FPL

Florida Power & Light Company, 215 S. Monroe St., Suite 810, Tallahassee, FL 32301

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Jessica Cano
Principal Attorney
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420
(561) 304-5226
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April 29, 2011

110000-OT

VIA HAND DELIVERY

Ms. Ann Cole
Division of the Commission Clerk and
Administrative Services
Florida Public Service Commission
Betty Easley Conference Center
2540 Shumard Oak Boulevard, Room 110
Tallahassee, FL 32399-0850

RE: Florida Power & Light Company's 2011 Ten Year Power Plant Site Plan

Dear Ms. Cole:

Enclosed are Florida Power & Light Company's ("FPL") responses to Staff's February 18, 2011 Supplemental Data Requests. An electronic copy of the responses are also enclosed on the disc attached.

If you have any questions or concerns please feel free to call me.

Sincerely,

Lynne Adams

for Jessica A. Cano

Enclosure

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RAD 3+1CD containing same.
SSC ___
ADM ___
OPC ___
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an FPL Group company

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Q.
General

Please provide all data requested in the attached forms labeled 'Appendix A,' in electronic (Excel) and hard copy. If any of the requested data is already included in the Company's Ten-Year Site Plan, state so on the appropriate form.

A.
See Appendix A attached.

Supplemental - DR Question No. 1
Attachment No. 1

History and Forecast of Summer Peak Demand
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	C / I Load Management	C / I Conservation	Net Firm Demand
HISTORY:									
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008		FPL did not utilize a high load forecast case when developing the resource plan presented in the 2011 Site Plan.							
2009									
2010									
FORECAST:									
2011									
2012									
2013									
2014									
2015									
2016									
2017									
2018									
2019									
2020									

Supplemental - DR Question No. 1
Attachment No. 1

History and Forecast of Summer Peak Demand
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	C / I Load Management	C / I Conservation	Net Firm Demand
HISTORY:									
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
FORECAST:									
2011									
2012									
2013									
2014									
2015									
2016									
2017									
2018									
2019									
2020									

FPL did not utilize a low load forecast case when developing the resource plan presented in the 2011 Site Plan.

Supplemental - DR Question No. 1
Attachment No. 1

History and Forecast of Winter Peak Demand
High Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) C / I Load Management	(9) C / I Conservation	(10) Net Firm Demand
HISTORY:									
2000/01									
2001/02									
2002/03									
2003/04									
2004/05									
2005/06									
2006/07									
2007/08									
2008/09		FPL did not utilize a high load forecast case when developing the resource plan presented in the 2011 Site Plan.							
2009/10									
FORECAST:									
2010/11									
2011/12									
2012/13									
2013/14									
2014/15									
2015/16									
2016/17									
2017/18									
2018/19									
2019/20									

Supplemental - DR Question No. 1
Attachment No. 1

History and Forecast of Winter Peak Demand
Low Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) C / I Load Management	(9) C / I Conservation	(10) Net Firm Demand
HISTORY:									
2000/01									
2001/02									
2002/03									
2003/04									
2004/05									
2005/06									
2006/07									
2007/08									
2008/09		FPL did not utilize a low load forecast case when developing the resource plan presented in the 2011 Site Plan.							
2009/10									
FORECAST:									
2010/11									
2011/12									
2012/13									
2013/14									
2014/15									
2015/16									
2016/17									
2017/18									
2018/19									
2019/20									

Supplemental - DR Question No. 1
Attachment No. 1

History and Forecast of Annual Net Energy for Load - GWH
High Case

(1) Year	(2) Total	(3) Residential Conservation	(4) C / I Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor (%)
HISTORY:								
2001								
2002								
2003								
2004								
2005								
2006								
2007								
2008								
2009								
2010								
FORECAST:								
2011								
2012								
2013								
2014								
2015								
2016								
2017								
2018								
2019								
2020								

FPL did not utilize a high load forecast case when developing the resource plan presented in the 2011 Site Plan.

Supplemental - DR Question No. 1
Attachment No. 1

History and Forecast of Annual Net Energy for Load - GWH
Low Case

(1) Year	(2) Total	(3) Residential Conservation	(4) C / I Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor (%)
HISTORY:								
2001								
2002								
2003								
2004								
2005								
2006								
2007								
2008								
2009								
2010								
FORECAST:								
2011								
2012								
2013								
2014								
2015								
2016								
2017								
2018								
2019								
2020								

FPL did not utilize a low load forecast case when developing the resource plan presented in the 2011 Site Plan.

Supplemental - DR Question No. 1
Attachment No. 1

NOMINAL, DELIVERED RESIDUAL FUEL OIL PRICES
BASE CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)
	0.7% Sulfur Fuel Oil		Escalation	1.0% Sulfur Fuel Oil		Escalation	1.0% Sulfur Fuel Oil		Escalation	1.0% Sulfur Fuel Oil		Escalation	1.0% Sulfur Fuel Oil		Escalation	1.0% Sulfur Fuel Oil		Escalation	1.0% Sulfur Fuel Oil		Escalation
YEAR	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%
History: (1)																					
2008	$65.91	$10.30																			
2009	$68.11	$10.64	3.34%																		
2010	$73.51	$11.49	7.93%																		
PLANT		MARTIN			EVERGLADES			MANATEE			TURKEY POINT			CANAVERAL			SANFORD			RIVIERA	
Forecast:																					
2011	$88.88	$13.89	20.91%	$84.75	$13.24	15.29%	$84.75	$13.24	15.29%	$84.41	$13.19	14.83%	$84.79	$13.25	15.34%	$84.79	$13.25	15.34%	$84.80	$13.25	15.36%
2012	$91.47	$14.29	2.92%	$88.42	$13.82	4.33%	$88.42	$13.82	4.33%	$88.08	$13.76	4.35%	$88.46	$13.82	4.33%	$88.46	$13.82	4.33%	$88.47	$13.82	4.33%
2013	$90.56	$14.15	-1.00%	$87.51	$13.67	-1.03%	$87.51	$13.67	-1.03%	$87.17	$13.62	-1.03%	$87.55	$13.68	-1.03%	$87.55	$13.68	-1.03%	$87.56	$13.68	-1.03%
2014	$92.62	$14.47	2.27%	$89.52	$13.99	2.30%	$89.52	$13.99	2.30%	$89.18	$13.93	2.30%	$89.56	$13.99	2.29%	$89.56	$13.99	2.29%	$89.57	$13.99	2.29%
2015	$94.83	$14.82	2.39%	$91.68	$14.33	2.42%	$91.68	$14.33	2.42%	$91.34	$14.27	2.43%	$91.72	$14.33	2.42%	$91.72	$14.33	2.42%	$91.73	$14.33	2.42%
2016	$112.65	$17.60	18.79%	$110.06	$17.20	20.04%	$110.06	$17.20	20.04%	$109.72	$17.14	20.12%	$110.10	$17.20	20.04%	$110.10	$17.20	20.04%	$110.11	$17.20	20.03%
2017	$117.55	$18.37	4.35%	$114.66	$17.92	4.18%	$114.66	$17.92	4.18%	$114.32	$17.86	4.19%	$114.70	$17.92	4.18%	$114.70	$17.92	4.18%	$114.71	$17.92	4.18%
2018	$121.88	$19.04	3.68%	$118.87	$18.57	3.67%	$118.87	$18.57	3.67%	$118.53	$18.52	3.68%	$118.91	$18.58	3.67%	$118.91	$18.58	3.67%	$118.92	$18.58	3.67%
2019	$125.87	$19.67	3.28%	$122.75	$19.18	3.27%	$122.75	$19.18	3.27%	$122.41	$19.13	3.28%	$122.79	$19.19	3.27%	$122.79	$19.19	3.27%	$122.80	$19.19	3.27%
2020	$130.10	$20.33	3.36%	$125.78	$19.65	2.47%	$125.78	$19.65	2.47%	$125.44	$19.60	2.48%	$125.82	$19.66	2.47%	$125.82	$19.66	2.47%	$125.83	$19.66	2.47%

(1) The actual cost of residual fuel oil consumed has not been recorded by sulfur grade to date.
(2) $/BBL were converted to $/MMBTU using a conversion rate of 6.4 . The ash content of the residual fuel oil is 0.06%

Supplemental - DR Question No. 1
Attachment No. 1

NOMINAL, DELIVERED RESIDUAL FUEL OIL PRICES
HIGH CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)
	0.7% Sulfur Fuel Oil		Escalation	1.0% Sulfur Fuel Oil		Escalation	1.0% Sulfur Fuel Oil		Escalation	1.0% Sulfur Fuel Oil		Escalation	1.0% Sulfur Fuel Oil		Escalation	1.0% Sulfur Fuel Oil		Escalation	1.0% Sulfur Fuel Oil		Escalation
YEAR	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%
History: (1)																					
2008	$65.91	$10.30																			
2009	$68.11	$10.64	3.34%																		
2010	$73.51	$11.49	7.93%																		
PLANT		MARTIN			EVERGLADES			MANATEE			TURKEY POINT			CANAVERAL			SANFORD			RIVIERA	
Forecast:																					
2011	$110.72	$17.30	50.62%	$105.62	$16.50	43.68%	$105.62	$16.50	43.68%	$105.19	$16.44	43.11%	$105.67	$16.51	43.75%	$105.67	$16.51	43.75%	$105.68	$16.51	43.77%
2012	$115.98	$18.12	4.75%	$112.12	$17.52	6.15%	$112.12	$17.52	6.15%	$111.69	$17.45	6.17%	$112.17	$17.53	6.15%	$112.17	$17.53	6.15%	$112.18	$17.53	6.15%
2013	$114.83	$17.94	-1.00%	$110.96	$17.34	-1.03%	$110.96	$17.34	-1.03%	$110.53	$17.27	-1.03%	$111.01	$17.35	-1.03%	$111.01	$17.35	-1.03%	$111.03	$17.35	-1.03%
2014	$117.44	$18.35	2.27%	$113.51	$17.74	2.30%	$113.51	$17.74	2.30%	$113.08	$17.67	2.30%	$113.56	$17.74	2.29%	$113.56	$17.74	2.29%	$113.57	$17.75	2.29%
2015	$120.25	$18.79	2.39%	$116.25	$18.16	2.42%	$116.25	$18.16	2.42%	$115.82	$18.10	2.43%	$116.31	$18.17	2.42%	$116.31	$18.17	2.42%	$116.32	$18.17	2.42%
2016	$142.84	$22.32	18.79%	$139.56	$21.81	20.04%	$139.56	$21.81	20.04%	$139.13	$21.74	20.12%	$139.61	$21.81	20.04%	$139.61	$21.81	20.04%	$139.62	$21.82	20.03%
2017	$149.06	$23.29	4.35%	$145.39	$22.72	4.18%	$145.39	$22.72	4.18%	$144.96	$22.65	4.19%	$145.44	$22.72	4.18%	$145.44	$22.72	4.18%	$145.45	$22.73	4.18%
2018	$154.54	$24.15	3.68%	$150.72	$23.55	3.67%	$150.72	$23.55	3.67%	$150.29	$23.48	3.68%	$150.77	$23.56	3.67%	$150.77	$23.56	3.67%	$150.79	$23.56	3.67%
2019	$159.61	$24.94	3.28%	$155.65	$24.32	3.27%	$155.65	$24.32	3.27%	$155.22	$24.25	3.28%	$155.70	$24.33	3.27%	$155.70	$24.33	3.27%	$155.71	$24.33	3.27%
2020	$164.97	$25.78	3.36%	$159.49	$24.92	2.47%	$159.49	$24.92	2.47%	$159.06	$24.85	2.48%	$159.55	$24.93	2.47%	$159.55	$24.93	2.47%	$159.56	$24.93	2.47%

(1) The actual cost of residual fuel oil consumed has not been recorded by sulfur grade to date.
(2) $/BBL were converted to $/MMBTU using a conversion rate of 6.4 . The ash content of the residual fuel oil is 0.06%

Supplemental - DR Question No. 1
Attachment No. 1

NOMINAL, DELIVERED RESIDUAL FUEL OIL PRICES
LOW CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)
	0.7% Sulfur Fuel Oil		Escalation	1.0% Sulfur Fuel Oil		Escalation	1.0% Sulfur Fuel Oil		Escalation	1.0% Sulfur Fuel Oil		Escalation	1.0% Sulfur Fuel Oil		Escalation	1.0% Sulfur Fuel Oil		Escalation	1.0% Sulfur Fuel Oil		Escalation
YEAR	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%
History: (1)																					
2008	$65.91	$10.30																			
2009	$68.11	$10.64	3.34%																		
2010	$73.51	$11.49	7.93%																		
PLANT		MARTIN			EVERGLADES			MANATEE			TURKEY POINT			CANAVERAL			SANFORD			RIVIERA	
Forecast:																					
2011	$67.03	$10.47	-8.81%	$63.88	$9.98	-13.11%	$63.88	$9.98	-13.11%	$63.62	$9.94	-13.45%	$63.91	$9.99	-13.06%	$63.91	$9.99	-13.06%	$63.91	$9.99	-13.05%
2012	$66.96	$10.46	-0.11%	$64.72	$10.11	1.33%	$64.72	$10.11	1.33%	$64.47	$10.07	1.35%	$64.75	$10.12	1.33%	$64.75	$10.12	1.33%	$64.76	$10.12	1.33%
2013	$66.29	$10.36	-1.00%	$64.06	$10.01	-1.03%	$64.06	$10.01	-1.03%	$63.81	$9.97	-1.03%	$64.09	$10.01	-1.03%	$64.09	$10.01	-1.03%	$64.09	$10.01	-1.03%
2014	$67.79	$10.59	2.27%	$65.53	$10.24	2.30%	$65.53	$10.24	2.30%	$65.28	$10.20	2.30%	$65.56	$10.24	2.29%	$65.56	$10.24	2.29%	$65.56	$10.24	2.29%
2015	$69.42	$10.85	2.39%	$67.11	$10.49	2.42%	$67.11	$10.49	2.42%	$66.86	$10.45	2.43%	$67.14	$10.49	2.42%	$67.14	$10.49	2.42%	$67.15	$10.49	2.42%
2016	$82.46	$12.88	18.79%	$80.56	$12.59	20.04%	$80.56	$12.59	20.04%	$80.32	$12.55	20.12%	$80.59	$12.59	20.04%	$80.59	$12.59	20.04%	$80.60	$12.59	20.03%
2017	$86.05	$13.45	4.35%	$83.93	$13.11	4.18%	$83.93	$13.11	4.18%	$83.68	$13.08	4.19%	$83.96	$13.12	4.18%	$83.96	$13.12	4.18%	$83.97	$13.12	4.18%
2018	$89.22	$13.94	3.68%	$87.01	$13.60	3.67%	$87.01	$13.60	3.67%	$86.76	$13.56	3.68%	$87.04	$13.60	3.67%	$87.04	$13.60	3.67%	$87.05	$13.60	3.67%
2019	$92.14	$14.40	3.28%	$89.85	$14.04	3.27%	$89.85	$14.04	3.27%	$89.61	$14.00	3.28%	$89.88	$14.04	3.27%	$89.88	$14.04	3.27%	$89.89	$14.05	3.27%
2020	$95.24	$14.88	3.36%	$92.07	$14.39	2.47%	$92.07	$14.39	2.47%	$91.83	$14.35	2.48%	$92.10	$14.39	2.47%	$92.10	$14.39	2.47%	$92.11	$14.39	2.47%

(1) The actual cost of residual fuel oil consumed has not been recorded by sulfur grade to date.
(2) $/BBL were converted to $/MMBTU using a conversion rate of 6.4 . The ash content of the residual fuel oil is 0.06%

Supplemental - DR Question No. 1
Attachment No. 1

NOMINAL, DELIVERED DISTILLATE FUEL OIL AND NATURAL GAS PRICES
BASE CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	0.3% Sulfur Distillate		Escalation	0.3% Sulfur Distillate		Escalation	0.3% Sulfur Distillate		Escalation	0.3% Sulfur Distillate		Escalation	0.3% Sulfur Distillate		Escalation
YEAR	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%
History (1):															
2008	$92.31	$15.83													
2009	$81.99	$14.06	-11.18%												
2010	$80.74	$13.85	-1.53%												
PLANT	GAS TURBINES AT EVERGLADES			GAS TURBINES & COMBINED CYCLES AT LAUDERDALE			GAS TURBINES & NEW CT'S AT FORT MYERS			COMBINED CYLES AT PUTNAM			COMBINED CYLES AT WCEC		
Forecast:															
2011	$113.16	$19.41	40.17%	$113.16	$19.41	40.17%	$116.10	$19.91	43.81%	$117.15	$20.10	45.11%	$116.76	$20.03	44.61%
2012	$115.26	$19.77	1.85%	$115.26	$19.77	1.85%	$118.20	$20.27	1.81%	$119.25	$20.45	1.79%	$118.85	$20.39	1.80%
2013	$116.49	$19.98	1.06%	$116.49	$19.98	1.06%	$119.43	$20.49	1.04%	$120.48	$20.67	1.03%	$120.08	$20.60	1.03%
2014	$120.55	$20.68	3.48%	$120.55	$20.68	3.48%	$123.49	$21.18	3.40%	$124.54	$21.36	3.37%	$124.14	$21.29	3.38%
2015	$123.52	$21.19	2.47%	$123.52	$21.19	2.47%	$126.46	$21.69	2.41%	$127.51	$21.87	2.39%	$127.11	$21.80	2.39%
2016	$135.64	$23.27	9.81%	$135.64	$23.27	9.81%	$138.58	$23.77	9.59%	$139.63	$23.95	9.51%	$139.23	$23.88	9.54%
2017	$141.31	$24.24	4.18%	$141.31	$24.24	4.18%	$144.25	$24.74	4.09%	$145.30	$24.92	4.06%	$144.90	$24.85	4.08%
2018	$146.58	$25.14	3.73%	$146.58	$25.14	3.73%	$149.52	$25.65	3.65%	$150.57	$25.83	3.63%	$150.17	$25.76	3.64%
2019	$151.62	$26.01	3.44%	$151.62	$26.01	3.44%	$154.56	$26.51	3.37%	$155.61	$26.69	3.35%	$155.22	$26.62	3.36%
2020	$156.88	$26.91	3.47%	$156.88	$26.91	3.47%	$159.82	$27.41	3.40%	$160.87	$27.59	3.38%	$160.47	$27.52	3.39%

(1) The actual cost of distillate fuel oil consumed has not been recorded by sulfur grade to date.
(2) $/BBL were converted to $/MMBTU using a conversion rate of 5.83 . The ash content of the distillate fuel oil is 0.001%.

Supplemental - DR Question No. 1
Attachment No. 1

NOMINAL, DELIVERED DISTILLATE FUEL OIL AND NATURAL GAS PRICES
BASE CASE

(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)
0.3% Sulfur $/BBL	Distillate $/MMBTU	Escalation %	0.3% Sulfur $/BBL	Distillate $/MMBTU	Escalation %	0.3% Sulfur $/BBL	Distillate $/MMBTU	Escalation %	0.3% Sulfur $/BBL	Distillate $/MMBTU	Escalation %	Natural Gas $/MMBTU	Escalation %
												$10.24	
												$8.19	-20.08%
												$6.36	-22.38%
COMBINED CYLES AT MARTIN			COMBINED CYLES AT TURKEY POINT			COMBINED CYLES AT CANAVERAL			COMBINED CYLES AT RIVIERA			NON-FIRM FGT VARIABLE GAS DISPATCH	
$116.94	$20.06	44.85%	$118.20	$20.28	46.41%	$117.15	$20.10	45.11%	$116.76	$20.03	44.61%	$5.29	-16.72%
$119.04	$20.42	1.79%	$120.30	$20.63	1.77%	$119.25	$20.45	1.79%	$118.85	$20.39	1.80%	$5.75	8.72%
$120.27	$20.63	1.03%	$121.53	$20.85	1.02%	$120.48	$20.67	1.03%	$120.08	$20.60	1.03%	$5.97	3.81%
$124.33	$21.33	3.37%	$125.59	$21.54	3.34%	$124.54	$21.36	3.37%	$124.14	$21.29	3.38%	$6.05	1.34%
$127.30	$21.83	2.39%	$128.56	$22.05	2.37%	$127.51	$21.87	2.39%	$127.11	$21.80	2.39%	$6.44	6.42%
$139.42	$23.91	9.52%	$140.68	$24.13	9.43%	$139.63	$23.95	9.51%	$139.23	$23.88	9.54%	$7.02	8.94%
$145.09	$24.89	4.07%	$146.35	$25.10	4.03%	$145.30	$24.92	4.06%	$144.90	$24.85	4.08%	$7.56	7.69%
$150.36	$25.79	3.63%	$151.62	$26.01	3.60%	$150.57	$25.83	3.63%	$150.17	$25.76	3.64%	$8.12	7.44%
$155.40	$26.66	3.35%	$156.66	$26.87	3.33%	$155.61	$26.69	3.35%	$155.22	$26.62	3.36%	$8.57	5.59%
$160.66	$27.56	3.38%	$161.92	$27.77	3.35%	$160.87	$27.59	3.38%	$160.47	$27.52	3.39%	$9.05	5.50%

Supplemental - DR Question No. 1
Attachment No. 1

NOMINAL, DELIVERED DISTILLATE FUEL OIL AND NATURAL GAS PRICES
BASE CASE

(31)	(32)	(33)	(34)	(35)	(36)	(37)	(38)	(39)	(40)	(41)	(42)	(43)	(44)	(45)	(46)
Natural Gas $/MMBTU	Escalation %	Natural Gas $/MMBTU	Escalation %	Natural Gas $/MMBTU	Escalation %	Natural Gas $/MMBTU	Escalation %	Natural Gas $/MMBTU	Escalation %	Natural Gas $/MMBTU	Escalation %	Natural Gas $/MMBTU	Escalation %	Natural Gas $/MMBTU	Escalation %
FIRM FGT				NON-FIRM GULFSTREAM		NON-FIRM GULFSTREAM BACKHAUL		GULFSTREAM FIRM				GULFSTREAM/SESH FIRM			
VARIABLE GAS DISPATCH		DEMAND CHARGE		VARIABLE GAS DISPATCH		VARIABLE GAS DISPATCH		VARIABLE DISPATCH		DEMAND CHARGE		VARIABLE DISPATCH		DEMAND CHARGE	
$4.86	-23.55%	$0.62		$5.45	-14.32%	$5.83	-8.26%	$4.85	-23.68%	$0.56		$4.73	-25.63%	$0.84	
$5.32	9.51%	$0.70	12.52%	$5.90	8.37%	$6.29	7.84%	$5.31	9.40%	$0.56	0.00%	$5.17	9.43%	$0.84	0.00%
$5.54	4.12%	$0.79	13.43%	$6.12	3.67%	$6.50	3.45%	$5.52	4.08%	$0.56	0.00%	$5.39	4.18%	$0.84	0.00%
$5.62	1.45%	$0.79	0.01%	$6.20	1.29%	$6.58	1.22%	$5.60	1.43%	$0.56	0.00%	$5.47	1.47%	$0.84	0.00%
$6.01	6.92%	$0.79	0.00%	$6.58	6.20%	$6.97	5.85%	$5.99	6.85%	$0.56	0.00%	$5.85	7.02%	$0.84	0.00%
$6.59	9.70%	$0.79	0.00%	$7.15	8.64%	$7.54	8.18%	$6.55	9.50%	$0.56	0.00%	$6.42	9.72%	$0.84	0.00%
$7.13	8.23%	$0.79	-0.01%	$7.68	7.45%	$8.07	7.09%	$7.09	8.13%	$0.56	0.00%	$6.95	8.30%	$0.84	0.00%
$7.70	7.88%	$0.79	0.01%	$8.24	7.23%	$8.63	6.90%	$7.64	7.84%	$0.56	0.00%	$7.51	7.99%	$0.84	0.00%
$8.15	5.90%	$0.79	0.00%	$8.69	5.44%	$9.08	5.21%	$8.09	5.87%	$0.56	0.00%	$7.96	5.97%	$0.84	0.00%
$8.62	5.79%	$0.79	0.00%	$9.15	5.37%	$9.55	5.15%	$8.56	5.76%	$0.56	0.00%	$8.42	5.86%	$0.84	0.00%

Supplemental - DR Question No. 1
Attachment No. 1

NOMINAL, DELIVERED DISTILLATE FUEL OIL (2) AND NATURAL GAS PRICES
HIGH CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
YEAR	0.3% Sulfur Distillate $/BBL	0.3% Sulfur Distillate $/MMBTU	Escalation %	0.3% Sulfur Distillate $/BBL	0.3% Sulfur Distillate $/MMBTU	Escalation %	0.3% Sulfur Distillate $/BBL	0.3% Sulfur Distillate $/MMBTU	Escalation %	0.3% Sulfur Distillate $/BBL	0.3% Sulfur Distillate $/MMBTU	Escalation %	0.3% Sulfur Distillate $/BBL	0.3% Sulfur Distillate $/MMBTU	Escalation %
History (1):															
2008	$92.31	$15.83													
2009	$81.99	$14.06	-11.18%												
2010	$80.74	$13.85	-1.53%												
PLANT	GAS TURBINES AT EVERGLADES			GAS TURBINES & COMBINED CYCLES AT LAUDERDALE			GAS TURBINES & NEW CT'S AT FORT MYERS			COMBINED CYLES AT PUTNAM			COMBINED CYLES AT WCEC		
Forecast:															
2011	$141.05	$24.19	74.71%	$141.05	$24.19	74.71%	######	$24.82	79.24%	$146.02	$25.05	80.86%	$145.52	$24.96	80.25%
2012	$146.15	$25.07	3.62%	$146.15	$25.07	3.62%	######	$25.71	3.57%	$151.21	$25.94	3.55%	$150.70	$25.85	3.56%
2013	$147.71	$25.34	1.06%	$147.71	$25.34	1.06%	######	$25.98	1.04%	$152.77	$26.20	1.03%	$152.26	$26.12	1.03%
2014	$152.85	$26.22	3.48%	$152.85	$26.22	3.48%	######	$26.86	3.40%	$157.91	$27.09	3.37%	$157.40	$27.00	3.38%
2015	$156.62	$26.86	2.47%	$156.62	$26.86	2.47%	######	$27.50	2.41%	$161.68	$27.73	2.39%	$161.17	$27.65	2.39%
2016	$171.99	$29.50	9.81%	$171.99	$29.50	9.81%	######	$30.14	9.59%	$177.05	$30.37	9.51%	$176.54	$30.28	9.54%
2017	$179.18	$30.73	4.18%	$179.18	$30.73	4.18%	######	$31.37	4.09%	$184.24	$31.60	4.06%	$183.74	$31.52	4.08%
2018	$185.86	$31.88	3.73%	$185.86	$31.88	3.73%	######	$32.52	3.65%	$190.92	$32.75	3.63%	$190.42	$32.66	3.64%
2019	$192.26	$32.98	3.44%	$192.26	$32.98	3.44%	######	$33.62	3.37%	$197.32	$33.85	3.35%	$196.81	$33.76	3.36%
2020	$198.92	$34.12	3.47%	$198.92	$34.12	3.47%	######	$34.76	3.40%	$203.98	$34.99	3.38%	$203.48	$34.90	3.39%

(1) The actual cost of distillate fuel oil consumed has not been recorded by sulfur grade to date.
(2) $/BBL were converted to $/MMBTU using a conversion rate of 5.83 . The ash content of the distillate fuel oil is 0.001%.

Supplemental - DR Question No. 1
Attachment No. 1

NOMINAL, DELIVERED DISTILLATE FUEL OIL (2) AND NATURAL GAS PRICES
HIGH CASE

(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)
0.3% Sulfur $/BBL	Distillate $/MMBTU	Escalation %	0.3% Sulfur $/BBL	Distillate $/MMBTU	Escalation %	0.3% Sulfur $/BBL	Distillate $/MMBTU	Escalation %	0.3% Sulfur $/BBL	Distillate $/MMBTU	Escalation %	Natural Gas $/MMBTU	Escalation %
												$10.24	
												$8.19	-20.08%
												$6.36	-22.38%
COMBINED CYLES AT MARTIN			COMBINED CYLES AT TURKEY POINT			COMBINED CYLES AT CANAVERAL			COMBINED CYLES AT RIVIERA			NON-FIRM FGT VARIABLE GAS DISPATCH	
$145.76	$25.00	80.54%	$147.33	$25.27	82.48%	$146.02	$25.05	80.86%	$145.52	$24.96	80.25%	$6.32	-0.62%
$150.94	$25.89	3.56%	$152.54	$26.16	3.54%	$151.21	$25.94	3.55%	$150.70	$25.85	3.56%	$6.96	10.13%
$152.50	$26.16	1.03%	$154.10	$26.43	1.02%	$152.77	$26.20	1.03%	$152.26	$26.12	1.03%	$7.22	3.81%
$157.64	$27.04	3.37%	$159.24	$27.31	3.34%	$157.91	$27.09	3.37%	$157.40	$27.00	3.38%	$7.32	1.34%
$161.41	$27.69	2.39%	$163.01	$27.96	2.37%	$161.68	$27.73	2.39%	$161.17	$27.65	2.39%	$7.79	6.42%
$176.78	$30.32	9.52%	$178.38	$30.60	9.43%	$177.05	$30.37	9.51%	$176.54	$30.28	9.54%	$8.48	8.94%
$183.98	$31.56	4.07%	$185.58	$31.83	4.03%	$184.24	$31.60	4.06%	$183.74	$31.52	4.08%	$9.14	7.69%
$190.66	$32.70	3.63%	$192.25	$32.98	3.60%	$190.92	$32.75	3.63%	$190.42	$32.66	3.64%	$9.82	7.44%
$197.05	$33.80	3.35%	$198.65	$34.07	3.33%	$197.32	$33.85	3.35%	$196.81	$33.76	3.36%	$10.37	5.59%
$203.72	$34.94	3.38%	$205.31	$35.22	3.35%	$203.98	$34.99	3.38%	$203.48	$34.90	3.39%	$10.94	5.50%

Supplemental - DR Question No. 1
Attachment No. 1

NOMINAL, DELIVERED DISTILLATE FUEL OIL (2) AND NATURAL GAS PRICES
HIGH CASE

(31)	(32)	(33)	(34)	(35)	(36)	(37)	(38)	(39)	(40)	(41)	(42)	(43)	(44)	(45)	(46)
Natural Gas $/MMBTU	Escalation %	Natural Gas $/MMBTU	Escalation %	Natural Gas $/MMBTU	Escalation %	Natural Gas $/MMBTU	Escalation %	Natural Gas $/MMBTU	Escalation %	atural Gas $/MMBTU	Escalation %	Natural Gas $/MMBTU	Escalation %	Natural Gas $/MMBTU	Escalation %
FIRM FGT				NON-FIRM GULFSTREAM		NON-FIRM GULFSTREAM		GULFSTREAM FIRM				GULFSTREAM/SESH FIRM			
VARIABLE GAS DISPATCH		DEMAND CHARGE		VARIABLE GAS DISPATCH		BACKHAUL) VARIABLE GAS DISPATCH		VARIABLE DISPATCH		DEMAND CHARGE		VARIABLE DISPATCH		DEMAND CHARGE	
$5.80	-8.78%	$0.62		$6.50	2.21%	$6.96	9.47%	$5.79	-8.94%	$0.56		$5.64	-11.27%	$0.84	
$6.43	10.96%	$0.70	12.52%	$7.13	9.82%	$7.60	9.26%	$6.42	10.85%	$0.56	0.00%	$6.25	10.90%	$0.84	0.00%
$6.70	4.12%	$0.79	13.43%	$7.40	3.67%	$7.86	3.45%	$6.68	4.08%	$0.56	0.00%	$6.52	4.18%	$0.84	0.00%
$6.79	1.45%	$0.79	0.01%	$7.49	1.29%	$7.96	1.22%	$6.77	1.43%	$0.56	0.00%	$6.61	1.47%	$0.84	0.00%
$7.26	6.92%	$0.79	0.00%	$7.96	6.20%	$8.43	5.85%	$7.24	6.85%	$0.56	0.00%	$7.08	7.02%	$0.84	0.00%
$7.97	9.70%	$0.79	0.00%	$8.64	8.64%	$9.11	8.18%	$7.92	9.50%	$0.56	0.00%	$7.76	9.72%	$0.84	0.00%
$8.63	8.23%	$0.79	-0.01%	$9.29	7.45%	$9.76	7.09%	$8.57	8.13%	$0.56	0.00%	$8.41	8.30%	$0.84	0.00%
$9.30	7.88%	$0.79	0.01%	$9.96	7.23%	$10.43	6.90%	$9.24	7.84%	$0.56	0.00%	$9.08	7.99%	$0.84	0.00%
$9.85	5.90%	$0.79	0.00%	$10.50	5.44%	$10.98	5.21%	$9.78	5.87%	$0.56	0.00%	$9.62	5.97%	$0.84	0.00%
$10.42	5.79%	$0.79	0.00%	$11.07	5.37%	$11.54	5.15%	$10.35	5.76%	$0.56	0.00%	$10.18	5.86%	$0.84	0.00%

Supplemental - DR Question No. 1
Attachment No. 1

NOMINAL, DELIVERED DISTILLATE FUEL OIL (2) AND NATURAL GAS PRICES
LOW CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	0.3% Sulfur Distillate		Escalation	0.3% Sulfur Distillate		Escalation	0.3% Sulfur Distillate		Escalation	0.3% Sulfur Distillate		Escalation	0.3% Sulfur Distillate		Escalation
YEAR	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%
History (1):															
2008	$92.31	$15.83													
2009	$81.99	$14.06	-11.18%												
2010	$80.74	$13.85	-1.53%												
PLANT	GAS TURBINES AT EVERGLADES			GAS TURBINES & COMBINED CYCLES AT LAUDERDALE			GAS TURBINES & NEW CT'S AT FORT MYERS			COMBINED CYLES AT PUTNAM			COMBINED CYLES AT WCEC		
Forecast:															
2011	$85.28	$14.63	5.63%	$85.28	$14.63	5.63%	$87.50	$15.01	8.37%	$88.29	$15.14	9.36%	$87.99	$15.09	8.98%
2012	$84.37	$14.47	-1.06%	$84.37	$14.47	-1.06%	$86.52	$14.84	-1.11%	$87.29	$14.97	-1.13%	$87.00	$14.92	-1.12%
2013	$85.27	$14.63	1.06%	$85.27	$14.63	1.06%	$87.42	$15.00	1.04%	$88.19	$15.13	1.03%	$87.90	$15.08	1.03%
2014	$88.24	$15.14	3.48%	$88.24	$15.14	3.48%	$90.39	$15.50	3.40%	$91.16	$15.64	3.37%	$90.87	$15.59	3.38%
2015	$90.41	$15.51	2.47%	$90.41	$15.51	2.47%	$92.57	$15.88	2.41%	$93.33	$16.01	2.39%	$93.04	$15.96	2.39%
2016	$99.29	$17.03	9.81%	$99.29	$17.03	9.81%	$101.44	$17.40	9.59%	$102.21	$17.53	9.51%	$101.92	$17.48	9.54%
2017	$103.44	$17.74	4.18%	$103.44	$17.74	4.18%	$105.59	$18.11	4.09%	$106.36	$18.24	4.06%	$106.07	$18.19	4.08%
2018	$107.30	$18.40	3.73%	$107.30	$18.40	3.73%	$109.45	$18.77	3.65%	$110.22	$18.91	3.63%	$109.93	$18.86	3.64%
2019	$110.99	$19.04	3.44%	$110.99	$19.04	3.44%	$113.14	$19.41	3.37%	$113.91	$19.54	3.35%	$113.62	$19.49	3.36%
2020	$114.84	$19.70	3.47%	$114.84	$19.70	3.47%	$116.99	$20.07	3.40%	$117.76	$20.20	3.38%	$117.46	$20.15	3.39%

(1) The actual cost of distillate fuel oil consumed has not been recorded by sulfur grade to date.
(2) $/BBL were converted to $/MMBTU using a conversion rate of 5.83 . The ash content of the distillate fuel oil is 0.001%.

Supplemental - DR Question No. 1
Attachment No. 1

NOMINAL, DELIVERED DISTILLATE FUEL OIL (2) AND NATURAL GAS PRICES
LOW CASE

(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)
0.3% Sulfur Distillate		Escalation	0.3% Sulfur Distillate		Escalation	0.3% Sulfur Distillate		Escalation	0.3% Sulfur Distillate		Escalation	Natural Gas	Escalation
$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%	$/BBL	$/MMBTU	%	$/MMBTU	%
												$10.24	
												$8.19	-20.08%
												$6.36	-22.38%
COMBINED CYLES AT MARTIN			COMBINED CYLES AT TURKEY POINT			COMBINED CYLES AT CANAVERAL			COMBINED CYLES AT RIVIERA			NON-FIRM FGT VARIABLE GAS DISPATCH	
$88.13	$15.12	9.16%	$89.08	$15.28	10.34%	$88.29	$15.14	9.36%	$87.99	$15.09	8.98%	$4.27	-32.83%
$87.14	$14.95	-1.13%	$88.06	$15.10	-1.15%	$87.29	$14.97	-1.13%	$87.00	$14.92	-1.12%	$4.55	6.62%
$88.04	$15.10	1.03%	$88.96	$15.26	1.02%	$88.19	$15.13	1.03%	$87.90	$15.08	1.03%	$4.72	3.81%
$91.01	$15.61	3.37%	$91.93	$15.77	3.34%	$91.16	$15.64	3.37%	$90.87	$15.59	3.38%	$4.79	1.34%
$93.18	$15.98	2.39%	$94.10	$16.14	2.37%	$93.33	$16.01	2.39%	$93.04	$15.96	2.39%	$5.10	6.42%
$102.05	$17.50	9.52%	$102.98	$17.66	9.43%	$102.21	$17.53	9.51%	$101.92	$17.48	9.54%	$5.55	8.94%
$106.21	$18.22	4.07%	$107.13	$18.38	4.03%	$106.36	$18.24	4.06%	$106.07	$18.19	4.08%	$5.98	7.69%
$110.06	$18.88	3.63%	$110.99	$19.04	3.60%	$110.22	$18.91	3.63%	$109.93	$18.86	3.64%	$6.42	7.44%
$113.76	$19.51	3.35%	$114.68	$19.67	3.33%	$113.91	$19.54	3.35%	$113.62	$19.49	3.36%	$6.78	5.59%
$117.60	$20.17	3.38%	$118.53	$20.33	3.35%	$117.76	$20.20	3.38%	$117.46	$20.15	3.39%	$7.15	5.50%

Supplemental - DR Question No. 1
Attachment No. 1

NOMINAL, DELIVERED DISTILLATE FUEL OIL (2) AND NATURAL GAS PRICES
LOW CASE

(31)	(32)	(33)	(34)	(35)	(36)	(37)	(38)	(39)	(40)	(41)	(42)	(43)	(44)	(45)	(46)
Natural Gas $/MMBTU	Escalation %	Natural Gas $/MMBTU	Escalation %	Natural Gas $/MMBTU	Escalation %	Natural Gas $/MMBTU	Escalation %	Natural Gas $/MMBTU	Escalation %	Natural Gas $/MMBTU	Escalation %	Natural Gas $/MMBTU	Escalation %	Natural Gas $/MMBTU	Escalation %
FIRM FGT VARIABLE GAS DISPATCH		FIRM FGT DEMAND CHARGE		NON-FIRM GULFSTREAM VARIABLE GAS DISPATCH		NON-FIRM GULFSTREAM BACKHAUL) VARIABLE GAS DISPATCH		GULFSTREAM FIRM VARIABLE DISPATCH		GULFSTREAM FIRM DEMAND CHARGE		GULFSTREAM/SESH FIRM VARIABLE DISPATCH		GULFSTREAM/SESH FIRM DEMAND CHARGE	
$0.00	-100.00%	$0.62		$4.39	-30.86%	$4.70	-25.99%	$3.91	-38.42%	$0.56		$3.81	-39.99%	$0.84	
$0.00	#DIV/0!	$0.70	12.52%	$4.67	6.22%	$4.97	5.73%	$4.20	7.25%	$0.56	0.00%	$4.09	7.27%	$0.84	0.00%
$0.00	#DIV/0!	$0.79	13.43%	$4.84	3.67%	$5.14	3.45%	$4.37	4.08%	$0.56	0.00%	$4.26	4.18%	$0.84	0.00%
$0.00	#DIV/0!	$0.79	0.01%	$4.90	1.29%	$5.21	1.22%	$4.43	1.43%	$0.56	0.00%	$4.33	1.47%	$0.84	0.00%
$0.00	#DIV/0!	$0.79	0.00%	$5.21	6.20%	$5.51	5.85%	$4.73	6.85%	$0.56	0.00%	$4.63	7.02%	$0.84	0.00%
$0.00	#DIV/0!	$0.79	0.00%	$5.66	8.64%	$5.96	8.18%	$5.18	9.50%	$0.56	0.00%	$5.08	9.72%	$0.84	0.00%
$0.00	#DIV/0!	$0.79	-0.01%	$6.08	7.45%	$6.39	7.09%	$5.61	8.13%	$0.56	0.00%	$5.50	8.30%	$0.84	0.00%
$0.00	#DIV/0!	$0.79	0.01%	$6.52	7.23%	$6.83	6.90%	$6.05	7.84%	$0.56	0.00%	$5.94	7.99%	$0.84	0.00%
$0.00	#DIV/0!	$0.79	0.00%	$6.87	5.44%	$7.18	5.21%	$6.40	5.87%	$0.56	0.00%	$6.29	5.97%	$0.84	0.00%
$0.00	#DIV/0!	$0.79	0.00%	$7.24	5.37%	$7.55	5.15%	$6.77	5.76%	$0.56	0.00%	$6.66	5.86%	$0.84	0.00%

Supplemental - DR Question No. 1
Attachment No. 1

NOMINAL, DELIVERED SOLID FUEL (COAL AND PETROLEUM COKE) PRICES
BASE CASE

(1)	(2)	(3)	(4)	(5)
YEAR	<1% Sulfur $/MMBTU	Escalation %	1% - 2% Sulfui $/MMBTU	Escalation %
History (1):				
2008	$2.24			
2009	$2.44	9.16%		
2010	$2.59	5.90%		
PLANT	SCHERER PLANT WEIGHTED AVERAGE		ST. JOHNS RIVER POWER PARK (SJRPP) WEIGHTED AVERAGE	
Forecast:				
2011	$2.26	-12.68%	$3.15	21.92%
2012	$2.28	0.76%	$2.54	-19.58%
2013	$2.29	0.39%	$2.57	1.19%
2014	$2.33	2.09%	$2.60	1.49%
2015	$2.39	2.60%	$2.64	1.44%
2016	$2.45	2.49%	$2.69	1.82%
2017	$2.49	1.53%	$2.74	1.70%
2018	$2.54	1.81%	$2.77	1.23%
2019	$2.82	11.08%	$2.81	1.31%
2020	$2.86	1.70%	$2.84	1.29%

(1) The actual cost of solid fuel (coal and petroleum coke) consumed has not been recorded by sulfur grade to date.
(2) The heat content of the low sulfur coal is 8,600 BTU/lb. and the medium sulfur coal is 11,000 BTU/lb. The ash content of the low sulfur coal is 5.0% and the ash content of the medium sulfur coal is 11.0%.

Supplemental - DR Question No. 1
Attachment No. 1

NOMINAL, DELIVERED SOLID FUEL (COAL AND PETROLEUM COKE) PRICES
HIGH CASE

(1)	(2)	(3)	(4)	(5)
YEAR	<1% Sulfur $/MMBTU	Escalation %	1% - 2% Sulfui $/MMBTU	Escalation %
History (1):				
2008	$2.24			
2009	$2.44	9.16%		
2010	$2.59	5.90%		
PLANT	SCHERER PLANT WEIGHTED AVERAGE		ST. JOHNS RIVER POWER PARK (SJRPP) WEIGHTED AVERAGE	
Forecast:				
2011	$2.60	0.33%	$3.62	40.08%
2012	$2.62	0.76%	$2.91	-19.58%
2013	$2.63	0.39%	$2.95	1.19%
2014	$2.68	2.09%	$2.99	1.49%
2015	$2.75	2.60%	$3.04	1.44%
2016	$2.82	2.49%	$3.09	1.82%
2017	$2.86	1.53%	$3.14	1.70%
2018	$2.91	1.81%	$3.18	1.23%
2019	$3.24	11.08%	$3.22	1.31%
2020	$3.29	1.70%	$3.27	1.29%

(1) The actual cost of solid fuel (coal and petroleum coke) consumed has not been recorded by sulfur grade to date.

(2) The heat content of the low sulfur coal is 8,600 BTU/lb. and the medium sulfur coal is 11,000 BTU/lb. The ash content of the low sulfur coal is 5.0% and the ash content of the medium sulfur coal is 11.0%.

Supplemental - DR Question No. 1
Attachment No. 1

NOMINAL, DELIVERED SOLID FUEL (COAL AND PETROLEUM COKE) PRICES
LOW CASE

(1)	(2)	(3)	(4)	(5)
YEAR	<1% Sulfur $/MMBTU	Escalation %	1% - 2% Sulfur $/MMBTU	Escalation %
History (1):				
2008	$2.24			
2009	$2.44	9.16%		
2010	$2.59	5.90%		
PLANT	SCHERER PLANT WEIGHTED AVERAGE		ST. JOHNS RIVER POWER PARK (SJRPP) WEIGHTED AVERAGE	
Forecast:				
2011	$1.92	-25.69%	$2.68	3.75%
2012	$1.94	0.76%	$2.16	-19.58%
2013	$1.94	0.39%	$2.18	1.19%
2014	$1.99	2.09%	$2.22	1.49%
2015	$2.04	2.60%	$2.25	1.44%
2016	$2.09	2.49%	$2.29	1.82%
2017	$2.12	1.53%	$2.33	1.70%
2018	$2.16	1.81%	$2.36	1.23%
2019	$2.40	11.08%	$2.39	1.31%
2020	$2.44	1.70%	$2.42	1.29%

(1) The actual cost of solid fuel (coal and petroleum coke) consumed has not been recorded by sulfur grade to date.
(2) The heat content of the low sulfur coal is 8,600 BTU/lb. and the medium sulfur coal is 11,000 BTU/lb. The ash content of the low sulfur coal is 5.0% and the ash content of the medium sulfur coal is 11.0%.

Supplemental - DR Question No. 1
Attachment No. 1

Nominal, Delivered Nuclear Fuel and Firm Purchases

(1)	(2)	(3)	(4)	(5)
	Nuclear		Firm Purchases	
		Escalation		Escalation
Year	c/MBTU	%	$/MWh	%
HISTORY:				
2008	53.15		$ 28.17	
2009	61.57	15.84	$ 31.87	13.13
2010	65.49	6.37	$ 34.34	7.75
FORECAST:				
2011	72.07	10.05	$ 40.89	19.08
2012	70.11	-2.72	$ 37.26	-8.88
2013	76.63	9.30	$ 37.03	-0.62
2014	77.91	1.67	$ 37.77	2.01
2015	78.90	1.27	$ 38.67	2.37
2016	80.26	1.72	$ 44.99	16.36
2017	82.34	2.59	$ 48.91	8.71
2018	84.28	2.36	$ 50.38	3.00
2019	86.44	2.56	$ 52.30	3.81
2020	88.68	2.59	$ 53.42	2.15

Note: Nuclear Fuel Costs are recoverable under the Fuel Clause.
Starting in 2010, Nuclear Fuel is no longer under the fuel lease and is now a capital asset of FPL and will earn a rate of return as approved in the last rate case. Although the nuclear fuel cost to be passed under the fuel clause no longer has an interest component, the impact of nuclear fuel as a capital asset needs to be recognized.

Supplemental - DR Question No. 1
Attachment No. 1

Existing Generating Unit Operating Performance

(1)	(2)	(3)		(4)		(5)		(6)	
		Planned Outage Factor (POF)		Forced Outage Factor (FOF)		Equivalent Availability Factor (EAF)		Average Net Operating Heat Rate (ANOHR)	
Plant Name	Unit No.	Historical	Projected	Historical	Projected	Historical	Projected	Historical	Projected
Cutler[1]	5	0.0%	See note 1	0.2%	See note 1	99.8%	See note 1	12,126	See note 1
Cutler[1]	6	5.8%	See note 1	0.6%	See note 1	93.6%	See note 1	11,370	See note 1
Lauderdale	4	8.0%	3.7%	3.6%	1.0%	84.0%	90.5%	8,280	7,741
Lauderdale	5	6.2%	3.0%	1.2%	1.0%	90.8%	91.2%	8,200	7,731
Lauderdale GT	1-24	0.1%	0.1%	0.0%	0.0%	95.2%	95.2%	16,892	15,805
Ft. Myers CC	2	3.8%	3.1%	0.8%	0.9%	90.7%	91.4%	7,261	7,006
Ft. Myers	3A	9.6%	2.4%	1.1%	0.5%	85.9%	93.4%	10,630	11,375
Ft. Myers	3B	0.6%	2.4%	0.8%	0.5%	95.7%	93.4%	10,627	11,375
Ft. Myers GT	1-12	0.6%	0.6%	0.4%	0.4%	98.8%	98.8%	13,377	30,649
St Johns	1	5.8%	3.6%	3.8%	2.5%	88.6%	92.9%	9,738	9,853
St Johns	2	7.5%	3.6%	2.4%	2.5%	89.7%	92.9%	9,733	9,776
Martin	1	8.4%	16.1%	0.4%	1.5%	87.1%	79.8%	10,259	9,961
Martin	2	11.4%	16.9%	0.3%	1.2%	83.9%	79.3%	9,663	9,940
Martin	3	5.3%	2.6%	0.5%	0.9%	85.8%	93.7%	7,490	7,405
Martin	4	7.6%	3.0%	0.5%	1.0%	89.4%	93.2%	7,360	7,299
Martin	8	7.4%	3.0%	1.4%	1.1%	86.3%	93.3%	7,170	7,117
Manatee	1	9.7%	14.8%	0.2%	1.0%	83.1%	75.4%	10,693	10,167
Manatee	2	8.3%	15.4%	0.1%	0.8%	84.2%	75.0%	10,833	10,154
Manatee	3	4.7%	2.8%	0.4%	1.1%	91.9%	92.4%	6,986	7,040
Port Everglades[2]	1	4.5%	See note 2	0.6%	See note 2	93.7%	See note 2	11,057	See note 2
Port Everglades[2]	2	0.0%	See note 2	0.3%	See note 2	98.8%	See note 2	11,060	See note 2
Port Everglades[2]	3	2.5%	See note 2	0.4%	See note 2	89.0%	See note 2	10,311	9,985
Port Everglades[2]	4	2.5%	See note 2	0.6%	See note 2	90.8%	See note 2	10,450	10,298
Port Everglades GT	1-12	5.7%	5.7%	0.0%	0.0%	93.1%	93.1%	15,842	16,472
Putnam	1	9.9%	2.8%	0.7%	1.0%	87.2%	95.1%	9,331	8,776
Putnam	2	11.3%	3.5%	1.6%	1.0%	85.0%	94.3%	9,436	8,821
Riviera[3]	3	0.4%	See note 3	0.3%	See note 3	98.5%	See note 3	10,355	See note 3
Riviera[3]	4	1.7%	See note 3	4.7%	See note 3	92.0%	See note 3	10,387	See note 3
Scherer	4	9.8%	3.6%	1.1%	3.3%	87.8%	91.9%	10,026	10,206
Sanford[1]	3	0.0%	See note 1	0.2%	See note 1	99.8%	See note 1	11,109	See note 1

Supplemental - DR Question No. 1
Attachment No. 1

Sanford CC	4	5.0%	3.3%	1.6%	1.1%	91.0%	93.2%	7,394	7,094
Sanford CC	5	4.9%	2.6%	0.5%	1.1%	92.3%	93.9%	7,384	7,098
Turkey Point	1	7.5%	6.8%	0.6%	0.7%	85.4%	83.9%	11,012	11,035
Turkey Point[4]	2	3.5%	See note 4	1.9%	See note 4	89.3%	See note 4	10,514	See note 4
Turkey Point	3	7.1%	7.50	3.6%	2.30	89.3%	90.20	10,992	11,187
Turkey Point	4	8.1%	9.20	2.4%	2.30	88.7%	88.60	10,996	11,845
Turkey Point	5	4.9%	2.5%	2.4%	1.1%	89.1%	93.5%	7,131	7,039
St Lucie	1	9.7%	8.40	3.2%	2.30	87.0%	89.30	10,797	10,760
St Lucie	2	3.5%	9.40	6.6%	2.30	88.9%	88.30	10,738	10,653
West County[5]	1	2.0%	2.8%	1.1%	2.4%	88.2%	93.4%	7,031	6,854
West County[5]	2	1.8%	2.7%	0.7%	2.4%	91.9%	93.4%	6,945	6,854

Notes:

[1] FPL currently expects that three of these generating units, Cutler 5 & 6 and Sanford 3, will be retired by 2012. FPL will be examining other potential uses for these sites, including their potential use as sites for new renewable energy facilities.

[2] The four steam units at FPL's Port Everglades site will remain available to return to service at least until 2014. Two of these four steam units, Port Everglades Units 3 & 4, are currently scheduled to be returned to active service in 2012 and then return to Inactive Reserve status at least until the "modernized" units at Cape Canaveral and Riviera are in normal operation (i.e., until mid-2014). The other two steam units, Port Everglades Units 1 & 2, are currently scheduled to remain on Inactive Reserve status during this time period.

[3] Unit retired in February 2011

[4] Turkey Point 2, will remain on Inactive Reserve status, but will operate as a synchronous condenser (which provides reactive power support for FPL's transmission system in Southeastern Florida) rather than as provider of electricity. This unit is capable of returning to active service in the future to provide MW and MWh.

[5] Historical averages based on unit in-service dates: WCEC 1 August '09, and WCEC 2 November '09

Historical - average of past three years

Projected - average of next ten years

Supplemental - DR Question No. 1
Attachment No. 1

Financial Assumptions
Base Case

AFUDC RATE	2010	6.45	%
	2011	6.67	
	2012	6.64	
	2013	6.74	
	2014	6.69	
CAPITALIZATION RATIOS:			
	DEBT	40.9	%
	PREFERRED	0	%
	EQUITY	59.1	%
RATE OF RETURN			
	DEBT	5.5	%
	PREFERRED	0	%
	EQUITY	10	%
INCOME TAX RATE:			
	STATE	5.5	%
	FEDERAL	35	%
	EFFECTIVE	38.575	%
OTHER TAX RATE:		1.84	%
DISCOUNT RATE:		7.29	%
TAX			
DEPRECIATION RATE:		3.75	%
		7.219	%
		6.677	%
		6.177	%
		5.713	%
		5.285	%
		4.888	%
		4.522	%
		4.462	%
		4.461	%
		4.462	%
		4.461	%
		4.462	%
		4.461	%
		4.462	%
		4.461	%
		4.462	%
		4.461	%
		4.462	%
		4.461	%
		2.231	%

Supplemental - DR Question No. 1
Attachment No. 1

Financial Escalation Assumptions

(1)	(2)	(3)	(4)	(5)
Year	General Inflation %	Plant Construction Cost %	Fixed O&M Cost %	Variable O&M Cost %
2011	2.5	3	2.5	2.5
2012	2.5	3	2.5	2.5
2013	2.5	3	2.5	2.5
2014	2.5	3	2.5	2.5
2015	2.5	3	2.5	2.5
2016	2.5	3	2.5	2.5
2017	2.5	3	2.5	2.5
2018	2.5	3	2.5	2.5
2019	2.5	3	2.5	2.5
2020	2.5	3	2.5	2.5

Supplemental - DR Question No. 1
Attachment No. 1

Loss of Load Probability, Reserve Margin, and Expected Unserved Energy
Base Case Load Forecast

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Annual Isolated			Annual Assisted [1/]		
Year	Loss of Load Probability (Days/Yr)	Reserve Margin (%) (Including Firm Purchases)	Expected Unserved Energy (MWh) [2/]	Loss of Load Probability (Days/Yr)	Reserve Margin (%) (Including Firm Purchases)	Expected Unserved Energy (MWh) [2/]
2011	0.001319	22.7		0.001319	22.7	
2012	0.002531	23.4		0.002531	23.4	
2013	0.000385	25.4		0.000385	25.4	
2014	0.000296	24.8		0.000296	24.8	
2015	0.000238	25.9		0.000238	25.9	
2016	0.000385	23.8		0.000385	23.8	
2017	0.000880	22.2		0.000880	22.2	
2018	0.001302	21.6		0.001302	21.6	
2019	0.002800	20.0		0.002800	20.0	
2020	0.000490	23.1		0.000490	23.1	

1/ FPL modeled its system as an "isolated" system in its 2010 planning work.(FPL accounted for its projected assistance as an additional unit within FPL's system.) Consequently, FPL does not have separate values for Assisted systems.

2/ FPL does not project EUE in its system reliability analyses.

Q.
General

Please provide all data requested in the attached forms labeled 'Appendix B,' which consist of Schedules 1 through 10 from the Company's Ten-Year Site Plan, in an electronic copy in Excel (.xls file format).

A.
Please see attachment.

Supplemental DR - Question No. 2
Attachment No. 1

Schedule 1
Existing Generating Facilities
As of December 31, 2010

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt. Fuel	Commercial	Expected	Gen. Max.	Net Capability	
	Unit		Unit	Fuel		Fuel Transport		Days	*In-Service*	*Retirement*	*Nameplate*	*Summer*	*Winter*
Plant Name	No.	Location	Type	Pri	Alt	Pri	Alt	Use	Month/Year	Month/Year	KW	MW	MW
Cape Canaveral	1	Brevard County	ST	FO6	NG	WA	PL	Unknown	Apr-65	Jun-10	0	0	0
Cape Canaveral	2	Brevard County	ST	FO6	NG	WA	PL	Unknown	May-69	Jun-10	0	0	0
Cutler	5	Miami Dade County	ST	NG	No	PL	No	Unknown	Nov-54	Jan-12	75,000	68	69
Cutler	6	Miami Dade County	ST	NG	No	PL	No	Unknown	Jul-55	Jan-12	161,500	137	138
DeSoto	1	DeSoto County	PV	N/A	N/A	N/A	N/A	Unknown	Oct-09	Unknown	25,000	25	25
Fort Myers	2	Lee County	CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,775,390	1,432	1,490
Fort Myers	3A & B	Lee County	CT	NG	FO2	PL	PL	Unknown	Jun-03	Unknown	376,380	315	352
Fort Myers	1-12	Lee County	GT	FO2	No	PL	No	Unknown	May-74	Unknown	744,120	648	710
Lauderdale	4	Broward County	CC	NG	FO2	PL	PL	Unknown	May-93	Unknown	526,250	442	483
Lauderdale	5	Broward County	CC	NG	FO2	PL	PL	Unknown	Jun-93	Unknown	526,250	442	483
Lauderdale	1-12	Broward County	GT	NG	FO2	PL	PL	Unknown	Aug-70	Unknown	410,734	420	459
Lauderdale	13-24	Broward County	GT	NG	FO2	PL	PL	Unknown	Aug-72	Unknown	410,734	420	459
Manatee	1	Manatee County	ST	FO6	NG	WA	PL	Unknown	Oct-76	Unknown	863,300	812	822
Manatee	2	Manatee County	ST	FO6	NG	WA	PL	Unknown	Dec-77	Unknown	863,300	812	822
Manatee	3	Manatee County	CC	NG	No	PL	No	Unknown	Jun-05	Unknown	1,224,510	1,111	1,168
Martin	1	Martin County	ST	FO6	NG	PL	PL	Unknown	Dec-80	Unknown	934,500	826	832
Martin	2	Martin County	ST	FO6	NG	PL	PL	Unknown	Jun-81	Unknown	934,500	826	832
Martin	3	Martin County	CC	NG	No	PL	No	Unknown	Feb-94	Unknown	612,000	469	489
Martin	4	Martin County	CC	NG	No	PL	No	Unknown	Apr-94	Unknown	612,000	469	489
Martin	8	Martin County	CC	NG	FO2	PL	PL	Unknown	Jun-05	Unknown	1,224,510	1,105	1,162
Port Everglades	1	City of Hollywood	ST	FO6	NG	WA	PL	Unknown	Jun-60	Unknown	225,250	213	214
Port Everglades	2	City of Hollywood	ST	FO6	NG	WA	PL	Unknown	Apr-61	Unknown	225,250	213	214
Port Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	Unknown	Jul-64	Unknown	402,050	387	389
Port Everglades	4	City of Hollywood	ST	FO6	NG	WA	PL	Unknown	Apr-65	Unknown	402,050	374	376
Port Everglades	1-12	City of Hollywood	GT	NG	FO2	PL	PL	Unknown	Aug-71	Unknown	410,734	420	459
Putnam	1	Putnam County	CC	NG	FO2	PL	WA	Unknown	Apr-78	Unknown	290,004	249	265
Putnam	2	Putnam County	CC	NG	FO2	PL	WA	Unknown	Aug-77	Unknown	290,004	249	265
Riviera	3	City of Riviera Beach	ST	FO6	NG	WA	PL	Unknown	Jun-62	Feb-11	310,420	277	280
Riviera	4	City of Riviera Beach	ST	FO6	NG	WA	PL	Unknown	Mar-63	Feb-11	310,420	288	291
Sanford	3	Volusia County	ST	FO6	NG	WA	PL	Unknown	May-59	Jan-12	156,250	138	140
Sanford	4	Volusia County	CC	NG	No	PL	No	Unknown	Oct-03	Unknown	1,188,860	958	1,040
Sanford	5	Volusia County	CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,188,860	954	1,037
Scherer	4	Monroe, GA	BIT	SUB	No	RR	No	Unknown	Jul-89	Unknown	680,368	646	652
Space Coast	1	Brevard County	PV	N/A	N/A	N/A	N/A	Unknown	Apr-10	Unknown	10,000	10	10
SJRPP	1	Duval County	BIT	BIT	Pet	RR	WA	Unknown	Mar-87	Unknown	135,918	127	125
SJRPP	2	Duval County	BIT	BIT	Pet	RR	WA	Unknown	May-88	Unknown	135,918	127	125
St. Lucie	1	St. Lucie County	NP	UR	No	TK	No	Unknown	May-76	Unknown	850,000	839	853
St. Lucie	2	St. Lucie County	NP	UR	No	TK	No	Unknown	Jun-83	Unknown	723,775	714	726
Turkey Point	1	Miami Dade County	ST	FO6	NG	WA	PL	Unknown	Apr-67	Unknown	402,050	396	398
Turkey Point	2	Miami Dade County	ST	FO6	NG	WA	PL	Unknown	Apr-68	Unknown	402,050	392	394
Turkey Point	3	Miami Dade County	NP	UR	No	TK	No	Unknown	Nov-72	Unknown	759,970	693	717
Turkey Point	4	Miami Dade County	NP	UR	No	TK	No	Unknown	Jun-73	Unknown	759,970	693	717
Turkey Point	5	Miami Dade County	CC	NG	FO2	PL	PL	Unknown	May-07	Unknown	1,224,510	1,148	1,156
West County	1	Palm Beach County	CC	NG	FO2	PL	PL	Unknown	Aug-09	Unknown	1,366,800	1,219	1,335
West County	2	Palm Beach County	CC	NG	FO2	PL	PL	Unknown	Nov-09	Unknown	1,366,800	1,219	1,335

Supplemental DR - Question No. 2
Attachment No. 1

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		Rural and Residential					Commercial	
Year	Population	Members per Household	GWH	Average No. of Customers	Average KWH Consumption Per Customer	GWH	Average No. of Customers	Average KWH Consumption Per Customer
HISTORY:								
2001	7,754,846	2.22	47,588	3,490,541	13,633	37,960	426,573	88,989
2002	7,898,628	2.21	50,865	3,566,167	14,263	40,029	435,313	91,955
2003	8,079,316	2.21	53,485	3,652,663	14,643	41,425	444,650	93,163
2004	8,247,442	2.20	52,502	3,744,915	14,020	42,064	458,053	91,832
2005	8,469,602	2.21	54,348	3,828,374	14,196	43,468	469,973	92,490
2006	8,620,855	2.21	54,570	3,906,267	13,970	44,487	478,867	92,901
2007	8,729,806	2.19	55,138	3,981,451	13,849	45,921	493,130	93,121
2008	8,771,694	2.20	53,229	3,992,257	13,333	45,561	500,748	90,987
2009	8,732,591	2.19	53,950	3,984,490	13,540	45,025	501,055	89,860
2010	8,739,209	2.18	56,343	4,004,366	14,070	44,544	503,529	88,464
FORECAST:								
2011	8,873,003	2.20	54,364	4,033,183	13,479	44,188	504,216	87,637
2012	8,965,719	2.20	54,932	4,075,327	13,479	44,496	505,886	87,956
2013	9,106,253	2.20	56,399	4,139,206	13,626	45,134	510,436	88,423
2014	9,263,516	2.20	58,257	4,210,689	13,836	46,214	517,941	89,226
2015	9,418,816	2.20	59,326	4,281,280	13,857	47,089	526,406	89,455
2016	9,564,956	2.20	60,382	4,347,707	13,888	47,869	534,487	89,560
2017	9,700,967	2.20	61,118	4,409,530	13,860	48,660	542,273	89,733
2018	9,830,014	2.20	61,828	4,468,188	13,837	49,456	549,902	89,937
2019	9,955,509	2.20	62,480	4,525,231	13,807	50,385	557,399	90,393
2020	10,080,541	2.20	63,575	4,582,064	13,875	51,512	564,827	91,199

Supplemental DR - Question No. 2
Attachment No. 1

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

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial						
Year	GWH	Average No. of Customers	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting GWH	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
HISTORY:							
2001	4,091	15,445	264,872	86	419	67	90,212
2002	4,057	15,533	261,199	89	420	63	95,523
2003	4,004	17,029	235,135	93	425	64	99,496
2004	3,964	18,512	214,139	93	413	58	99,095
2005	3,913	20,392	191,873	95	424	49	102,296
2006	4,036	21,211	190,277	94	422	49	103,659
2007	3,774	18,732	201,499	91	437	53	105,415
2008	3,587	13,377	268,168	81	423	37	102,919
2009	3,245	10,084	321,796	80	422	34	102,755
2010	3,130	8,910	351,318	81	431	28	104,557
FORECAST:							
2011	3,152	8,848	356,191	82	442	30	102,257
2012	3,082	9,306	331,150	91	452	30	103,083
2013	3,037	9,733	312,057	92	463	30	105,155
2014	3,018	10,054	300,163	92	475	30	108,085
2015	3,013	10,241	294,231	92	487	30	110,038
2016	3,015	10,437	288,893	92	500	30	111,888
2017	3,004	10,527	285,355	92	514	30	113,418
2018	2,992	10,516	284,534	92	529	30	114,928
2019	2,987	10,545	283,288	92	544	30	116,518
2020	2,981	10,598	281,312	92	560	30	118,749

Supplemental DR - Question No. 2
Attachment No. 1

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

(1)	(17)	(18)	(19)	(20)	(21)
Year	Sales for Resale GWH	Utility Use & Losses GWH	Net Energy for Load GWH	Other Customers (Average No.)	Total No. of Customers
HISTORY:					
2001	970	7,222	98,404	2,722	3,935,281
2002	1,233	7,443	104,199	2,792	4,019,805
2003	1,511	7,386	108,393	2,879	4,117,221
2004	1,531	7,467	108,093	3,029	4,224,509
2005	1,506	7,498	111,301	3,156	4,321,895
2006	1,569	7,909	113,137	3,218	4,409,563
2007	1,499	7,401	114,315	3,276	4,496,589
2008	993	7,092	111,004	3,348	4,509,730
2009	1,155	7,394	111,303	3,439	4,499,067
2010	2,049	7,768	114,373	3,523	4,520,328
FORECAST:					
2011	2,142	6,776	111,175	3,590	4,549,837
2012	2,142	7,292	112,517	3,672	4,594,191
2013	2,047	7,445	114,647	3,756	4,663,131
2014	4,935	8,014	121,035	3,845	4,742,529
2015	5,566	8,006	123,610	3,940	4,821,867
2016	5,599	8,106	125,593	4,041	4,896,672
2017	5,625	8,208	127,251	4,147	4,966,477
2018	5,672	8,310	128,910	4,258	5,032,864
2019	5,717	8,443	130,679	4,373	5,097,548
2020	5,770	8,601	133,121	4,493	5,161,981

Supplemental DR - Question No. 2
Attachment No. 1

Schedule 3.1
History and Forecast of Summer Peak Demand
Base Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
HISTORY:									
2001	18,754	169	18,585	0	835	516	483	469	17,436
2002	19,219	261	18,958	0	870	576	483	506	17,866
2003	19,668	253	19,415	0	885	618	566	541	18,217
2004	20,545	258	20,287	0	895	665	586	566	19,064
2005	22,361	264	22,097	0	898	715	592	599	20,871
2006	21,819	256	21,563	0	910	770	607	634	20,302
2007	21,962	261	21,701	0	941	808	676	672	20,345
2008	21,060	181	20,879	0	966	861	734	697	19,360
2009	22,351	249	22,102	0	976	902	780	719	20,595
2010	22,256	419	21,837	0	991	982	816	747	18,720
FORECAST:									
2011	21,679	383	21,295	0	1,005	79	858	39	19,697
2012	21,853	385	21,468	0	1,017	154	878	93	19,712
2013	22,155	343	21,812	0	1,023	244	896	154	19,837
2014	23,452	1,129	22,322	0	1,041	343	934	216	20,917
2015	24,172	1,136	23,037	0	1,044	442	952	272	21,462
2016	24,605	1,143	23,463	0	1,047	536	971	318	21,734
2017	25,025	1,150	23,875	0	1,050	625	989	353	22,008
2018	25,266	1,157	24,109	0	1,053	711	1,007	378	22,117
2019	25,690	1,165	24,526	0	1,056	792	1,026	397	22,419
2020	26,193	1,172	25,022	0	1,080	837	1,042	412	22,823

Supplemental DR - Question No. 2
Attachment No. 1

Schedule 3.2
History and Forecast of Winter Peak Demand
Base Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
HISTORY:									
2000/01	18,199	150	18,049	0	749	500	448	196	17,002
2001/02	17,597	145	17,452	0	768	546	457	206	16,373
2002/03	20,190	246	19,944	0	802	567	453	227	18,935
2003/04	14,752	211	14,541	0	814	583	535	233	13,403
2004/05	18,108	225	17,883	0	816	600	542	240	16,750
2005/06	19,683	225	19,458	0	822	620	549	249	18,312
2006/07	16,815	223	16,592	0	849	644	579	279	15,387
2007/08	18,055	163	17,892	0	868	666	636	285	16,551
2008/09	20,081	207	19,874	0	884	687	680	291	18,517
2009/10	24,346	500	23,846	0	895	718	721	303	21,709
FORECAST:									
2010/11	21,443	376	21,067	0	911	31	754	15	19,732
2011/12	21,491	378	21,113	0	922	63	769	47	19,689
2012/13	21,683	380	21,303	0	932	104	784	89	19,774
2013/14	22,584	1,015	21,569	0	956	158	817	134	20,518
2014/15	23,048	1,222	21,826	0	959	214	832	177	20,866
2015/16	23,302	1,229	22,073	0	961	267	846	215	21,014
2016/17	23,543	1,237	22,306	0	963	314	860	244	21,161
2017/18	23,794	1,245	22,550	0	966	358	874	266	21,331
2018/19	24,044	1,252	22,792	0	968	398	889	282	21,508
2019/20	24,305	1,260	23,045	0	970	431	902	293	21,709

Supplemental DR - Question No. 2
Attachment No. 1

Schedule 3.3
History of Annual Net Energy for Load (GWH)
Base Case

(1) Year	(2) Total	(3) Residential Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor %
HISTORY:							
2001	101,364	1,554	98,404	970	7,222	90,212	59.9%
2002	107,380	1,682	104,199	1,233	7,443	95,523	61.9%
2003	111,784	1,773	108,393	1,511	7,386	99,496	62.9%
2004	111,659	1,872	108,093	1,531	7,467	99,095	59.9%
2005	115,065	1,970	111,301	1,506	7,498	102,296	56.8%
2006	117,116	2,078	113,137	1,569	7,909	103,659	59.2%
2007	118,518	2,138	114,315	1,499	7,401	105,415	59.4%
2008	115,379	2,249	111,004	993	7,092	102,919	60.0%
2009	115,844	2,345	111,303	1,155	7,394	102,755	56.8%
2010	119,119	2,487	114,373	2,049	7,768	109,302	61.1%
FORECAST:							
2011	111,175	73	111,028	2,142	6,776	102,257	58.5%
2012	112,517	230	112,041	2,142	7,292	103,083	58.6%
2013	114,647	408	113,797	2,047	7,445	105,155	59.1%
2014	121,035	601	119,793	4,935	8,014	108,085	58.9%
2015	123,610	798	121,991	5,566	8,006	110,038	58.4%
2016	125,593	986	123,634	5,599	8,106	111,888	58.1%
2017	127,251	1,165	124,994	5,625	8,208	113,418	58.0%
2018	128,910	1,335	126,387	5,672	8,310	114,928	58.2%
2019	130,679	1,497	127,915	5,717	8,443	116,518	58.1%
2020	133,121	1,657	130,135	5,770	8,601	118,749	58.0%

Supplemental DR - Question No. 2
Attachment No. 1

Schedule 4
Previous Year and 2-Year Forecast of Retail Peak Demand and Net Energy for Load by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2010 Actual		2011 Forecast		2012 Forecast	
Month	Peak Demand MW	NEL GWH	Peak Demand MW	NEL GWH	Peak Demand MW	NEL GWH
January	24,346	9,410	21,443	8,191	21,491	8,301
February	16,488	7,470	17,558	7,365	17,596	7,449
March	17,748	8,001	17,460	8,239	17,499	8,328
April	15,480	8,179	17,160	8,368	17,299	8,449
May	19,217	9,950	19,255	9,905	19,410	9,992
June	21,901	11,619	20,557	10,336	20,723	10,423
July	21,633	11,215	21,155	11,101	21,326	11,199
August	22,256	11,651	21,679	11,218	21,853	11,323
September	20,738	11,094	20,917	10,424	21,086	10,543
October	19,116	9,020	19,582	9,728	19,740	9,872
November	17,052	8,145	17,922	8,099	18,082	8,255
December	21,153	8,619	17,787	8,202	17,946	8,383
		114,373		111,175		112,517

Supplemental DR - Question No. 2
Attachment No. 1

Schedule 5
Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Fuel Requirements		Units	Actual 2009	Actual 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
(1)	Nuclear		Trillion BTU	250	250	257	217	278	292	289	290	295	290	290	296
(2)	Coal		1000 Ton	3,577	3,191	3,570	3,250	3,959	3,645	3,956	3,655	3,951	3,599	3,932	3,633
(3)	Residual	Total	1000 BBL	7,489	6,754	2,489	1,455	845	712	907	1,066	1,256	1,213	1,378	1,240
(4)		Steam	1000 BBL	7,489	6,754	2,489	1,455	845	712	907	1,066	1,256	1,213	1,378	1,240
(5)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		Other	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	1000 BBL	47	522	121	2	5	0	15	19	71	47	63	2
(9)		Steam	1000 BBL	0	4	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	6	194	100	2	4	0	0	0	0	0	0	0
(11)		CT	1000 BBL	40	324	21	0	1	0	15	19	71	47	63	2
(12)		Other	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	481,426	504,996	529,619	542,420	505,993	538,782	541,899	575,212	589,224	605,055	612,589	626,151
(14)		Steam	1000 MCF	81,260	56,729	40,917	27,439	13,860	11,609	13,620	16,789	19,179	18,634	21,159	19,608
(15)		CC	1000 MCF	395,703	443,108	487,142	514,015	491,405	526,628	527,571	557,375	567,865	584,757	589,172	605,395
(16)		CT	1000 MCF	4,462	5,159	1,559	966	728	544	709	1,048	2,180	1,664	2,258	1,148
(17)	Other (Specify)		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0

Supplemental DR - Question No. 2
Attachment No. 1

Schedule 6.1
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2009	Actual 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
(1)	Firm Inter-Region Interchange		GWH	9,508	8,333	5,797	5,947	5,274	5,163	5,082	1,726	0	0	0	0
(2)	Nuclear		GWH	22,893	22,850	20,758	19,718	25,388	26,720	26,406	26,567	26,981	26,591	26,491	27,058
(3)	Coal		GWH	6,362	5,721	6,738	6,230	7,446	6,903	7,440	6,926	7,428	6,795	7,390	6,873
(4)	Residual	Total	GWH	4,560	4,081	1,627	964	559	467	602	704	829	801	909	820
(5)		Steam	GWH	4,560	4,081	1,627	964	559	467	602	704	829	801	909	820
(6)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Other	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	GWH	21	279	93	2	4	0	5	6	25	15	20	1
(10)		Steam	GWH	3	2	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWH	3	143	84	2	4	0	0	0	0	0	0	0
(12)		CT	GWH	15	134	9	0	0	0	5	6	25	15	20	1
(13)		Other	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWH	62,728	66,771	73,272	75,939	71,971	77,352	78,200	83,199	85,127	87,616	88,496	90,766
(15)		Steam	GWH	8,705	5,041	3,984	2,711	1,365	1,134	1,347	1,655	1,894	1,838	2,087	1,935
(16)		CC	GWH	53,636	61,304	69,166	73,151	70,549	76,174	76,797	81,464	83,071	85,651	86,241	88,742
(17)		CT	GWH	387	426	123	77	57	44	56	81	163	126	169	90
(18)	NUG		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(19)	Renewables	Total	GWH	0	69	228	227	226	225	225	225	224	224	222	221
(20)		Biofuels	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(21)		Biomass	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(22)		Hydro	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(23)		Landfill Gas	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(24)		MSW	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(25)		Solar	GWH	0	69	228	227	226	225	225	225	224	224	222	221
(26)		Wind	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(27)		Other	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(28)	Other (Specify)		GWH	5,231	6,339	2,663	3,489	3,780	4,204	5,650	6,239	6,636	6,869	7,149	7,380
(29)	Net Energy for Load		GWH	111,304	114,373	111,176	112,517	114,647	121,035	123,610	125,593	127,250	128,910	130,679	133,121

Supplemental DR - Question No. 2
Attachment No. 1

Schedule 6.2
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2009	Actual 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
(1)	Firm Inter-Region Interchange		%	8.5	7.3	5.2	5.3	4.6	4.3	4.1	1.4	0.0	0.0	0.0	0.0
(2)	Nuclear		%	20.6	20.0	18.7	17.5	22.1	22.1	21.4	21.2	21.2	20.6	20.3	20.3
(3)	Coal		%	5.7	5.0	6.1	5.5	6.5	5.7	6.0	5.5	5.8	5.3	5.7	5.2
(4)	Residual	Total	%	4.1	3.6	1.5	0.9	0.5	0.4	0.5	0.6	0.7	0.6	0.7	0.6
(5)		Steam	%	4.1	3.6	1.5	0.9	0.5	0.4	0.5	0.6	0.7	0.6	0.7	0.6
(6)		CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)		CT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8)		Other	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	Distillate	Total	%	0.0	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)		Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)		CC	%	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(12)		CT	%	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(13)		Other	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(14)	Natural Gas	Total	%	56.4	58.4	65.9	67.5	62.8	63.9	63.3	66.2	66.9	68.0	67.7	68.2
(15)		Steam	%	7.8	4.4	3.6	2.4	1.2	0.9	1.1	1.3	1.5	1.4	1.6	1.5
(16)		CC	%	48.2	53.6	62.2	65.0	61.5	62.9	62.1	64.9	65.3	66.4	66.0	66.7
(17)		CT	%	0.3	0.4	0.1	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
(18)	NUG		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(19)	Renewables	Total	%	0.0	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(20)		Biofuels	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(21)		Biomass	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(22)		Hydro	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(23)		Landfill Gas	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(24)		MSW	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(25)		Solar	%	0.0	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(26)		Wind	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(27)		Other	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(28)	Other (Specify)		%	4.7	5.5	2.4	3.1	3.3	3.5	4.6	5.0	5.2	5.3	5.5	5.5
(29)	Net Energy for Load		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Supplemental DR - Question No. 2
Attachment No. 1

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	Actual Summer Peak Demand *	Reserve Margin before Maintenance		Scheduled Maintenance	Reserve Margin after Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
HISTORY:											
2001	17,704	1,509	0	886	20,099	18,754	1,345	7.2	0	1,345	7.2
2002	17,860	2,403	0	877	21,140	19,219	1,921	10.0	0	1,921	10.0
2003	18,864	2,263	0	877	22,004	19,668	2,336	11.9	656	1,680	8.5
2004	19,130	2,667	0	880	22,677	20,545	2,132	10.4	0	2,132	10.4
2005	20,846	2,247	0	874	23,967	22,361	1,606	7.2	0	1,606	7.2
2006	20,919	2,669	0	738	24,326	21,819	2,507	11.5	159	2,348	10.8
2007	22,123	2,255	0	738	25,116	21,962	3,154	14.4	0	3,154	14.4
2008	22,149	2,255	0	738	25,142	21,060	4,082	19.4	0	4,082	19.4
2009	23,985	1,824	0	690	26,499	22,351	4,148	18.6	29	4,119	18.4
2010	22,394	1,460	0	640	24,494	22,256	2,238	10.1	209	2,029	9.1
FORECAST:											
2011	22,462	1,461	0	595	24,518	19,698	4,819	24.5	350	4,469	22.7
2012	23,437	1,306	0	650	25,393	19,712	5,681	28.8	1,064	4,617	23.4
2013	24,105	1,306	0	650	26,061	19,838	6,223	31.4	1,176	5,047	25.4
2014	25,317	1,306	0	650	27,273	20,918	6,354	30.4	1,176	5,178	24.8
2015	25,317	1,306	0	740	27,363	21,462	5,900	27.5	350	5,550	25.9
2016	26,508	0	0	740	27,248	21,734	5,514	25.4	350	5,164	23.8
2017	26,508	0	0	740	27,248	22,009	5,239	23.8	350	4,889	22.2
2018	26,508	0	0	740	27,248	22,117	5,130	23.2	350	4,780	21.6
2019	26,508	0	0	740	27,248	22,419	4,828	21.5	350	4,478	20.0
2020	27,699	0	0	740	28,439	22,822	5,616	24.6	350	5,266	23.1

Note: Historical projected data for yrs 2001 - 2010 (cols 2- 6) is from the Ten Year Site Plans for that year.
* This column reflect actual peaks and matches values shown on Schedule 3.1 col. (2). Some of these peaks fell in the months of June and July.

Supplemental DR - Question No. 2
Attachment No. 1

Schedule 7.2
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	Actual Winter Peak Demand *	Reserve Margin before Maintenance		Scheduled Maintenance	Reserve Margin after Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
HISTORY:											
2000/01	17,785	1,319	0	886	19,990	18,199	1,791	9.8	29	1,762	9.7
2001/02	17,730	1,910	0	886	20,526	17,597	2,929	16.6	284	2,645	15.0
2002/03	18,780	2,475	0	877	22,132	20,190	1,942	9.6	29	1,913	9.5
2003/04	20,356	2,345	0	880	23,581	14,752	8,829	59.8	1,269	7,560	51.2
2004/05	20,158	2,329	0	870	23,357	18,108	5,249	29.0	1,285	3,964	21.9
2005/06	22,304	2,467	0	738	25,509	19,683	5,826	29.6	680	5,146	26.1
2006/07	22,294	3,124	0	738	26,156	16,815	9,341	55.6	596	8,745	52.0
2007/08	23,535	2,288	0	738	26,561	18,055	8,506	47.1	961	7,545	41.8
2008/09	23,280	1,962	0	740	25,982	20,081	5,901	29.4	250	5,651	28.1
2009/10	24,638	1,481	0	690	26,809	24,346	2,463	10.1	852	1,611	6.6
FORECAST:											
2010/11	23,987	1,494	0	595	26076	19,732	6,343	32.1	1,276	5,067	25.7
2011/12	24,400	1,494	0	595	26489	19,689	6,799	34.5	2,942	3,857	19.6
2012/13	23,959	1,314	0	650	25923	19,774	6,148	31.1	1,372	4,776	24.2
2013/14	25,423	1,314	0	650	27387	20,519	6,868	33.5	1,382	5,486	26.7
2014/15	26,767	1,314	0	650	28731	20,866	7,864	37.7	550	7,314	35.1
2015/16	26,767	383	0	740	27890	21,014	6,876	32.7	550	6,326	30.1
2016/17	28,118	0	0	740	28858	21,161	7,696	36.4	550	7,146	33.8
2017/18	28,118	0	0	740	28858	21,330	7,527	35.3	550	6,977	32.7
2018/19	28,118	0	0	740	28858	21,508	7,350	34.2	550	6,800	31.6
2019/20	28,118	0	0	740	28858	21,709	7,148	32.9	550	6,598	30.4

Note: Historical projected data for yrs 2000/2001 - 2009/10 (cols 2- 6) is from the Ten Year Site Plans for that year.
* This column reflect actual peaks and matches values shown on Schedule 3.2 col. (2). Some of these peaks fell in the month of February.

Supplemental DR - Question No. 2
Attachment No. 1

Schedule 8
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
								Const.	Commercial	Expected	Gen. Max.	Net Capability		
	Unit		Unit	Fuel		Fuel Transport		Start	In-Service	Retirement	Nameplate	Summer	Winter	
Plant Name	No.	Location	Type	Pri	Alt	Pri	Alt	Mo/Yr	Mo/Yr	Mo/Yr	KW	MW	MW	Status
St. Lucie (Uprates)	2	St. Lucie County	NP	UR	No	TK	No	—	Apr-11	Unknown	723,775	17	—	OT
Riviera	3	City of Riviera Beach	ST	FO6	NG	WA	PL	Unknown	Unknown	Feb-11	310,420	(277)	—	OT
Riviera	4	City of Riviera Beach	ST	FO6	NG	WA	PL	Unknown	Unknown	Feb-11	310,420	(288)	—	OT
Scherer	4	Monroe, GA	BIT	SUB	No	RR	No	—	Jul-11	Unknown	680,368	26	—	OT
West County Energy Center	3	Palm Beach County	CC	NG	FO2	PL	PL	Jan-09	Jun-11	Unknown	1,366,800	1219	—	V
Cutler	5	Miami Dade County	ST	FO6	NG	WA	PL	—	—	—	75,000	(68)	(69)	OT
Cutler	6	Miami Dade County	ST	FO6	NG	WA	PL	—	—	—	161,500	(137)	(138)	OT
Sanford	3	Volusia County	ST	FO6	NG	WA	PL	—	—	—	156,250	(138)	(140)	OT
Port Everglades	1	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	225,250	(213)	(214)	OT
Port Everglades	2	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	225,250	(213)	(214)	OT
Port Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	(387)	—	OT
Port Everglades	4	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	(374)	—	OT
Turkey Point	2	Miami Dade County	ST	FO6	NG	WA	PL	—	—	—	402,050	(392)	—	OT
Riviera	3	City of Riviera Beach	ST	FO6	NG	WA	PL	Unknown	Unknown	Unknown	310,420	—	(280)	OT
Riviera	4	City of Riviera Beach	ST	FO6	NG	WA	PL	Unknown	Unknown	Unknown	310,420	—	(291)	OT
Scherer	4	Monroe, GA	BIT	SUB	No	RR	No	—	Jul-11	Unknown	680,368	—	26	OT
St. Lucie (Uprates)	2	St. Lucie County	NP	UR	No	TK	No	—	See Note 2	Unknown	723,775	(17)	17	T
St. Lucie (Uprates)	1	St. Lucie County	NP	UR	No	TK	No	—	Dec-11	Unknown	850,000	122	—	T
Turkey Point (Uprates)	3	Miami Dade County	NP	UR	No	TK	No	—	May-12	Unknown	759,900	109	—	T
West County Energy Center	3	Palm Beach County	CC	NG	FO2	PL	PL	Jan-09	Jun-11	Unknown	1,366,800	—	1,335	V
Turkey Point	2	Miami Dade County	ST	FO6	NG	WA	PL	—	—	—	402,050	—	(394)	OT
Port Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	387	—	OT
Port Everglades	4	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	374	—	T
St. Lucie (Uprates)	2	St. Lucie County	NP	UR	No	TK	No	—	See Note 2	Unknown	723,775	—	(17)	T
St. Lucie (Uprates)	1	St. Lucie County	NP	UR	No	TK	No	—	See Note 2	Unknown	850,000	—	122	T
Cape Canaveral Next Generation Clean Energy Center	1	Brevard County	CC	NG	FO2	PL	PL	Jun-11	Jun-13	Unknown	1,296,750	1,210	—	T
St. Lucie (Uprates)	2	St. Lucie County	NP	UR	No	TK	No	—	See Note 2	Unknown	723,775	93	93	T
Turkey Point (Uprates)	3	Miami Dade County	NP	UR	No	TK	No	—	See Note 2	Unknown	759,900	—	109	T
Turkey Point (Uprates)	4	Miami Dade County	NP	UR	No	TK	No	—	See Note 2	Unknown	759,900	109	—	OT
Port Everglades	3	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	(387)	(389)	OT
Port Everglades	4	City of Hollywood	ST	FO6	NG	WA	PL	—	—	—	402,050	(374)	(376)	
Turkey Point (Uprates)	4	Miami Dade County	NP	UR	No	TK	No	—	See Note 2	Unknown	759,900	—	109	T
Cape Canaveral Next Generation Clean Energy Center	1	Brevard County	CC	NG	FO2	PL	PL	Jun-11	Jun-13	Unknown	1,296,750	—	1,355	T
Riviera Beach Next Generation Clean Energy Center	1	City of Riviera Beach	CC	NG	FO2	PL	PL	Jun-12	Jun-14	Unknown	1,296,750	1,212	—	T
Riviera Beach Next Generation Clean Energy Center	1	City of Riviera Beach	CC	NG	FO2	PL	PL	Jun-12	Jun-14	Unknown	1,296,750	—	1,344	T
Unsited 3x1 H Combined Cycle	1	—	CC	NG	FO2	PL	PL	Jun-14	Jun-16	Unknown	Unknown	1,191	—	P
Unsited 3x1 H Combined Cycle	1	—	CC	NG	FO2	PL	PL	Jun-14	Jun-16	Unknown	Unknown	—	1,351	P
Unsited 3x1 H Combined Cycle	2	—	CC	NG	FO2	PL	PL	Jun-18	Jun-20	Unknown	Unknown	1,191	—	P

Supplemental DR - Question No. 2
Attachment No. 1

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** West County Energy Center Combined Cycle Unit 3

(2) **Capacity**
a. Summer 1,219 MW
b. Winter 1,335 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2009
b. Commercial In-service date: 2011

(5) **Fuel**
a. Primary Fuel Natural Gas
b. Alternate Fuel Distillate

(6) **Air Pollution and Control Strategy:** Natural Gas, Dry Low No_x Combustors, SCR
0.0015% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Cooling Tower

(8) **Total Site Area:** 220 Acres

(9) **Construction Status:** V (Under construction, more than 50% Complete)

(10) **Certification Status:** Permitted

(11) **Status with Federal Agencies:** Permitted

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.1%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.8%	(Base & Duct Firing Operation)
Resulting Capacity Factor (%):	Approx. 93%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,582 Btu/kWh	(Base Operation)
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30 years
Total Installed Cost (2011 $/kW):	709
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	71
Escalation ($/kW):	
Fixed O&M ($/kW -Yr.): (2011 $kW-Yr)	11.63
Variable O&M ($/MWH)(2011 $/MWH)	0.480
K Factor:	1.4697

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement, but not firm gas transportation costs

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration escalation, and AFUDC.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** St. Lucie 1 Nuclear (Uprate)

(2) **Capacity**
a. Summer 122 MW (Incremental)
b. Winter 122 MW (Incremental)

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: During scheduled refueling outage
b. Commercial In-service date: 2012

(5) **Fuel**
a. Primary Fuel Uranium
b. Alternate Fuel ---

(6) **Air Pollution and Control Strategy:** No change from existing unit

(7) **Cooling Method:** No change from existing unit

(8) **Total Site Area:** No change from existing unit

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	No change from existing unit
Forced Outage Factor (FOF):	No change from existing unit
Equivalent Availability Factor (EAF):	No change from existing unit
Resulting Capacity Factor (%):	No change from existing unit
Average Net Operating Heat Rate (ANOHR):	No change from existing unit
Base Operation 75F,100%	No change from existing unit

(13) **Projected Unit Financial Data ***

Book Life (Years):	25	years (Matches the current operating license period.)
Total Installed Cost ($/kW): **	TBD	(See Note (1) for explanation.)
Direct Construction Cost:	TBD	(See Note (1) for explanation.)
AFUDC Amount ($/kW):		(See Note (2) for explanation.)
Escalation ($/kW):		(See Note (3) for explanation.)
Fixed O&M ($/kW -Yr.):	There is no additional O&M impact from this project.	
Variable O&M ($/MWH):	There is no additional O&M impact from this project.	
K Factor:		(See Note (2) for explanation.)

NOTE:
(1) The projected capital cost values for the capacity uprates at each of FPL's existing nuclear units is currently being reviewed in on-going analyses as this document is being prepared. The capital cost projections that will result from these analyses are expected to be presented in FPL's May 2011 Nuclear Cost Recovery filing
(2) Not applicable due to early recovery of capital carrying costs
(3) These costs are included in the Total Installed Cost value

* $/kW values are based on incremental Summer capacity.
** $/incremental kW

Supplemental DR - Question No. 2
Attachment No. 1

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Turkey Point 3 Nuclear (Uprate)

(2) **Capacity**
a. Summer 109 MW (Incremental)
b. Winter 109 MW (Incremental)

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: During scheduled refueling outage
b. Commercial In-service date: 2012

(5) **Fuel**
a. Primary Fuel Uranium
b. Alternate Fuel —

(6) **Air Pollution and Control Strategy:** No change from existing unit

(7) **Cooling Method:** No change from existing unit

(8) **Total Site Area:** No change from existing unit

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	No change from existing unit
Forced Outage Factor (FOF):	No change from existing unit
Equivalent Availability Factor (EAF):	No change from existing unit
Resulting Capacity Factor (%):	No change from existing unit
Average Net Operating Heat Rate (ANOHR):	No change from existing unit
Base Operation 75F,100%	No change from existing unit

(13) **Projected Unit Financial Data ***

Book Life (Years):	21	years (Matches the current operating license period.)
Total Installed Cost ($/kW): **	TBD	(See Note (1) for explanation.)
Direct Construction Cost ($/kW):	TBD	(See Note (1) for explanation.)
AFUDC Amount ($/kW):		(See Note (2) for explanation.)
Escalation ($/kW):		(See Note (3) for explanation.)
Fixed O&M ($/kW-Yr.):	There is no additional O&M impact from this project.	
Variable O&M ($/MWH):	There is no additional O&M impact from this project.	
K Factor:		(See Note (2) for explanation.)

NOTE:
(1) The projected capital cost values for the capacity uprates at each of FPL's existing nuclear units is currently being reviewed in on-going analyses as this document is being prepared. The capital cost projections that will result from these analyses are expected to be presented in FPL's May 2011 Nuclear Cost Recovery filing
(2) Not applicable due to early recovery of capital carrying costs
(3) These costs are included in the Total Installed Cost value.

* $/kW values are based on incremental Summer capacity.
** $/incremental kW

Supplemental DR - Question No. 2
Attachment No. 1

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** St. Lucie 2 Nuclear (Uprate)

(2) **Capacity**
a. Summer — 17 MW (Interim Incremental FPL's ownership share), 110 MW (final incremental FPL's ownership share)
b. Winter — 17 MW (Interim Incremental FPL's ownership share), 110 MW (final incremental FPL's ownership share)

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: During scheduled refueling outage
b. Commercial In-service date: 2011 (Interim increase), 2012 (final increase)

(5) **Fuel**
a. Primary Fuel — Uranium
b. Alternate Fuel — —

(6) **Air Pollution and Control Strategy:** No change from existing unit

(7) **Cooling Method:** No change from existing unit

(8) **Total Site Area:** No change from existing unit

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	No change from existing unit
Forced Outage Factor (FOF):	No change from existing unit
Equivalent Availability Factor (EAF):	No change from existing unit
Resulting Capacity Factor (%):	No change from existing unit
Average Net Operating Heat Rate (ANOHR):	No change from existing unit
Base Operation 75F,100%	No change from existing unit

(13) **Projected Unit Financial Data *,****

Book Life (Years):	32	years (Matches the current operating license period.)
Total Installed Cost ($/kW): **	TBD	(See Note (1) for explanation.)
Direct Construction Cost ($/kW):	TBD	(See Note (1) for explanation.)
AFUDC Amount ($/kW):		(See Note (2) for explanation.)
Escalation ($/kW):		(See Note (3) for explanation.)
Fixed O&M ($/kW-Yr.):	There is no additional O&M impact from this project.	
Variable O&M ($/MWH):	There is no additional O&M impact from this project.	
K Factor:		(See Note (2) for explanation.)

NOTE:
(1) The projected capital cost values for the capacity uprates at each of FPL's existing nuclear units is currently being reviewed in on-going analyses as this document is being prepared. The capital cost projections that will result from these analyses are expected to be presented in FPL's May 2011 Nuclear Cost Recovery filing. nuclear units.
(2) Not applicable due to early recovery of capital carrying costs.
(3) These costs are included in the Total Installed Cost value.

* $/kW values are based on incremental Summer capacity.
** $/incremental kW

Supplemental DR - Question No. 2
Attachment No. 1

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Turkey Point 4 Nuclear (Uprate)

(2) **Capacity**
a. Summer 109 MW (Incremental)
b. Winter 109 MW (Incremental)

(3) **Technology Type:** Nuclear

(4) **Anticipated Construction Timing**
a. Field construction start-date: During scheduled refueling outage
b. Commercial In-service date: 2013

(5) **Fuel**
a. Primary Fuel Uranium
b. Alternate Fuel —

(6) **Air Pollution and Control Strategy:** No change from existing unit

(7) **Cooling Method:** No change from existing unit

(8) **Total Site Area:** No change from existing unit

(9) **Construction Status:** T (Regulatory approval received, but not under construction)

(10) **Certification Status:** T (Regulatory approval received, but not under construction)

(11) **Status with Federal Agencies:** T (Regulatory approval received, but not under construction)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	No change from existing unit
Forced Outage Factor (FOF):	No change from existing unit
Equivalent Availability Factor (EAF):	No change from existing unit
Resulting Capacity Factor (%):	No change from existing unit
Average Net Operating Heat Rate (ANOHR):	No change from existing unit
Base Operation 75F,100%	No change from existing unit

(13) **Projected Unit Financial Data *,****

Book Life (Years):	21	years (Matches the current operating license period.)
Total Installed Cost ($/kW): **	TBD	(See Note (1) for explanation.)
Direct Construction Cost ($/kW):	TBD	(See Note (1) for explanation.)
AFUDC Amount ($/kW):		(See Note (2) for explanation.)
Escalation ($/kW):		(See Note (3) for explanation.)
Fixed O&M ($/kW-Yr.):	There is no additional O&M impact from this project.	
Variable O&M ($/MWH):	There is no additional O&M impact from this project.	
K Factor:		(See Note (2) for explanation.)

NOTE:
(1) The projected capital cost values for the capacity uprates at each of FPL's existing nuclear units is currently being reviewed in on-going analyses as this document is being prepared. The capital cost projections that will result from these analyses are expected to be presented in FPL's May 2011 Nuclear Cost Recovery filing
(2) Not applicable due to early recovery of capital carrying costs
(3) These costs are included in the Total Installed Cost value.

* $/kW values are based on incremental Summer capacity.
** $/incremental kW

Supplemental DR - Question No. 2
Attachment No. 1

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Cape Canaveral Next Generation Clean Energy Center

(2) **Capacity**
a. Summer 1,210 MW
b. Winter 1,355 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2011
b. Commercial In-service date: 2013

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas,
0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** 43 Acres

(9) **Construction Status:** U (Under construction, less than or equal to 50% complete)

(10) **Certification Status:** Permitted

(11) **Status with Federal Agencies:** Permitted

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.4%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	96.5%	
Resulting Capacity Factor (%):	Approx. 90 %	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,484	Btu/kWh
Base Operation 75F,100%		

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30	years
Total Installed Cost (2013 $/kW):	921	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):	98	
Escalation ($/kW):		
Fixed O&M ($/kW-Yr): (2013 $)	13.29	
Variable O&M ($/MWH; (2013 $)	0.16	
K Factor:	1.484	

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration escalation, and AFUDC.

Supplemental DR - Question No. 2
Attachment No. 1

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Riviera Beach Next Generation Clean Energy Center

(2) **Capacity**
a. Summer 1,212 MW
b. Winter 1,344 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2012
b. Commercial In-service date: 2014

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** 33 Acres

(9) **Construction Status:** U (Under construction, less than or equal to 50% complete)

(10) **Certification Status:** Permitted

(11) **Status with Federal Agencies:** Permitted

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.4%
Forced Outage Factor (FOF):	1.1%
Equivalent Availability Factor (EAF):	96.5%
Resulting Capacity Factor (%):	Approx. 90% (First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR)	6,480 Btu/kWh
Base Operation 75F,100%	

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30 years
Total Installed Cost (2014 $/kW):	1,053
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	121
Escalation ($/kW):	
Fixed O&M ($/kW-Yr): (2014 $)	13.67
Variable O&M ($/MWH (2014 $)	0.13
K Factor:	1.509

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Supplemental DR - Question No. 2
Attachment No. 1

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Greenfield 3x1 Combined Cycle

(2) **Capacity**
a. Summer 1,191 MW
b. Winter 1,351 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2014
b. Commercial In-service date: 2016

(5) **Fuel**
a. Primary Fuel Natural Gas
b. Alternate Fuel Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** --- Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.4%
Forced Outage Factor (FOF):	1.1%
Equivalent Availability Factor (EAF):	96.5%
Resulting Capacity Factor (%):	Approx. 90% (First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR)	6,607 Btu/kWh
Base Operation 75F,100%	

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30 years
Total Installed Cost (2016 $/kW):	956
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	98
Escalation ($/kW):	
Fixed O&M ($/kW-Yr): (2016 $)	17.65
Variable O&M ($/MWH (2016 $)	0.50
K Factor:	1.5136

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Supplemental DR - Question No. 2
Attachment No. 1

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Greenfield 3x1 Combined Cycle

(2) **Capacity**
a. Summer 1,191 MW
b. Winter 1,351 MW

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2018
b. Commercial In-service date: 2020

(5) **Fuel**
a. Primary Fuel Natural Gas
b. Alternate Fuel Ultra-low sulfur distillate

(6) **Air Pollution and Control Strategy:** Dry Low No_x Burners, SCR, Natural Gas, 0.0015% S. Distillate and Water Injection on Distillate

(7) **Cooling Method:** Once-through cooling water

(8) **Total Site Area:** — Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** —

(11) **Status with Federal Agencies:** —

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	2.4%
Forced Outage Factor (FOF):	1.1%
Equivalent Availability Factor (EAF):	96.5%
Resulting Capacity Factor (%):	Approx. 90% (First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR)	6,607 Btu/kWh
Base Operation 75F,100%	

(13) **Projected Unit Financial Data *,****

Book Life (Years):	30 years
Total Installed Cost (2020 $/kW):	1,076
Direct Construction Cost ($/kW):	
AFUDC Amount ($/kW):	111
Escalation ($/kW):	
Fixed O&M ($/kW-Yr): (2020 $)	19.79
Variable O&M ($/MWH (2020 $)	0.55
K Factor:	1.5136

* $/kW values are based on Summer capacity.
** Fixed O&M cost includes capital replacement.

NOTE: Total installed cost includes gas expansion, transmission interconnection and integration, escalation, and AFUDC.

Supplemental DR - Question No. 2
Attachment No. 1

Schedule 10
Status Report and Specifications of Proposed Directly Associated Transmission Lines
West County Energy Center Unit 3

(1)	Point of Origin and Termination	New Sugar Substation – Corbett Substatior
(2)	Number of Lines:	1
(3)	Right-of-Way:	FPL - Owned
(4)	Line Length:	1 mile
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing	Start date: May 2009 End date: November 2010 (Completed)
(7)	Anticipated Capital Investment:	$11,300,000
(8)	Substations:	New Sugar Substation and Corbett Substatior
(9)	Participation with Other Utilities	None

Supplemental DR - Question No. 2
Attachment No. 1

Schedule 10
Status Report and Specifications of Proposed Directly Associated Transmission Lines
West County Energy Center Unit 3

(1)	Point of Origin and Termination	Riviera – Cedar Substation
(2)	Number of Lines:	1
(3)	Right-of-Way:	Existing, FPL - Owned
(4)	Line Length:	15 miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Start date: 2012 End date: 2014
(7)	Anticipated Capital Investment:	$12,100,000
(8)	Substations:	Riviera Substation and Cedar Substatior
(9)	Participation with Other Utilities	None

Q.

Load and Demand Forecasting

Please provide, on a system-wide basis, an average month of observed peak capacity values for Summer and Winter. From this data, excluding weekends and holidays, generate an average seasonal Daily Loading Curve. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

A.

Please see attachment.

Supplemental DR - Question No. 3
Attachment No. 1

Typical Summer Month

Year	Month	Day	Day of Week	Observed Hourly Peak Capacity (MW) 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	MAX (MW)	MIN (MW)
2010	8	1	Sunday																										
2010	8	2	Monday	13490	12636	12011	11648	11547	11791	12412	13028	14204	15593	16952	18241	19345	20168	20461	20243	20009	19596	18940	18212	18100	17398	16123	14648	20461	11547
2010	8	3	Tuesday	13334	12417	11823	11472	11355	11638	12305	12953	14262	15830	17312	18547	19548	20402	20744	21069	21071	20654	19937	19066	18714	17962	16586	15019	21071	11355
2010	8	4	Wednesday	13679	12709	12083	11624	11466	11757	12434	12936	13979	15379	16663	17665	18340	19002	19539	19722	19541	19147	18495	17454	17106	16427	15172	13744	19722	11466
2010	8	5	Thursday	12559	11721	11157	10834	10730	11045	11758	12453	13796	15377	16860	18045	18854	19565	20056	20295	20414	20225	19751	18930	18574	17800	16358	14872	20414	10730
2010	8	6	Friday	13480	12466	11819	11386	11235	11479	12097	12725	14219	15918	17536	18781	19667	20307	20653	20661	20431	19692	19063	18250	17811	17057	15896	14648	20661	11235
2010	8	7	Saturday																										
2010	8	8	Sunday																										
2010	8	9	Monday	10949	10235	9881	9670	9728	10178	10971	11702	12766	14089	15374	16444	17011	17478	17996	18319	18530	18350	17848	17111	16872	16145	14920	13554	18530	9670
2010	8	10	Tuesday	12268	11457	10916	10650	10565	10902	11782	12363	13092	13958	14882	15708	16327	16486	16362	16134	15905	15645	15337	15019	15066	14419	13376	12139	16486	10565
2010	8	11	Wednesday	11099	10379	9910	9645	9667	10085	10990	11779	13239	14760	16174	17364	18199	18812	19260	19597	19816	19710	19175	18280	17927	16874	15655	14075	19816	9645
2010	8	12	Thursday	12744	11802	11194	10813	10706	11027	11813	12420	13846	15482	17090	18518	19543	20402	20978	21213	21384	21141	20541	19574	19224	18303	16813	15262	21384	10706
2010	8	13	Friday	13961	12937	12220	11750	11568	11770	12430	13018	14470	16108	17662	19074	20096	20944	21418	21560	21406	20956	20376	19394	19041	18159	16934	15539	21560	11568
2010	8	14	Saturday																										
2010	8	15	Sunday																										
2010	8	16	Monday	12656	11801	11247	10955	10872	11198	12018	12629	13885	15567	17218	18724	19832	20447	20646	20583	20434	20085	19387	18594	18353	17310	15893	14340	20646	10872
2010	8	17	Tuesday	13096	12259	11660	11308	11177	11542	12444	13070	14407	16056	17662	19017	19939	20588	20928	21064	21067	20755	20232	19205	18889	18010	16615	15063	21067	11177
2010	8	18	Wednesday	13675	12769	12039	11655	11486	11776	12619	13168	14455	16216	17902	19236	20232	21051	21608	21836	21908	21686	21170	20254	19923	18988	17404	15741	21908	11486
2010	8	19	Thursday	14436	13493	12769	12338	12162	12445	13221	13725	15013	16713	18369	19778	20828	21556	21959	22323	22277	21925	21165	20163	19521	18279	16664	14967	22323	12162
2010	8	20	Friday	13641	12692	12012	11607	11423	11736	12520	13093	14511	16219	17916	19361	20416	21249	21624	21843	21546	20579	19599	18686	18365	17359	16080	14701	21843	11423
2010	8	21	Saturday																										
2010	8	22	Sunday																										
2010	8	23	Monday	11926	11142	10724	10502	10467	10987	12076	12626	13543	14992	16275	17395	18057	17869	17065	16825	16883	16964	16794	16531	16587	15737	14421	13074	18057	10467
2010	8	24	Tuesday	11925	11269	10846	10687	10745	11320	12523	13075	13732	14859	15961	16831	17307	17642	18069	18065	17556	17050	16695	16476	16594	15767	14430	13007	18069	10687
2010	8	25	Wednesday	11879	11134	10632	10410	10423	10996	12216	12744	13204	14290	15413	16524	17299	18022	18539	18810	18550	17760	16902	16506	16306	15387	14167	12720	18810	10410
2010	8	26	Thursday	11676	10921	10418	10163	10147	10648	11729	12159	12564	13631	14944	16140	16978	18004	18631	19080	19365	19096	18348	17780	17550	16466	14949	13481	19365	10147
2010	8	27	Friday	12242	11497	11008	10722	10622	11044	12086	12557	13189	14811	16279	17720	18663	19570	20067	20429	20593	20193	19154	18103	17924	16986	15773	14540	20593	10622
2010	8	28	Saturday																										
2010	8	29	Sunday																										
2010	8	30	Monday	11522	10804	10366	10171	10235	10814	12057	12635	13262	14369	15358	16316	17241	17815	18074	18143	18132	17797	17079	16671	16692	15785	14343	12921	18143	10171
2010	8	31	Tuesday	11723	10976	10518	10327	10373	10900	12011	12564	13347	14278	15663	16936	17832	18058	18402	18738	18856	18481	17782	17112	17164	16234	14671	13364	18856	10327
		AVG		12635	11796	11239	10924	10850	11231	12114	12701	13772	15204	16612	17835	18707	19338	19685	19843	19803	19431	18808	18062	17832	16948	15602	14155	19990	10838
		MAX		14436	13493	12769	12338	12162	12445	13221	13725	15013	16713	18369	19778	20828	21556	21959	22323	22277	21925	21170	20254	19923	18988	17404	15741	22323	12162
		MIN		10949	10235	9881	9645	9667	10085	10971	11702	12564	13631	14882	15708	16327	16486	16362	16134	15905	15645	15337	15019	15066	14419	13376	12139	16486	9645

Supplemental DR - Question No. 3
Attachment No. 1

Typical Winter Month

Year	Month	Day	Day of Week	Observed Hourly Peak Capacity (MW)																								MAX	MIN
				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	(MW)	(MW)
2010	1	1	Friday	8812	8304	7725	7362	7187	7247	7413	7597	8419	9703	10817	11497	11774	11783	11556	11116	10858	11214	11921	11716	11307	10689	10128	9387	11921	7187
2010	1	2	Saturday																										
2010	1	3	Sunday																										
2010	1	4	Monday	12412	12188	12253	12538	13047	14258	16247	17559	17344	16709	15975	15076	14198	13517	12842	12510	12848	14581	16706	17107	17015	16469	15564	14504	17559	12188
2010	1	5	Tuesday	13736	13317	13283	13298	13631	14785	16727	17630	17122	16431	15921	15148	14552	14036	13553	13379	13791	15622	18077	18666	18807	18403	17486	16591	18807	13283
2010	1	6	Wednesday	16043	16088	16251	16569	17128	18407	20564	21525	20632	19517	18404	17256	16109	15126	14361	13944	14228	16030	18522	19187	19477	19016	18047	17016	21525	13944
2010	1	7	Thursday	16326	16137	16180	16385	16903	18073	20101	21021	20362	19066	17660	16228	14920	13848	12912	12487	12875	14548	16825	17455	17474	16914	16016	14872	21021	12487
2010	1	8	Friday	14141	13811	13772	13858	14104	15033	16829	17513	16512	15205	14198	13260	12579	12206	11813	11688	11950	12879	13750	13542	13094	12527	11896	11078	17513	11078
2010	1	9	Saturday																										
2010	1	10	Sunday																										
2010	1	11	Monday	19792	19766	19920	20228	20829	21783	23614	24353	23292	22279	20989	19372	17730	16327	15118	14411	14695	16445	19273	19931	19925	19433	18310	17328	24353	14411
2010	1	12	Tuesday	16772	16829	17154	17590	18266	19624	21787	22592	21404	19532	17855	16445	15260	14205	13275	12794	13059	14483	16601	17227	17286	16862	16050	15010	22592	12794
2010	1	13	Wednesday	14540	14523	14803	15222	15935	17370	19609	20587	19492	18029	16602	15256	14094	13161	12519	12217	12571	13975	15862	16115	15872	15329	14337	13201	20587	12217
2010	1	14	Thursday	12502	12222	12168	12323	12730	13891	15733	16383	15716	14557	13536	12624	12021	11556	11129	10916	10993	11706	12984	13010	12631	11808	10732	9636	16383	9636
2010	1	15	Friday	8812	8402	8252	8235	8479	9343	11015	11928	11822	11500	11417	11335	11161	11053	10909	10821	10832	11144	11995	11822	11331	10561	9767	8876	11995	8235
2010	1	16	Saturday																										
2010	1	17	Sunday																										
2010	1	18	Monday	7829	7245	6936	6863	6968	7412	8267	9207	10114	10811	11273	11398	11420	11328	11261	11225	11282	11595	12604	12294	11811	10966	10012	8909	12604	6863
2010	1	19	Tuesday	8026	7564	7377	7387	7638	8467	10057	11197	11370	11390	11310	11215	11037	10891	10748	10695	10788	11152	12365	12391	11879	11104	10080	9025	12391	7377
2010	1	20	Wednesday	8182	7827	7704	7769	8037	8980	10746	11863	11703	11424	11302	11165	11144	11101	11100	11166	11290	11546	12555	12494	11899	11119	9973	8847	12555	7704
2010	1	21	Thursday	7950	7475	7245	7197	7343	8039	9526	10453	10730	11262	11735	12003	12240	12393	12430	12530	12590	12778	13664	13526	12902	11921	10817	9687	13664	7197
2010	1	22	Friday	8653	8066	7778	7641	7734	8290	9607	10532	11206	11974	12714	13163	13400	13562	13571	13533	13433	13320	13946	13623	12868	11972	11079	10028	13946	7641
2010	1	23	Saturday																										
2010	1	24	Sunday																										
2010	1	25	Monday	9110	8512	8222	8124	8237	8845	10139	10979	11455	12035	12599	12798	12765	12462	12089	11768	11554	11717	12629	12573	11819	10872	9812	8689	12798	8124
2010	1	26	Tuesday	7803	7368	7206	7217	7486	8436	10201	11386	11482	11345	11287	11100	10952	10769	10621	10574	10660	10975	12152	12249	11779	11127	10201	9181	12249	7206
2010	1	27	Wednesday	8472	8138	8089	8192	8534	9583	11559	12659	12391	11995	11695	11341	11103	10875	10804	10757	10772	11113	12301	12455	12115	11373	10489	9426	12659	8089
2010	1	28	Thursday	8634	8294	8176	8225	8520	9488	11193	12088	11872	11601	11445	11275	11165	11042	10985	10956	10987	11171	12242	12310	11858	11078	9993	8912	12310	8176
2010	1	29	Friday	8043	7578	7375	7349	7547	8315	9906	10829	11017	11148	11273	11335	11371	11309	11228	11208	11193	11347	12096	11930	11449	10726	9955	9057	12096	7349
2010	1	30	Saturday																										
2010	1	31	Sunday																										
		AVG		11266	10936	10851	10932	11252	12175	13850	14756	14546	14167	13810	13347	12905	12502	12134	11938	12059	12826	14241	14363	14028	13346	12416	11393	15787	9676
		MAX		19792	19766	19920	20228	20829	21783	23614	24353	23292	22279	20989	19372	17730	16327	15118	14411	14695	16445	19273	19931	19925	19433	18310	17328	24353	14411
		MIN		7803	7245	6936	6863	6968	7247	7413	7597	8419	9703	10817	11100	10952	10769	10621	10574	10660	10975	11921	11716	11307	10561	9767	8689	11921	6863

Q.

Load & Demand Forecasting

Please provide, on a system-wide basis, historical annual heating degree day (HDD) and cooling degree day (CDD) data for the period 2001 through 2010 and forecasted annual HDD and CDD data for the period 2011 through 2020. Describe how the Company derives system-wide temperature if more than one weather station is used. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

A.

Currently, four weather stations are used to compile the system-wide temperature. The weather station temperature is weighted based on the monthly retail sales for the territory in which it is located. MIA (Miami International Airport) weather station is used for the Southern and Southeastern Divisions. PBI (Palm Beach International Airport) weather station is used for the Eastern Division. FTM (Ft. Myers) weather station is used for the Western Division. DTB (Daytona Beach) is used for the Northeastern Division.

Year		HDD	CDD
Actual	2001	305	1,769
	2002	226	2,016
	2003	365	2,010
	2004	263	1,837
	2005	278	1,906
	2006	203	1,919
	2007	149	2,028
	2008	121	1,957
	2009	252	2,130
	2010	776	2,040
Projected	2011	248	1,956
	2012	248	1,956
	2013	248	1,956
	2014	248	1,956
	2015	248	1,956
	2016	248	1,956
	2017	248	1,956
	2018	248	1,956
	2019	248	1,956
	2020	248	1,956

Q.

Load & Demand Forecasting

Please provide the following data to support Schedule 4 of the Company s Ten-Year Site Plan: the 12 monthly peak demands for the years 2008, 2009, and 2010; the date when these monthly peaks occurred; and, the temperature at the time of these monthly peaks. Describe how the Company derives system-wide temperature if more than one weather station is used. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

A.

Currently, four weather stations are used to compile the system-wide temperature. The weather station temperature is weighted based on the monthly retail sales for the territory in which it is located. MIA (Miami International Airport) weather station is used for the Southern and Southeastern Divisions. PBI (Palm Beach International Airport) weather station is used for the Eastern Division. FTM (Ft. Myers) weather station is used for the Western Division. DTB (Daytona Beach) is used for the Northeastern Division.

Florida Power & Light Company
Docket No.
2011 Ten Year Site Plan Supplemental Data Request No. 1
Question No. 5

Year	Month	Peak Demand (MW)	Date	Day of Week	Hour	Temperature (F)
2008	1	18055	1/3/2008	Thursday	8-9 AM	41.29
	2	15735	2/7/2008	Thursday	6-7 PM	75.33
	3	16226	3/16/2008	Sunday	4-5 PM	80.61
	4	16995	4/28/2008	Monday	4-5 PM	80.62
	5	20289	5/21/2008	Wednesday	4-5 PM	91.64
	6	20565	6/5/2008	Thursday	4-5 PM	86.86
	7	20951	7/21/2008	Monday	4-5 PM	89.02
	8	21060	8/7/2008	Thursday	4-5 PM	90.12
	9	20456	8/29/2008	Friday	4-5 PM	89.13
	10	18752	10/10/2008	Friday	4-5 PM	85.78
	11	16538	11/14/2008	Friday	1-2 PM	83.70
	12	14849	12/10/2008	Wednesday	6-7 PM	76.45
2009	1	19378	1/22/2009	Thursday	7-8 AM	37.92
	2	20081	2/5/2009	Thursday	7-8 AM	34.63
	3	15347	3/16/2009	Monday	5-6 PM	79.62
	4	17145	4/6/2009	Monday	3-4 PM	88.48
	5	19210	5/11/2009	Monday	3-4 PM	87.76
	6	22351	6/22/2009	Monday	4-5 PM	94.98
	7	21138	7/17/2009	Friday	3-4 PM	91.11
	8	21015	8/20/2009	Thursday	4-5 PM	88.90
	9	20334	9/22/2009	Tuesday	4-5 PM	88.13
	10	21014	10/8/2009	Thursday	4-5 PM	89.54
	11	19226	10/29/2009	Thursday	4-5 PM	85.50
	12	16122	12/9/2009	Wednesday	6-7 PM	77.73
2010	1	24346	1/11/2010	Monday	7-8 AM	35.05
	2	16488	2/17/2010	Wednesday	7-8 AM	45.99
	3	17748	3/5/2010	Friday	7-8 AM	46.32
	4	15480	4/25/2010	Sunday	4-5 PM	83.94
	5	19217	5/7/2010	Friday	4-5 PM	85.72
	6	21901	6/16/2010	Wednesday	3-4 PM	92.88
	7	21633	7/28/2010	Wednesday	3-4 PM	92.05
	8	22256	8/19/2010	Thursday	3-4 PM	92.10
	9	20738	9/13/2010	Monday	4-5 PM	89.21
	10	19116	10/27/2010	Wednesday	4-5 PM	84.26
	11	17052	10/29/2010	Friday	3-4 PM	85.63
	12	21153	12/15/2010	Wednesday	7-8 AM	39.71

Q.

Load & Demand Forecasting

Please discuss any recent trends in customer growth, by customer type (residential, industrial & commercial, etc), and as a whole. Please explain the nature or reason for these trends, and identify what types of customers are most affected by these trends. (For example, is a decline in customers a loss of temporary construction meters or a decline in population?)

A.

The average number of customers for the year 2010 increased over 2009, a reversal of the decline in customers experienced in 2009. On a year-over-year basis, customer growth has been steadily increasing since December 2009, following 16 months of consecutive declines. Nevertheless, the level of customer growth remains well below its historical level. The gradual increase in customer growth is the result of an economy that is slowly improving.

The residential sector began experiencing positive customer growth at the end of 2009. In early 2010, customer growth in the commercial sector followed suit and began posting positive growth. Residential customers have accounted for the largest share of customer growth, but like the commercial sector, growth remains well below its historical level. The industrial sector is still experiencing a decline in customers, however the negative trend has been improving. The number of industrial customers has continued to fall although the rate of decline has been decelerating. The continued decline in industrial customers is due primarily to the classification of temporary and construction accounts as industrial customers, which have been adversely affected by the new housing market that is not improving to any significant degree.

Q.

Load & Demand Forecasting

Please discuss any impacts of "smart" or digital meter installations on forecasting sales and net energy for load. Please explain the nature or reason for these trends, and identify what types of customers are most affected by these trends. (For example, are increased sales due to more accurate measurement of low-load conditions?)

A.

Currently FPL's AMI project has no impact on forecasting sales and Net Energy for Load. The AMI project, which began in 2009, is scheduled for completion at the end of 2013 and we will evaluate any potential impacts on sales and net energy for load after the project is completed.

Q.

Renewable Generation

Please provide the estimated total capacity of all renewable resources the utility owns or purchases as of January 1, 2011. Include in this value the sum of all utility-owned, and purchased power contracts (firm and non-firm), and purchases from as-available energy producers (net-metering, self-generators, etc.). Please also include the estimated total capacity of all renewable resources (firm and non-firm) the utility is anticipated to own or purchase as of the end of the planning period in 2020.

A.

Each of the renewable resources FPL owns or purchases as of January 1, 2011 are presented in the table attached to FPL's response to Data Request No. 9. Please refer to FPL's response to this request. The total capacity of all renewables FPL currently owns or purchase are also included in this table.

FPL's response to Data Request No. 10 describes one renewable generating facility that FPL currently plans to add from 2011 through 2020. Please refer to FPL's response to that request. The projected 90,000 kW are firm and would result in FPL's projected 2020 firm renewable generation increasing from 64,500 to 154,500 kW. There would be no change in the current non-firm capacity value.

Q.

Renewable Generation

Please provide a description of each existing utility-owned renewable generation resource and each renewable purchased power agreement as of January 1, 2011. For both utility-owned and purchased resources, please divide them into Firm and Non-Firm categories as shown below. Please also include those renewable resources which provide fuel to conventional facilities, if applicable, with estimates of their capacity and energy contributions. As part of this response, please include the description of the unit's generator type, fuel type, commercial in-service date, seasonal net capacity (even if not considered firm capacity), annual energy generation. For purchased power agreements, also provide the contract start and end dates. Please complete the tables below and provide an electronic copy in Excel format and hardcopy.

A.

A description of utility-owned and existing renewable purchased power agreements as of January 1, 2011, with both firm and non-firm capacity, have been included in the attached Table 9.

Supplemental DR - Question No. 9
Attachment No. 1

2011 Ten Year Site Plan Supplemental Data Request - Table 9

Utility-Owned Non-Firm Renewable Resources

1)

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor
-	-	-	(MM/YYYY)	Sum	Win	(MWh)	(%)
DeSoto Next Generation Solar Energy Center	PV	SUN	10/2009	25,000	25,000	52,816 (1)	24.1 (1)
Space Coast Next Generation Solar Energy Center	PV	SUN	04/2010	10,000	10,000	18,050 (1)	20.6 (1)
Martin Next Generation Solar Energy Center	Thermal	SUN	12/2010	75,000	75,000	153,850 (1)	23.4 (1)
FPL Juno Beach Living Lab	PV	SUN	Various/2010	21	21	32.7 (2)	17.0 (1)
			Total:	**110,021**	**110,021**		

Note: 1) Represents average annual generation and capacity factor projection from 2011-2020.
2) Annual generation for the FPL living lab is estimated.

Existing Renewable Purchase Power Agreement (Firm Capacity)

2)

Seller	Facility Name	Fuel Type	Generator Type	Summer Capability (kw)	Winter Capability (kw)	Annual Generation MWh	Capacity Factor %	Contract Start Date	Original Contract End Date	Current Contract End Date	Docket Aproved (if any)
Wheelabrator Technologies	Broward North	MSW	ST	11,000	11,000	84,455	88%	1/1/1993	12/31/2026	12/31/2026	Docket # 911140
Wheelabrator Technologies	Broward South	MSW	ST	3,500	3,500	30,458	99%	1/1/1993	12/31/2026	12/31/2026	Docket # 911140
Solid Waste Authority of Palm Beach	Solid Waste Authority of Palm Beach	MSW	ST	50,000	50,000	206,080	47%	4/1/1992	3/31/2010	3/31/2032	Docket # 090150
			Total:	**64,500**	**64,500**						

Existing Renewable Purchase Power Agreement (Non-Firm Capacity)

3)

Seller	Facility Name	Fuel Type	Generator Type	Summer Capability (kw)	Winter Capability (kw)	Annual Generation MWh	Capacity Factor %	Contract Start Date[3]	Original Contract End Date	Current Contract End Date	Docket Aproved (if any)
Georgia Pacific	Georgia Pacific	Other (Paper By Product)	ST	52,000	52,000	2,548	1%	1992	N/A	N/A	N/A
Wheelabrator Technologies	Broward South[1]	MSW	ST	50,600	50,600	391,286	88%	2009	N/A	N/A	N/A
Wheelabrator Technologies	Broward North[2]	MSW	ST	45,000	45,000	345,498	88%	2011	N/A	N/A	N/A
New Hope Power Partnership	New Hope & Okeelanta	AB	ST	140,000	140,000	240,829	20%	1996 & 2005	N/A	N/A	N/A
Waste Management Inc.	WM Renewable Energy	LFG	GT	8,000	8,000	60,656	87%	2010	N/A	N/A	N/A
Tomoka	Tomoka	LFG	GT	3,800	3,800	24,527	74%	1997	N/A	N/A	N/A
MMA FLA LP	MMA Bee Ridge	SUN	PV	250	250	259	12%	2007	N/A	N/A	N/A
			Total:	**299,650**	**299,650**						

Note: 1) After standard offer contract contract expired on August 1, 2009 Broward South began selling As-Available energy to FPL.
2) After standard offer contract expired on December 31, 2010, Broward North began selling As-Available energy to FPL.
3) Year Transmission Service Agreement was executed and facility began selling As-Available energy to FPL under COG-1 Tariff.
4) Total Renewable Capacities (kw):

Firm Capacity: =	64,500	(Section 2 above)
Non-Firm Capacity:=	409,671	(Section 1 and 3 above)
Non-Firm Customer-owned PV*: =	9,200	* from 2011 Site Plan Schedule 11.2 (Approx. MW)
Total Non-Firm: =	418,871	
Total:	**483,371**	

Q.

Renewable Generation

Please provide a description of each existing utility-owned renewable generation resource and each renewable purchased power agreement planned during the 2011 through 2020 period. For both utility-owned and purchased resources, please divide them into Firm and Non-Firm categories as shown below. Please also include those renewable resources which provide fuel to conventional facilities, if applicable, with estimates of their capacity and energy contributions. As part of this response, please include the description of the unit's generator type, fuel type, commercial in-service date, seasonal net capacity (even if not considered firm capacity), annual energy generation. For purchased power agreements, also provide the contract start and end dates. Please complete the tables below and provide an electronic copy in Excel format and hardcopy.

A.

A description of each existing utility-owned renewable generation resource is provided in response to Interrogatory No. 9. Please refer to FPL's response to that interrogatory. There is only one additional renewable resource that is currently planned for the 2011 - 2020 period. This firm capacity renewable purchased power agreement is attached.

Supplemental DR - Question No. 10
Attachment No. 1

2011 Ten Year Site Plan Supplemental Data Request - Table 10

Existing Renewable Purchase Power Agreement (Firm Capacity)

Seller	Facility Name	Fuel Type	Generator Type	Summer Capability (kw)	Winter Capability (kw)	Annual Generation MWh	Capacity Factor %	Contract Start Date	Current Contract End Date	Docket Aproved (if any)
Solid Waste Authority of Palm Beach	Solid Waste Authority of Palm Beach	MSW	ST	90,000	90,000	670,140	85%	4/1/2015	4/1/2032	Pending

Q.

Renewable Generation

Please refer to the list of planned utility-owned renewable resource additions with an in-service date for the renewable generator during the 2011 through 2020 period outlined above. Please discuss the current status of each project.

A.

Because no legislation supporting utility development of new solar power generation facilities has been passed at this time, FPL has not fully developed specific solar projects at specific power plant sites. Rather, FPL has identified potential sites for solar development and performed initial permitting and due diligence with respect to available solar and other renewable power technologies that may be used depending upon the outcome of supporting legislation.

Q.

Renewable Generation

Please refer to the list of existing or planned renewable PPAs with an in-service date for the renewable generator during the 2011 through 2020 period outlined above. Please discuss the current status of each project.

A.

The project is currently going through the need determination process at the FPSC as part of obtaining Florida Power Plant Siting Act approval. An EPC vendor has been recommended to the Board of the SWA for approval.

Q.

Renewable Generation

Please provide a description of each renewable facility in the company's service territory that it does not currently have a PPA with, including self-service facilities. As part of this response, please include the description of the unit's location, generator type, fuel type, commercial in-service date, seasonal net capacity (even if not considered firm capacity), annual energy generation. Please exclude from this response small customer-owned renewable resources, such as rooftop PV, which are more appropriately included in the following question. Please complete the tables below and provide an electronic copy in Excel format and hardcopy.

A.

Please see attachment.

Supplemental DR - Question No. 13
Attachment No. 1

Pending Small Generator Interconnections > 2 MW and < 20MW							
Project	*Medley Landfill*	*Collier Landfill*	*North Dade Landfill*	*South Dade Landfill*	*Bee Ridge Landfill*	*Vero Beach Landfill*	*Sugar Cane Growers*
Customer	*WM Renewable Energy*	*WM Renewable Energy*	*INGENCO*	*INGENCO*	*Timberline Energy*	*INPB*	*Sugar Cane Growers of FL*
County	*Miami-Dade*	*Collier*	*Miami-Dade*	*Miami-Dade*	*Sarasota*	*Indian River*	*Palm Beach*
Generation Type	*Landfill Gas*	*Landfill Gas*	*Landfill Gas*	*Landfill Gas*	*Landfill Gas*	*Landfill Gas*	*Bagasse*
Size	*7.2 MW*	*7.2 MW*	*6 MW*	*10 MW*	*3.2 MW*	*3 MW*	*10 MW*
Date Application Received		09/26/07	03/02/08	03/02/08	07/14/08	02/11/10	02/25/10
Customer Expected In-Service Date	2011	09/30/10	09/30/10	09/30/10	09/30/10	07/01/11	11/01/11
Technical Data	C	C	C	C	C	U	U
Fast Track Screen of Gen. < 2MW	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Feasibility Study Agreement	C	11/05/07	08/01/08	08/01/08	08/06/08		
Feasibility Study	02/01/08	09/11/09	03/02/09	03/02/09	12/28/08		
Facilities Study Agreement	N/A	06/20/08	N/A	N/A	N/A		
Facilities Study	07/17/08	08/04/08	N/A	N/A	N/A		
Interconnection Agreement	U	12/18/10	U	U	01/29/10		
Next Deadline Responsibility	FPL/Customer	FPL/Customer	Customer	Customer	Customer	Customer	Customer
Next Deadline Date		09/30/10	04/20/10	04/20/10	09/30/10	03/31/10	
Comments	**System Impact Study will be required to proceed with interconnection request.**	Engineenng/Construction Underway.	Customer must execute IA by 4/20/10.	Customer must execute IA by 4/20/10.	Awaiting financial secunty to begin project.	Customer to provide deficiencies by 3/31/10.	**Customer to resubmit application as a large generator interconnection request.**

C - Complete
P - Pending
U - Underway
N/A - Not Applicable
IA - Interconnection Agreement

Supplemental DR - Question No. 13
Attachment No. 1

Self-Service Renewable Generators the FPL Currently Does not have a PPA with

Owner[1]	Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Summer Capacity (kW)	Winter Capacity (kW)	Annual Output[3] (MWh)	Capacity Factor
Brevard Energy, LLC	Brevard Landfill	Reciprocating Engine	Landfill Gas	Apr-08	9,600	9,600	75,521	89.8033%
Georgia Pacific Corporation	Georgia Pacific[2]	Synchronous	Paper by-Product	Jul-95	52,000	52,000	2,548	0.5594%
Lee County	Lee County Resource Recovery #1	Synchronous	Solid Waste	Sep-94	40,000	40,000	293,090	83.6444%
Lee County	Lee County Resource Recovery #2	Steam Turbine	Solid Waste	Sep-94	21,000	21,000	(both facilities)	
Metropolitan Dade County	Dade County Resource Recovery	Synchronous	Landfill Gas	Sep-91	77,000	77,000	320,662	47.5393%
MM Tomoka Farms, LLC	Tomoka Farms[2, 5]	Reciprocating Engine	Landfill Gas	Apr-99	3,800	3,800	24,527	73.6812%
MMA FLA, LP	Rothenbach Park[2]	Inverter	Solar PV	Oct-07	250	250	259	11.8265%
New Hope Power	Okeelanta #1[2]	Synchronous	Bagasse/Wood	Jul-04	74,000	74,000	240,829 (total for both	
New Hope Power	Okeelanta #2[2]	Steam Turbine	Bagasse/Wood	Jul-04	65,000	65,000	facilities)	23.9060%
Palm Beach County Solid Waste Authority	Solid Waste Authority Resource Recovery[2]	Synchronous	Solid Waste	Jan-89	50,000	50,000	206,080	47.0502%
Seminole Energy, LLC	Seminole Landfill	Reciprocating Engine	Landfill Gas	Apr-08	6,400	6,400	40,548	72.3245%
Wheelabrator	Broward Resource Recovery - North[2]	Synchronous	Solid Waste	Feb-87	56,000	56,000	429,953	95.491%
Wheelabrator	Broward Resource Recovery - South[2]	Synchronous	Solid Waste	Feb-87	54,000	54,000	421,744	89.748%
WM Renewable Energy, LLC	Broward North Landfill[4]	Reciprocating Engine	Landfill Gas		8,000	8,000	60656	86.5525%

Notes :

1) All of the facilities listed have an interconnection agreement with FPL
2) Facilities FPL purchases from were included in the response to question #2 in the Renewable section of the Ten Year Site Plan supplemental data request
3) Annual Output in MWh is for historical year 2010 and is provided only for facilities FPL purchases from. **MWh Values shown represent only energy deliveries to FPL**
4) Energy deliveries from this facility began in January, 2010
5) No longer making sales to FPL starting January, 2011

;

Q.

Renewable Generation

Please provide the number of customer-owned renewable resources within the Company's service territory. Please organize by resource type, and include total estimated installed capacity and annual output. Please exclude from this response any customer-owned renewable resources already accounted for under PPAs or other sources. If renewable energy types beyond those listed were utilized, please include an additional row and a description of the renewable fuel and generator. For non-electricity generating renewable energy systems, such as geothermal cooling and solar hot water heaters, please use kilowatt-equivalent and kilowatt-hour-equivalent units. Please complete the tables below and provide an electronic copy in Excel (.xls file format) and hard copy.

A.

Customer Class	Renewable Type	# of Connections	Installed Capacity (kW)	Annual Output (kWh)
Residential	Solar Photovoltaic	932	4,438	5,925,372
Residential	Solar Thermal Water Heating	unknown		
Residential	Geothermal Heat Pump	unknown		
Residential	Wind Turbine	3	8	unknown
Residential	Other (Describe)	unknown		
Commercial	Solar Photovoltaic	129	4,718	6,298,009
Commercial	Solar Thermal Water Heating	unknown		
Commercial	Geothermal Heat Pump	unknown		
Commercial	Wind Turbine	unknown		
Commercial	Other (Describe)	unknown		

Q.

Renewable Generation

Please provide the annual output for the company's renewable resources (owned and purchased through PPA), retail sales, and the net energy for load for the period 2010 through 2020. Please complete the tables below and provide an electronic copy in Excel (.xls file format) and hard copy.

A.

Please see attachment.

Supplemental DR - Question No. 15
Attachment No. 1

2011 TYSP Supplemental Data Request - Question 15

Annual Output (GWh)		Actual 2010	Projected 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Renewable Generation	Utility	69	228	227	226	225	225	225	224	224	222	221
	PPA	1,051	1,051	1,051	1,051	1,051	1,515	1,515	1,515	1,515	1,515	1,515
	Total	1,120	1,279	1,279	1,277	1,277	1,740	1,741	1,739	1,739	1,738	1,737
Retail Sales		104,557	102,257	103,083	105,155	108,085	110,038	111,888	113,418	114,928	116,518	118,749
Net Energy for Load		114,373	111,175	112,517	114,647	121,035	123,610	125,593	127,251	128,910	130,679	133,121

Q.

Renewable Generation

Provide, on a system-wide basis, the historical annual average as-available energy rate in the Company's service territory for the period 2001 through 2010. Also, provide the forecasted annual average as-available energy rate in the Company's service territory for the period 2011 through 2020. Please use the Consumer Price Index to calculate real as-available energy rates. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

A.

Please see attachment.

Supplemental DR - Question No. 16
Attachment No. 1

2011 TYSP Supplemental Data Request - Question 16

As-Available Energy Rates (C/KWH) - South Region

Year		Annual Average		On-Peak		Off-Peak		Deflator
		Real	Nominal	Real	Nominal	Real	Nominal	
Actual	2001	1.85	3.28	2.14	3.78	1.76	3.11	177.04
	2002	1.80	3.24	2.10	3.77	1.64	2.95	179.87
	2003	2.16	3.98	2.59	4.77	2.02	3.71	184.00
	2004	2.15	4.06	2.68	5.06	1.97	3.72	188.91
	2005	3.24	6.33	4.19	8.18	2.92	5.70	195.27
	2006	2.73	5.51	3.54	7.14	2.46	4.96	201.56
	2007	2.82	5.85	3.73	7.73	2.50	5.18	207.34
	2008	3.42	7.37	4.53	9.74	3.04	6.55	215.25
	2009	1.76	3.76	2.06	4.41	1.66	3.56	214.55
	2010	2.15	4.68	3.05	6.66	1.83	3.99	218.08
Projected	2011	2.55	5.68	2.64	5.89	2.50	5.57	222.99
	2012	2.13	4.85	2.07	4.71	2.25	5.14	228.06
	2013	1.99	4.64	2.10	4.90	1.94	4.52	233.17
	2014	1.94	4.61	2.03	4.84	1.89	4.50	238.09
	2015	2.02	4.91	1.98	4.80	2.12	5.15	242.98
	2016	2.24	5.55	2.36	5.86	2.18	5.40	247.85
	2017	2.38	6.02	2.50	6.33	2.33	5.89	252.83
	2018	2.46	6.35	2.56	6.60	2.41	6.22	258.11
	2019	2.58	6.78	2.67	7.03	2.53	6.67	263.21
	2020	2.67	7.15	2.81	7.53	2.60	6.97	268.25

As-Available Energy Rates (C/KWH) - Southeast Region

Year		Annual Average		On-Peak		Off-Peak		Deflator
		Real	Nominal	Real	Nominal	Real	Nominal	
Actual	2001	1.88	3.32	2.17	3.85	1.78	3.15	177.04
	2002	1.78	3.2	2.12	3.82	1.65	2.96	179.87
	2003	2.16	3.98	2.59	4.77	2.02	3.71	184.00
	2004	2.13	4.03	2.66	5.02	1.96	3.70	188.91
	2005	3.22	6.29	4.17	8.14	2.90	5.67	195.27
	2006	2.71	5.47	3.51	7.07	2.44	4.92	201.56
	2007	2.84	5.89	3.76	7.79	2.52	5.23	207.34
	2008	3.45	7.43	4.56	9.81	3.07	6.60	215.25
	2009	1.78	3.82	2.10	4.49	1.69	3.62	214.55
	2010	2.13	4.64	3.02	6.58	1.82	3.97	218.08
Projected	2011	2.55	5.68	2.64	5.89	2.50	5.57	222.99
	2012	2.13	4.85	2.07	4.71	2.25	5.14	228.06
	2013	1.99	4.64	2.10	4.90	1.94	4.52	233.17
	2014	1.94	4.61	2.03	4.84	1.89	4.50	238.09
	2015	2.02	4.91	1.98	4.80	2.12	5.15	242.98
	2016	2.24	5.55	2.36	5.86	2.18	5.40	247.85
	2017	2.38	6.02	2.50	6.33	2.33	5.89	252.83
	2018	2.46	6.35	2.56	6.60	2.41	6.22	258.11
	2019	2.58	6.78	2.67	7.03	2.53	6.67	263.21
	2020	2.67	7.15	2.81	7.53	2.60	6.97	268.25

As-Available Energy Rates (C/KWH) - Northeast South Region

Year		Annual Average		On-Peak		Off-Peak		Deflator
		Real	Nominal	Real	Nominal	Real	Nominal	
Actual	2001	1.80	3.18	2.06	3.64	1.71	3.02	177.04
	2002	1.72	3.09	2.03	3.66	1.60	2.88	179.87
	2003	2.08	3.82	2.47	4.54	1.79	3.30	184.00
	2004	2.04	3.85	2.51	4.74	1.73	3.27	188.91
	2005	3.06	5.98	3.90	7.62	2.57	5.01	195.27
	2006	2.59	5.23	3.32	6.69	2.17	4.37	201.56
	2007	2.72	5.65	3.57	7.40	2.43	5.03	207.34
	2008	3.34	7.18	4.37	9.41	2.99	6.44	215.25
	2009	1.76	3.78	2.07	4.43	1.67	3.57	214.55
	2010	2.15	4.69	3.05	6.66	1.83	4.00	218.08
Projected	2011	2.55	5.68	2.64	5.89	2.50	5.57	222.99
	2012	2.13	4.85	2.07	4.71	2.25	5.14	228.06
	2013	1.99	4.64	2.10	4.90	1.94	4.52	233.17
	2014	1.94	4.61	2.03	4.84	1.89	4.50	238.09
	2015	2.02	4.91	1.98	4.80	2.12	5.15	242.98
	2016	2.24	5.55	2.36	5.86	2.18	5.40	247.85
	2017	2.38	6.02	2.50	6.33	2.33	5.89	252.83
	2018	2.46	6.35	2.56	6.60	2.41	6.22	258.11
	2019	2.58	6.78	2.67	7.03	2.53	6.67	263.21
	2020	2.67	7.15	2.81	7.53	2.60	6.97	268.25

As-Available Energy Rates (C/KWH) - Northeast North Region

Year		Annual Average		On-Peak		Off-Peak		Deflator
		Real	Nominal	Real	Nominal	Real	Nominal	
Actual	2001	1.73	3.06	1.98	3.51	1.64	2.91	177.04
	2002	1.67	3.01	1.98	3.56	1.56	2.81	179.87
	2003	1.98	3.64	2.36	4.34	1.73	3.19	184.00
	2004	1.97	3.72	2.43	4.59	1.67	3.16	188.91
	2005	2.94	5.75	3.77	7.36	2.46	4.80	195.27
	2006	2.49	5.01	3.19	6.43	2.07	4.17	201.56
	2007	2.62	5.44	3.45	7.15	2.33	4.83	207.34
	2008	3.19	6.87	4.20	9.03	2.84	6.12	215.25
	2009	1.69	3.63	1.99	4.27	1.61	3.44	214.55
	2010	2.05	4.48	2.66	5.81	1.71	3.74	218.08
Projected	2011	2.55	5.68	2.64	5.89	2.50	5.57	222.99
	2012	2.13	4.85	2.07	4.71	2.25	5.14	228.06
	2013	1.99	4.64	2.10	4.90	1.94	4.52	233.17
	2014	1.94	4.61	2.03	4.84	1.89	4.50	238.09
	2015	2.02	4.91	1.98	4.80	2.12	5.15	242.98
	2016	2.24	5.55	2.36	5.86	2.18	5.40	247.85
	2017	2.38	6.02	2.50	6.33	2.33	5.89	252.83
	2018	2.46	6.35	2.56	6.60	2.41	6.22	258.11
	2019	2.58	6.78	2.67	7.03	2.53	6.67	263.21
	2020	2.67	7.15	2.81	7.53	2.60	6.97	268.25

As-Available Energy Rates (C/KWH) - West Region

Year		Annual Average		On-Peak		Off-Peak		Deflator
		Real	Nominal	Real	Nominal	Real	Nominal	
Actual	2001	1.78	3.16	2.04	3.61	1.69	3.00	177.04
	2002	1.70	3.06	2.02	3.64	1.60	2.87	179.87
	2003	2.04	3.76	2.43	4.47	1.91	3.52	184.00
	2004	2.01	3.80	2.48	4.68	1.86	3.51	188.91
	2005	2.99	5.84	3.80	7.42	2.71	5.30	195.27
	2006	2.52	5.08	3.21	6.47	2.28	4.60	201.56
	2007	2.66	5.51	3.47	7.20	2.37	4.92	207.34
	2008	3.23	6.96	4.23	9.11	2.89	6.22	215.25
	2009	1.72	3.69	2.01	4.31	1.63	3.50	214.55
	2010	1.96	4.28	2.66	5.81	1.71	3.74	218.08
Projected	2011	2.55	5.68	2.64	5.89	2.50	5.57	222.99
	2012	2.13	4.85	2.07	4.71	2.25	5.14	228.06
	2013	1.99	4.64	2.10	4.90	1.94	4.52	233.17
	2014	1.94	4.61	2.03	4.84	1.89	4.50	238.09
	2015	2.02	4.91	1.98	4.80	2.12	5.15	242.98
	2016	2.24	5.55	2.36	5.86	2.18	5.40	247.85
	2017	2.38	6.02	2.50	6.33	2.33	5.89	252.83
	2018	2.46	6.35	2.56	6.60	2.41	6.22	258.11
	2019	2.58	6.78	2.67	7.03	2.53	6.67	263.21
	2020	2.67	7.15	2.81	7.53	2.60	6.97	268.25

Note : FPL historically keeps track of avoided costs on a regional basis but forecasts avoided costs on an system average basis

Q.

Renewable Generation

Please discuss any studies conducted or planned regarding the use combinations of renewable and fossil fuels in existing or future fossil units. What potential does the Company identify in this area?

A.

FPL has not conducted any studies regarding combining renewable and existing fossil fuel units. The Martin Next Generation Solar Energy Center, which became commercial in December 2010, is the world's first "hybrid" solar energy facility – integrating a 75MW solar thermal facility with an existing natural gas combined cycle unit. At this time, FPL has not identified the potential for other similar projects.

Q.

Renewable Generation

Please discuss any planned renewable generation or renewable purchased power agreements within the past 5 years that did not materialize. What was the primary reason these generation plans or purchased power contracts were not realized? What, if any, were the secondary reasons?

A.

On October 31, 2007, FPL executed a contract to purchase the output of the Manatee Landfill gas project from Siemens Technologies Inc. The project was projected to provide 5.25 MW of firm capacity and to have an in-service date of January 1, 2009.

On February 22, 2008, the FPSC issued an order approving the recovery of energy and capacity payments, but declining to approve the recovery of that portion of the payments above FPL's "avoided cost" that would correspond to the renewable energy credits (RECs) produced by the facility. Siemens and FPL verbally agreed to modify the contract to include an option, but not an obligation, for FPL to purchase the RECs at some point in the future.

Siemens has not elected, thus far, to proceed with the project.

Q.

Renewable Generation

Please discuss whether the company purchases or sells Renewable Energy Credits. As part of this response, please discuss whether the company offers the sale of Renewable Energy Credits to its customers through a green pricing or similar program.

A.

FPL currently has one contract to purchase RECs from a solar photovoltaic facility. In 2010, the facility produced 292 megawatt hours (MWh), and correspondingly 292 RECs. The contract expires December 31, 2015.

The modification of the contract with the Solid Waste Authority of Palm Beach County, signed on March 18, 2009 and approved by the Florida Public Service Commission (FPSC), grants FPL a right of first refusal for the purchase of renewable attributes. This contract modification includes an increase in capacity for up to 55 MW and expires twenty years after completion of the plant refurbishment, but not later than 2034.

Similarly, the contract for the Expanded Facility with the Solid Waste Authority provides FPL a right of first refusal to purchase renewable attributes.

FPL does not offer REC's for sale to customers through a green pricing or similar program.

Q.

Traditional Generation

Please provide the cumulative present worth revenue requirement of the Company's Base Case for the 2011 Ten-Year Site Plan. If available, please provide the cumulative present worth revenue requirement for any sensitivities conducted of the Company's generation expansion plan.

A.

The projected cumulative present value of revenue requirements (CPVRR) for the resource plan presented in FPL's 2011 resource plan is approximately $130,707 million in 2011 for the years 2011-2040 assuming a 7.29% discount factor. (This CPVRR value includes no capital costs for increased nuclear capacity from FPL's EPU project within the 2011 – 2020 time frame addressed by the 2011 Site Plan or from FPL's planned two new nuclear units at Turkey Point that are projected to be added after this time frame. Please refer to Note 1 on Schedule 9 (pages 3-6 of 8) of FPL's Ten Year Site Plan.)

Q.

Traditional Generation

Please illustrate what the Companys generation expansion plan would be as a result of sensitivities to the base case demand. Include impacts on unit in-service dates for any possible delays, cancellations, accelerated completion, or new additions as a result.

A.

The resource plan presented in FPL's 2011 Site Plan is based on a February 2011 load forecast. Due to the recent vintage of this load forecast, FPL has not performed any resource planning sensitivity analyses that would be based on alternate load forecasts. Accordingly, the information requested does not exist.

Q.

Traditional Generation

Please complete the following table detailing planned unit additions, including information on capacity and in-service dates. Please include only planned conventional units with an in-service date past January 1, 2011, and including nuclear units, nuclear unit uprates, combustion turbines, and combined-cycle units. For each planned unit, provide the date of the Commission's Determination of Need and Power Plant Siting Act certification (if applicable), and the anticipated in-service date.

A.

Plesae see attachment.

Supplemental DR - Question No. 22
Attachment No. 1

2011 TYSP Supplemental Data Request - Question 22

Table Staff - 22:

Planned Unit Additions for 2011 through 2020

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Nuclear Unit Additions / Uprates				
St. Lucie 1 Extended Power Uprate	122	Jan-08	Sep-08	3/1/2012
Turkey Point 3 Extended Power Uprate	109	Jan-08	Oct-08	6/1/2012
St. Lucie 2 Extended Power Uprate *	110	Jan-08	Sep-08	10/1/2012
Turkey Point 4 Extended Power Uprate	109	Jan-08	Oct-08	2/1/2013
Combustion Turbine Unit Additions				
---	---	---	---	---
Combined Cycle Unit Additions				
West County Energy Center 3	1219	Sep-08	Nov-08	6/1/2011
Cape Canaveral NGCEC	1210	Sep-08	Aug-09	6/1/2013
Riviera NGCEC	1212	Sep-08	Nov-09	6/1/2014
Greenfield CC Unit #1	1191	---	---	6/1/2016
Greenfield CC Unit #2	1191	---	---	6/1/2020
Steam Turbine Unit Additions				
---	---	---	---	---

* St. Lucie 2 has a 17 MW interim increase occurring approximately April 2011 with the balance of the MWs coming into service in October 2012.

Q.
Traditional Generation

For each of the generating units contained in the Companys Ten-Year Site Plan, please discuss the drop dead date for a decision on whether or not to construct each unit. Provide a time line for the construction of each unit, including regulatory approval, and final decision point.

A.
FPL's 2011 Ten Year Site Plan lists the following new generating units which are projected to provide firm capacity, and for which construction of the unit had not started at the end of 2010:

1. Greenfield CC for 2016
2. Greenfield CC for 2020

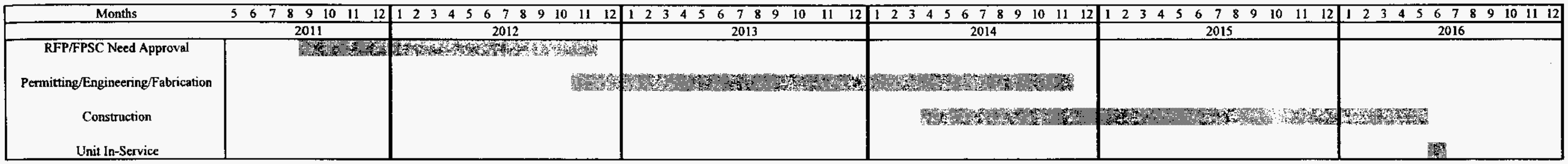
Construction/pre-construction activities have begun at 7 other units/sites: Turkey Point 3 (uprates), Turkey Point 4 (uprates), St. Lucie 1 (uprates), St. Lucie 2 (uprates), Cape Canaveral (modernization), and Riviera (modernization).

The attached timelines provide FPL's current projections of the approximate time periods for the permitting, engineering and construction phases of the two greenfield CC units. FPL currently has no future specific date or milestone that would constitute a future "drop dead" date related to a decision to proceed with construction of either of these projects.

Supplemental DR - Question No. 23
Attachment No. 1
Page 1 of 2

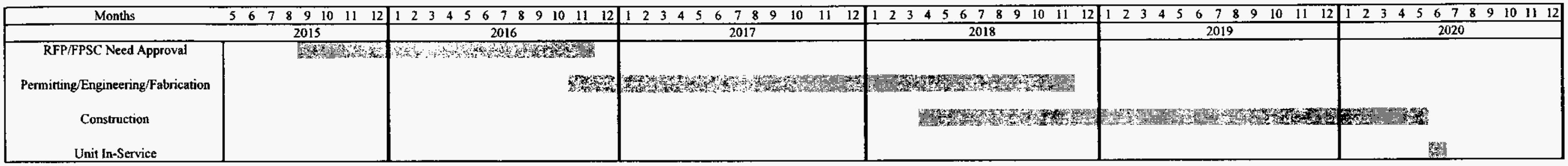
Greenfield CC Unit - 2016

(Dates shown are approximate and are subject to change)



Greenfield CC Unit - 2020

(Dates shown are approximate and are subject to change)



Q.

Traditional Generation

Please complete the following table detailing unit specific information on capacity and fuel consumption for 2010. For each unit on the Company's system, provide the following data based upon historic data from 2010: the unit's capacity; annual generation; resulting capacity factor; estimated annual availability factor; unit average heat rate; quantity of fuel burned; average cost of fuel; and resulting average energy cost for the unit's production. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

A.

Please see attachment.

Supplemental DR - Question No. 24
Attachment No. 1

2010 Unit Information

Plant	Unit #	Unit Type	Fuel Type	Nameplate Capacity (MW)	Net Capacity (MW) Summer	Net Capacity (MW) Winter	Annual Generation (MWh)	Capacity Factor (%)	Availability Factor (%)	In-Service Date	Heat Rate (BTU/kWh)	Total Fuel Burned (MMBTU)	Total Fuel Cost ($000)	Unit Fuel Cost ($/MMBTU)	Unit Fuel Cost (¢/kWh)
				(A)	(A)	(A)									
CAPE CANAVERAL	# 1	ST	#6 OIL	402	378	380	25,792	8.4	90.4	Apr-65	10,515	269,874	3,244	12.02	12.58
	# 1		GAS				94,975					1,000,000	7,032	7.03	7.40
	# 2	ST	#6 OIL	402	358	380	56,956	13.4	98.1	May-69	11,019	582,470	6,890	11.83	12.10
	# 2		GAS				113,250					1,293,001	8,777	6.79	7.75
FT. MYERS	# 2	CC	GAS	1,775	1,432	1,490	8,641,811	74.1	92.1	Jun-02	7,353	63,542,683	405,314	6.38	4.69
	#3A	CT	GAS	188	158	176	177,690	14.9	92.2	Jun-03	11,090	1,970,627	12,308	6.25	6.93
	#3A		#2 OIL				13,160					147,264	1,949	13.24	14.81
	#3B	CT	GAS	188	158	176	179,646	15.3	92.5	Jun-03	11,032	1,981,822	12,368	6.24	6.88
	#3B		#2 OIL				16,792					179,820	2,406	13.38	14.33
LAUDERDALE	# 4	CC	#2 OIL	526	442	483	375	56.8	79.4	May-93	8,236	3,067	48	15.52	12.69
	# 4		GAS				2,132,362					17,562,231	111,577	6.35	5.23
	# 5	CC	#2 OIL	526	442	483	354	59.7	84.0	Jun-93	8,251	2,890	45	15.54	12.69
	# 5		GAS				2,254,880					18,605,520	118,697	6.38	5.26
MANATEE	# 1	ST	#6 OIL	863	812	822	620,977	17.6	74.8	Oct-76	10,677	6,630,083	76,090	11.48	12.25
	# 1		GAS				582,582					6,688,592	41,776	6.25	7.17
	# 2	ST	#6 OIL	863	812	822	695,023	20.6	90.6	Dec-77	10,728	7,456,183	85,583	11.48	12.31
	# 2		GAS				720,661					8,336,803	51,876	6.22	7.20
	# 3	CC	GAS	1,225	1,111	1,168	6,213,247	68.0	88.3	Jun-05	7,017	43,599,634	278,534	6.39	4.48
MARTIN	# 1	ST	#6 OIL	935	826	832	771,257	30.5	88.6	Dec-80	10,896	8,009,259	91,622	11.44	11.88
	# 1		GAS				1,328,038					14,865,498	93,701	6.30	7.06
	# 2	ST	#6 OIL	935	826	832	664,045	25.3	80.3	Jun-81	10,031	6,430,957	74,121	11.53	11.16
	# 2		GAS				1,098,066					11,245,142	69,588	6.19	6.34
	# 3	CC	GAS	612	469	489	2,398,281	66.3	88.1	Feb-94	7,614	18,260,523	115,706	6.34	4.82
	# 4	CC	GAS	612	469	489	2,748,759	75.6	95.8	Apr-94	7,465	20,520,067	130,329	6.35	4.74
	# 8	CC	#2 OIL	1,225	1,105	1,162	14,385	65.4	87.4	Jun-05	7,260	102,108	1,396	13.67	9.70
	# 8		GAS				5,853,502					42,498,836	269,906	6.35	4.61
PT EVERGLADES	# 1	ST	#6 OIL	225	213	214	5,599	0.3	100	Jun-60	17,990	78,751	928	11.79	16.58
	# 1		GAS				(811)					7,385	53	7.19	(6.55)
	# 2	ST	#6 OIL	225	213	214	8,382	0.4	100	Apr-61	15,290	106,702	1,258	11.79	15.00
	# 2		GAS				(962)					6,752	49	7.19	(5.05)
	# 3	ST	#6 OIL	402	387	389	324,597	24.1	86.3	Jul-64	11,533	3,404,079	38,861	11.42	11.97
	# 3		GAS				444,074					5,461,160	34,027	6.23	7.66
	# 4	ST	#6 OIL	402	374	376	349,743	20.6	92.2	Apr-65	11,702	3,752,991	42,936	11.44	12.28
	# 4		GAS				311,035					3,979,188	24,881	6.25	8.00
RIVIERA	# 3	ST	#6 OIL	310	277	280	(710)	0	100	Jun-62	-8	12	0	0	0
	# 3		GAS				(710)					0	0	0	0
	# 4	ST	#6 OIL	310	288	291	(444)	0	100	Mar-63	0	0	0	0	0
	# 4		GAS				(444)					0	0	0	0
SANFORD	# 3	ST	#6 OIL	156	138	140	(2,715)	0	100	May-59	0	0	0	0	0
	# 3		GAS				(2,715)					0	0	0	0
	# 4	CC	GAS	1,189	958	1,040	5,406,628	69.72	91.04	Oct-03	7,423	40,132,148	254,976	6.35	4.72
	# 5	CC	GAS	1,189	954	1,037	5,247,587	68.19	91.87	Jun-02	7,423	38,954,419	247,849	6.36	4.72
TURKEY POINT	# 1	ST	#6 OIL	402	396	398	281,703	14.2	90.4	Apr-67	12,580	3,198,070	36,807	11.51	13.07
	# 1		GAS				191,148					2,750,530	17,236	6.27	9.02
	# 2	ST	#6 OIL	402	392	394	280,872	13.5	91.7	Apr-68	11,755	2,995,125	34,565	11.54	12.31
	# 2		GAS				157,214					2,154,367	13,416	6.23	8.53
	# 5	CC	#2 OIL	1,225	1,148	1,156	3,937	63.23	86.38	May-07	7,184	28,460	442	15.52	11.22
	# 5		GAS				5,789,625					41,592,439	265,665	6.39	4.59

Supplemental DR - Question No. 24
Attachment No. 1

2010 Unit Information

Plant	Unit #	Unit Type	Fuel Type	Nameplate Capacity (MW)	Net Capacity (MW) Summer	Net Capacity (MW) Winter	Annual Generation (MWh)	Capacity Factor (%)	Availability Factor (%)	In-Service Date	Heat Rate (BTU/kWh)	Total Fuel Burned (MMBTU)	Total Fuel Cost ($000)	Unit Fuel Cost ($/MMBTU)	Unit Fuel Cost (¢/kWh)
WEST COUNTY	# 1	CC	# 2 OIL	1,367	1,219	1,335	96,488	61.57	76.72	Aug-09	7,066	707,526	10,290	14.54	10.66
	# 1		GAS				6,395,111					45,164,284	289,471	6.41	4.53
	# 2	CC	# 2 OIL	1,367	1,219	1,335	0	68.73	82.83	Nov-09	6,940	0	0	0	0
	# 2		GAS				7,261,983					50,399,818	319,476	6.34	4.40
	# 3	CC	# 2 OIL	(B)	(B)	(B)	(675)	(B)	(B)	(B)	(B)	0	0	0	0
	# 3		GAS				(675)					0	0	0	0
CUTLER	# 5	ST	GAS	75	68	69	(810)	0	100	Nov-54	0	0	0	0	0
	# 6	ST	GAS	162	137	138	(812)	0	100	Jul-55	0	0	0	0	0
FT MYERS	1-12	GT	#2 OIL	744	648	710	57,738	1.19	99.13	May-74	13,400	773,709	10,422	13.47	18.05
LAUDERDALE	1-12	GT	#2 OIL	411	420	459	12,729	1.64	92.19	Aug-70	17,887	204,366	3,115	15.24	24.47
	1-12		GAS				36,547					677,033	4,212	6.22	11.52
	13-24	GT	#2 OIL	411	420	459	19,163	1.16	96.68	Aug-72	17,831	310,481	4,734	15.25	24.70
	13-24		GAS				15,641					310,110	1,930	6.22	12.34
EVERGLADES	1-12	GT	#2 OIL	411	420	459	14,460	1.02	92.46	Aug-71	17,729	225,367	3,173	14.08	21.95
	1-12		GAS				16,235					318,823	2,031	6.37	12.51
PUTNAM	# 1	CC	#2 OIL	290	249	265	16,882	25.17	80.89	Apr-78	10,161	171,837	1,829	10.64	10.83
	# 1		GAS				502,400					5,104,694	32,280	6.32	6.43
	# 2	CC	#2 OIL	290	249	265	10,252	22.75	82.17	Aug-77	10,309	104,203	1,109	10.64	10.82
	# 2		GAS				457,676					4,719,480	29,794	6.31	6.51
ST JOHNS	# 1	ST	COAL	(C) 136	(C) 127	(C) 125	(D) 954,147	86.3	96	Mar-87	(D) 9,628	9,087,844	30,293	3.33	(D) 3.17
	# 1		GAS				2,101					118,942	168	1.41	7.98
	# 2	ST	COAL	(C) 136	(C) 127	(C) 125	(D) 881,033	79.46	88.46	May-88	(D) 9,494	8,364,897	27,686	3.31	(D) 3.14
	# 2		#2 OIL				443					4,251	41	9.57	9.19
	# 2		GAS				346					19,407	157	8.09	45.36
SCHERER	# 4	ST	COAL	(C) 680	(C) 646	(C) 652	(D) 3,886,301	71.55	78.4	Jul-89	(D) 10,697	41,567,051	94,720	2.28	(D) 2.44
	# 4		#2 OIL				1,894					24,479	382	15.61	20.17
DESOTO		PV	SOLAR	25	25	25	53,341	26.8	-	Oct-09	-	-	-	-	-
SPACE COAST		PV	SOLAR	10	10	10	15,272	22.7	-	Apr-10	-	-	-	-	-
TURKEY POINT	# 3	ST	NUCLEAR	760	693	717	5,355,242	88.2	85.8	Nov-72	11,010	58,962,415	36,983	0.63	0.69
	# 4	ST	NUCLEAR	760	693	717	5,949,649	98.1	95.0	Jun-73	10,975	65,299,912	39,481	0.60	0.66
ST LUCIE	# 1	ST	NUCLEAR	850	839	853	5,298,963	72.1	72.6	May-76	10,932	57,930,536	31,134	0.54	0.59
	# 2	ST	NUCLEAR	*** 724	*** 714	*** 726	*** 6,245,755	**** 99.8	**** 97.6	Jun-83	*** 10,817	67,557,484	29,432	0.44	0.47
*** EXCLUDES PARTICIPANTS															
**** INCLUDES PARTICIPANTS															

1. ALL COAL DATA AND GAS COST & CONSUMPTION REPORTED ON A CALENDAR PERIOD BASIS. ALL OTHER DATA IS REPORTED ON A FISCAL PERIOD BASIS
2. NET HEAT RATE CALCULATED BASED ON THE GENERATION AND FUEL CONSUMPTION REPORTED ON THIS SCHEDULE AND MAY BE DIFFERENT THAN THE ACTUAL HEAT RATE DUE TO THE REPORTING TIME PERIOD DIFFERENTIAL BETWEEN THE DIFFERENT FUEL TYPES (REFER TO FOOTNOTE #1)

(A) CAPE CANAVERAL UNITS WERE RETIRED IN JUNE 2010.

(B) UNIT NOT IN COMMERCIAL OPERATION IN 2010

(C) FPL SHARE.

Q.

Traditional Generation

For each unit on the Company's system, provide the following data based upon historic data from 2010 and forecasted capacity factor values for the period 2011 through 2020. Please complete the tables below and provide an electronic copy in Excel (.xls file format) and hard copy.

Projected Unit Information – Capacity Factor (%)

Plant	Unit #	Unit Type	Fuel Typ e	Actual	Projected
				2010	2011201220132014201520162017201820192020

A.

Please see attachment.

Supplemental DR - Question No. 25
Attachment No. 1

2011 TYSP Supplemental Data Request - question 25

Projected Unit Information – Capacity Factor (%)

Plant	Unit #	Unit Type	Fuel Type	Actual 2010	Projected 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CAPE CANAVERAL 1	1	ST	OIL/GAS	8.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPE CANAVERAL 2	2	ST	OIL/GAS	13.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CAPE CANAVERAL 3	3	CC	GAS	0.0	0.0	0.0	56.7	89.1	94.9	90.1	91.6	95.6	86.5	95.7
GREENFIELD CC 2016	-	CC	GAS	0.0	0.0	0.0	0.0	0.0	0.0	52.7	89.5	90.2	90.7	91.2
GREENFIELD CC 2019	-	CC	GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	52.3
CUTLER 5	5	ST	OIL/GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CUTLER 6	6	ST	OIL/GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DESOTO SOLAR (PV)	-	PV	SOLAR	26.8	24.8	24.7	24.5	24.3	24.2	24.1	23.9	23.7	23.6	23.5
EVERGLADES 1-12	-	GT	OIL/GAS	1.0	0.2	0.0	0.1	0.0	0.1	0.2	0.7	0.5	0.7	0.0
EVERGLADES 1	1	ST	OIL/GAS	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EVERGLADES 2	2	ST	OIL/GAS	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EVERGLADES 3	3	ST	OIL/GAS	24.1	1.9	9.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EVERGLADES 4	4	ST	OIL/GAS	20.6	0.8	3.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FORT MYERS 1-12	-	GT	OIL/GAS	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.1	0.1	0.0
FORT MYERS 2	2	CC	GAS	74.1	80.5	87.2	75.7	69.7	65.1	62.8	61.7	63.2	62.6	58.2
FORT MYERS 3A_B	3	CT	GAS	15.1	3.5	2.4	1.6	1.4	1.4	1.9	3.5	2.8	3.5	2.3
LAUDERDALE 1-24	-	GT	OIL/GAS	1.4	0.6	0.2	0.2	0.1	0.3	0.5	1.2	0.8	1.2	0.5
LAUDERDALE 4	4	CC	OIL/GAS	56.8	31.3	30.5	22.5	22.0	15.2	14.8	14.5	13.7	12.9	15.5
LAUDERDALE 5	5	CC	OIL/GAS	59.7	36.1	35.5	26.0	25.6	20.3	18.9	16.9	17.7	18.4	17.7
MANATEE 1	1	ST	OIL/GAS	17.6	9.6	5.7	3.5	4.5	3.9	4.5	5.6	5.8	7.0	4.9
MANATEE 2	2	ST	OIL/GAS	20.6	29.4	7.3	6.9	6.7	4.9	7.5	8.2	8.7	10.0	8.3
MANATEE 3	3	CC	GAS	68.0	71.6	76.5	61.7	56.0	47.9	50.4	48.4	47.0	48.0	46.0
MARTIN 1	1	ST	OIL/GAS	30.5	17.2	14.7	3.6	10.6	7.4	11.0	10.6	11.7	10.5	11.9
MARTIN 2	2	ST	OIL/GAS	25.3	22.6	18.4	13.4	1.1	11.5	10.4	14.2	11.2	15.0	14.0
MARTIN 3	3	CC	GAS	66.3	38.8	39.9	30.6	24.8	23.8	21.8	21.7	20.3	20.3	22.4
MARTIN 4	4	CC	GAS	75.6	38.6	43.6	34.4	34.0	28.5	25.3	24.0	24.0	26.0	26.2
MARTIN 8*	8	CC	GAS	65.4	57.6	62.0	50.6	45.8	40.1	31.2	38.3	36.5	39.0	38.9
PUTNAM 1	1	CC	GAS	25.2	19.0	20.3	12.0	11.6	8.3	11.6	12.3	11.4	12.4	11.3
PUTNAM 2	2	CC	GAS	22.8	15.6	18.2	11.0	10.0	8.8	10.4	11.1	10.5	11.1	11.0
RIVIERA 3	3	ST	OIL/GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RIVIERA 4	4	ST	OIL/GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RIVIERA 5	5	CC	GAS	0.0	0.0	0.0	0.0	56.6	89.3	95.8	90.7	93.2	95.8	83.5
SANFORD 3	3	ST	OIL/GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SANFORD 4	4	CC	GAS	69.7	48.5	49.0	32.3	40.1	34.7	32.0	31.6	32.0	32.7	37.4
SANFORD 5	5	CC	GAS	68.2	55.4	42.4	43.4	45.2	38.9	34.9	38.6	36.5	37.9	39.2
SCHERER 4	4	Coal	COAL	71.6	86.6	75.5	97.8	88.1	97.7	88.1	97.7	87.7	97.3	87.8
SPACE COAST SOLAR (PV)	-	PV	SOLAR	22.7	21.2	21.1	20.9	20.8	20.7	20.6	20.4	20.3	20.1	20.0
ST JOHNS 1	1	Coal	COAL	86.3	86.0	97.6	89.9	97.5	89.6	97.4	89.2	97.3	87.1	97.0
ST JOHNS 2	2	Coal	COAL	79.5	94.9	89.6	97.7	89.7	97.7	89.7	97.0	81.8	97.6	87.2
ST LUCIE 1	1	Nuclear	Nuclear	72.1	87.1	78.5	87.3	87.3	97.5	89.7	89.9	97.5	89.7	90.0
ST LUCIE 2	2	Nuclear	Nuclear	99.8	75.5	71.9	87.3	97.5	87.3	90.0	97.5	89.9	89.9	97.5
TURKEY POINT 1	1	ST	OIL/GAS	14.2	0.8	0.4	0.2	0.2	0.3	0.5	1.0	0.7	1.0	0.5
TURKEY POINT 2	2	ST	OIL/GAS	13.5	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TURKEY POINT 3	3	Nuclear	Nuclear	88.2	97.5	65.5	88.1	97.5	89.4	90.0	97.5	90.0	90.0	97.5
TURKEY POINT 4	4	Nuclear	Nuclear	98.1	68.2	73.0	89.2	89.7	90.0	97.5	89.9	89.7	97.5	90.0
TURKEY POINT 5	5	CC	GAS	63.2	76.1	68.9	55.7	53.7	46.8	46.8	43.5	51.0	52.2	51.1
WCEC 1	1	CC	GAS	61.6	91.3	92.9	90.0	80.0	84.8	89.7	76.3	84.1	90.1	76.5
WCEC 2	2	CC	GAS	68.7	91.6	90.2	90.3	83.0	78.1	84.1	76.6	85.2	84.7	78.3
WCEC 3	3	CC	GAS	0.0	57.2	89.8	88.8	79.1	85.2	76.9	80.1	76.8	77.5	71.3

* The generation values for Martin 8 include energy from steam generated at the Martin solar thermal facility. Capacity factor values are not separately available for the Martin Solar Thermal site.

Q.

Traditional Generation

Please complete the table below, providing a list of all of the Company's steam units or combustion turbines that are candidates for repowering. As part of this response, please provide the unit's fuel and unit type, summer capacity rating, in-service date, and what potential conversion/repowering would be most applicable. Also include a description of any major obstacles that could affect repowering efforts at any of these sites, such as unit age, land availability, or other requirements.

Plant Name	Fuel & Unit Type	Summer Capacity (MW)	In-Service Date	Potential Conversion Type

A.

All existing conventional steam generating units and the combustion turbine units at Fort Myers are capable of being converted to combined cycle operation. The list of such units on FPL's system, in alphabetical order, which are potential candidates for repowering or conversion are:

- Cape Canaveral Units 1 and 2
- Cutler Units 5 and 6
- Ft. Myers Combustion Turbines Units 3A and 3B
- Manatee Units 1 and 2
- Martin Units 1 and 2
- Port Everglades Units 1, 2, 3, and 4
- Riviera Units 3 and 4
- Sanford Unit 3
- Turkey Point Units 1 and 2

Included in the above list are four units which FPL received FPSC approval to convert into new combined cycle units. These units are Cape Canaveral Units 1 and 2, which are currently planned to be converted in 2013 and Riviera Units 3 and 4, which are currently planned to be converted in 2014. In practice, there are a number of considerations that are taken into account when analyzing whether to convert an existing conventional steam generating unit to a combined cycle unit. Some of these considerations can be thought of as feasibility issues (such as whether there is sufficient land at the existing site for this type of unit) while other issues are typically thought of as economic issues. Any of these considerations could potentially become a major obstacle to a plant conversion at a specific site.

The considerations listed below are examples of issues typically addressed in analyses of potential conversions. However, other issues may also enter into analyses of conversions for specific sites:

- Physical site limitations
- Available water quantity, quality and cost
- Permitting issues
- Projected environmental compliance costs for the existing units and/or for the FPL system
- Projected on-going O&M and capital replacement costs for the existing units
- Projected fuel and environmental compliance costs
- Projected fixed and variable costs for new generating units
- Net capacity addition (after removing existing capacity and adding the new 3 x 1 advanced CT CC capacity)
- Impacts to FPL system reserve margin after removing the existing units
- Feasibility and cost of securing adequate additional firm natural gas to the site (especially for those sites with significant urbanization around them)
- Feasibility and cost of transmission upgrades to bring increased capacity and energy from the site (especially for those sites with significant urbanization around them)

Please see attachment.

Supplemental DR - Question No. 26
Attachment No. 1

Plant Name	Fuel & Unit Type	Summer Capacity (MW)	In-Service Date	Potential Conversion Type
Cape Canaveral Unit 1	FO6/NG, ST	0		CC
Cape Canaveral Unit 2	FO6/NG, ST	0		CC
Cutler Unit 5	NG, ST	68	Nov-54	CC
Cutler Unit 6	NG, ST	137	Jul-55	CC
Ft. Myers Combustion Turbines Unit 3A	NG/FO2, CT	158	Jun-03	CC
Ft. Myers Combustion Turbines Units 3B	NG/FO2, CT	158	Jun-03	CC
Manatee Unit 1	FO6/NG, ST	812	Oct-76	CC
Manatee Unit 2	FO6/NG, ST	812	Dec-77	CC
Martin Unit 1	FO6/NG, ST	826	Dec-80	CC
Martin Unit 2	FO6/NG, ST	826	Jun-81	CC
Port Everglades Unit 1	FO6/NG, ST	213	Jun-60	CC
Port Everglades Unit 2	FO6/NG, ST	213	Apr-61	CC
Port Everglades Unit 3	FO6/NG, ST	387	Jul-64	CC
Port Everglades Unit 4	FO6/NG, ST	374	Apr-65	CC
Riviera Unit 3	FO6/NG, ST	0		CC
Riviera Unit 4	FO6/NG, ST	0		CC
Sanford Unit 3	FO6/NG, ST	138	May-59	CC
Turkey Point Unit 1	FO6/NG, ST	396	Apr-67	CC
Turkey Point Unit 2	FO6/NG, ST	392	Apr-68	CC

Note: Cape Canaveral 1 & 2 and Riviera 3 & 4 show 0 MW of summer capacity and no in-service date since these units are currently being modernized to combined cycle generators.

Florida Power & Light Company
Docket No.
2011 Ten Year Site Plan Supplemental Data Request No. 1
Question No. 27

Q.

Traditional Generation

Please complete the table below, in electronic (Excel) and hard copy, regarding the Company's generation fleet and the typical use of each unit. Please identify capacity type as either Baseload, Intermediate, or Peaking, and group units by their capacity type. Please use the abbreviations for fuel and generation facilities from the FRCC Load and Resource Plan for the table below. (For example, a combustion turbine that is not part of a combined cycle unit is identified with generator code "GT.") Please complete the tables below and provide an electronic copy in Excel (.xls file format) and hard copy.

Existing Facilities as of January 1, 2011

Plant	Unit #	Unit Type	Fuel Type	Typical Capacity Factor	Capacity Type	Summer Capacity
				(%)		(MW)
				Sub-Total	Baseload	
				Sub-Total	Intermediate	
				Sub-Total	Peaking	
					Total	

Planned Facilities during 2011 to 2020

Plant	Unit #	Unit Type	Fuel Type	Typical Capacity Factor	Capacity Type	Summer Capacity
				(%)		(MW)
				Sub-Total	Baseload	
				Sub-Total	Intermediate	
				Sub-Total	Peaking	
					Total	

A.

In regard to the "capacity type" designation, FPL is using the following general convention for these designations: FPL's nuclear, coal and combined cycle units are designated as base load units; the steam units are designated as intermediate units; and the combustion turbine and gas turbines are designated as peaking units. The exception to this convention is Putnam units 1 & 2; these older combined cycle units are designated as intermediate units in the attached table. In addition, the PV facilities at DeSoto and Space Coast are currently considered as non-firm capacity facilities because their output in intermittent. For purposes of this response, FPL is designating these facilities as intermediate resources.

Existing Units

Existing Units	Unit No.	Generator Code	Fuel Code	2010 Capacity Factor (%)	Capacity Type	Summer MW
Scherer	4	BIT	BIT	72	Baseload	646
SJRPP	1	BIT	BIT	86	Baseload	127
SJRPP	2	BIT	BIT	79	Baseload	127
Fort Myers	2	CC	NG	74	Baseload	1,432
Lauderdale	4	CC	NG	57	Baseload	442
Lauderdale	5	CC	NG	60	Baseload	442
Manatee	3	CC	NG	68	Baseload	1,111
Martin	3	CC	NG	66	Baseload	469
Martin	4	CC	NG	76	Baseload	469
Martin	8	CC	NG	65	Baseload	1,105
Sanford	4	CC	NG	70	Baseload	958
Sanford	5	CC	NG	68	Baseload	954
Turkey Point	5	CC	NG	63	Baseload	1,148
St. Lucie	1	NP	UR	72	Baseload	839
St. Lucie	2	NP	UR	100	Baseload	714
Turkey Point	3	NP	UR	88	Baseload	693
Turkey Point	4	NP	UR	98	Baseload	693
West County	1	CC	NG	62	Baseload	1,219
West County	2	CC	NG	69	Baseload	1,219
				Subtotal	Baseload	14,807
Cape Canaveral	1	ST	FO6	8	Intermediate	0
Cape Canaveral	2	ST	FO6	13	Intermediate	0
Cutler	5	ST	NG	0	Intermediate	68
Cutler	6	ST	NG	0	Intermediate	137
DeSoto Next Generation Energy Center	1	PV	PV	27	Intermediate	25
Space Coast Next Generation Energy Center	1	PV	PV	23	Intermediate	10
Manatee	1	ST	FO6	18	Intermediate	812
Manatee	2	ST	FO6	21	Intermediate	812
Martin	1	ST	FO6	31	Intermediate	826
Martin	2	ST	FO6	25	Intermediate	826
Port Everglades	1	ST	FO6	0.3	Intermediate	213
Port Everglades	2	ST	FO6	0.4	Intermediate	213
Port Everglades	3	ST	FO6	24	Intermediate	387
Port Everglades	4	ST	FO6	21	Intermediate	374
Putnam	1	CC	NG	25	Intermediate	249
Putnam	2	CC	NG	23	Intermediate	249
Riviera	3	ST	FO6	0	Intermediate	277
Riviera	4	ST	FO6	0	Intermediate	288
Sanford	3	ST	FO6	0	Intermediate	138
Turkey Point	1	ST	FO6	14	Intermediate	396
Turkey Point	2	ST	FO6	14	Intermediate	392
				Subtotal	Intermediate	6,692
Fort Myers	1-12	GT	FO2	1	Peaking	648
Fort Myers	3A & B	CT	NG	15	Peaking	315
Lauderdale	1-24	GT	NG	2	Peaking	840
Port Everglades	1-12	GT	NG	1	Peaking	420
				Subtotal	Peaking	2,223
Total System Generating Capacity as of December 31, 2010 =					Total	23,722
System Firm Generating Capacity as of December 31, 2010=						23,687

Planned Units

Future Unit	Unit No.	Generator Code	Fuel Code	In-Service Year	Projected Capacity Factor (Approx.%)	Capacity Type	Summer MW
West County Energy Center	3	CC	NG	2011	90	Baseload	1,219
Cape Canaveral Next Generation Clean Energy Center	1	CC	NG	2013	90	Baseload	1,210
Riviera Beach Next Generation Clean Energy Center	1	CC	NG	2014	89	Baseload	1,212
Greenfield CC	1	CC	NG	2016	90	Baseload	1,191
Greenfield CC	1	CC	NG	2020	90	Baseload	1,191
					Subtotal	Baseload	6,023

Q.
Traditional Generation

Please complete the table below regarding the system's installed capacity, categorized by capacity type, for the period 2001 through 2020. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

A.
Please see attachment.

Supplemental DR - Question No. 28
Attachment No. 1

System Installed Capacity Type

	Year	Baseload Capacity (MW)	Intermediate Capacity (MW)	Peaking Capacity (MW)	Total Installed Capacity (MW)
Actual	2001	6,030	7,498	3,100	16,628
	2002	7,973	7,462	2,206	17,641
	2003	8,956	7,538	2,562	19,056
	2004	8,964	7,432	2,566	18,962
	2005	11,127	7,404	2,246	20,777
	2006	11,216	7,521	2,244	20,981
	2007	12,370	7,521	2,244	22,135
	2008	12,382	7,467	2,238	22,087
	2009	14,815	7,492	2,223	24,530
	2010	14,807	6,692	2,223	23,722
Projected	2011	16,069	4,205	2,223	22,497
	2012	16,283	4,966	2,223	23,472
	2013	17,712	4,205	2,223	24,140
	2014	18,924	4,205	2,223	25,352
	2015	18,924	4,205	2,223	25,352
	2016	20,115	4,205	2,223	26,543
	2017	20,115	4,205	2,223	26,543
	2018	20,115	4,205	2,223	26,543
	2019	20,115	4,205	2,223	26,543
	2020	21,306	4,205	2,223	27,734

Q.

Traditional Generation

Please provide the system average heat rate for the generation fleet for each year for the period 2001 through 2020. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

A.

Please see attachment.

Supplemental DR - Question No. 29
Attachment No. 1

2011 Supplemental Data Request - Question 29

Year		System Average Heat Rate (BTU/kWh)
Actual	2001	10,018
	2002	9,739
	2003	9,454
	2004	9,301
	2005	9,117
	2006	9,057
	2007	8,916
	2008	8,963
	2009	8,866
	2010	8,705
Projected	2011	8,479
	2012	8,068
	2013	8,184
	2014	8,106
	2015	8,074
	2016	8,012
	2017	8,021
	2018	7,966
	2019	7,982
	2020	7,946

Q.
Traditional Generation

Please provide the average cost of a residential customer bill, based upon a monthly usage of 1200 kilowatt-hours, in nominal and real dollars for the period 2001 through 2020. Please use the Consumer Price Index to calculate real residential bill values. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

A.
Please see attachment.

Supplemental DR - Question No. 30
Attachment No. 1

2011 TYSP Supplemental Data Request - Question 30

	Monthly Bills ($/1200 kWh-mo.)			
	Year	Real	Nominal	Deflator*
Actual:	2001	125.42	101.82	177.042
	2002	113.28	93.43	179.867
	2003	117.82	99.40	184.000
	2004	120.14	104.07	188.908
	2005	123.28	110.39	195.267
	2006	144.29	133.36	201.558
	2007	133.79	127.20	207.337
	2008	132.02	130.31	215.251
	2009	136.07	133.87	214.548
	2010	120.09	120.09	218.079
Projected:	2011	116.74	119.37	222.992
	2012	125.83	131.59	228.057
	2013	123.95	132.53	233.171
	2014	122.14	133.34	238.088
	2015	122.67	136.68	242.978
	2016	126.79	144.10	247.847
	2017	128.96	149.51	252.832
	2018	141.47	167.44	258.106
	2019	143.91	173.69	263.209
	2020	143.29	176.25	268.248

Comments:
The real values are adjusted by the actual CPI values, based on 2010 dollars.
The actual nominal values are based on the annual average of actual monthly billings with a 1,200 kWh usage.

Projected monthly bills values were based on FPL's 2011 resource plan.
The projected nominal values represent a system average electric rate applied to a usage of 1200 kWh/month.
The real values are adjusted by the projected CPI values, based on 2010 dollars.

* The deflator is CPI (series 1982-84).

Q.
Power Purchases/Sales

Please identify each of the Company's existing and planned power purchase contracts, including firm capacity imports reflected in Schedule 7 of the Company's Ten-Year Site Plan. Provide the seller, capacity, associated energy, and term of each purchase, and provide unit information if a unit power purchase. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Existing Purchased Power Agreements as of January 1, 2011

Seller	Contract Term	Contract Capacity (MW)	Annual Generation	Capacity Factor	Primary Fuel (if any)	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)

Planned Purchased Power Agreements for 2011 through 2020

Seller	Contract Term	Contract Capacity (MW)	Annual Generation	Capacity Factor	Primary Fuel (if any)	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)

A.
Please see attachment.

Supplemental DR - Question No. 31
Attachment No. 1

2011 Ten Year Site Plan Supplemental Data Request - Question 31

Existing Purchased Power Agreements as of January 1, 2011

Seller	Contract Term		Contract Capacity (MW)		Annual Generation (Note 1)	Capacity Factor (Note 2)	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	
Southern Co	6/1/2010	12/31/2015	584	584	1,482,286	50%	Natural Gas	Harris
Southern Co	6/1/2010	12/31/2015	185	185	486,164	51%	Natural Gas	Franklin
Southern Co	6/1/2010	12/31/2015	159	159	495,275	61%	Coal	Scherer 3
Oleander	6/1/2007	5/31/2012	155	180	239,269	18%	Natural Gas	---
Wheelabrator Technologies	12/31/2026	12/31/2026	11	11	84,455	88%	MSW	Broward North
Wheelabrator Technologies	12/31/2026	12/31/2026	3.5	3.5	30,458	99%	MSW	Broward South
Cedar Bay Generating Co.	1/25/1994	12/31/2024	250	250	1,508,720	97%	Coal	---
Indiantown Cogen, LP	12/22/1995	12/1/2025	330	330	1,382,586	99%	Coal	---
SJRPP *	4/2/1982	4/1/2016	375	383	2,960,457	97%	Coal	---

* Contract End Date shown does not represent the actual contract date. Instead, this date represents a projection of the date at which FPL's ability to receive further capacity and energy from this purchase will be suspended due to IRS regulations.

Planned Purchased Power Agreements for 2011 through 2020

Seller	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	
Solid Waste Authority of Palm Beach	4/1/2012	4/1/2032	55	55	409,530	85%	MSW	Solid Waste Authority of Palm Beach
Solid Waste Authority of Palm Beach	4/1/2015	4/1/2032	90	90	670,140	85%	MSW	Solid Waste Authority of Palm Beach

Note 1 - Purchases for year 2010 reported in FERC Form 1
Note 2 - Calculated based on Summer Contract Capacity

Q.

Power Purchases/Sales

Please identify each of the Company's existing and planned power sales, including firm capacity exports reflected in Schedule 7 of the Company's Ten-Year Site Plan. Provide the purchaser, capacity, associated energy, and term of each purchase, and provide unit information if a unit power sale. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

A.

The Company's existing and planned power sales, including firm capacity exports reflected in Schedule 7 of the Ten-Year Site Plan, have been summarized in the attached file.

Supplemental DR - Question No. 32
Attachment No. 1

Existing Power Sales as of January 1, 2011

Purchaser	Contract Term		Contract Capacity (MW)		Annual Generation	Load Factor **	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	
Florida Keys Long Term Agreement *	January 1, 1992	December 31, 2031	111 - 127	88 - 101	710,939 - 802,439	72.1%	System Average	Partial Requirements
Key West Long Term Agreement	June 1, 1993	May 31, 2013	45	45	238,016	60.4%	System Average	Partial Requirements
Lee County Partial Requirements Agreement	January 1, 2010	December 31, 2013	226 - 230	242 - 245	1,179,574 - 1,209,240	56.3%	System Average	Partial Requirements
Metro-Dade Transmission Service Agreement	July 9, 1996	October 31, 2013	1	1	6,499 - 6,576	75.1%	System Average	Transmission Losses

Planned Power Sales for 2011 through 2020

Purchaser	Contract Term		Contract Capacity (MW)		Annual Generation	Load Factor **	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	
Lee County Full Requirements Agreement	January 1, 2014	December 31, 2053	816 - 854	925 - 966	3,964,696 - 4,146,409	49.0%	System Average	Full Requirements
Seminole Electric Cooperative	June 1, 2014	May 31, 2021	200	200	489,600 - 835,200	47.7%	Natural Gas	Heat Rate Call Option
Metro-Dade Transmission Service Agreement ***	November 1, 2013	End of Planning Period	1	1	6,499 - 6,576	75.1%	System Average	Transmission Losses

* Florida Keys contract capacity and generation data is based on the original 1992 agreement and forecasted to continue throughout the planning period (2011-2020).
A new agreement, dated February 7, 2011, is pending FERC approval. This agreement was not included in the forecast, which was based on January 14, 2011 contract information.

** Load Factor calculations use the highest annual generation and peak annual contract capacity values forecast during the planning period (2011-2020).

*** The Metro-Dade contract is forecast to continue throughout the planning period (2011-2020).

Q.

Power Purchases/Sales

Please discuss and identify the impacts on the Company's capacity needs of all known firm power purchases and sales over the planning horizon. As part of this discussion, please include whether options to extend purchases or sales exist, and the potential effects of expiration of these purchase or sales.

A.

The MW impact of all of FPL's long-term firm capacity contracts is shown in Table I.B.1 and Table I.B.2 in Chapter 1 of FPL's 2011 Ten Year Site Plan.

FPL projects that two contracts will begin to add capacity during the 2011-2020 time period. The first of these contracts is with the Solid Waste Authority (SWA) of Palm Beach County and is scheduled to provide 55 MW of firm capacity with a start date of 4/1/2012. This contract is a revision of an earlier contract which ended 3/31/2010. This revised contract was approved by the FPSC in Docket No. 090150. The second contract scheduled to add capacity during the 2011-2020 time period is an additional 90 MW of firm capacity from SWA scheduled to begin on 4/1/2015.

The following long-term firm capacity contracts have contract end dates that fall within the 2011-2020 time period addressed by this Site Plan:

- UPS Replacement contract for 931 MW with a contract end date of 12/31/2015;
- SJRPP for 381 MW with a "contract end date" (as shown in the tables) of 4/1/2016; and
- Oleander for 156 MW with a contract end date of 5/31/2012.

The UPS Replacement contract for 931 MW began on 6/1/2010 and will remain in place through 12/31/2015. No extension of that contract is currently projected by FPL.

The amount of firm capacity that FPL receives under the SJRPP contract is subject to an energy "cap" regarding the cumulative total MWh received under Internal Revenue Service regulations. Once this energy cap has been reached, FPL cannot receive additional energy under the contract. FPL currently estimates that this energy cap will be reached in early 2016. Consequently, the date shown in the table as the "contract end date" is actually the estimated date at which this energy cap will be reached.

In regard to the Oleander purchase listed above, this contract was entered into shortly after FPL experienced the large increase in peak load in the Summer of 2005. This contract provided near-term capacity that is no longer needed due to the addition of FPL's Turkey Point 5 and WCEC units.

For purposes of its resource planning, FPL assumes that all of its existing long-term firm capacity purchases shown in Table I.B.1 and Table I.B.2 in Chapter 1 of its 2011 Site Plan will remain in place to the Contract End Date shown in these tables. Individual contracts may have options with which one or both parties may either terminate earlier than the listed contract end date or extend this date. In addition, these contracts may be subject to renegotiation with mutual consent of both parties. As dictated by changes in resource needs, economic conditions, regulatory changes, and/or performance under the contract, FPL may examine such options available under the contract.

Discussion of all of FPL's sales can be found in Chapter 2, section C of the Ten Year Site Plan.

Q.

Environmental Issues

Please discuss the impact of environmental restrictions, relating to air or water quality or emissions, on the Company's system during the 2010 period, such as unit curtailments. As part of your discussion, please include the potential for environmental restrictions to impact unit dispatch or retirement during the 2011 through 2020 period.

A.

FPL operates its Electric Generating Units in compliance with all applicable federal, state and local regulations that limit impacts to air and water quality. Compliance with permit requirements requires FPL to monitor and operate facilities within specific allowable limits at all times. Environmental restrictions relating to air or water quality and emissions from facility operations are incorporated within those permits, and operating procedures are implemented at FPL's facilities to ensure compliance. Regulatory changes which impose environmental restrictions are ultimately incorporated within the operating permits as changes to existing limits or new requirements. Compliance with existing permits and new requirements is continuous, on a unit and fleet-wide basis. Changes to operations of facilities to comply with existing and new requirements are included in both existing and planned operating costs, and unit generating performance impacts for unit dispatch and production costing modeling. Impacts to operation of facilities include, but is not limited to, the installation of new pollution controls (which may impact unit efficiency and generation output), purchase of emission allowances, changes to the fuels combusted, and use of alternative products where applicable. Costs associated with new air and water compliance requirements are recovered by FPL through the Environmental Cost Recovery Clause (ECRC), and through the Fuel Cost Recovery Clause. Impacts of environmental requirements on operations from the ECRC projects for which FPL has received approval from the FPSC are detailed within FPL's ECRC Projection and True-Up testimonies.

In 2010, FPL generating unit operations were directly impacted by (but not limited to) the following environmental requirements: 1) Use of "environmental" natural gas during startup of FPL's oil/gas steam units; 2) Initial operation and tuning of the Baghouse-Sorbant injection system at Plant Scherer Unit 3 for mercury emission control; 3) Dispatch of the Cape Canaveral fossil steam generating units to provide warm water for manatees in compliance with manatee protection plan requirements.

In March 2011 the EPA published the Air Toxics Rule which will require emission control equipment installation on coal- and oil-fired electric generating units. FPL plans to install Electrostatic Precipitators (ESPs) on all four of its 800 MW oil-fired generating units at Martin and Manatee to comply with the rule. Installation of controls will required extended planned outages at each unit beginning in 2011 for the demolition of existing duct work, construction of the ESPs, and initial tuning commissioning of the controls. Construction is projected to be completed in 2014. FPL does not yet know what additional controls, if any, will be required at SJRPP for compliance with this rule. While FPL anticipates that there are likely to be additional environmental regulations that will be promulgated in the next several years, we cannot know what additional controls or restrictions will be required until the rules are published.

Q.

Environmental Issues

Please provide the rate of emissions, on an annual and per megawatt-hour basis, of regulated materials and carbon dioxide for the generation fleet each year for the period 2001 through 2020. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Year	SOX	NOX	Mercury	Particulates	CO2e
	lb/MWh	Tons	lb/MWh	Tons	lb/MWhTonslb/MWhTonslb/MWhTons
Actual	2001				
	2002				
	2003				
	2004				
	2005				
	2006				
	2007				
	2008				
	2009				
	2010				
Projected	2011				
	2012				
	2013				
	2014				
	2015				
	2016				
	2017				
	2018				
	2019				
	2020				

A.

Please see attachment.

Supplemental DR - Question No. 35
Attachment No. 1

Year		SOX		NOX		Mercury		Particulates		CO2	
		lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons
Actual	2001	4.310	173267	1.832	73239	*	*	*	*	1036.3	41635416
	2002	2.781	117611	1.402	59278	*	*	*	*	979.3	41406953
	2003	2.871	126640	1.243	54828	*	*	*	*	988.5	43606284
	2004	2.770	120018	1.150	49850	*	*	*	*	1009.0	43630249
	2005	2.570	118289	1.150	52883	*	*	*	*	976.0	44930742
	2006	1.370	66443	0.850	41417	*	*	*	*	878.0	42683702
	2007	1.400	68441	0.810	39735	*	*	*	*	896.0	43826364
	2008	1.010	47976	0.679	32375	*	*	*	*	851.0	40444387
	2009	0.847	40790	0.574	27618	*	*	*	*	845.4	40706301
	2010	0.688	34419	0.448	22409	*	*	*	*	817.9	40912209.5
Projected	2011	0.501	25717	0.295	15133	*	*	*	*	771.2	39606000
	2012	0.227	11721	0.248	12765	*	*	*	*	759.6	39149000
	2013	0.140	7400	0.165	8686	*	*	*	*	719.8	38001000
	2014	0.125	6986	0.144	8067	*	*	*	*	703.1	39258000
	2015	0.137	7709	0.138	7783	*	*	*	*	711.1	40134000
	2016	0.140	8255	0.137	8048	*	*	*	*	707.6	41614000
	2017	0.150	9017	0.145	8752	*	*	*	*	714.9	43113000
	2018	0.143	8732	0.137	8379	*	*	*	*	710.0	43325000
	2019	0.153	9444	0.145	8959	*	*	*	*	720.5	44501000
	2020	0.142	8907	0.135	8492	*	*	*	*	710.0	44639000

* FPL does not currently calculate or report actual or projected Particulate or Mercury air emission releases for all units or on a system basis.

Q.

Fuel

Please provide, on a system-wide basis, the historic average fuel price (in nominal \$/MMBTU) for each fuel type for the period 2001 through 2010. Also, provide the forecasted annual average fuel price (in nominal \$/MMBTU) for each fuel type for the period 2011 through 2020. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

A.

Please see attachment.

Supplemental DR - Question No. 36
Attaachment No. 1

Nominal Fuel Price ($/MMBTU)		Uranium	Coal	Natural Gas	Residual Oil	Distillate Oil
Actual (A3)	2001	0.2658	1.7138	4.5825	3.8077	6.4159
	2002	0.2566	1.7141	4.0643	3.5221	6.3732
	2003	0.2553	1.8301	6.2373	4.4597	7.1352
	2004	0.2765	1.6859	6.3698	4.4291	7.9592
	2005	0.3214	1.7236	8.5325	6.1643	12.0933
	2006	0.3758	2.0310	8.8057	8.1540	13.8764
	2007	0.3798	2.1223	9.7033	9.3058	14.4720
	2008	0.4273	2.2382	10.2445	10.2983	15.8338
	2009	0.5124	2.4432	8.1877	10.6453	14.0630
	2010	0.5487	2.5873	6.3556	11.4857	13.8405
Projected (1) (2) (3) (4) (5) (6)	2011	72.0700	3.1543	4.8588	13.2417	20.0284
	2012	70.1100	2.5366	5.3209	13.8156	20.3882
	2013	76.6300	2.5667	5.5399	13.6733	20.5987
	2014	77.9100	2.6048	5.6201	13.9871	21.2946
	2015	78.9000	2.6423	6.0088	14.3255	21.8043
	2016	80.2600	2.6905	6.5915	17.1970	23.8835
	2017	82.3400	2.7363	7.1340	17.9155	24.8568
	2018	84.2800	2.7699	7.6963	18.5729	25.7604
	2019	86.4400	2.8062	8.1503	19.1800	26.6256
	2020	88.6800	2.8425	8.6223	19.6538	27.5270

(1) Uranium price projections were obtained from Nominal Delivered Nuclear Fuel and Firm Purchase Table in Appendix A.
(2) Coal price projections are based on St. Johns River Power Park (SJRPP) price forecast information.
(3) Natural gas price projections are based on Average Florida Gas Transmission (FGT) Firm price forecast information.
(4) Residual oil price projections are based on Manatee Power Plant 1% residual fuel oil price forecast information.
(5) Distillate oil price projections are based on West County Energy Center (WCEC) light fuel oil price forecast information.
(6) Projected fossil fuel prices were developed from the January 14, 2011 FPL Long-Term base case fuel forecast.

Q.

Fuel

Please provide, on a system-wide basis, the historic annual fuel usage (in GWh) for each fuel type for the period 2001 through 2010. Also, provide the forecasted annual fuel usage (in GWh) for each fuel type for the period 2011 through 2020. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

A.

The system-wide average annual fuel usage values (in GWh) for the period from 2001 to 2020 have been included in the attached file.

Supplemental DR - Question No. 37
Attachment No. 1

2011 TYSP Supplemental Data Request - Question 37

Fuel Usage (GWh)		Uranium	Coal	Natural Gas	Residual Oil	Distillate Oil
Actual	2001	24,070	6,267	24,497	25,802	162
	2002	25,295	5,977	34,546	18,708	188
	2003	23,524	6,625	37,707	20,304	248
	2004	23,013	6,315	40,970	19,709	199
	2005	21,406	5,765	47,114	19,069	186
	2006	23,533	6,168	56,985	9,586	26
	2007	21,899	6,856	59,300	9,651	27
	2008	24,024	6,423	58,820	5,702	17
	2009	22,893	6,363	62,728	4,560	21
	2010	22,850	5,721	66,765	4,081	278
Projected	2011	20,758	6,738	73,272	1,627	93
	2012	19,718	6,230	75,939	964	2
	2013	25,388	7,446	71,971	559	4
	2014	26,720	6,903	77,352	467	0
	2015	26,406	7,440	78,200	602	5
	2016	26,567	6,926	83,199	704	6
	2017	26,981	7,428	85,127	829	25
	2018	26,591	6,795	87,616	801	15
	2019	26,491	7,390	88,496	909	20
	2020	27,058	6,873	90,766	820	1

Q.
Fuel

Please discuss how the Company compares its fuel price forecasts to recognized, authoritative independent forecasts.

A.
FPL's medium fossil fuel price forecast methodology utilizes projections from The PIRA Energy Group (PIRA), rates of escalation from the Department of Energy's (DOE) Energy Information Administration (EIA), forward commodity price curves for oil and natural gas, as well as projections from JD Energy, Inc. PIRA, a world-recognized consulting firm with extensive expertise in all aspects of the oil and natural gas industry, supplies FPL with an extensive database to support its short and long-term projections for future prices of oil and natural gas. FPL utilizes forward commodity price curves for oil and natural gas to project the first few years of the forecast (short-term) and applies escalation rates provided by the EIA for the long-term oil and natural gas projections. JD Energy, a consulting firm retained by many utilities and coal suppliers with extensive expertise in all aspects of the coal and petroleum coke industry, supplies FPL with an extensive database to support its short and long-term projections for future prices of coal and petroleum coke. FPL does not develop price forecasts of its own for review or testing of these independent forecasts. Because FPL's forecasts reflect these authoritative and independent sources, FPL believes that the projections are reasonable and comparisons to other forecasts are not necessary.

For nuclear fuel price projections, FPL subscribes to a number of publications such as reports published by Ux consulting, Energy Resources International and Trade Tech. These firms represent a broad spectrum of companies and serves as indicators for spot and long term market behaviors. FPL long term price projections are reasonably consistent with the best estimates/projections of these recognized independent companies. FPL expects that there will be times when uranium market prices will fluctuates about these projections, but the price used for uranium provides a better representation of long term trends.

Q.
Fuel

For each fuel type (coal, natural gas, nuclear fuel, etc.), please discuss in detail the expected industry trends and factors for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company.

A.
Coal prices are expected to slowly increase over the 2011 through 2020 period as worldwide demand growth, primarily in the Pacific rim countries, places upward pressure on domestic and imported coal prices throughout the period. The supply of domestic coal and the availability of imports will be sufficient to meet a stable to very slow growth in domestic demand over the period.

The demand for natural gas in the United States as well as in the Florida market is expected to continue to grow through the 2011 through 2020 period, primarily in the power generation sector. The supply of natural gas to the United States as well as to the Florida markets is expected to grow and match the growth in demand as declines in production from the mature conventional gas regions of the Gulf Coast onshore, Gulf Coast offshore, and Permian Basin are replaced with rapid growth in unconventional gas mainly from the Mid-Continent and Central Appalachian regions. This will result in natural gas prices increasing moderately over the 2011 through 2020 period.

Similarly, oil prices will increase moderately over the 2011 through 2020 period. The worldwide demand for oil will grow over the forecast horizon primarily in the emerging market countries in the Pacific Rim and in the transportation end-use sector. Non-OPEC supply is projected to grow moderately over this period and OPEC production will grow to fill the supply shortfall.

There continues to be some volatility in the current uranium market. Demand is rather stable and supply exceeds current demand. Uranium price has been volatile recently, first increasing at news of significant increase in future demand to feed a recently announced increase in the Chinese nuclear power program, but then countered by recent events in Japan and the decision from the Department of Energy to sell some of its excess uranium inventories to fund some of the decontamination and decommissioning activities of old uranium enrichment plants. Although the market went up on the news of a more aggressive Chinese build up of nuclear plants, we expect uranium prices to return to our long term predictions, when the impact of the events in Japan are fully factored into the market. FPL expects less volatility in uranium prices within the next few years, with price behavior to be more consistent with market fundamentals.

As for the other steps of the fabrication of nuclear fuel (conversion, enrichment and fabrication services), we expect prices will remain rather stable and additional productions would be added as needed to meet new reactor requirements.

Q.

Fuel

What steps has the Company taken to ensure gas supply availability and transport over the 2011 through 2020 planning period?

A.

FPL has contracted for sufficient gas transportation capacity with the Florida Gas Transmission (FGT) and Gulfstream Natural Gas System (Gulfstream) pipelines to serve existing plants, including West County Energy Center Unit 3, and is evaluating the appropriate method and timing to secure transportation for the Cape Canaveral Next Generation Clean Energy Center and the Riviera Beach Next Generation Clean Energy Center modernization projects. The current gas transportation portfolio provides FPL access to a diverse range of gas supply alternatives, which helps mitigate FPL's exposure to supply disruptions. In addition, FPL has access to natural gas underground storage, which further enhances supply reliability.

FPL will continue to evaluate strategies that will increase the reliability and supply diversity of the gas transportation portfolio to ensure adequate gas availability for future generation growth. In the 2011 Ten Year Site Plan, FPL identified new generation facilities in 2016 and 2020. We are in the process of identifying gas transportation and supply requirements to support those facilities, along with the longer term requirements of the Cape Canaveral Next Generation Clean Energy Center and the Riviera Beach Next Generation Clean Energy Center modernizations.

Q.
Fuel

Regarding existing and planned natural gas pipeline expansion projects, including new pipelines, affecting the Company for the period 2011 through 2020, please identify each project and discuss it in detail.

A.
With regard to existing pipelines, on April 1, 2011 Florida Gas Transmission (FGT) placed the Phase VIII expansion into commercial operation. FGT's expansion increases FGT's capacity by 820,000 MMBtu/d. FPL has contracted for 400,000 MMBtu/d of this Phase VIII capacity. Gas provided to FPL through the Phase VIII expansion will be used to meet existing generation system requirements, including West County Energy Center Unit 3. Inclusive of Phase VIII, FPL has secured a total of 1.274 billion cubic feet per day of firm summer transport with FGT.

Gulfstream Natural Gas System (Gulfstream) completed their Phase III expansion in 2008. FPL receives a total of 695,000 MMBtu/d of natural gas service from Gulfstream, including 345,000 MMBtu/d of natural gas to serve the West County Clean Energy Center (WCEC) via Gulfstream's Phase III expansion.

In the 2011 Ten Year Site Plan, FPL identified new generation facilities in 2016 and 2020. We are in the process of identifying gas transportation and supply requirements to support those facilities, along with the longer term requirements of the Cape Canaveral Next Generation Clean Energy Center and the Riviera Beach Next Generation Clean Energy Center modernizations.

Q.
Fuel

Please discuss in detail any existing or planned natural gas pipeline expansion project, including new pipelines and off-shore projects, outside the State of Florida that will affect the Company over the period 2011 through 2020.

A.
Transcontinental Gas Pipe Line (Transco) is in the process of expanding their 4A Lateral (from Transco Station 85 to interconnections with Florida Gas Transmission, LLC (FGT) and Gulfstream Natural Gas System (Gulfstream) in Mobile, Alabama) which will provide additional capacity to transport unconventional shale gas into Florida. FPL anticipates that the Destin Pipeline and the Southeast Supply Header Pipeline will also be expanded to provide additional capacity to transport unconventional shale gas from Texas and Louisiana to Gulfstream and FGT. From an off-shore perspective, FPL anticipates that the Gulf Clean Energy LNG Terminal in Pascagoula, Mississippi will be completed in this timeframe connecting to both FGT and Gulfstream.

Q.
Fuel

Regarding unconventional natural gas production (shale gas, tight sands, etc.), please discuss in detail the expected industry factors and trends for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company.

A.
Domestic unconventional natural gas production (shale, tight sands, and Coal Bed Methane) is expected to increase from about 24.77 billion cubic feet per day (Bcf/d) in 2011 to about 41.31 Bcf/d by 2020 primarily in the Mid-Continent (15.87 Bcf/d to 22.32 Bcf/d) and Central Appalachian (3.52 Bcf/d to 9.05 Bcf/d) regions. This projected growth in unconventional production will be more than sufficient in insuring ample natural gas supply to meet the anticipated growth in U. S., Florida, and FPL demand well into the next decade.

Q.
Fuel

Regarding liquefied natural gas (LNG) imports to the United States, please discuss in detail the expected industry factors and trends for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company.

A.
Net Liquified Natural Gas (LNG) imports to the United States are expected to remain relatively stable over the 2011 through 2020 period, increasing and decreasing within a narrow range of 1.05 Billion cubic feet per day (Bcf/d) to 1.21 Bcf/d over the period. As domestic production grows moderately over this period, primarily from unconventional production, and Canadian imports initially decline and eventually grow towards the end of the period, net LNG imports mainly are assumed to balance U.S. natural gas supply and demand. This relatively stable level in net LNG imports will have minimal impact on FPL's projected natural gas supply and price to FPL's customers, as this represents only about a 1.23% to 1.50% of total U.S. supply over the 2011 through 2020 period.

Q.
Fuel

Please discuss in detail the Company's plans for the use of firm natural gas storage for the period 2011 through 2020.

A.
Bay Gas Storage

FPL is under contract for 2 Billion cubic feet (Bcf) of firm natural gas storage capacity in the Bay Gas storage facility located in Alabama. The Bay Gas storage facility is interconnected with the Florida Gas Transmission (FGT) pipeline.

FPL typically maintains nearly full natural gas inventory at the Bay Gas storage facility during normal operations from June through November. When severe weather is forecasted to impact the Gulf of Mexico, FPL will attempt to increase its inventory to full capacity (if not already full) prior to the severe weather event. Maintaining slightly less than full inventory at certain times allows FPL the flexibility to inject gas, if necessary, due to the unexpected loss of generation and/or lower than forecasted load resulting in a natural gas oversupply situation.

When severe weather is forecasted to impact Florida, FPL's target inventory will depend on the projected location and severity of weather. Generally, storage levels will be reduced prior to severe weather to allow injection due to a natural gas oversupply situation caused by loss of load after the severe weather.

During the winter months, December through March, FPL typically maintains lower levels of natural gas inventory as compared to peak months. Inventory levels can vary between a minimum of four to five days maximum withdrawal capability to a maximum of 100% of capacity, if necessary. The appropriate level is determined by the projected duration and severity of cold weather.

Future Natural Gas Storage

The Bay Gas storage contract terminates March 31, 2013. FPL has a one-time right to extend the agreement for a one year period by providing Bay Gas at least 12 months notice. Additionally, FPL continues to evaluate available storage opportunities to meet long-term operational needs.

Q.

Fuel

Please discuss the actions taken by the Company to promote competition within and among coal transportation modes.

A.

FPL is a co-owner of two coal-fired power plants, the St. Johns River Power Park (SJRPP) in Jacksonville, Florida, and Plant Scherer, which is located near Macon, Georgia. JEA, formerly known as the Jacksonville Electric Authority, is FPL's partner at SJRPP. Plant Scherer has six owners in addition to FPL.

One of the factors in the site selection process for SJRPP was the value of having alternative forms of coal transportation. FPL and JEA designed and equipped SJRPP to receive the annual coal supply by rail delivery, water delivery, or by a combination of rail and water.

Unit train rail service to SJRPP is provided by CSX Transportation. SJRPP currently owns approximately 365 railcars that can be utilized for hauling the coal. Vessels and ocean-going barges unload fuel at the St. Johns River Coal Terminal (SJRCT). A 3.5-mile conveyor system connects the deep water port to the plant site.

Plant Scherer receives coal only by rail via the Norfolk Southern Railroad (NS). FPL supported the conversion of Scherer from eastern to western coal in part because of transportation considerations. Many of the coal mines in Wyoming's Powder River Basin (PRB) are served by two railroads, the Union Pacific (UP) and the Burlington Northern Santa Fe (BNSF). As both the UP and BNSF can connect with NS for final delivery of PRB coal to the plant, a level of competition among the carriers is facilitated.

FPL currently owns 622 railcars which are assigned to the Scherer train pool that is utilized to transport PRB coal to the plant.

Q.
Fuel

Regarding coal transportation by rail, please discuss the expected industry trends and factors for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company. Also include a discussion of any expected changes to terminals and port facilities that could affect coal transportation for the Company.

A.
FPL does not anticipate being impacted to a significant extent by evolving rail industry trends and factors in the period 2011 through 2020.

The Plant Scherer co-owners, including FPL, will not be in the market for rail transportation services until very late in the period.

Although the St. Johns River Power Park (SJRPP) may be in the market for rail transportation services early in the period, the capability to receive water-borne coal via SJRCT (See Data Request No. 46) should tend to mitigate any rail developments of consequence.

The Staggers Act deregulated the railroad industry in 1980. In recent years, the Surface Transportation Board (STB) has had increased concern about rates imposed by the railroads, particularly on shippers without transportation alternatives, rail service, and industry oversight. Trade groups such as Consumers United for Rail Equity (CURE) and the National Industrial Transportation League (NIT) have aggressively advocated legislative reform. The ongoing debate with the American Association of Railroads (AAR) has put the industry in the political limelight where the outcome remains very much uncertain.

Emerging technology could alter the railroad operations environment and the underlying cost structure. The Plant Scherer Co-owners, including FPL, are currently planning to evaluate electronic brakes by placing a test train provided by the NS in service. If the Scherer test and other industry tests of electronic braking systems are successful, the Federal Rail Administration could mandate the technology and the retrofitting of existing railcar fleets.

The need to update the uniform rail cost system (URCS) utilized by the STB in rail rate cases is being discussed. The impact from a revision to the current, long-running, methodology might have on future rates is unknown.

Q.
Fuel

Regarding coal transportation by water, please discuss the expected industry trends and factors for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company. Also include a discussion of any expected changes to terminals and port facilities that could affect coal transportation for the Company.

A.
There are no water transportation implications for inland Plant Scherer. Recurring issues for St. John's River Power Park (SJRPP) include dredging and constraints imposed by the Jones Act. SJRPP is responsible for maintenance dredging at the berth. Dredging of the main channel is the responsibility of the U.S. Army Corps of Engineers (ACOE). Should proper funding not be available to the ACOE on a timely basis, when and if conditions warrant future dredging, vessel access to SJRCT could be constrained, thus impacting rates.

There are a limited number of Jones Act vessels and ocean-going barges. If demand for the shipment of domestic coal or petroleum coke between U.S. ports should exceed supply at any time between 2011 and 2020, alternative fuel supply chains would have to be considered and shipping costs could be impacted.

The increased globalization of the water-borne solid fuel trade driven by severe weather events like the historic Australian floods of 2010 and the rapidly expanding demand for coal in China & India could indicate that factors impacting vessel/ocean barge transportation to SJRPP might change more frequently and rapidly between 2011 and 2020. Existing agreements would mitigate the impact to contract purchases. Spot transactions would be immediately affected.

Q.
Fuel

Regarding planned changes and construction projects at coal generating units, please discuss the expected changes for coal handling, blending, unloading, and storage for the period 2011 through 2020.

A.
FPL does not expect any significant changes at SJRPP or Scherer in coal handling, blending, unloading or storage for the period 2011 through 2020.

Q.
Fuel

For the period 2011 through 2020, please discuss in detail the Company's plans for the storage and disposal of spent nuclear fuel. As part of this discussion, please include the Company's expectation regarding Yucca Mountain, dry cask storage, and litigation involving spent nuclear fuel, and the future of the Nuclear Waste Disposal Act.

A.
All FPL nuclear units have or are constructing dry cask storage facilities at their sites, which will allow for the safe, long-term on site storage of spent nuclear fuel (SNF) until a final repository is built.

On March 3, 2010, the U.S. Department of Energy filed a motion with the Nuclear Regulatory Commission to withdraw the license application for a high-level nuclear waste repository at Yucca Mountain with prejudice. In light of the decision not to proceed with the Yucca Mountain nuclear waste repository, the President directed the Secretary of Energy to establish a Blue Ribbon Commission on America's Nuclear Future to conduct a comprehensive review of policies for managing the back end of the nuclear fuel cycle and to provide recommendations for developing a safe, long-term solution to managing SNF and nuclear waste. DOE's withdrawal motion is being litigated before the NRC's Atomic Safety and Licensing Board and in the U.S. Court of Appeals for the D.C. Circuit. This development will delay the program for eventual final disposal of SNF from commercial nuclear power plants.

On March 31, 2009, NextEra Energy Inc. reached a settlement with the U.S. Government that reimbursed certain costs incurred by NextEra Energy Inc. for on-site storage of SNF due to DOE's failures to dispose of SNF. The settlement allowed FPL to recover past SNF management costs incurred up to December 31, 2007. The settlement also permits an annual filing to recover spent fuel storage costs incurred by FPL, payable by the Government on an annual basis.

Q.
Fuel

Regarding uranium production, please discuss the expected industry trends and factors for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company.

A.
See response to Data Request No. 39.

Q.
Fuel

Regarding the transportation of heavy fuel oil and distillate fuel oil, please discuss the expected industry trends and factors for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company.

A.

Heavy Fuel Oil

The general consensus is that 2011 will be another weak year on Panamax freight worldwide. This has been a predicted reality since mid-2008 with spot and time charter rates dropping 20% or more from the 2008 highs. One-year time charter rates for first class Panamax ships have gone from a $31,000 per day high in Spring 2007 to the current market of $27,000 per day. These rates are expected to drop further through the balance of 2011. Market recovery was predicted to occur in 2011 when many older ships will be phased out due to regulation 13G of Annex I of Marpol. The new build order book offsets the phase-out schedule to some extent, indicating a flat market in 2011 into 2012, but the new build order book is now expected to be less than predicted due to the economy and financial issues with both shipyards and ship owners. Below please find the expected escalation schedule for Panamax tankers:

Panamax 12-month time charter

2011: current $27,000 per day, expected to drop to $23,000 - $24,000 range per day
2012: $28,000
2013: $29,500
2014: $31,000
2015: $31,500
2016: $31,500
2017: $32,000
2018: $33,000
2019: $33,500
2020: $34,000

Historically, the U.S. flag ocean-going fuel oil barges which deliver the majority of Fuel Oil into the FPL system follow the same increases and decreases as Panamax charters. The rates listed above are for a time charter, not a spot move. As an example, in 2010, 150,000 barrels of ocean-going charter was going for $20,500 a day. In 2011, the same unit rate is $21,750.00 per day. FPL believes the same percentage increase will continue through 2020.

Distillate Fuel Oil

All of FPL's distillate deliveries into the power plants are truck deliveries. These deliveries are sporadic during the year, but freight rates on trucks do not change much. They usually follow the U.S. inflation rate. During the period from 2011 through 2020, FPL does not believe this will change.

Q.
Fuel

Please discuss the effect of changes in fossil fuel prices on the competitiveness of renewable technologies.

A.
Assuming all things remain constant, the cost competitiveness of renewable energy technologies is directly correlated to the costs of fossil fuels. As the costs of fossil fuels increase, the cost competitiveness of renewable energy technologies increases. The opposite is also true; as fossil fuel costs decrease, the competitiveness of renewable energy technologies decrease.

The degree to which the cost competitiveness of renewable energy technologies is affected by changes in fossil fuel cost for a specific utility will depend upon several factors including: the fuel mix of the utility, particularly the type of fossil fuel that is the marginal fuel(s) at the time the renewable energy technology is projected to operate; the magnitude of the changes in the marginal energy fuel costs; externalities affecting investment; and operation decisions driven by regulation or taxation (e.g., BACT technology requirements or "carbon taxes").

Q.

Fuel

Please discuss the effect of renewable resource development (for electric generation and non-generation technologies) on fossil fuel prices.

A.

Substantial investment in renewable energy is expected to continue during the next 10 years due to a combination of state and possibly federal renewable portfolio standards (RPS), policies aimed at reducing carbon emissions, and favorable tax treatment. Growth in renewable energy alone will limit consumption of fossil fuels in the power sector that would otherwise have been needed to meet demand. Reduction in demand for fossil fuels will, in turn, result in lower market-clearing prices for these fuels. However, the impact on different fuels may vary depending on the mix of policies used to encourage renewable energy supply and types of resources added.

For example, introduction of an environmental compliance cost for carbon dioxide (CO2) in addition to encouraging renewable development could increase the demand for natural gas and decrease the demand for coal and oil. This is because using natural gas to generate electricity generally results in lower CO2 emissions compared to using oil or coal for electricity generation. The resulting higher demand for natural gas could serve to increase natural gas prices while the resulting lower demand for oil and coal could serve to decrease prices for these fuels. In addition, the intermittent nature of some renewable energy may favor the addition of low fixed cost, fast-start fossil-fueled capacity (gas-fired combustion turbines) at the expense of higher fixed cost, less flexible capacity (coal-fired steam units). Development of renewable energy generation facilities may increase as coal and oil become less attractive economically and the alternative to oil and coal -- natural gas -- becomes more expensive.

Q.

Transmission

Please provide a list of all proposed transmission lines in the planning period that require certification under the Transmission Line Siting Act. Please also include those that have been approved, but are not yet in-service.

A.

Transmission Line	Line Length	Nominal Voltage	Date Need Approved	Date TLSA Certified	In-Service Date
	(Miles)	(kV)			
Manatee – Bobwhite	30	230		Nov 6 2008	Dec 2015
St Johns – Pringle	25	230		Apr 21, 2006	Dec 2016