	6,132	$469	[redacted]	78,840	$5,178	$5,648	$1,000
2027	$79.49	$67.82	0.164	[redacted]	6,132	$487	[redacted]	78,840	$5,347	$5,834	$958
2028	$81.41	$70.21	0.152	[redacted]	6,132	$499	[redacted]	78,840	$5,535	$6,035	$919
2029	$84.10	$72.75	0.141	[redacted]	6,132	$516	[redacted]	78,840	$5,736	$6,251	$883
2030	$86.92	$75.34	0.131	[redacted]	6,132	$533	[redacted]	78,840	$5,940	$6,473	$848
2031	$90.90	$77.88	0.121	[redacted]	6,132	$557	[redacted]	78,840	$6,140	$6,697	$814
										NPV Total ($000) =	$64,254

Appendix M
Calculation of Costs for Annual Energy Losses:

Portfolio Description: **Bid 2**

On-Peak Hours =	876
Off-Peak Hours =	7,884
Discount Factor =	0.07819

	(1)	(2)	(3)	(4)	(5) = (4)*On-Peak Hours	(6) = (1)*(5)/1000	(7)	(8) = (7)*Off-Peak Hours	(9) = (2)*(8)/1000	(10) = (6) + (9)	(11) = (3)*(10)
Year	On-Peak Marginal Energy Cost ($/mwh)	Off-Peak Marginal Energy Cost ($/mwh)	Discount Factor	Peak Load Loss (MW)	On - Peak Hours Annual Energy Loss (MWH)	On - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	Average Load Loss (MW)	Off - Peak Hours Annual Energy Loss (MWH)	Off - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	Total Annual Energy Loss Cost Nominal ($ 000)	Total Annual Energy Loss Cost NPV ($ 000)
2003	0	0	1.000	0	0	$0	0	0	$0	$0	$0
2004	0	0	0.927	0	0	$0	0	0	$0	$0	$0
2005	0	0	0.860	0	0	$0	0	0	$0	$0	$0
2006	0	0	0.798	0	0	$0	0	0	$0	$0	$0
2007	$46.92	$39.15	0.740	[redacted]	28,032	$1,315	[redacted]	47,304	$1,852	$3,167	$2,344
2008	$45.77	$38.49	0.686	[redacted]	28,032	$1,283	[redacted]	47,304	$1,821	$3,104	$2,130
2009	$47.31	$39.94	0.637	[redacted]	28,032	$1,326	[redacted]	47,304	$1,889	$3,216	$2,047
2010	$47.82	$40.13	0.590	[redacted]	28,032	$1,340	[redacted]	47,304	$1,898	$3,239	$1,912
2011	$50.00	$41.91	0.548	[redacted]	28,032	$1,402	[redacted]	47,304	$1,983	$3,384	$1,853
2012	$50.26	$42 68	0.508	[redacted]	28,032	$1,409	[redacted]	47,304	$2,019	$3,428	$1,741
2013	$53.33	$44.79	0 471	[redacted]	28,032	$1,495	[redacted]	47,304	$2,119	$3,614	$1,702
2014	$55.90	$44.73	0 437	[redacted]	28,032	$1,567	[redacted]	47,304	$2,116	$3,683	$1,609
2015	$56.67	$46.05	0.405	[redacted]	28,032	$1,589	[redacted]	47,304	$2,178	$3,767	$1,526
2016	$58 97	$48.44	0.376	[redacted]	28,032	$1,653	[redacted]	47,304	$2,291	$3,944	$1,482
2017	$60.77	$49.38	0 349	[redacted]	28,032	$1,704	[redacted]	47,304	$2,336	$4,039	$1,408
2018	$62.69	$51.47	0 323	[redacted]	28,032	$1,757	[redacted]	47,304	$2,435	$4,192	$1,355
2019	$63.08	$52.28	0 300	[redacted]	28,032	$1,768	[redacted]	47,304	$2,473	$4,241	$1,272
2020	$63.59	$53.21	0.278	[redacted]	28,032	$1,783	[redacted]	47,304	$2,517	$4,300	$1,196
2021	$66.15	$55.35	0.258	[redacted]	28,032	$1,854	[redacted]	47,304	$2,618	$4,473	$1,154
2022	$68.21	$57.24	0.239	[redacted]	14,892	$1,016	[redacted]	15,768	$903	$1,918	$459
2023	$68.85	$58 71	0.222	[redacted]	14,892	$1,025	[redacted]	15,768	$926	$1,951	$433
2024	$72.56	$61.38	0.206	[redacted]	14,892	$1,081	[redacted]	15,768	$968	$2,048	$422
2025	$73.97	$63.40	0.191	[redacted]	14,892	$1,102	[redacted]	15,768	$1,000	$2,101	$401
2026	$76.54	$65 68	0.177	[redacted]	14,892	$1,140	[redacted]	15,768	$1,036	$2,175	$385
2027	$79.49	$67.82	0.164	[redacted]	14,892	$1,184	[redacted]	15,768	$1,069	$2,253	$370
2028	$81.41	$70.21	0 152	[redacted]	14,892	$1,212	[redacted]	15,768	$1,107	$2,319	$353
2029	$84.10	$72.75	0.141	[redacted]	14,892	$1,252	[redacted]	15,768	$1,147	$2,400	$339
2030	$86.92	$75.34	0.131	[redacted]	14,892	$1,294	[redacted]	15,768	$1,188	$2,482	$325
2031	$90 90	$77 88	0 121	[redacted]	14,892	$1,354	[redacted]	15,768	$1,228	$2,582	$314
										NPV Total ($000) =	$28,531

Appendix M
Calculation of Costs for Annual Energy Losses:

Portfolio Description: **FPL 4 CT & Bid 4 & Bid 1**

On-Peak Hours =	876
Off-Peak Hours =	7,884
Discount Factor =	0.07819

	(1)	(2)	(3)	(4)	(5) = (4)*On-Peak Hours	(6) = (1)*(5)/1000	(7)	(8) = (7)*Off-Peak Hours	(9) = (2)*(8)/1000	(10) = (6) + (9)	(11) = (3)*(10)
Year	On-Peak Marginal Energy Cost ($/mwh)	Off-Peak Marginal Energy Cost ($/mwh)	Discount Factor	Peak Load Loss (MW)	On - Peak Hours Annual Energy Loss (MWH)	On - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	Average Load Loss (MW)	Off - Peak Hours Annual Energy Loss (MWH)	Off - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	Total Annual Energy Loss Cost Nominal ($ 000)	Total Annual Energy Loss Cost NPV ($ 000)
2003	0	0	1.000	0	0	$0	0	0	$0	$0	$0
2004	0	0	0.927	0	0	$0	0	0	$0	$0	$0
2005	0	0	0.860	0	0	$0	0	0	$0	$0	$0
2006	0	0	0.798	0	0	$0	0	0	$0	$0	$0
2007	$46.92	$39.15	0.740	[redacted]	14,892	$699	[redacted]	118,260	$4,630	$5,329	$3,943
2008	$45.77	$38.49	0.686	[redacted]	14,892	$682	[redacted]	118,260	$4,552	$5,233	$3,592
2009	$47.31	$39.94	0.637	[redacted]	14,892	$705	[redacted]	118,260	$4,723	$5,428	$3,455
2010	$47.82	$40.13	0.590	[redacted]	14,892	$712	[redacted]	118,260	$4,746	$5,458	$3,222
2011	$50.00	$41.91	0.548	[redacted]	14,892	$745	[redacted]	118,260	$4,956	$5,701	$3,122
2012	$50.26	$42.68	0.508	[redacted]	14,892	$748	[redacted]	118,260	$5,047	$5,796	$2,943
2013	$53.33	$44.79	0.471	[redacted]	14,892	$794	[redacted]	118,260	$5,297	$6,091	$2,869
2014	$55.90	$44.73	0.437	[redacted]	14,892	$832	[redacted]	118,260	$5,290	$6,122	$2,675
2015	$56.67	$46.05	0.405	[redacted]	14,892	$844	[redacted]	118,260	$5,446	$6,290	$2,549
2016	$58.97	$48.44	0.376	[redacted]	14,892	$878	[redacted]	118,260	$5,729	$6,607	$2,483
2017	$60.77	$49.38	0.349	[redacted]	14,892	$905	[redacted]	118,260	$5,840	$6,745	$2,351
2018	$62.69	$51.47	0.323	[redacted]	14,892	$934	[redacted]	118,260	$6,087	$7,020	$2,270
2019	$63.08	$52.28	0.300	[redacted]	14,892	$939	[redacted]	118,260	$6,183	$7,122	$2,135
2020	$63.59	$53.21	0.278	[redacted]	14,892	$947	[redacted]	118,260	$6,293	$7,240	$2,013
2021	$66.15	$55.35	0.258	[redacted]	14,892	$985	[redacted]	118,260	$6,546	$7,531	$1,942
2022	$68.21	$57.24	0.239	[redacted]	(1,752)	($120)	[redacted]	47,304	$2,708	$2,588	$619
2023	$68.85	$58.71	0.222	[redacted]	(1,752)	($121)	[redacted]	47,304	$2,777	$2,657	$589
2024	$72.56	$61.38	0.206	[redacted]	(1,752)	($127)	[redacted]	47,304	$2,904	$2,776	$571
2025	$73.97	$63.40	0.191	[redacted]	(1,752)	($130)	[redacted]	47,304	$2,999	$2,869	$548
2026	$76.54	$65.68	0.177	[redacted]	(1,752)	($134)	[redacted]	47,304	$3,107	$2,973	$526
2027	$79.49	$67.82	0.164	[redacted]	(1,752)	($139)	[redacted]	47,304	$3,208	$3,069	$504
2028	$81.41	$70.21	0.152	[redacted]	(1,752)	($143)	[redacted]	47,304	$3,321	$3,179	$484
2029	$84.10	$72.75	0.141	[redacted]	(1,752)	($147)	[redacted]	47,304	$3,441	$3,294	$465
2030	$86.92	$75.34	0.131	[redacted]	(1,752)	($152)	[redacted]	47,304	$3,564	$3,412	$447
2031	$90.90	$77.88	0.121	[redacted]	(1,752)	($159)	[redacted]	47,304	$3,684	$3,525	$428
										NPV Total ($000) =	$46,746

Appendix M
Calculation of Costs for Annual Energy Losses:

Portfolio Description: **Bid 2 & Bid 1**

On-Peak Hours =	876
Off-Peak Hours =	7,884
Discount Factor =	0 07819

	(1)	(2)	(3)	(4)	(5) = (4)*On-Peak Hours	(6) = (1)*(5)/1000	(7)	(8) = (7)*Off-Peak Hours	(9) = (2)*(8)/1000	(10) = (6) + (9)	(11) = (3)*(10)
Year	On-Peak Marginal Energy Cost ($/mwh)	Off-Peak Marginal Energy Cost ($/mwh)	Discount Factor	Peak Load Loss (MW)	On - Peak Hours Annual Energy Loss (MWH)	On - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	Average Load Loss (MW)	Off - Peak Hours Annual Energy Loss (MWH)	Off - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	Total Annual Energy Loss Cost Nominal ($ 000)	Total Annual Energy Loss Cost NPV ($ 000)
2003	0	0	1.000	0	0	$0	0	0	$0	$0	$0
2004	0	0	0.927	0	0	$0	0	0	$0	$0	$0
2005	0	0	0.860	0	0	$0	0	0	$0	$0	$0
2006	0	0	0.798	0	0	$0	0	0	$0	$0	$0
2007	$46.92	$39.15	0.740	[redacted]	25,404	$1,192	[redacted]	15,768	$617	$1,809	$1,339
2008	$45 77	$38.49	0.686	[redacted]	25,404	$1,163	[redacted]	15,768	$607	$1,770	$1,215
2009	$47.31	$39.94	0.637	[redacted]	25,404	$1,202	[redacted]	15,768	$630	$1,832	$1,166
2010	$47.82	$40.13	0.590	[redacted]	25,404	$1,215	[redacted]	15,768	$633	$1,848	$1,091
2011	$50.00	$41.91	0.548	[redacted]	25,404	$1,270	[redacted]	15,768	$661	$1,931	$1,057
2012	$50.26	$42.68	0.508	[redacted]	25,404	$1,277	[redacted]	15,768	$673	$1,950	$990
2013	$53.33	$44 79	0.471	[redacted]	25,404	$1,355	[redacted]	15,768	$706	$2,061	$971
2014	$55.90	$44.73	0.437	[redacted]	25,404	$1,420	[redacted]	15,768	$705	$2,125	$929
2015	$56.67	$46.05	0.405	[redacted]	25,404	$1,440	[redacted]	15,768	$726	$2,166	$878
2016	$58 97	$48.44	0.376	[redacted]	25,404	$1,498	[redacted]	15,768	$764	$2,262	$850
2017	$60.77	$49.38	0.349	[redacted]	25,404	$1,544	[redacted]	15,768	$779	$2,322	$809
2018	$62.69	$51.47	0.323	[redacted]	25,404	$1,593	[redacted]	15,768	$812	$2,404	$777
2019	$63.08	$52.28	0.300	[redacted]	25,404	$1,602	[redacted]	15,768	$824	$2,427	$728
2020	$63.59	$53.21	0.278	[redacted]	25,404	$1,615	[redacted]	15,768	$839	$2,454	$683
2021	$66.15	$55.35	0.258	[redacted]	25,404	$1,680	[redacted]	15,768	$873	$2,553	$659
2022	$68 21	$57.24	0.239	[redacted]	13,140	$896	[redacted]	(15,768)	($903)	($6)	($2)
2023	$68.85	$58.71	0.222	[redacted]	13,140	$905	[redacted]	(15,768)	($926)	($21)	($5)
2024	$72 56	$61.38	0.206	[redacted]	13,140	$953	[redacted]	(15,768)	($968)	($14)	($3)
2025	$73.97	$63.40	0.191	[redacted]	13,140	$972	[redacted]	(15,768)	($1,000)	($28)	($5)
2026	$76.54	$65.68	0.177	[redacted]	13,140	$1,006	[redacted]	(15,768)	($1,036)	($30)	($5)
2027	$79 49	$67.82	0.164	[redacted]	13,140	$1,044	[redacted]	(15,768)	($1,069)	($25)	($4)
2028	$81.41	$70.21	0 152	[redacted]	13,140	$1,070	[redacted]	(15,768)	($1,107)	($37)	($6)
2029	$84.10	$72.75	0.141	[redacted]	13,140	$1,105	[redacted]	(15,768)	($1,147)	($42)	($6)
2030	$86.92	$75.34	0.131	[redacted]	13,140	$1,142	[redacted]	(15,768)	($1,188)	($46)	($6)
2031	$90.90	$77 88	0 121	[redacted]	13,140	$1,194	[redacted]	(15,768)	($1,228)	($34)	($4)
										NPV Total ($000) =	$14,094

Appendix M
Calculation of Costs for Annual Energy Losses:

Portfolio Description: **FPL 4 CT & Bid 4 & Bid 5**

On-Peak Hours =	876
Off-Peak Hours =	7,884
Discount Factor =	0.07819

	(1)	(2)	(3)	(4)	(5) = (4)*On-Peak Hours	(6) = (1)*(5)/1000	(7)	(8) = (7)*Off-Peak Hours	(9) = (2)*(8)/1000	(10) = (6) + (9)	(11) = (3)*(10)
Year	On-Peak Marginal Energy Cost ($/mwh)	Off-Peak Marginal Energy Cost ($/mwh)	Discount Factor	Peak Load Loss (MW)	On - Peak Hours Annual Energy Loss (MWH)	On - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	Average Load Loss (MW)	Off - Peak Hours Annual Energy Loss (MWH)	Off - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	Total Annual Energy Loss Cost Nominal ($ 000)	Total Annual Energy Loss Cost NPV ($ 000)
2003	0	0	1.000	0	0	$0	0	0	$0	$0	$0
2004	0	0	0.927	0	0	$0	0	0	$0	$0	$0
2005	0	0	0.860	0	0	$0	0	0	$0	$0	$0
2006	0	0	0.798	0	0	$0	0	0	$0	$0	$0
2007	$46.92	$39.15	0.740	[redacted]	18,396	$863	[redacted]	78,840	$3,087	$3,950	$2,923
2008	$45.77	$38.49	0.686	[redacted]	18,396	$842	[redacted]	78,840	$3,035	$3,877	$2,661
2009	$47.31	$39.94	0.637	[redacted]	18,396	$870	[redacted]	78,840	$3,149	$4,019	$2,558
2010	$47.82	$40.13	0.590	[redacted]	18,396	$880	[redacted]	78,840	$3,164	$4,044	$2,387
2011	$50.00	$41.91	0.548	[redacted]	18,396	$920	[redacted]	78,840	$3,304	$4,224	$2,313
2012	$50.26	$42.68	0.508	[redacted]	18,396	$925	[redacted]	78,840	$3,365	$4,289	$2,178
2013	$53.33	$44.79	0.471	[redacted]	18,396	$981	[redacted]	78,840	$3,531	$4,512	$2,125
2014	$55.90	$44.73	0.437	[redacted]	18,396	$1,028	[redacted]	78,840	$3,527	$4,555	$1,990
2015	$56.67	$46.05	0.405	[redacted]	18,396	$1,043	[redacted]	78,840	$3,631	$4,673	$1,893
2016	$58.97	$48.44	0.376	[redacted]	18,396	$1,085	[redacted]	78,840	$3,819	$4,904	$1,843
2017	$60.77	$49.38	0.349	[redacted]	18,396	$1,118	[redacted]	78,840	$3,893	$5,011	$1,747
2018	$62.69	$51.47	0.323	[redacted]	18,396	$1,153	[redacted]	78,840	$4,058	$5,211	$1,685
2019	$63.08	$52.28	0.300	[redacted]	18,396	$1,160	[redacted]	78,840	$4,122	$5,282	$1,584
2020	$63.59	$53.21	0.278	[redacted]	18,396	$1,170	[redacted]	78,840	$4,195	$5,365	$1,492
2021	$66.15	$55.35	0.258	[redacted]	18,396	$1,217	[redacted]	78,840	$4,364	$5,581	$1,439
2022	$68.21	$57.24	0.239	[redacted]	(1,752)	($120)	[redacted]	94,608	$5,415	$5,296	$1,267
2023	$68.85	$58.71	0.222	[redacted]	(1,752)	($121)	[redacted]	94,608	$5,554	$5,434	$1,206
2024	$72.56	$61.38	0.206	[redacted]	(1,752)	($127)	[redacted]	94,608	$5,807	$5,680	$1,169
2025	$73.97	$63.40	0.191	[redacted]	(1,752)	($130)	[redacted]	94,608	$5,998	$5,869	$1,120
2026	$76.54	$65.68	0.177	[redacted]	(1,752)	($134)	[redacted]	94,608	$6,214	$6,080	$1,076
2027	$79.49	$67.82	0.164	[redacted]	(1,752)	($139)	[redacted]	94,608	$6,416	$6,277	$1,031
2028	$81.41	$70.21	0.152	[redacted]	(1,752)	($143)	[redacted]	94,608	$6,642	$6,500	$990
2029	$84.10	$72.75	0.141	[redacted]	(1,752)	($147)	[redacted]	94,608	$6,883	$6,735	$951
2030	$86.92	$75.34	0.131	[redacted]	(1,752)	($152)	[redacted]	94,608	$7,128	$6,975	$914
2031	$90.90	$77.88	0.121	[redacted]	(1,752)	($159)	[redacted]	94,608	$7,368	$7,209	$876
										NPV Total ($000) =	$41,417

Appendix M
Calculation of Costs for Annual Energy Losses:

Portfolio Description: **Bid 3**

On-Peak Hours =	876
Off-Peak Hours =	7,884
Discount Factor =	0 07819

Year	(1) On-Peak Marginal Energy Cost ($/mwh)	(2) Off-Peak Marginal Energy Cost ($/mwh)	(3) Discount Factor	(4) Peak Load Loss (MW)	(5) = (4)*On-Peak Hours On - Peak Hours Annual Energy Loss (MWH)	(6) = (1)*(5)/1000 On - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	(7) Average Load Loss (MW)	(8) = (7)*Off-Peak Hours Off - Peak Hours Annual Energy Loss (MWH)	(9) = (2)*(8)/1000 Off - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	(10) = (6) + (9) Total Annual Energy Loss Cost Nominal ($ 000)	(11) = (3)*(10) Total Annual Energy Loss Cost NPV ($ 000)
2003	0	0	1.000	0	0	$0	0	0	$0	$0	$0
2004	0	0	0.927	0	0	$0	0	0	$0	$0	$0
2005	0	0	0 860	0	0	$0	0	0	$0	$0	$0
2006	0	0	0.798	0	0	$0	0	0	$0	$0	$0
2007	$46.92	$39.15	0.740	[redacted]	28,032	$1,315	[redacted]	47,304	$1,852	$3,167	$2,344
2008	$45.77	$38.49	0.686	[redacted]	28,032	$1,283	[redacted]	47,304	$1,821	$3,104	$2,130
2009	$47.31	$39.94	0 637	[redacted]	28,032	$1,326	[redacted]	47,304	$1,889	$3,216	$2,047
2010	$47.82	$40.13	0 590	[redacted]	28,032	$1,340	[redacted]	47,304	$1,898	$3,239	$1,912
2011	$50.00	$41.91	0 548	[redacted]	28,032	$1,402	[redacted]	47,304	$1,983	$3,384	$1,853
2012	$50.26	$42.68	0.508	[redacted]	28,032	$1,409	[redacted]	47,304	$2,019	$3,428	$1,741
2013	$53.33	$44 79	0.471	[redacted]	28,032	$1,495	[redacted]	47,304	$2,119	$3,614	$1,702
2014	$55.90	$44.73	0.437	[redacted]	28,032	$1,567	[redacted]	47,304	$2,116	$3,683	$1,609
2015	$56.67	$46.05	0.405	[redacted]	28,032	$1,589	[redacted]	47,304	$2,178	$3,767	$1,526
2016	$58.97	$48.44	0.376	[redacted]	28,032	$1,653	[redacted]	47,304	$2,291	$3,944	$1,482
2017	$60.77	$49.38	0.349	[redacted]	28,032	$1,704	[redacted]	47,304	$2,336	$4,039	$1,408
2018	$62.69	$51 47	0.323	[redacted]	28,032	$1,757	[redacted]	47,304	$2,435	$4,192	$1,355
2019	$63.08	$52.28	0.300	[redacted]	28,032	$1,768	[redacted]	47,304	$2,473	$4,241	$1,272
2020	$63.59	$53.21	0.278	[redacted]	28,032	$1,783	[redacted]	47,304	$2,517	$4,300	$1,196
2021	$66.15	$55.35	0 258	[redacted]	28,032	$1,854	[redacted]	47,304	$2,618	$4,473	$1,154
2022	$68.21	$57.24	0.239	[redacted]	28,032	$1,912	[redacted]	47,304	$2,708	$4,620	$1,105
2023	$68.85	$58.71	0.222	[redacted]	28,032	$1,930	[redacted]	47,304	$2,777	$4,707	$1,044
2024	$72.56	$61.38	0.206	[redacted]	28,032	$2,034	[redacted]	47,304	$2,904	$4,938	$1,016
2025	$73.97	$63.40	0.191	[redacted]	28,032	$2,074	[redacted]	47,304	$2,999	$5,073	$968
2026	$76.54	$65.68	0.177	[redacted]	28,032	$2,146	[redacted]	47,304	$3,107	$5,252	$930
2027	$79.49	$67.82	0.164	[redacted]	28,032	$2,228	[redacted]	47,304	$3,208	$5,436	$893
2028	$81.41	$70.21	0.152	[redacted]	28,032	$2,282	[redacted]	47,304	$3,321	$5,603	$853
2029	$84 10	$72.75	0.141	[redacted]	28,032	$2,357	[redacted]	47,304	$3,441	$5,799	$819
2030	$86 92	$75.34	0.131	[redacted]	28,032	$2,437	[redacted]	47,304	$3,564	$6,000	$786
2031	$90.90	$77.88	0.121	[redacted]	28,032	$2,548	[redacted]	47,304	$3,684	$6,232	$757
										NPV Total ($000) =	$33,902

Appendix M
Calculation of Costs for Annual Energy Losses:

Portfolio Description: **Bid 3 & Bid 1**

On-Peak Hours =	876
Off-Peak Hours =	7,884
Discount Factor =	0.07819

Year	(1) On-Peak Marginal Energy Cost ($/mwh)	(2) Off-Peak Marginal Energy Cost ($/mwh)	(3) Discount Factor	(4) Peak Load Loss (MW)	(5) = (4)*On-Peak Hours On - Peak Hours Annual Energy Loss (MWH)	(6) = (1)*(5)/1000 On - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	(7) Average Load Loss (MW)	(8) = (7)*Off-Peak Hours Off - Peak Hours Annual Energy Loss (MWH)	(9) = (2)*(8)/1000 Off - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	(10) = (6) + (9) Total Annual Energy Loss Cost Nominal ($ 000)	(11) = (3)*(10) Total Annual Energy Loss Cost NPV ($ 000)
2003	0	0	1.000	0	0	$0	0	0	$0	$0	$0
2004	0	0	0.927	0	0	$0	0	0	$0	$0	$0
2005	0	0	0.860	0	0	$0	0	0	$0	$0	$0
2006	0	0	0.798	0	0	$0	0	0	$0	$0	$0
2007	$46.92	$39.15	0.740	29	25,404	$1,192	2	15,768	$617	$1,809	$1,339
2008	$45.77	$38.49	0.686	29	25,404	$1,163	2	15,768	$607	$1,770	$1,215
2009	$47.31	$39.94	0.637	29	25,404	$1,202	2	15,768	$630	$1,832	$1,166
2010	$47.82	$40.13	0.590	29	25,404	$1,215	2	15,768	$633	$1,848	$1,091
2011	$50.00	$41.91	0.548	29	25,404	$1,270	2	15,768	$661	$1,931	$1,057
2012	$50.26	$42.68	0.508	29	25,404	$1,277	2	15,768	$673	$1,950	$990
2013	$53.33	$44.79	0.471	29	25,404	$1,355	2	15,768	$706	$2,061	$971
2014	$55.90	$44.73	0.437	29	25,404	$1,420	2	15,768	$705	$2,125	$929
2015	$56 67	$46.05	0.405	29	25,404	$1,440	2	15,768	$726	$2,166	$878
2016	$58.97	$48 44	0.376	29	25,404	$1,498	2	15,768	$764	$2,262	$850
2017	$60.77	$49.38	0.349	29	25,404	$1,544	2	15,768	$779	$2,322	$809
2018	$62 69	$51.47	0.323	29	25,404	$1,593	2	15,768	$812	$2,404	$777
2019	$63.08	$52.28	0.300	29	25,404	$1,602	2	15,768	$824	$2,427	$728
2020	$63 59	$53.21	0.278	29	25,404	$1,615	2	15,768	$839	$2,454	$683
2021	$66 15	$55.35	0.258	29	25,404	$1,680	2	15,768	$873	$2,553	$659
2022	$68.21	$57.24	0.239	29	25,404	$1,733	2	15,768	$903	$2,635	$630
2023	$68.85	$58 71	0 222	29	25,404	$1,749	2	15,768	$926	$2,675	$593
2024	$72.56	$61.38	0.206	29	25,404	$1,843	2	15,768	$968	$2,811	$578
2025	$73.97	$63.40	0.191	29	25,404	$1,879	2	15,768	$1,000	$2,879	$549
2026	$76.54	$65.68	0 177	29	25,404	$1,944	2	15,768	$1,036	$2,980	$528
2027	$79.49	$67.82	0.164	29	25,404	$2,019	2	15,768	$1,069	$3,089	$507
2028	$81.41	$70.21	0.152	29	25,404	$2,068	2	15,768	$1,107	$3,175	$483
2029	$84.10	$72.75	0.141	29	25,404	$2,136	2	15,768	$1,147	$3,284	$464
2030	$86.92	$75.34	0.131	29	25,404	$2,208	2	15,768	$1,188	$3,396	$445
2031	$90.90	$77 88	0.121	29	25,404	$2,309	2	15,768	$1,228	$3,537	$430
										NPV Total ($000) =	$19,348

Appendix M
Calculation of Costs for Peak Hour Capacity (MW) Losses:

Portfolio Description: **FPL CC**

Discount Rate =	0.07819
Purchase Proxy Starting Cost ($/kw) =	$5.00
Annual Escalation Rate for Proxy Purchase =	1.7%

Year	(1) Proxy Purchase Cost ($/kw-mo)	(2) Discount Factor	(3) Peak Load Loss (MW)	(4) = (1)*(3)*12 Peak Hour Capacity Loss Cost Nominal ($ 000)	(5) = (2)*(4) Peak Hour Capacity Loss Cost NPV ($ 000)
2003	$0	1.000	0	$0	$0
2004	$0	0.927	0	$0	$0
2005	$0	0.860	0	$0	$0
2006	$0	0.798	0	$0	$0
2007	$0	0.740	[redacted]	$0	$0
2008	$0	0.686	[redacted]	$0	$0
2009	$5.00	0.637	[redacted]	$0	$0
2010	$5.09	0.590	[redacted]	$0	$0
2011	$5.17	0.548	[redacted]	$0	$0
2012	$5.26	0.508	[redacted]	$0	$0
2013	$5.35	0.471	[redacted]	$0	$0
2014	$5.44	0.437	[redacted]	$0	$0
2015	$5.53	0.405	[redacted]	$0	$0
2016	$5.63	0.376	[redacted]	$0	$0
2017	$5.72	0.349	[redacted]	$0	$0
2018	$5.82	0.323	[redacted]	$0	$0
2019	$5.92	0.300	[redacted]	$0	$0
2020	$6.02	0.278	[redacted]	$0	$0
2021	$6.12	0.258	[redacted]	$0	$0
2022	$6.23	0.239	[redacted]	$0	$0
2023	$6.33	0.222	[redacted]	$0	$0
2024	$6.44	0.206	[redacted]	$0	$0
2025	$6.55	0.191	[redacted]	$0	$0
2026	$6.66	0.177	[redacted]	$0	$0
2027	$6.77	0.164	[redacted]	$0	$0
2028	$6.89	0.152	[redacted]	$0	$0
2029	$7.00	0.141	[redacted]	$0	$0
2030	$7.12	0.131	[redacted]	$0	$0
2031	$7.24	0.121	[redacted]	$0	$0
				NPV Total ($000) =	$0

Appendix M
Calculation of Costs for Peak Hour Capacity (MW) Losses:

Portfolio Description: **FPL 4 CT & Bid 4**

Discount Rate =	0.07819
Purchase Proxy Starting Cost ($/kw) =	$5.00
Annual Escalation Rate for Proxy Purchase =	1.7%

	(1)	(2)	(3)	(4) = (1)*(3)*12	(5) = (2)*(4)
Year	Proxy Purchase Cost ($/kw-mo)	Discount Factor	Peak Load Loss (MW)	Peak Hour Capacity Loss Cost Nominal ($ 000)	Peak Hour Capacity Loss Cost NPV ($ 000)
2003	$0	1 000	0	$0	$0
2004	$0	0.927	0	$0	$0
2005	$0	0.860	0	$0	$0
2006	$0	0 798	0	$0	$0
2007	$0	0.740	[redacted]	$0	$0
2008	$0	0.686	[redacted]	$0	$0
2009	$5.00	0 637	[redacted]	$1,620	$1,031
2010	$5.09	0.590	[redacted]	$1,648	$973
2011	$5.17	0 548	[redacted]	$1,676	$917
2012	$5.26	0.508	[redacted]	$1,704	$865
2013	$5.35	0.471	[redacted]	$1,733	$816
2014	$5.44	0 437	[redacted]	$1,762	$770
2015	$5.53	0 405	[redacted]	$1,792	$726
2016	$5.63	0.376	[redacted]	$1,823	$685
2017	$5.72	0.349	[redacted]	$1,854	$646
2018	$5.82	0.323	[redacted]	$1,885	$610
2019	$5.92	0.300	[redacted]	$1,917	$575
2020	$6.02	0.278	[redacted]	$1,950	$542
2021	$6.12	0.258	[redacted]	$1,983	$512
2022	$6.23	0.239	[redacted]	$523	$125
2023	$6.33	0.222	[redacted]	$532	$118
2024	$6.44	0.206	[redacted]	$541	$111
2025	$6.55	0.191	[redacted]	$550	$105
2026	$6.66	0.177	[redacted]	$559	$99
2027	$6 77	0.164	[redacted]	$569	$93
2028	$6.89	0.152	[redacted]	$579	$88
2029	$7.00	0.141	[redacted]	$588	$83
2030	$7.12	0 131	[redacted]	$598	$78
2031	$7 24	0.121	[redacted]	$609	$74
				NPV Total ($000) =	$10,644

Appendix M
Calculation of Costs for Peak Hour Capacity (MW) Losses:

Portfolio Description: **Bid 2**

Discount Rate =	0.07819
Purchase Proxy Starting Cost ($/kw) =	$5.00
Annual Escalation Rate for Proxy Purchase =	1 7%

	(1)	(2)	(3)	(4) = (1)*(3)*12	(5) = (2)*(4)
Year	Proxy Purchase Cost ($/kw-mo)	Discount Factor	Peak Load Loss (MW)	Peak Hour Capacity Loss Cost Nominal ($ 000)	Peak Hour Capacity Loss Cost NPV ($ 000)
2003	$0	1.000	0	$0	$0
2004	$0	0.927	0	$0	$0
2005	$0	0.860	0	$0	$0
2006	$0	0.798	0	$0	$0
2007	$0	0 740	[redacted]	$0	$0
2008	$0	0.686	[redacted]	$0	$0
2009	$5.00	0 637	[redacted]	$1,920	$1,222
2010	$5.09	0.590	[redacted]	$1,953	$1,153
2011	$5.17	0.548	[redacted]	$1,986	$1,087
2012	$5.26	0.508	[redacted]	$2,020	$1,026
2013	$5.35	0.471	[redacted]	$2,054	$967
2014	$5.44	0.437	[redacted]	$2,089	$913
2015	$5.53	0 405	[redacted]	$2,124	$861
2016	$5 63	0.376	[redacted]	$2,160	$812
2017	$5.72	0.349	[redacted]	$2,197	$766
2018	$5.82	0.323	[redacted]	$2,235	$722
2019	$5.92	0.300	[redacted]	$2,273	$681
2020	$6.02	0.278	[redacted]	$2,311	$643
2021	$6.12	0.258	[redacted]	$2,350	$606
2022	$6.23	0.239	[redacted]	$1,270	$304
2023	$6.33	0 222	[redacted]	$1,291	$287
2024	$6.44	0 206	[redacted]	$1,313	$270
2025	$6.55	0.191	[redacted]	$1,336	$255
2026	$6.66	0.177	[redacted]	$1,358	$240
2027	$6.77	0.164	[redacted]	$1,382	$227
2028	$6.89	0.152	[redacted]	$1,405	$214
2029	$7.00	0.141	[redacted]	$1,429	$202
2030	$7.12	0.131	[redacted]	$1,453	$190
2031	$7.24	0.121	[redacted]	$1,478	$180
				NPV Total ($000) =	$13,828

Appendix M
Calculation of Costs for Peak Hour Capacity (MW) Losses:

Portfolio Description: **FPL CT & Bid 4 & Bid 1**

Discount Rate =	0 07819
Purchase Proxy Starting Cost ($/kw) =	$5.00
Annual Escalation Rate for Proxy Purchase =	1.7%

	(1)	(2)	(3)	(4) = (1)*(3)*12	(5) = (2)*(4)
Year	Proxy Purchase Cost ($/kw-mo)	Discount Factor	Peak Load Loss (MW)	Peak Hour Capacity Loss Cost Nominal ($ 000)	Peak Hour Capacity Loss Cost NPV ($ 000)
2003	$0	1.000	0	$0	$0
2004	$0	0.927	0	$0	$0
2005	$0	0.860	0	$0	$0
2006	$0	0.798	0	$0	$0
2007	$0	0.740	[redacted]	$0	$0
2008	$0	0.686	[redacted]	$0	$0
2009	$5 00	0.637	[redacted]	$1,020	$649
2010	$5 09	0.590	[redacted]	$1,037	$612
2011	$5.17	0.548	[redacted]	$1,055	$578
2012	$5.26	0.508	[redacted]	$1,073	$545
2013	$5.35	0.471	[redacted]	$1,091	$514
2014	$5 44	0.437	[redacted]	$1,110	$485
2015	$5.53	0 405	[redacted]	$1,129	$457
2016	$5.63	0 376	[redacted]	$1,148	$431
2017	$5.72	0 349	[redacted]	$1,167	$407
2018	$5.82	0.323	[redacted]	$1,187	$384
2019	$5.92	0 300	[redacted]	$1,207	$362
2020	$6.02	0.278	[redacted]	$1,228	$341
2021	$6.12	0 258	[redacted]	$1,249	$322
2022	$6 23	0.239	[redacted]	($149)	($36)
2023	$6.33	0.222	[redacted]	($152)	($34)
2024	$6.44	0.206	[redacted]	($155)	($32)
2025	$6 55	0.191	[redacted]	($157)	($30)
2026	$6.66	0.177	[redacted]	($160)	($28)
2027	$6.77	0.164	[redacted]	($163)	($27)
2028	$6.89	0.152	[redacted]	($165)	($25)
2029	$7.00	0.141	[redacted]	($168)	($24)
2030	$7.12	0.131	[redacted]	($171)	($22)
2031	$7.24	0.121	[redacted]	($174)	($21)
				NPV Total ($000) =	$5,809

Appendix M
Calculation of Costs for Peak Hour Capacity (MW) Losses:

Portfolio Description: **Bid 2 & Bid 1**

Discount Rate =	0 07819
Purchase Proxy Starting Cost ($/kw) =	$5.00
Annual Escalation Rate for Proxy Purchase =	1.7%

	(1)	(2)	(3)	(4) = (1)*(3)*12	(5) = (2)*(4)
Year	Proxy Purchase Cost ($/kw-mo)	Discount Factor	Peak Load Loss (MW)	Peak Hour Capacity Loss Cost Nominal ($ 000)	Peak Hour Capacity Loss Cost NPV ($ 000)
2003	$0	1.000	0	$0	$0
2004	$0	0.927	0	$0	$0
2005	$0	0.860	0	$0	$0
2006	$0	0.798	0	$0	$0
2007	$0	0.740	[redacted]	$0	$0
2008	$0	0 686	[redacted]	$0	$0
2009	$5 00	0.637	[redacted]	$1,740	$1,108
2010	$5 09	0.590	[redacted]	$1,770	$1,045
2011	$5 17	0.548	[redacted]	$1,800	$985
2012	$5.26	0.508	[redacted]	$1,830	$930
2013	$5.35	0.471	[redacted]	$1,861	$877
2014	$5 44	0.437	[redacted]	$1,893	$827
2015	$5.53	0.405	[redacted]	$1,925	$780
2016	$5.63	0.376	[redacted]	$1,958	$736
2017	$5.72	0.349	[redacted]	$1,991	$694
2018	$5.82	0 323	[redacted]	$2,025	$655
2019	$5.92	0 300	[redacted]	$2,059	$617
2020	$6.02	0.278	[redacted]	$2,094	$582
2021	$6.12	0.258	[redacted]	$2,130	$549
2022	$6.23	0.239	[redacted]	$1,121	$268
2023	$6 33	0.222	[redacted]	$1,140	$253
2024	$6.44	0.206	[redacted]	$1,159	$238
2025	$6.55	0 191	[redacted]	$1,179	$225
2026	$6.66	0 177	[redacted]	$1,199	$212
2027	$6.77	0.164	[redacted]	$1,219	$200
2028	$6.89	0.152	[redacted]	$1,240	$189
2029	$7.00	0.141	[redacted]	$1,261	$178
2030	$7.12	0.131	[redacted]	$1,282	$168
2031	$7.24	0.121	[redacted]	$1,304	$158
				NPV Total ($000) =	$12,475

Appendix M
Calculation of Costs for Peak Hour Capacity (MW) Losses:

Portfolio Description: **FPL CT & Bid 4 & Bid 5**

Discount Rate =	0.07819
Purchase Proxy Starting Cost ($/kw) =	$5.00
Annual Escalation Rate for Proxy Purchase =	1.7%

	(1)	(2)	(3)	(4) = (1)*(3)*12	(5) = (2)*(4)
Year	Proxy Purchase Cost ($/kw-mo)	Discount Factor	Peak Load Loss (MW)	Peak Hour Capacity Loss Cost Nominal ($ 000)	Peak Hour Capacity Loss Cost NPV ($ 000)
2003	$0	1.000	0	$0	$0
2004	$0	0.927	0	$0	$0
2005	$0	0.860	0	$0	$0
2006	$0	0.798	0	$0	$0
2007	$0	0 740	[redacted]	$0	$0
2008	$0	0.686		$0	$0
2009	$5.00	0.637		$1,260	$802
2010	$5.09	0.590		$1,281	$757
2011	$5.17	0.548		$1,303	$714
2012	$5.26	0 508		$1,325	$673
2013	$5.35	0.471		$1,348	$635
2014	$5.44	0.437		$1,371	$599
2015	$5.53	0 405		$1,394	$565
2016	$5.63	0.376		$1,418	$533
2017	$5.72	0.349		$1,442	$503
2018	$5.82	0.323		$1,466	$474
2019	$5.92	0.300		$1,491	$447
2020	$6.02	0 278		$1,517	$422
2021	$6.12	0.258		$1,542	$398
2022	$6.23	0 239		($149)	($36)
2023	$6 33	0.222		($152)	($34)
2024	$6.44	0.206		($155)	($32)
2025	$6.55	0.191		($157)	($30)
2026	$6.66	0.177		($160)	($28)
2027	$6.77	0.164		($163)	($27)
2028	$6.89	0 152		($165)	($25)
2029	$7 00	0.141		($168)	($24)
2030	$7.12	0.131		($171)	($22)
2031	$7.24	0.121		($174)	($21)
				NPV Total ($000) =	$7,241

Appendix M
Calculation of Costs for Peak Hour Capacity (MW) Losses:

Portfolio Description: **Bid 3**

Discount Rate =	0 07819
Purchase Proxy Starting Cost ($/kw) =	$5.00
Annual Escalation Rate for Proxy Purchase =	1.7%

	(1)	(2)	(3)	(4) = (1)*(3)*12	(5) = (2)*(4)
Year	Proxy Purchase Cost ($/kw-mo)	Discount Factor	Peak Load Loss (MW)	Peak Hour Capacity Loss Cost Nominal ($ 000)	Peak Hour Capacity Loss Cost NPV ($ 000)
2003	$0	1.000	0	$0	$0
2004	$0	0.927	0	$0	$0
2005	$0	0.860	0	$0	$0
2006	$0	0.798	0	$0	$0
2007	$0	0.740	[redacted]	$0	$0
2008	$0	0.686	[redacted]	$0	$0
2009	$5.00	0.637	[redacted]	$1,920	$1,222
2010	$5.09	0.590	[redacted]	$1,953	$1,153
2011	$5.17	0.548	[redacted]	$1,986	$1,087
2012	$5.26	0.508	[redacted]	$2,020	$1,026
2013	$5.35	0.471	[redacted]	$2,054	$967
2014	$5.44	0.437	[redacted]	$2,089	$913
2015	$5.53	0.405	[redacted]	$2,124	$861
2016	$5 63	0.376	[redacted]	$2,160	$812
2017	$5.72	0.349	[redacted]	$2,197	$766
2018	$5.82	0.323	[redacted]	$2,235	$722
2019	$5.92	0.300	[redacted]	$2,273	$681
2020	$6.02	0.278	[redacted]	$2,311	$643
2021	$6.12	0.258	[redacted]	$2,350	$606
2022	$6.23	0.239	[redacted]	$2,390	$572
2023	$6.33	0.222	[redacted]	$2,431	$539
2024	$6.44	0.206	[redacted]	$2,472	$509
2025	$6.55	0.191	[redacted]	$2,514	$480
2026	$6.66	0 177	[redacted]	$2,557	$453
2027	$6.77	0.164	[redacted]	$2,601	$427
2028	$6.89	0.152	[redacted]	$2,645	$403
2029	$7.00	0.141	[redacted]	$2,690	$380
2030	$7.12	0.131	[redacted]	$2,736	$358
2031	$7 24	0.121	[redacted]	$2,782	$338
				NPV Total ($000) =	$15,918

Appendix M
Calculation of Costs for Peak Hour Capacity (MW) Losses:

Portfolio Description: **Bid 3 & Bid 1**

Discount Rate =	0.07819
Purchase Proxy Starting Cost ($/kw) =	$5.00
Annual Escalation Rate for Proxy Purchase =	1.7%

	(1)	(2)	(3)	(4) = (1)*(3)*12	(5) = (2)*(4)
Year	Proxy Purchase Cost ($/kw-mo)	Discount Factor	Peak Load Loss (MW)	Peak Hour Capacity Loss Cost Nominal ($ 000)	Peak Hour Capacity Loss Cost NPV ($ 000)
2003	$0	1 000	0	$0	$0
2004	$0	0.927	0	$0	$0
2005	$0	0.860	0	$0	$0
2006	$0	0.798	0	$0	$0
2007	$0	0.740	[redacted]	$0	$0
2008	$0	0.686	[redacted]	$0	$0
2009	$5.00	0.637	[redacted]	$1,740	$1,108
2010	$5.09	0.590	[redacted]	$1,770	$1,045
2011	$5.17	0.548	[redacted]	$1,800	$985
2012	$5.26	0.508	[redacted]	$1,830	$930
2013	$5.35	0.471	[redacted]	$1,861	$877
2014	$5.44	0.437	[redacted]	$1,893	$827
2015	$5.53	0.405	[redacted]	$1,925	$780
2016	$5.63	0.376	[redacted]	$1,958	$736
2017	$5.72	0.349	[redacted]	$1,991	$694
2018	$5.82	0.323	[redacted]	$2,025	$655
2019	$5.92	0.300	[redacted]	$2,059	$617
2020	$6.02	0.278	[redacted]	$2,094	$582
2021	$6.12	0.258	[redacted]	$2,130	$549
2022	$6.23	0.239	[redacted]	$2,166	$518
2023	$6 33	0.222	[redacted]	$2,203	$489
2024	$6.44	0.206	[redacted]	$2,241	$461
2025	$6.55	0.191	[redacted]	$2,279	$435
2026	$6.66	0.177	[redacted]	$2,317	$410
2027	$6.77	0.164	[redacted]	$2,357	$387
2028	$6.89	0.152	[redacted]	$2,397	$365
2029	$7.00	0.141	[redacted]	$2,438	$344
2030	$7.12	0.131	[redacted]	$2,479	$325
2031	$7.24	0.121	[redacted]	$2,521	$306
				NPV Total ($000) =	$14,425

Appendix N
Increased Operating Cost Estimates

Portfolio	Import Limit	Present value of increased operating cost relative to Portfolio 1 (Millions of 2003 dollars)
1	7307	0
2	7174	15.5
3/4	7827	15.4
6	7225	11.4
7/8	7798	14.8
10	7184	15.3

APPENDIX O

NON ECONOMIC EVALUATION

I. Background

The following summarizes the results of a review of non-economic parameters associated with FPL's Next Planned Generating Unit in the 2003 RFP, a 4x1 natural gas fired combined cycle unit at Turkey Point, and a proposal received from Progress Ventures, Inc. in response to FPL's 2003 RFP. This analysis seeks to identify major issues of concern (risk) based on the information solicited in the RFP process. Should this analysis have identified areas of significant concern, further detailed information would have been obtained from the proposer in question if necessary to complete the non-economic evaluation.

In summary, the review found no areas of concern that are warranted for identification to management. Areas of difference are annotated by highlighting the appropriate item on the attached review sheets.

II. Process

The Progress Ventures, Inc. proposal data forms were sent to designated reviewers in the areas of Environmental, Operations and Contract Execution. These reviewers provided a review of the attributes of the Progress Ventures bid and FPL's NPGU. The results are documented on the tables that follow.

Table O-II.1 Environmental Area Parameters

	Progress Ventures	FPL NPGU
Compliance Experience		
Control Technology	Satisfactory	Satisfactory
Violation/ Non - Compliance	Satisfactory	Satisfactory
Proposed Project		
Licensing/Permitting	Satisfactory	Satisfactory
PPSA/Permitting Issues	Satisfactory	Satisfactory
PSD/NSR Issues	Satisfactory	Satisfactory
Land Use Issues	Satisfactory	Satisfactory
Zoning Issues	Satisfactory	Satisfactory
Variance Required	Satisfactory	Satisfactory
Exceptions Required	Satisfactory	Satisfactory
Community Outreach Plan	Satisfactory	Satisfactory
Water Supply Strategy	Satisfactory	Satisfactory
Water Discharge Strategy	Satisfactory	Satisfactory
Florida Permitting Experience		
PPSA	Not Applicable	Satisfactory
Non - PPSA	Satisfactory	Not Applicable
Other Infrastructure		
Water Supply or Discharge Easements	Satisfactory	Satisfactory
Fuel Supply Easements	Satisfactory	Satisfactory
Transmission Line Easements	Timing (Note 1)	Satisfactory

Note 1. Transmission upgrades will be required. The extent and timing of these upgrades would be the subject of a more detailed review if needed.

Table O-II.2 Technical/Operational Area Parameters

	Progress Ventures (Note 2)	FPL NPGU
Technology (Major Equipment Technology/Supplier)	Satisfactory	Satisfactory
Configuration (Type and Configuration of Unit)	Satisfactory	Satisfactory
Operational Limitations (Limitations in hrs/yr. and/or Time of Year Usage)	Satisfactory	Satisfactory
Fuel	Satisfactory	Satisfactory
Guaranteed Firm Capacity, Net MWs (@GSU Transformer High Side)	Satisfactory	Satisfactory
Guaranteed Heat Rate (@Guaranteed Firm Capacity) Btus/kWh (HHV)	Satisfactory	Satisfactory
Generator(s) VAR Capability (Lead/Lag)	Satisfactory	Satisfactory
Commercial Availability Minimum % (Annual)	Satisfactory	Satisfactory
Startup Time, minutes (to committed Capacity)		
Cold Start (offline:>48 hrs.)	Satisfactory	Satisfactory
Cold/Warm Start (off-line:12-48 hrs.)	Satisfactory	Satisfactory
Warm/Hot Start (off-line:4-12 hrs.)	Satisfactory	Satisfactory
Hot Start (offline:<4 hrs.)	Satisfactory	Satisfactory
Minimum Load, MWs (@GSU Transformer High Side)	Satisfactory	Satisfactory
Startup Time, minutes (to Minimum Load)		
Cold Start (offline:>48 hrs.)	Satisfactory	Satisfactory
Cold/Warm Start (off-line:12-48 hrs.)	Satisfactory	Satisfactory
Warm/Hot Start (off-line:4-12 hrs.)	Satisfactory	Satisfactory
Hot Start (offline:<4 hrs.)	Satisfactory	Satisfactory
Ramp Rate, MWs/minute (Minimum > Guaranteed)	Satisfactory	Satisfactory
Generating Units' Operating & Maintenance Experience		
Scope of Historical O&M Experience	Satisfactory	Satisfactory
Performance Results	Satisfactory	Satisfactory
Relevance	High	High

Note 2. FPL is familiar with the proposed technology and does not foresee any significant technical risks unless the bidder has imposed unusual requirements on the equipment supplier. The satisfactory rankings are based on the assumption that the proposed equipment is purchased from GE in accordance with its engineering and design standards.

Table O-II.3 Project Execution Area Parameters

	Progress Ventures	FPL NPGU
Nature of Exceptions	Note 3	None
Impact to Risk Profile	None negative	None
Departure from Scope	None	None
Probability of Resolution	> 75% likelihood	Not Applicable
Development Experience	Sufficient	Sufficient
Design/Construct Experience	Sufficient	Sufficient
Operational Experience	Sufficient	Sufficient

Note 3. No explicit exceptions were taken. PV recommends pursuing a gas tolling agreement "substantially similar" to the current PPA. There will be some differences in the content of a long term PPA versus the current short term PPA; however, it is anticipated that these can be mutually developed.

Appendix P
FPL's Approved DSM Programs

FPL's Current DSM Programs

FPL's currently approved DSM programs are summarized as follows:

Residential Conservation Service: This is an energy audit program designed to assist residential customers in understanding how to make their homes more energy-efficient through the installation of conservation measures/practices.

Residential Building Envelope: This program encourages the installation of energy-efficient ceiling insulation in residential dwellings that utilize whole-house electric air conditioning.

Duct System Testing and Repair: This program encourages demand and energy conservation through the identification of air leaks in whole-house air conditioning duct systems and by the repair of these leaks by qualified contractors.

Residential Air Conditioning: This is a program to encourage customers to purchase higher efficiency central cooling and heating equipment.

Residential Load Management (On-Call): This program offers load control of major appliances/household equipment to residential customers, in exchange for monthly electric bill credits.

New Construction (BuildSmart): This program encourages the design and construction of energy-efficient homes that cost-effectively reduce coincident peak demand and energy consumption.

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FPL's Approved DSM Programs

Business Energy Evaluation: This program encourages energy efficiency in both new and existing commercial and industrial facilities by identifying DSM opportunities and providing recommendations to the customer.

Commercial/Industrial Heating, Ventilating, and Air Conditioning: This program encourages the use of high-efficiency heating, ventilation and air conditioning (HVAC) systems in commercial/industrial facilities.

Commercial/Industrial Efficient Lighting: This program encourages the installation of energy-efficient lighting measures in commercial/industrial facilities.

Business Custom Incentive: This program encourages commercial/industrial customers to implement unique energy conservation measures or projects not covered by other FPL programs.

Commercial/Industrial Load Control: This program reduces peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity shortages, in exchange for monthly electric bill credits. (This program was closed to new participants in 2000).

Commercial/Industrial Demand Reduction: This program, which started in 2002, is similar to the Commercial/Industrial Load Control program mentioned above in continuing the objective to reduce peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity shortages in exchange for monthly electric bill credits.

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FPL's Approved DSM Programs

<u>**Commercial/Industrial Building Envelope:**</u> This program encourages the installation of energy-efficient building envelope measures, such as window treatments and roof/ceiling insulation for commercial/industrial facilities.

<u>**Business On Call:**</u> This program offers load control of central air conditioning units to both small, non-demand-billed and medium, demand-billed commercial/industrial customers, in exchange for monthly electric bill credits.

Research and Development

FPL's DSM Plan continues to support research and development activities. Historically, FPL has performed extensive DSM research and development. FPL will continue such activities, not only through its Conservation Research and Development program, but also through individual research projects. These efforts will examine a wide variety of technologies that build on prior FPL research where applicable and will expand the research to new and promising technologies as they emerge.

<u>Conservation Research and Development Program</u>

FPL's Conservation Research and Development Program is designed to evaluate emerging conservation technologies to determine which are worthy of pursuing for program development and approval. FPL has researched a wide variety of technologies and, from that research, has been able to develop new programs such as Residential New Construction, Commercial/Industrial Building Envelope and Business On Call.

Appendix P
FPL's Approved DSM Programs

Low Income Weatherization Retrofit Project

This R&D project investigated cost-effective methods of increasing the energy efficiency in the homes of FPL's low-income customers. The research project addressed the needs of low-income housing retrofits by providing monetary incentives to various housing authorities, including weatherization agency providers (WAPS), and non-weatherization agency providers (non-WAPS). These incentives were used by the housing authorities to leverage their funds to increase the overall energy efficiency of the homes they are retrofitting.

This project was completed in November 2003. Of the seven different DSM measures evaluated, it was found that two measures, addressing HVAC maintenance and infiltration, were cost-effective. FPL has filed a petition for a permanent Low-Income Weatherization Program that includes these cost-effective measures.

Photovoltaic Research, Development and Education Project

Photovotaic (PV) roof-tile systems are a relatively new technology which directly replaces existing roofing materials such as shingles and standing-rib roofing with PV materials. These PV materials have the same waterproofing characteristics as conventional roofing materials. This project is consistent with the Federal Government's Million Solar Roofs Initiative. However, based on FPL's research to-date, a primary hurdle to the physical installation of PV systems, whether roofing materials or flat plate modules, is the lack of awareness, understanding and acceptance by local building officials. For the most part, these officials are unclear about how these systems work and how to address these systems as part of the building, permitting and inspection process. This creates barriers toward the use of this technology. As part of this project, FPL has been holding workshops to address this issue. This project is scheduled to be completed in the first quarter of 2004.

Green Energy Project

Under this project, FPL is examining the feasibility of purchasing tradable renewable energy credits generated from new renewable resources including solar-powered technologies, biomass energy, landfill methane, wind energy, low impact hydroelectric energy and/or other renewable sources. Customers who participate would then be charged higher premiums for purchasing tradable renewable energy credits that are associated with electric energy generated by these sources.

Development of the Green Pricing program was completed and filed with the FPSC in August 2003. As part of this process, a supply contract was put into place that allows FPL to match supply with demand for green energy. The FPSC approved the program on December 2, 2003 with program implementation scheduled for the first quarter of 2004.

On Call Incentive Reduction Pilot

In March 2003, FPL received FPSC approval to perform a pilot for its On Call program. Under the pilot FPL is offering to new participants a residential load control service similar to the On Call Program at a reduced incentive level. The offering of this pilot is allowing FPL to test its market research data and gauge whether FPL can repackage its current residential load control service, minimize customer attrition, achieve current goals for residential load control, and, ultimately, change On Call incentive levels without damaging system reliability.