Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
Staff				
1		Exhibit List	Comprehensive Exhibit List	
FLORIDA POWER & LIGHT (FPL)				
2	Rene Silva	RS-1	Summary of Benefits of Modernization of FPL's Port Everglades Plant (PEEC Project)	
3	John Gnecco	JCG-1	Typical 3x1 CC Unit Process Diagram	
4	John Gnecco	JCG-2	FPL Operational Combined Cycle Plants and FPL Combined Cycle Construction Projects in Progress	
5	John Gnecco	JCG-3	Aerial view of Existing Facility	
6	John Gnecco	JCG-4	PEEC Rendering	
7	John Gnecco	JCG-5	PEEC Vicinity Map	
8	John Gnecco	JCG-6	PEEC Power Block Arrangement	
9	John Gnecco	JCG-7	PEEC Operating Characteristics	
10	John Gnecco	JCG-8	PEEC Expected Construction Schedule	
11	John Gnecco	JCG-9	PEEC Construction Cost Components	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 1
PARTY Florida Public Service Commission Staff
DESCRIPTION Comprehensive Exhibit List
DATE 02/20/12

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
12	Rosemary Morley	RM-1	Florida Population	
13	Rosemary Morley	RM-2	Total Average Customers	
14	Rosemary Morley	RM-3	Summer Peak Weather Variables	
15	Rosemary Morley	RM-4	Weighted Real Per Capita Income	
16	Rosemary Morley	RM-5	Energy Efficiency Standards (MW)	
17	Rosemary Morley	RM-6	Real Price of Electricity (cents/kWh)	
18	Rosemary Morley	RM-7	Summer Peak Load (MW)	
19	Rosemary Morley	RM-8	Winter Peak Load (MW)	
20	Rosemary Morley	RM-9	Calendar Net Energy for Load (GWh)	
21	Heather Stubblefield	HCS-1	FPL's Fuel Price Forecast	
22	Kennard Kosky	KFK-1	Curriculum Vitae of Kennard F. Kosky	
23	Kennard Kosky	KFK-2	Sulfur Dioxide (SO2), nitrogen oxides (NOx), and Particulate Matter (PM) emissions (tons/year) – Existing and Port Everglades Next Generation Clean Energy Center (PEEC)	
24	Kennard Kosky	KFK-3	SO2, NOx and Particulate Matter emission rate (1b/MWh)- Existing and PEEC	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
25	Kennard Kosky	KFK-4	Carbon dioxide (CO2) emission rate (1b/MWh)- Existing and PEEC	
26	Kennard Kosky	KFK-5	Cumulative CO2 reductions in FPL's system with PEEC	
27	Pedro Modia	PM-1	Summary of Required Facilities for the Port Everglades Next Generation Clean Energy Center (PEEC)	
28	Juan Enjamio	JEE-1	Projection of FPL's Resource Needs through 2021	
29	Juan Enjamio	JEE-2	Resource Plans Utilized in the Analyses	
30	Juan Enjamio	JEE-3	Results of the Economic Analysis Relative to PEEC	
31	Juan Enjamio	JEE-4	Projection of Approximate Bill Impacts	
32	Juan Enjamio	JEE-5	Non-Economic Analysis Results: Emission Reductions Compared to PEEC Resource Plan	
33	Juan Enjamio	JEE-6	Non-Economic Analysis Results: Reduction in Fuel Use Compared to PEEC Resource Plan	
34	Juan Enjamio	JEE-7	Forecasted Cost of Air Emissions	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
STAFF				
35		Staff's Exhibit #35	FPL's Responses to Staff's First Set of Interrogatories (Nos. 1-61) (including the original and the corrected responses to Nos. 34 and 59) *[Bates Nos. 000001 – 000138]*	
36		Staff's Exhibit #36	FPL's Responses to Staff's Second Set of Interrogatories (Nos. 62-71) *[Bates Nos. 000139 – 000154]*	
37		Staff's Exhibit #37	FPL's Responses to Staff's Third Set of Interrogatories (Nos. 72-99) *[Bates Nos. 000155 – 000209]*	
38		Staff's Exhibit #38	FPL's Responses to Staff's First Request for Production of Documents (Nos. 1-6) *[Bates Nos. 000210 – 000220]*	
39		Staff's Exhibit #39	FPL's Responses to Staff's Second Request for Production of Documents (Nos. 7-10) *[Bates Nos. 000221 – 000231]*	
40		Staff's Exhibit #40	FPL's Responses to Staff's Request for PEEC Resource Plan *[Bates Nos. 000232 – 000239]*	
Exhibits 41-42 added				
41	Rene Silva		PPAs from Summer 2006 to Summer 2011	
42	Rene Silva		Transcript of NextEra Investors Call – November 4, 2011	

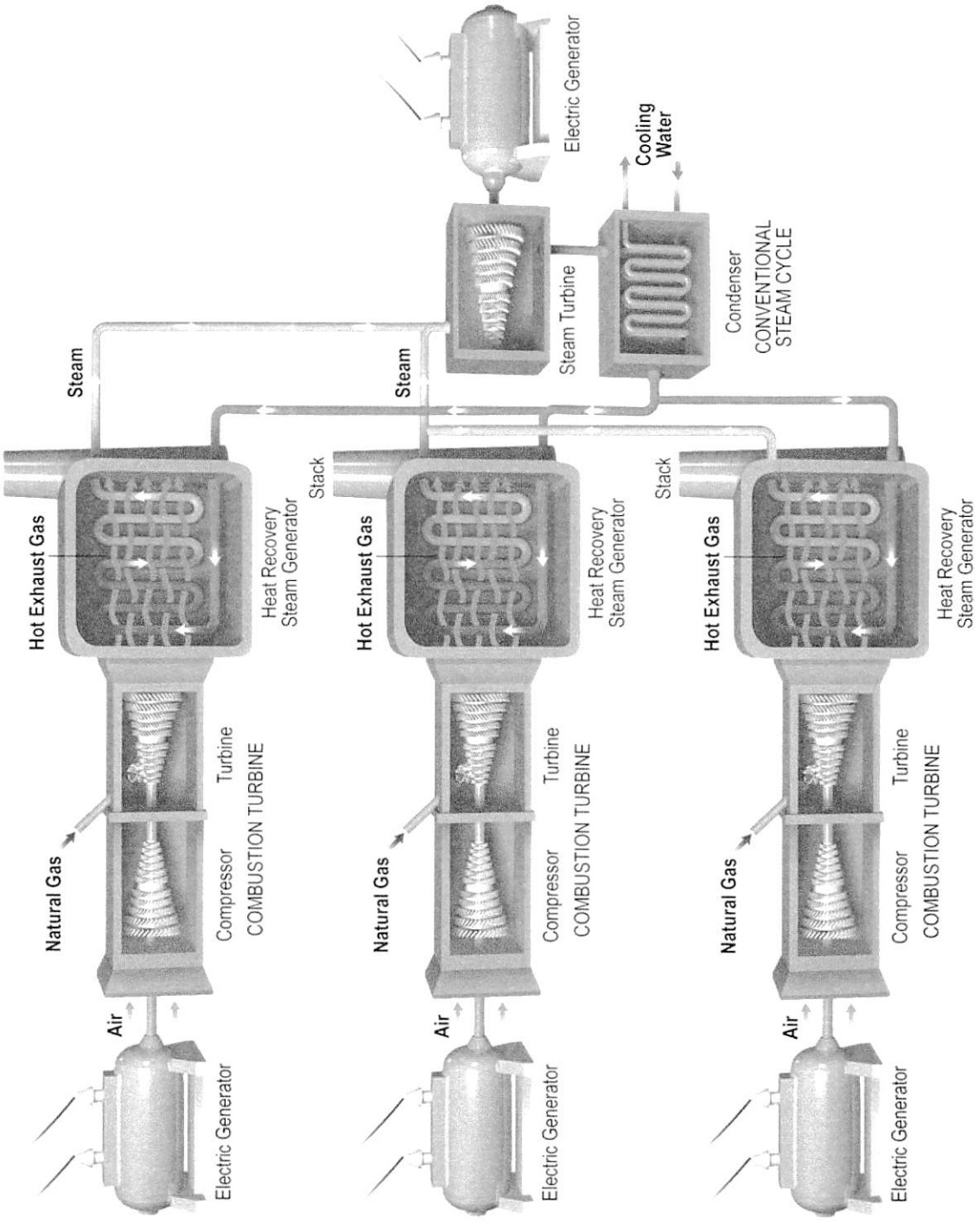
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 2
PARTY Florida Power & Light (FPL)
DESCRIPTION Rene Silva (RS-1)
DATE 02/20/12

Summary of Benefits of PEEC Project

- **Best, most cost-effective alternative to ensure system reliability**
- **Compared to returning to service old steam units from inactive reserve:**
  - **Customer savings of $469 Million (CPVRR);**
  - **Reduced air emissions through 2047: CO_2 by 22 million tons, SO_2 by 41 thousand tons, NOx by 33 thousand tons;**
  - **Improved FPL system average heat rate, the measure of fuel efficiency, by more than 1.3%; and**
  - **Reduced use of fuel oil by 5.3 million barrels and natural gas by 48 million MMBtu in 2017 through 2026 alone.**
- **Compared to a new CC unit at a greenfield site:**
  - **Customer savings of $838 million (CPVRR) vs. CC unit;**
  - **Avoids need for $638 million (2016 dollars) in transmission upgrades into the Miami-Dade and Broward County area by 2020;**
  - **Avoids the need for new land, new water resource allocation, and new rights-of-way for transmission and gas pipelines; and**
  - **Provides option to deliver backup fuel via waterborne transportation, thus enhancing system reliability.**
- **Compared to adding new CTs that defer PEEC to 2019:**
  - **Customer savings of $425 Million (CPVRR) vs. CT; and**
  - **Avoids likely increase in the cost of PEEC if deferred.**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 3
PARTY Florida Power & Light (FPL)
DESCRIPTION John Gnecco (JCG-1)
DATE 02/20/12

Docket No. 11 _____ -EI
Typical 3x1 CC Unit Process Diagram
Exhibit JCG-1, Page 1 of 1



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 4
PARTY Florida Power & Light (FPL)
DESCRIPTION John Gnecco (JCG-2)
DATE 02/20/12

FPL OPERATIONAL COMBINED CYCLE POWER PLANTS

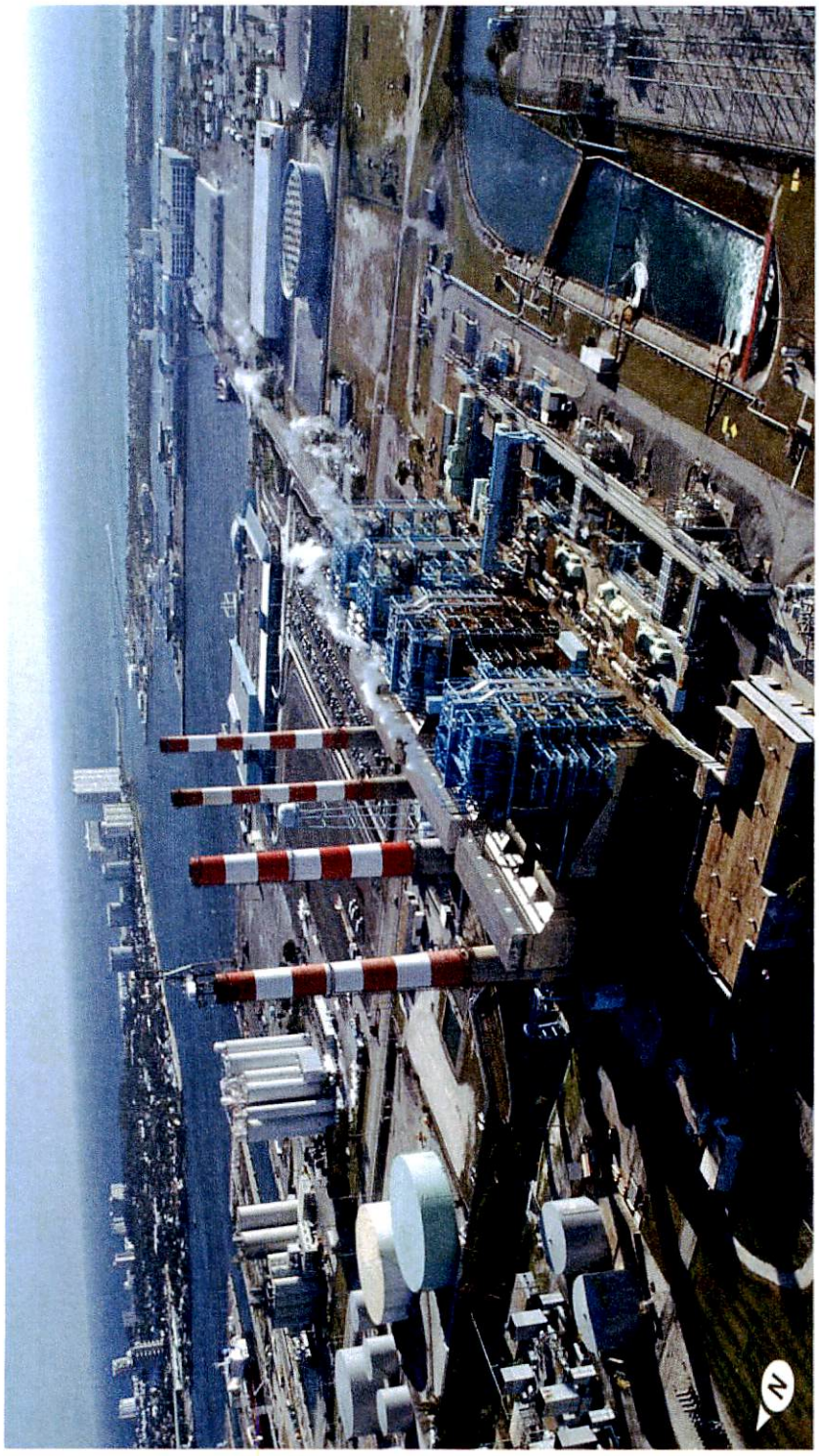
Facility	Location	In-Service Year	Technology	Summer Capacity (MW)	Primary Fuel
West County Unit 3	FL	2010	3x1 combined cycle	1,219	Natural gas
West County Unit 2	FL	2009	3 x 1 combined cycle	1,219	Natural gas
West County Unit 1	FL	2008	3 x 1 combined cycle	1,219	Natural gas
Turkey Point Unit 5	FL	2007	4 x 1 combined cycle	1,148	Natural gas
Martin Unit 8	FL	2005	4 x 1 combined cycle	1,105	Natural gas
Manatee Unit 3	FL	2005	4 x 1 combined cycle	1,111	Natural gas
Sanford Unit 4	FL	2003	4x1 combined cycle	958	Natural gas
Fort Myers Unit 2	FL	2002	6x2 combined cycle	1,432	Natural gas
Sanford Unit 5	FL	2002	4x1 combined cycle	954	Natural gas
Martin Unit 3	FL	1994	2x1 combined cycle	469	Natural gas
Martin Unit 4	FL	1994	2x1 combined cycle	469	Natural gas
Lauderdale Unit 4	FL	1993	2x1 combined cycle	442	Natural gas
Lauderdale Unit 5	FL	1993	2x1 combined cycle	442	Natural gas
Putnam Unit 1	FL	1976	2x1 combined cycle	249	Natural gas
Putnam Unit 2	FL	1976	2x1 combined cycle	249	Natural gas
Total Combined Cycle Capacity In Operation - Summer (net) →				12,685	

FPL COMBINED CYCLE CONSTRUCTION PROJECTS IN PROGRESS

Project	Technology	Summer Capacity (MW)	Primary Fuel
Cape Canaveral Energy Center	3x1 combined cycle	1,210	Natural gas
Riviera Beach Energy Center	3 x 1 combined cycle	1,212	Natural gas
Total Combined Cycle Capacity In Construction - Summer (net) →		2,422	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 5
PARTY Florida Power & Light (FPL)
DESCRIPTION John Gnecco (JCG-3)
DATE 02/20/12

Aerial View of Existing Facility

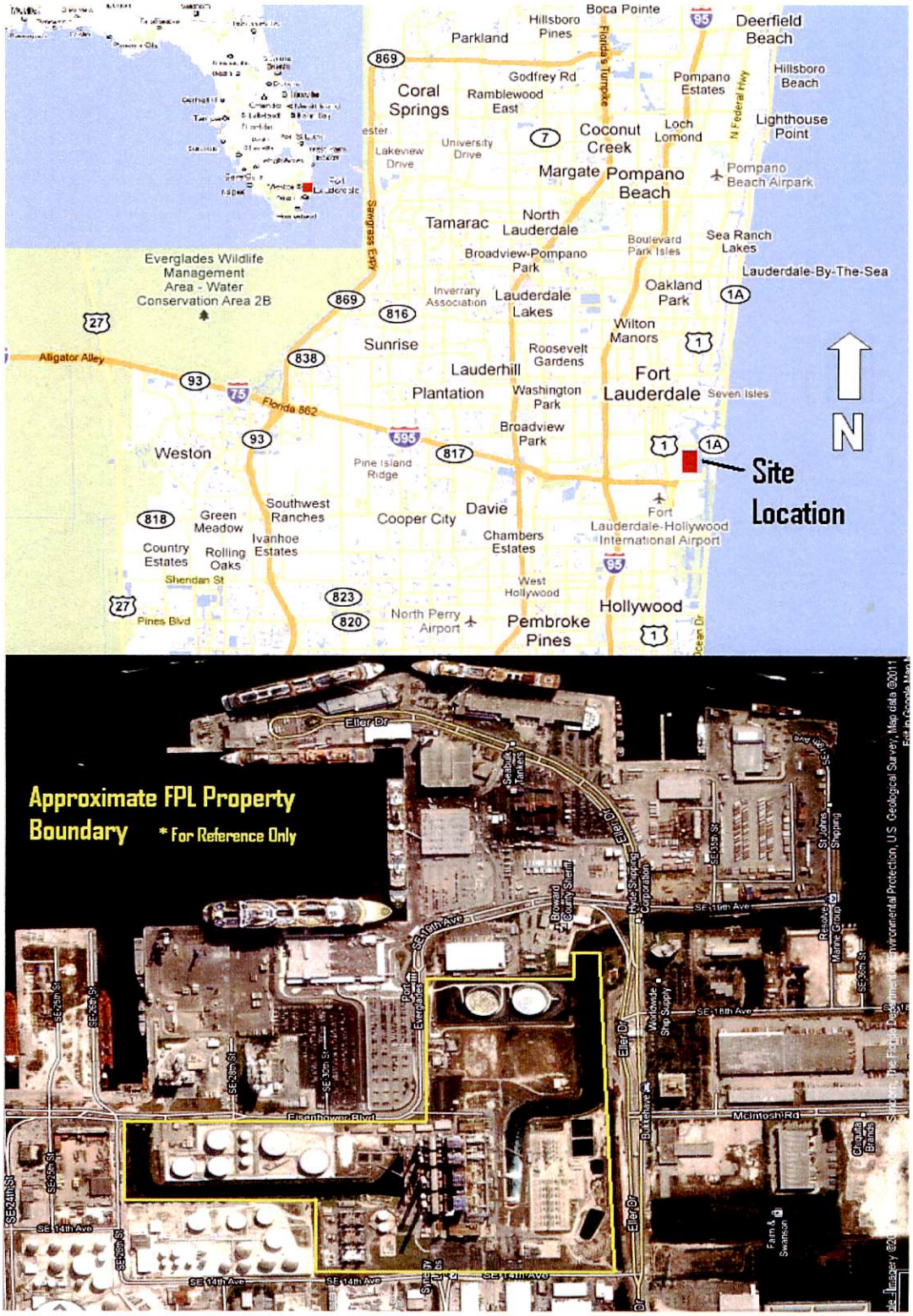


FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 6
PARTY Florida Power & Light (FPL)
DESCRIPTION John Gnecco (JCG-4)
DATE 02/20/12

PEEC Rendering

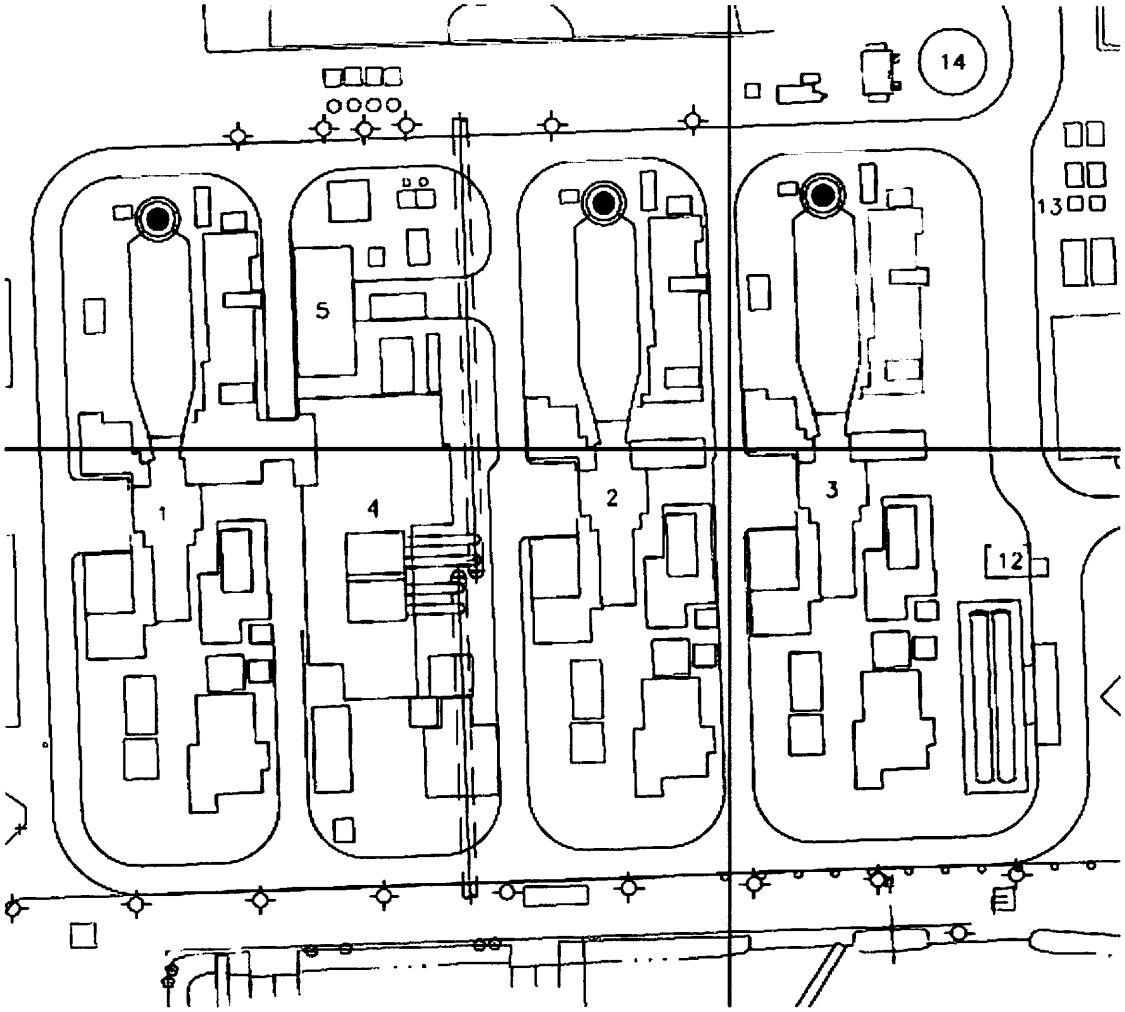
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 7
PARTY Florida Power & Light (FPL)
DESCRIPTION John Gnecco (JCG-5)
DATE 02/20/12

PEEC VICINITY MAP



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 8
PARTY Florida Power & Light (FPL)
DESCRIPTION John Gnecco (JCG-6)
DATE 02/20/12

PEEC PROPOSED POWER BLOCK AREA



Item No.	Description
1	Combustion Turbine
2	Combustion Turbine
3	Combustion Turbine
4	Steam Turbine
5	Control/Hurricane Shelter
12	Storage
13	Air Compressors and Receivers
14	Fire Water Storage Tank

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 9
PARTY Florida Power & Light (FPL)
DESCRIPTION John Gnecco (JCG-7)
DATE 02/20/12

PEEC FACT SHEET

Generation Technology - "Three on One" (3x1) Combined Cycle Configuration:

- Three (3) Advanced Combustion Turbines w/ Evaporative Coolers
- Three (3) Heat Recovery Steam Generators with Selective Catalytic Reduction System for NO_x Control
- One (1) Single-Reheat Steam Turbine

Expected Plant Peak Capacity:

Summer (95° F / 50% RH)	1,277 MW
Winter (35° F / 60% RH)	1,429 MW

Projected Unit Performance Data:

Average Forced Outage Rate (EFOR)	1.1%
Average Scheduled Maintenance Outages	18.3 days/yr (3.5% POF)
Average Equivalent Availability Factor (EAF)	95.4%
Base Average Net Operating Heat Rate @ 75° F / 60% RH	6,330 Btu/kWh (HHV)
Annual Fixed O&M – incremental (2016 dollars)	$6.33/kW-yr
Variable O&M – excluding fuel (2016 dollars)	$0.10/MWh

Fuel Type and Base Load Typical Usage @ 75° F:

Primary Fuel	Natural Gas
Natural Gas Consumption	8,171,048 scf/hr
Backup Fuel	Light Oil
Light Oil Consumption	51,873 gal/hr

Expected Base Load Air Emissions Per Train @ 75° F:	**Natural Gas**	**Light Oil**
NO_x (@ 15% O_2)	2 ppmvd	8 ppmvd
CO	9 ppmvd	35 ppmvd
PM_{10}	14.1 lb/hr	38.2 lb/hr
SO_2	16.8 lb/hr	3.6 lb/hr

Water Balance:

- Primary Water Source-Once through cooling
  - Utilizing existing FDEP permit to draw from Port Everglades surface water

Linear Facilities:

- One (1) gas compressor station and existing gas pipeline will serve the site
- Light oil delivered to site by truck and barging facilities

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 10
PARTY Florida Power & Light (FPL)
DESCRIPTION John Gnecco (JCG-8)
DATE 02/20/12

PEEC

EXPECTED CONSTRUCTION SCHEDULE

Milestone	Begin	End
Initiate sequence of HRSG orders (LNTP x 3)	Feb 13	Oct 13
Initiate sequence of CT orders (LNTP x 3)	Oct 12	Oct 14
Issue LNTP for steam turbine	Feb 13	Feb 15
Receive approvals necessary to begin construction	-	Mar 14
Site preparation & foundations	Jun 14	Feb 15
Balance of Plant	Jun 14	Dec 15
Erect HRSGs	Feb 14	May 16
Erect CTs	Dec 14	
Erect steam turbine	Feb 15	
Startup	Jan 16	
Commercial Operation	Jun 16	-

LNTP= Limited Notice to Proceed

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 11
PARTY Florida Power & Light (FPL)
DESCRIPTION John Gnecco (JCG-9)
DATE 02/20/12

PORT EVERGLADES ENERGY CENTER
PLANT CONSTRUCTION COST COMPONENTS

	Cost in millions (2016$)
Power Block	$1,041.1
Land	$0
Transmission Interconnect & Integration	$32.5
Third Party Gas Infrastructure	$0
AFUDC	$111.6
Total Plant Cost	$1,185.2*

Note:
*Does not include demolition of existing facility

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 12
PARTY Florida Power & Light (FPL)
DESCRIPTION Rosemary Morley (RM-1)
DATE 02/20/12

FLORIDA POPULATION

AVERAGE ANNUAL GROWTH

History (1980 to 2011)	296,118	2.2%
History (1990 to 2011)	285,169	1.8%
Based on 2011 TYSP (2011 to 2021)	271,107	1.3%
Based on Current Forecast (2011 to 2021)	242,656	1.2%

HISTORY

		Growth	
		Absolute	%
1980	9,746,961	368,682	3.9%
1981	10,110,616	363,655	3.7%
1982	10,403,778	293,162	2.9%
1983	10,678,494	274,716	2.6%
1984	10,965,170	286,676	2.7%
1985	11,272,327	307,157	2.8%
1986	11,587,219	314,892	2.8%
1987	11,916,377	329,158	2.8%
1988	12,231,270	314,893	2.6%
1989	12,547,730	316,460	2.6%
1990	12,938,071	390,341	3.1%
1991	13,258,732	320,661	2.5%
1992	13,497,541	238,809	1.8%
1993	13,730,115	232,574	1.7%
1994	14,043,757	313,642	2.3%
1995	14,335,992	292,235	2.1%
1996	14,623,421	287,429	2.0%
1997	14,938,314	314,893	2.2%
1998	15,230,421	292,107	2.0%
1999	15,580,244	349,823	2.3%
2000	15,982,824	402,580	2.6%
2001	16,305,100	322,276	2.0%
2002	16,634,256	329,156	2.0%
2003	16,979,706	345,450	2.1%
2004	17,374,824	395,118	2.3%
2005	17,778,156	403,332	2.3%
2006	18,154,475	376,319	2.1%
2007	18,446,768	292,293	1.6%
2008	18,613,905	167,137	0.9%
2009	18,687,425	73,520	0.4%
2010	18,801,310	113,885	0.6%
2011	18,926,629	125,319	0.7%

FORECAST

	Based on 2011 TYSP	Growth		Current	Growth		Delta	
	Forecast	Absolute	%	Forecast	Absolute	%	Absolute	%
2012	19,133,572	206,943	1.1%	19,043,964	117,335	0.6%	-89,609	-0.5%
2013	19,408,037	274,465	1.4%	19,214,917	170,953	0.9%	-193,121	-1.0%
2014	19,722,592	314,555	1.6%	19,449,098	234,182	1.2%	-273,493	-1.4%
2015	20,036,130	313,538	1.6%	19,727,742	278,643	1.4%	-308,388	-1.5%
2016	20,331,365	295,235	1.5%	20,019,815	292,074	1.5%	-311,550	-1.5%
2017	20,606,798	275,433	1.4%	20,295,648	275,833	1.4%	-311,150	-1.5%
2018	20,868,976	262,178	1.3%	20,560,959	265,311	1.3%	-308,017	-1.5%
2019	21,124,879	255,903	1.2%	20,826,655	265,696	1.3%	-298,224	-1.4%
2020	21,380,337	255,459	1.2%	21,091,643	264,988	1.3%	-288,695	-1.4%
2021	21,637,696	257,359	1.2%	21,353,188	261,546	1.2%	-284,508	-1.3%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 13
PARTY Florida Power & Light (FPL)
DESCRIPTION Rosemary Morley (RM-2)
DATE 02/20/12

TOTAL AVERAGE CUSTOMERS

AVERAGE ANNUAL GROWTH

History (1980 to 2011)	76,232	2.4%
History (1990 to 2011)	66,159	1.8%
Based on 2011 TYSP (2011 to 2021)	67,860	1.4%
Based on Current Forecast (2011 to 2021)	63,760	1.3%

HISTORY

		Growth	
		Absolute	%
1980	2,184,974	110,647	5.3%
1981	2,285,187	100,214	4.6%
1982	2,358,167	72,980	3.2%
1983	2,429,688	71,521	3.0%
1984	2,520,523	90,835	3.7%
1985	2,617,556	97,033	3.8%
1986	2,723,555	105,999	4.0%
1987	2,840,207	116,651	4.3%
1988	2,953,663	113,457	4.0%
1989	3,064,436	110,773	3.8%
1990	3,158,817	94,381	3.1%
1991	3,226,455	67,638	2.1%
1992	3,281,238	54,783	1.7%
1993	3,355,794	74,556	2.3%
1994	3,422,187	66,393	2.0%
1995	3,488,796	66,609	1.9%
1996	3,550,747	61,951	1.8%
1997	3,615,485	64,738	1.8%
1998	3,680,470	64,985	1.8%
1999	3,756,009	75,539	2.1%
2000	3,848,350	92,341	2.5%
2001	3,935,281	86,931	2.3%
2002	4,019,805	84,523	2.1%
2003	4,117,221	97,416	2.4%
2004	4,224,509	107,289	2.6%
2005	4,321,895	97,386	2.3%
2006	4,409,563	87,667	2.0%
2007	4,496,589	87,027	2.0%
2008	4,509,730	13,141	0.3%
2009	4,499,067	-10,663	-0.2%
2010	4,520,328	21,261	0.5%
2011*	4,548,154	27,826	0.6%

*2011 is an estimated actual

FORECAST

	Based on 2011 TYSP	Growth		Current	Growth		Delta	
	Forecast	Absolute	%	Forecast	Absolute	%	Absolute	%
2012	4,594,191	46,037	1.0%	4,579,174	31,021	0.7%	-15,017	-0.3%
2013	4,663,131	68,940	1.5%	4,625,149	45,975	1.0%	-37,982	-0.8%
2014	4,742,529	79,398	1.7%	4,687,365	62,216	1.3%	-55,164	-1.2%
2015	4,821,867	79,338	1.7%	4,760,867	73,501	1.6%	-61,000	-1.3%
2016	4,896,672	74,805	1.6%	4,837,621	76,754	1.6%	-59,051	-1.2%
2017	4,966,477	69,805	1.4%	4,909,988	72,367	1.5%	-56,490	-1.1%
2018	5,032,864	66,386	1.3%	4,979,439	69,452	1.4%	-53,424	-1.1%
2019	5,097,548	64,685	1.3%	5,048,794	69,355	1.4%	-48,754	-1.0%
2020	5,161,981	64,433	1.3%	5,117,793	68,999	1.4%	-44,188	-0.9%
2021	5,226,753	64,772	1.3%	5,185,756	67,963	1.3%	-40,997	-0.8%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 14
PARTY Florida Power & Light (FPL)
DESCRIPTION Rosemary Morley (RM-3)
DATE 02/20/12

SUMMER PEAK WEATHER VARIABLES

HISTORY

	Maximum Temp on Day of Summer Peak	Sum of Cooling Degree Hours During the Day Prior to Summer Peak
1989	95	309
1990	95	306
1991	92	286
1992	91	315
1993	91	341
1994	92	248
1995	93	269
1996	90	274
1997	92	288
1998	94	279
1999	91	320
2000	90	287
2001	91	280
2002	91	274
2003	90	291
2004	92	269
2005	94	335
2006	92	307
2007	92	315
2008	91	300
2009	95	330
2010	93	335
2011	93	316

FORECAST

	Maximum Temp on Day of Summer Peak	Sum of Cooling Degree Hours During the Day Prior to Summer Peak
2012	92	299
2013	92	299
2014	92	299
2015	92	299
2016	92	299
2017	92	299
2018	92	299
2019	92	299
2020	92	299
2021	92	299

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 15
PARTY Florida Power & Light (FPL)
DESCRIPTION Rosemary Morley (RM-4)
DATE 02/20/12

Real per Capita Income (Thousands 2005 $) Weighted by Percent of Population Employed

AVERAGE ANNUAL GROWTH

History (1982 to 2011)	0.2	1.9%
Based on Current Forecast (2011 to 2021)	0.4	2.6%

HISTORY

		Growth	
		Absolute	%
1982	7.8	-0.2	-2.4%
1983	8.2	0.4	4.9%
1984	9.0	0.8	9.6%
1985	9.5	0.5	5.5%
1986	9.9	0.4	4.1%
1987	10.3	0.4	4.2%
1988	10.7	0.5	4.5%
1989	11.3	0.5	4.9%
1990	11.1	-0.2	-1.4%
1991	10.5	-0.6	-5.6%
1992	10.5	0.0	-0.1%
1993	10.8	0.4	3.4%
1994	11.2	0.3	3.2%
1995	11.6	0.5	4.1%
1996	12.0	0.4	3.3%
1997	12.4	0.4	3.5%
1998	13.3	0.8	6.5%
1999	13.5	0.3	2.2%
2000	14.2	0.7	5.1%
2001	14.2	0.0	-0.2%
2002	14.0	-0.2	-1.1%
2003	14.0	-0.1	-0.6%
2004	14.7	0.8	5.5%
2005	15.4	0.7	4.9%
2006	16.2	0.8	4.9%
2007	16.1	-0.1	-0.7%
2008	15.2	-0.9	-5.8%
2009	13.7	-1.5	-9.7%
2010	13.4	-0.3	-2.0%
2011*	13.6	0.2	1.6%

*2011 is an estimated actual

FORECAST

	Current	Growth	
	Forecast	Absolute	%
2012	13.9	0.3	2.2%
2013	14.3	0.3	2.4%
2014	14.8	0.6	4.0%
2015	15.5	0.7	4.4%
2016	16.0	0.5	3.4%
2017	16.4	0.4	2.2%
2018	16.6	0.3	1.7%
2019	17.0	0.3	2.0%
2020	17.3	0.3	2.0%
2021	17.6	0.3	1.8%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 16
PARTY Florida Power & Light (FPL)
DESCRIPTION Rosemary Morley (RM-5)
DATE 02/20/12

ENERGY EFFICIENCY STANDARDS (MW)

HISTORY

	Energy Efficiency
2005	26
2006	185
2007	367
2008	766
2009	958
2010	1,153
2011	1,359

FORECAST

	Energy Efficiency
2012	1,569
2013	1,827
2014	2,089
2015	2,362
2016	2,633
2017	2,887
2018	3,107
2019	3,322
2020	3,393
2021	3,365

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 17
PARTY Florida Power & Light (FPL)
DESCRIPTION Rosemary Morley (RM-6)
DATE 02/20/12

REAL PRICE OF ELECTRICITY (CENTS/Kwh)- JULY OF EACH YEAR

AVERAGE ANNUAL GROWTH

History (1990 to 2011)	-0.06	-1.2%
Based on Current Forecast (2011 to 2021)	0.10	2.1%

HISTORY

		Growth	
		Absolute	%
1990	5.67	-0.01	-8.8%
1991	5.47	-0.20	-3.5%
1992	5.05	-0.42	-7.6%
1993	5.21	0.16	3.1%
1994	4.59	-0.62	-12.0%
1995	4.50	-0.09	-1.9%
1996	4.60	0.10	2.2%
1997	4.65	0.05	1.1%
1998	4.37	-0.29	-6.1%
1999	4.05	-0.32	-7.2%
2000	4.10	0.05	1.2%
2001	4.80	0.70	17.1%
2002	4.05	-0.75	-15.7%
2003	4.26	0.21	5.1%
2004	4.45	0.19	4.5%
2005	4.57	0.12	2.7%
2006	5.57	1.00	21.9%
2007	5.15	-0.41	-7.5%
2008	4.94	-0.21	-4.0%
2009	5.20	0.25	5.1%
2010	4.45	-0.74	-14.3%
2011	4.42	-0.04	-0.8%

FORECAST

	Current	Growth	
	Forecast	Absolute	%
2012	4.43	0.01	0.3%
2013	4.22	-0.21	-4.7%
2014	4.05	-0.17	-4.0%
2015	4.05	0.00	-0.1%
2016	4.02	-0.03	-0.7%
2017	4.46	0.44	10.8%
2018	4.99	0.54	12.0%
2019	5.12	0.13	2.6%
2020	5.23	0.11	2.2%
2021	5.42	0.19	3.6%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 18
PARTY Florida Power & Light (FPL)
DESCRIPTION Rosemary Morley (RM-7)
DATE 02/20/12

SUMMER PEAK LOAD (MW)

AVERAGE ANNUAL GROWTH

History (1980 to 2011)	387	2.6%
Based on 2011 TYSP (2011 to 2021)	521	2.2%
Based on Current Forecast (2011 to 2021)	434	1.8%

HISTORY

		Growth	
		Absolute	%
1980	9,623	973	11.2%
1981	9,738	115	1.2%
1982	9,862	124	1.3%
1983	10,676	814	8.3%
1984	10,270	-406	-3.8%
1985	10,654	384	3.7%
1986	11,022	368	3.5%
1987	12,394	1,372	12.4%
1988	12,382	-12	-0.1%
1989	13,425	1,043	8.4%
1990	13,754	329	2.5%
1991	14,123	369	2.7%
1992	14,661	538	3.8%
1993	15,266	605	4.1%
1994	15,179	-87	-0.6%
1995	15,813	634	4.2%
1996	16,064	251	1.6%
1997	16,613	549	3.4%
1998	17,897	1,284	7.7%
1999	17,615	-282	-1.6%
2000	17,808	193	1.1%
2001	18,754	946	5.3%
2002	19,219	465	2.5%
2003	19,668	449	2.3%
2004	20,545	877	4.5%
2005	22,361	1,816	8.8%
2006	21,819	-542	-2.4%
2007	21,962	143	0.7%
2008	21,060	-902	-4.1%
2009	22,351	1,291	6.1%
2010	22,256	-95	-0.4%
2011	21,619	-637	-2.9%

FORECAST

	Based on 2011 TYSP	Growth		Current	Growth		Delta	
	Forecast	Absolute	%	Forecast	Absolute	%	Absolute	%
2012	21,853	234	1.1%	21,623	4	0.0%	-230	-1.1%
2013	22,155	301	1.4%	21,931	308	1.4%	-224	-1.0%
2014	23,452	1,297	5.9%	23,243	1,312	6.0%	-208	-0.9%
2015	24,172	721	3.1%	23,786	543	2.3%	-386	-1.6%
2016	24,605	433	1.8%	24,315	528	2.2%	-291	-1.2%
2017	25,025	419	1.7%	24,529	214	0.9%	-496	-2.0%
2018	25,266	242	1.0%	24,674	145	0.6%	-592	-2.3%
2019	25,690	424	1.7%	25,041	367	1.5%	-649	-2.5%
2020	26,193	503	2.0%	25,499	458	1.8%	-694	-2.6%
2021	26,830	637	2.4%	25,960	460	1.8%	-871	-3.2%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 19
PARTY Florida Power & Light (FPL)
DESCRIPTION Rosemary Morley (RM-8)
DATE 02/20/12

WINTER PEAK LOAD (MW)

AVERAGE ANNUAL GROWTH

History (1980 to 2011)	368	2.5%
Based on 2011 TYSP (2011 to 2021)	347	1.5%
Based on Current Forecast (2011 to 2021)	283	1.3%

HISTORY

		Growth	
		Absolute	%
1980	9,732	941	10.7%
1981	11,360	1,628	16.7%
1982	11,345	-15	-0.1%
1983	9,280	-2,065	-18.2%
1984	11,050	1,770	19.1%
1985	12,533	1,483	13.4%
1986	12,139	-394	-3.1%
1987	10,779	-1,360	-11.2%
1988	12,372	1,593	14.8%
1989	12,876	504	4.1%
1990	16,046	3,170	24.6%
1991	11,868	-4,178	-26.0%
1992	13,319	1,451	12.2%
1993	12,932	-387	-2.9%
1994	12,594	-338	-2.6%
1995	16,563	3,969	31.5%
1996	18,252	1,689	10.2%
1997	17,298	-954	-5.2%
1998	13,060	-4,238	-24.5%
1999	16,802	3,742	28.7%
2000	17,057	255	1.5%
2001	18,199	1,142	6.7%
2002	17,597	-602	-3.3%
2003	20,190	2,593	14.7%
2004	14,752	-5,438	-26.9%
2005	18,108	3,356	22.7%
2006	19,683	1,575	8.7%
2007	16,815	-2,868	-14.6%
2008	18,055	1,240	7.4%
2009	20,081	2,026	11.2%
2010	24,346	4,265	21.2%
2011	21,126	-3,220	-13.2%

FORECAST

	Based on 2011 TYSP	Growth		Current	Growth		Delta	
	Forecast	Absolute	%	Forecast	Absolute	%	Absolute	%
2012	21,491	365	1.7%	20,889	-237	-1.1%	-602	-2.8%
2013	21,683	192	0.9%	21,101	212	1.0%	-582	-2.7%
2014	22,584	900	4.2%	21,959	858	4.1%	-624	-2.8%
2015	23,048	465	2.1%	22,412	453	2.1%	-636	-2.8%
2016	23,302	254	1.1%	22,675	263	1.2%	-627	-2.7%
2017	23,543	241	1.0%	22,902	227	1.0%	-641	-2.7%
2018	23,794	251	1.1%	23,151	249	1.1%	-643	-2.7%
2019	24,044	250	1.0%	23,403	252	1.1%	-641	-2.7%
2020	24,305	261	1.1%	23,667	264	1.1%	-638	-2.6%
2021	24,595	290	1.2%	23,952	285	1.2%	-643	-2.6%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 20
PARTY Florida Power & Light (FPL)
DESCRIPTION Rosemary Morley (RM-9)
DATE 02/20/12

CALENDAR NET ENERGY FOR LOAD (GWH)

AVERAGE ANNUAL GROWTH

History (1981 to 2011)	2,058	2.7%
Based on 2011 TYSP (2011 to 2021)	2,415	2.0%
Based on Current Forecast (2011 to 2021)	2,191	1.8%

HISTORY

		Growth	
		Absolute	%
1981	49,997	1,597	3.3%
1982	50,375	378	0.8%
1983	52,600	2,225	4.4%
1984	53,033	433	0.8%
1985	56,236	3,203	6.0%
1986	58,453	2,218	3.9%
1987	61,997	3,544	6.1%
1988	65,136	3,139	5.1%
1989	70,299	5,163	7.9%
1990	71,528	1,229	1.7%
1991	73,426	1,897	2.7%
1992	73,321	-105	-0.1%
1993	76,074	2,753	3.8%
1994	80,673	4,599	6.0%
1995	84,546	3,873	4.8%
1996	85,028	482	0.6%
1997	87,056	2,028	2.4%
1998	92,802	5,747	6.6%
1999	91,683	-1,119	-1.2%
2000	96,313	4,630	5.1%
2001	98,612	2,299	2.4%
2002	104,657	6,045	6.1%
2003	108,214	3,557	3.4%
2004	108,122	-93	-0.1%
2005	111,443	3,321	3.1%
2006	113,406	1,963	1.8%
2007	114,532	1,126	1.0%
2008	111,100	-3,432	-3.0%
2009	111,237	137	0.1%
2010	114,601	3,364	3.0%
2011*	111,735	-2,866	-2.5%

*2011 is an estimated actual

FORECAST

	Based on 2011 TYSP	Growth		Current	Growth		Delta	
	Forecast	Absolute	%	Forecast	Absolute	%	Absolute	%
2012	112,517	782	0.7%	111,156	-579	-0.5%	-1,360	-1.2%
2013	114,647	2,130	1.9%	112,487	1,331	1.2%	-2,160	-1.9%
2014	121,035	6,388	5.6%	117,982	5,495	4.9%	-3,052	-2.5%
2015	123,610	2,575	2.1%	121,407	3,425	2.9%	-2,203	-1.8%
2016	125,593	1,983	1.6%	123,310	1,903	1.6%	-2,283	-1.8%
2017	127,251	1,658	1.3%	124,806	1,496	1.2%	-2,445	-1.9%
2018	128,910	1,659	1.3%	126,270	1,464	1.2%	-2,640	-2.0%
2019	130,679	1,769	1.4%	127,918	1,648	1.3%	-2,761	-2.1%
2020	133,121	2,442	1.9%	130,631	2,713	2.1%	-2,490	-1.9%
2021	135,881	2,760	2.1%	133,646	3,015	2.3%	-2,235	-1.6%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 21
PARTY Florida Power & Light (FPL)
DESCRIPTION Heather Stubblefield (HCS-1)
DATE 02/20/12

	FPL'S NATURAL GAS PRICE FORECAST												
MONTH	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	ZONE 3 FGT FIRM $/MMBTU	ZONE 3 MOBILE BAY/DESTIN FGT FIRM $/MMBTU	PHASE VIII ZONE 3 MOBILE BAY/DESTIN FGT FIRM $/MMBTU	PHASE VIII TRANSCO 4A FGT FIRM $/MMBTU	FUTURE GAS PIPELINE $/MMBTU	FGT NON-FIRM $/MMBTU	GULFSTREAM FIRM SESH DISPATCH PRICE $/MMBTU	GULFSTREAM FIRM CONTRACTUAL DISPATCH PRICE $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	GULFSTREAM NON-FIRM BACKHAUL $/MMBTU	HENRY HUB $/MMBTU
2011	$4.36	$4.44	$4.53	$4.57	$4.63	$4.54		$4.93	$4.37	$4.50	$5.09	$5.48	$4.27
2012	$4.77	$4.85	$4.94	$4.98	$4.97	$4.88		$5.34	$4.79	$4.90	$5.49	$5.88	$4.66
2013	$5.23	$5.31	$5.39	$5.44	$5.43	$5.34		$5.80	$5.24	$5.35	$5.95	$6.33	$5.10
2014	$5.47	$5.55	$5.63	$5.67	$5.66	$5.58		$6.03	$5.47	$5.58	$6.18	$6.56	$5.32
2015	$5.89	$5.96	$6.05	$6.09	$6.08	$6.00		$6.45	$5.88	$6.00	$6.59	$6.98	$5.73
2016	$6.47	$6.55	$6.63	$6.67	$6.66	$6.71	$6.56	$7.03	$6.46	$6.57	$7.16	$7.55	$6.29
2017	$7.02	$7.10	$7.18	$7.22	$7.21		$7.11	$7.58	$7.00	$7.11	$7.71	$8.10	$6.82
2018	$7.58	$7.66	$7.74	$7.79	$7.78		$7.68	$8.15	$7.55	$7.67	$8.26	$8.65	$7.36
2019	$8.04	$8.12	$8.21	$8.25	$8.24		$8.14	$8.61	$8.01	$8.12	$8.72	$9.11	$7.81
2020	$8.52	$8.60	$8.68	$8.72	$8.71		$8.62	$9.08	$8.48	$8.59	$9.18	$9.58	$8.26
2021	$9.15	$9.23	$9.31	$9.36	$9.34		$9.25	$9.72	$9.10	$9.21	$9.81	$10.20	$8.87
2022	$9.82	$9.89	$9.98	$10.02	$10.01		$9.92	$10.38	$9.76	$9.87	$10.46	$10.86	$9.51
2023	$10.49	$10.57	$10.65	$10.69	$10.68		$10.60	$11.05	$10.42	$10.53	$11.12	$11.52	$10.16
2024	$11.44	$11.52	$11.60	$11.65	$11.63		$11.55	$12.01	$11.36	$11.47	$12.06	$12.46	$11.08
2025	$12.23	$12.31	$12.39	$12.43	$12.42		$12.34	$12.79	$12.13	$12.24	$12.84	$13.24	$11.84
2026	$12.50	$12.57	$12.66	$12.70	$12.69		$12.61	$13.06	$12.39	$12.51	$13.10	$13.51	$12.09
2027	$12.72	$12.80	$12.88	$12.92	$12.91		$12.83	$13.28	$12.62	$12.73	$13.32	$13.73	$12.31
2028	$12.95	$13.03	$13.11	$13.15	$13.14		$13.06	$13.51	$12.84	$12.95	$13.55	$13.95	$12.53
2029	$13.18	$13.26	$13.34	$13.39	$13.38		$13.30	$13.75	$13.07	$13.18	$13.78	$14.18	$12.75
2030	$13.42	$13.50	$13.58	$13.62	$13.61		$13.54	$13.98	$13.30	$13.42	$14.01	$14.42	$12.98
2031	$13.66	$13.74	$13.82	$13.87	$13.85		$13.78	$14.23	$13.54	$13.66	$14.25	$14.66	$13.22
2032	$13.91	$13.98	$14.07	$14.11	$14.10		$14.02	$14.47	$13.79	$13.90	$14.49	$14.90	$13.45
2033	$14.16	$14.23	$14.32	$14.36	$14.35		$14.28	$14.72	$14.03	$14.14	$14.74	$15.15	$13.69
2034	$14.41	$14.49	$14.57	$14.62	$14.61		$14.53	$14.98	$14.28	$14.40	$14.99	$15.40	$13.94
2035	$14.67	$14.75	$14.83	$14.88	$14.86		$14.79	$15.24	$14.54	$14.65	$15.25	$15.66	$14.19
2036	$14.94	$15.01	$15.10	$15.14	$15.13		$15.06	$15.50	$14.80	$14.91	$15.51	$15.92	$14.44
2037	$15.21	$15.28	$15.37	$15.41	$15.40		$15.33	$15.77	$15.06	$15.18	$15.77	$16.18	$14.70
2038	$15.48	$15.56	$15.64	$15.68	$15.67		$15.60	$16.04	$15.33	$15.45	$16.04	$16.45	$14.97
2039	$15.76	$15.83	$15.92	$15.96	$15.95		$15.88	$16.32	$15.61	$15.72	$16.31	$16.73	$15.23
2040	$16.04	$16.12	$16.20	$16.24	$16.23		$16.16	$16.60	$15.89	$16.00	$16.59	$17.01	$15.51
2041	$16.33	$16.41	$16.49	$16.53	$16.52		$16.45	$16.89	$16.17	$16.28	$16.88	$17.29	$15.78
2042	$16.62	$16.70	$16.78	$16.83	$16.82		$16.75	$17.19	$16.46	$16.57	$17.17	$17.58	$16.07
2043	$16.92	$17.00	$17.08	$17.13	$17.11		$17.05	$17.49	$16.76	$16.87	$17.46	$17.88	$16.36
2044	$17.23	$17.30	$17.39	$17.43	$17.42		$17.35	$17.79	$17.06	$17.17	$17.76	$18.18	$16.65
2045	$17.54	$17.61	$17.70	$17.74	$17.73		$17.66	$18.10	$17.36	$17.47	$18.07	$18.48	$16.95
2046	$17.85	$17.93	$18.01	$18.06	$18.04		$17.98	$18.42	$17.67	$17.78	$18.38	$18.80	$17.25
2047	$18.17	$18.25	$18.33	$18.38	$18.37		$18.30	$18.74	$17.99	$18.10	$18.69	$19.11	$17.56

Docket No. 11_____-EI
FPL's Fuel Price Forecast
Exhibit HCS-1, Page 1 of 4

	FPL'S SOLID FUEL PRICE FORECAST			
	PLANT SCHERER	ST. JOHNS RIVER POWER PARK	ICL	CEDAR BAY
	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx	DISPATCH PRICE WITHOUT SO2 & NOx
YEAR	$/MMBTU	$/MMBTU	$/MMBTU	$/MMBTU
2011	$2.32	$3.51	$4.11	$4.12
2012	$2.39	$3.51	$3.86	$4.07
2013	$2.45	$3.51	$3.86	$3.95
2014	$2.47	$3.52	$3.94	$3.53
2015	$2.50	$3.53	$4.01	$3.55
2016	$2.54	$3.56	$4.09	$3.61
2017	$2.58	$3.58	$4.18	$3.65
2018	$2.62	$3.61	$4.27	$3.70
2019	$3.34	$3.65	$4.37	$3.73
2020	$3.41	$3.73	$4.46	$3.77
2021	$3.47	$3.78	$4.54	$3.82
2022	$3.55	$3.86	$4.64	$3.89
2023	$3.61	$3.92	$4.73	$3.95
2024	$3.69	$4.00	$4.83	$4.02
2025	$3.76	$4.07	$4.92	$4.08
2026	$3.83	$4.12	$5.01	$4.13
2027	$3.91	$4.19	$5.12	$4.20
2028	$3.97	$4.25	$5.21	$4.25
2029	$4.06	$4.32	$5.33	$4.32
2030	$4.15	$4.41	$5.46	$4.41
2031	$4.23	$4.48	$5.58	$4.47
2032	$4.31	$4.54	$5.68	$4.53
2033	$4.40	$4.63	$5.80	$4.61
2034	$4.48	$4.69	$5.91	$4.67
2035	$4.57	$4.77	$6.03	$4.74
2036	$4.66	$4.85	$6.18	$4.82
2037	$4.75	$4.92	$6.29	$4.90
2038	$4.85	$5.00	$6.43	$4.97
2039	$4.94	$5.09	$6.56	$5.05
2040	$5.04	$5.17	$6.70	$5.12
2041	$5.14	$5.25	$6.85	$5.20
2042	$5.24	$5.34	$6.99	$5.28
2043	$5.35	$5.43	$7.14	$5.36
2044	$5.45	$5.52	$7.29	$5.45
2045	$5.56	$5.61	$7.45	$5.53
2046	$5.67	$5.70	$7.61	$5.61
2047	$5.78	$5.79	$7.77	$5.70

	FPL'S HEAVY OIL PRICE FORECAST								
YEAR	MARTIN 0.7% $/MMBTU	MARTIN 1% $/MMBTU	PORT EVERGLADES 1% $/MMBTU	MANATEE 1% $/MMBTU	TURKEY POINT 0.7% $/MMBTU	TURKEY POINT 1% $/MMBTU	CANAVERAL 1% $/MMBTU	SANFORD 1% $/MMBTU	RIVIERA 1% $/MMBTU
2011	$17.15	$16.28	$16.27	$16.27	$17.15	$16.22	$16.28	$16.28	$16.28
2012	$17.53	$16.63	$16.63	$16.63	$17.53	$16.57	$16.63	$16.63	$16.63
2013	$17.90	$16.50	$16.49	$16.49	$17.90	$16.44	$16.50	$16.50	$16.50
2014	$18.31	$16.88	$16.88	$16.88	$18.31	$16.82	$16.88	$16.88	$16.88
2015	$18.75	$17.29	$17.29	$17.29	$18.75	$17.23	$17.29	$17.29	$17.29
2016	$22.39	$21.99	$21.98	$21.98	$22.39	$21.93	$21.99	$21.99	$21.99
2017	$23.25	$22.80	$22.80	$22.80	$23.25	$22.74	$22.80	$22.80	$22.80
2018	$24.03	$23.56	$23.56	$23.56	$24.03	$23.50	$23.56	$23.56	$23.56
2019	$24.69	$24.21	$24.20	$24.20	$24.69	$24.14	$24.20	$24.20	$24.21
2020	$25.34	$24.67	$24.66	$24.66	$25.34	$24.61	$24.67	$24.67	$24.67
2021	$25.76	$25.03	$25.02	$25.02	$25.76	$24.97	$25.03	$25.03	$25.03
2022	$26.17	$25.42	$25.41	$25.41	$26.17	$25.36	$25.41	$25.41	$25.42
2023	$26.66	$25.88	$25.87	$25.87	$26.66	$25.82	$25.88	$25.88	$25.88
2024	$27.23	$26.44	$26.43	$26.43	$27.23	$26.37	$26.43	$26.43	$26.44
2025	$27.62	$26.82	$26.81	$26.81	$27.62	$26.75	$26.81	$26.81	$26.82
2026	$27.80	$26.99	$26.98	$26.98	$27.80	$26.93	$26.99	$26.99	$26.99
2027	$27.88	$27.06	$27.06	$27.06	$27.88	$27.00	$27.06	$27.06	$27.06
2028	$27.95	$27.14	$27.13	$27.13	$27.95	$27.08	$27.14	$27.14	$27.14
2029	$28.03	$27.21	$27.20	$27.20	$28.03	$27.15	$27.21	$27.21	$27.21
2030	$28.11	$27.29	$27.28	$27.28	$28.11	$27.23	$27.29	$27.29	$27.29
2031	$28.18	$27.36	$27.35	$27.35	$28.18	$27.30	$27.36	$27.36	$27.36
2032	$28.26	$27.44	$27.43	$27.43	$28.26	$27.38	$27.44	$27.44	$27.44
2033	$28.34	$27.51	$27.51	$27.51	$28.34	$27.45	$27.51	$27.51	$27.51
2034	$28.42	$27.59	$27.58	$27.58	$28.42	$27.53	$27.59	$27.59	$27.59
2035	$28.49	$27.67	$27.66	$27.66	$28.49	$27.60	$27.66	$27.66	$27.67
2036	$28.57	$27.74	$27.73	$27.73	$28.57	$27.68	$27.74	$27.74	$27.74
2037	$28.65	$27.82	$27.81	$27.81	$28.65	$27.76	$27.82	$27.82	$27.82
2038	$28.73	$27.89	$27.89	$27.89	$28.73	$27.83	$27.89	$27.89	$27.89
2039	$28.81	$27.97	$27.96	$27.96	$28.81	$27.91	$27.97	$27.97	$27.97
2040	$28.89	$28.05	$28.04	$28.04	$28.89	$27.99	$28.05	$28.05	$28.05
2041	$28.97	$28.13	$28.12	$28.12	$28.97	$28.07	$28.12	$28.12	$28.13
2042	$29.05	$28.20	$28.20	$28.20	$29.05	$28.14	$28.20	$28.20	$28.20
2043	$29.13	$28.28	$28.27	$28.27	$29.13	$28.22	$28.28	$28.28	$28.28
2044	$29.21	$28.36	$28.35	$28.35	$29.21	$28.30	$28.36	$28.36	$28.36
2045	$29.29	$28.44	$28.43	$28.43	$29.29	$28.38	$28.44	$28.44	$28.44
2046	$29.37	$28.52	$28.51	$28.51	$29.37	$28.46	$28.51	$28.51	$28.52
2047	$29.45	$28.59	$28.59	$28.59	$29.45	$28.53	$28.59	$28.59	$28.59

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FPL's Fuel Price Forecast
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	FPL'S LIGHT OIL PRICE FORECAST									
YEAR	TURKEY POINT $/MMBTU	WCEC $/MMBTU	OLEANDER $/MMBTU	PORT EVERGLADES $/MMBTU	LAUDERDALE $/MMBTU	FT MYERS $/MMBTU	PUTNAM $/MMBTU	MARTIN $/MMBTU	CANAVERAL $/MMBTU	RIVIERA $/MMBTU
2011	$23.33	$23.08	$23.07	$22.46	$22.46	$22.97	$23.17	$23.08	$23.17	$23.08
2012	$24.17	$23.92	$23.92	$23.31	$23.31	$23.81	$24.03	$23.92	$24.03	$23.92
2013	$24.40	$24.15		$23.54	$23.54	$24.04	$24.26	$24.14	$24.26	$24.15
2014	$25.17	$24.92		$24.30	$24.30	$24.81	$25.03	$24.91	$25.03	$24.92
2015	$25.76	$25.51		$24.89	$24.89	$25.40	$25.62	$25.50	$25.62	$25.51
2016	$30.22	$29.97		$29.35	$29.35	$29.86	$30.08	$29.96	$30.08	$29.97
2017	$31.23	$30.98		$30.36	$30.36	$30.87	$31.08	$30.97	$31.08	$30.98
2018	$32.20	$31.95		$31.34	$31.34	$31.84	$32.06	$31.95	$32.06	$31.95
2019	$33.12	$32.87		$32.26	$32.26	$32.76	$32.98	$32.87	$32.98	$32.87
2020	$34.04	$33.79		$33.17	$33.17	$33.68	$33.90	$33.78	$33.90	$33.79
2021	$35.24	$34.99		$34.37	$34.37	$34.88	$35.09	$34.98	$35.09	$34.99
2022	$36.29	$36.04		$35.43	$35.43	$35.93	$36.15	$36.04	$36.15	$36.04
2023	$37.35	$37.10		$36.48	$36.48	$36.99	$37.21	$37.09	$37.21	$37.10
2024	$38.45	$38.20		$37.59	$37.59	$38.09	$38.31	$38.20	$38.31	$38.20
2025	$39.48	$39.23		$38.61	$38.61	$39.12	$39.34	$39.22	$39.34	$39.23
2026	$39.90	$39.66		$39.04	$39.04	$39.54	$39.76	$39.65	$39.76	$39.66
2027	$40.20	$39.95		$39.33	$39.33	$39.84	$40.06	$39.94	$40.06	$39.95
2028	$40.49	$40.25		$39.63	$39.63	$40.13	$40.35	$40.24	$40.35	$40.25
2029	$40.79	$40.54		$39.93	$39.93	$40.43	$40.65	$40.54	$40.65	$40.54
2030	$41.09	$40.84		$40.23	$40.23	$40.73	$40.95	$40.84	$40.95	$40.84
2031	$41.40	$41.15		$40.53	$40.53	$41.04	$41.25	$41.14	$41.25	$41.15
2032	$41.70	$41.45		$40.84	$40.84	$41.34	$41.56	$41.45	$41.56	$41.45
2033	$42.01	$41.76		$41.14	$41.14	$41.65	$41.87	$41.75	$41.87	$41.76
2034	$42.32	$42.07		$41.46	$41.46	$41.96	$42.18	$42.06	$42.18	$42.07
2035	$42.63	$42.38		$41.77	$41.77	$42.27	$42.49	$42.38	$42.49	$42.38
2036	$42.95	$42.70		$42.08	$42.08	$42.59	$42.81	$42.69	$42.81	$42.70
2037	$43.26	$43.02		$42.40	$42.40	$42.90	$43.12	$43.01	$43.12	$43.02
2038	$43.58	$43.34		$42.72	$42.72	$43.22	$43.44	$43.33	$43.44	$43.34
2039	$43.91	$43.66		$43.04	$43.04	$43.55	$43.76	$43.65	$43.76	$43.66
2040	$44.23	$43.98		$43.37	$43.37	$43.87	$44.09	$43.98	$44.09	$43.98
2041	$44.56	$44.31		$43.69	$43.69	$44.20	$44.42	$44.30	$44.42	$44.31
2042	$44.89	$44.64		$44.02	$44.02	$44.53	$44.75	$44.63	$44.75	$44.64
2043	$45.22	$44.97		$44.36	$44.36	$44.86	$45.08	$44.97	$45.08	$44.97
2044	$45.56	$45.31		$44.69	$44.69	$45.19	$45.41	$45.30	$45.41	$45.31
2045	$45.89	$45.64		$45.03	$45.03	$45.53	$45.75	$45.64	$45.75	$45.64
2046	$46.23	$45.98		$45.37	$45.37	$45.87	$46.09	$45.98	$46.09	$45.98
2047	$46.58	$46.33		$45.71	$45.71	$46.21	$46.43	$46.32	$46.43	$46.33

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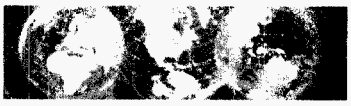
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 22
PARTY Florida Power & Light (FPL)
DESCRIPTION Kennard Kosky (KFK-1)
DATE 02/20/12



Resumé KENNARD F. KOSKY

Education

Completed coursework (1.5 years) for Ph.D. in Environmental Engineering. University of Florida. Gainesville, FL. 1982

M.S. Environmental Engineering. University of Central Florida. Orlando FL. 1976

B.S.E. Ocean Engineering. Florida Atlantic University. 1970

Languages

English – Fluent

Golder Associates Inc. – Gainesville

Employment History

Golder Associates – Gainesville, FL

Principal (1996 to Present)

Principal Engineer, Project Director, and Project Manager for Permitting and Environmental Impact Assessments. Specializes in power plants, industrial facilities, and agricultural activities involving air quality. Provides oversight on permitting and licensing activities including emissions estimates and impact analyses. Provides expert testimony on pollution control quality issues and noise for a variety of electrical power, industrial, and mining activities. Note: KBN merged with Golder Associates in 1996.

KBN Engineering and Applied Sciences (KBN) – Gainesville, FL

President and Principal Engineer (1985 to 1996)

Responsible for administration of a 100-person environmental consulting firm generating about $8 million per year in revenues. Principal Engineer, Project Director, and Project Manager for Permitting and Environmental Impact Assessments for electric power and industrial facilities. Provided expert testimony on pollution control and quality issues for a variety of industrial activities.

Environmental Science and Engineering, Inc. (ESE), Energy and Power Programs, Project Operations Department – Gainesville, FL

Vice President/Director (1980 to 1985)

Directed Power Programs group that included a wide diversity of services to the power industry. Project Manager of the $3 million Florida Acid Deposition Study. Project Director and Manager for a variety of permitting and licensing projects. Provided expert testimony on a variety of projects.

ESE – Gainesville, FL

Director, Air Science Division (1978 to 1980)

Responsible for all corporate air resource activities including stack testing, permitting dispersion modeling, ambient monitoring, noise monitoring, and industrial hygiene. Staff consisted of 25 professionals in three groups: Source Testing, Ambient Monitoring, and Permitting. Project Manager for multidisciplinary power projects.

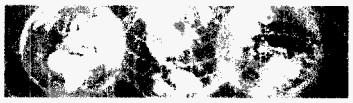
ESE – Gainesville, FL

Group Leader, Air Quality Management, Air Sciences Division (1974 to 1978)

Responsible for staff involved with ambient air monitoring, dispersion modeling, and air permitting. Project Manager for multidisciplinary power projects.

Florida Dept. of Pollution Control – Tallahassee/Orlando, FL

Air Pollutant Engineer (1970 to 1974)



Lead engineer in air operations involved in implementing State Implementation Plan (SIP) and air pollution regulations. Performed air permitting for over 200 facilities. Coauthor of the first Florida SIP including conducting emission inventory, ambient monitoring analysis, regulatory analysis, and regulation development.

Schlumberger Well Services – Morgan City, LA
Well Logging Engineer (1970 to 1970)

Performed geological logging of exploratory wells for oil and/or gas production in the Gulf of Mexico.

Resumé KENNARD F. KOSKY

PROJECT EXPERIENCE – ENVIRONMENTAL ENGINEERING

Environmental Engineering

Mr. Kosky has performed over 200 projects focusing on a variety of industrial activities. These projects have involved control technology evaluations, regulatory interpretation, monitoring, permitting, impact analyses, and expert testimony. The following overview and project descriptions are examples of Mr. Kosky's experience.

Major Project Experience
Multiple Sites

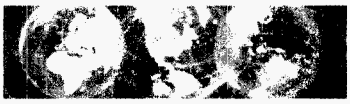
Type of Industrial Activities
Power Plants – 71
Landfills – 4
Chemical Plants – 7
Rubber Manufacturing – 2
Metal Coil Coating – 3
Mining – 4
Pulp & Paper – 7
Resource Recovery/Incinerator – 9
Steel Mills – 4
Printing/Coating – 4
Food/Agricultural Facilities – 15
Petroleum Exploration and Refining – 9
Aerospace – 2
Fiberglass Boat Manufacturing – 4
Superfund – 5

Type of Projects
Permitting and Licensing – 92
Air Pollution Emission Estimates – 67
Air Impact Analyses – 63
Air Pollution Control – 75
Policy and Regulations – 6
Air Monitoring – 26

Domestic Experience
Multiple Sites

Mr. Kosky has directed and performed projects related to his expertise in the following states:

Southeastern US: Florida, Georgia, South Carolina, North Carolina, Alabama, Mississippi, Tennessee, Kentucky, Louisiana, and Arkansas
Mid-Atlantic: Maryland, Virginia, West Virginia, District of Columbia, and New Jersey
Northeast: Connecticut and New York
Mid-West: Illinois, Indiana, Missouri, and Iowa
West: Texas, Nevada, California, Montana, Arizona, Alaska, and Hawaii.



Resumé KENNARD F. KOSKY

International Project Experience

Mr. Kosky has performed a wide variety of international projects—many associated with the Multi-Lateral (e.g., World Bank) and Bi-Lateral (e.g., USAID) organizations. Projects located in the following continents and countries:
Asia: China, Pakistan, India, Russia, Taiwan, Thailand, and Indonesia
Africa: Egypt and Mauritius
Latin America and Caribbean: Guatemala, Honduras, Jamaica, Dominican Republic, Mexico, and Panama
South America: Brazil and Argentina
Europe: Italy, Poland, Hungary and Bulgaria, and the Czech Republic
Middle East: Saudi Arabia.

Expert Testimony

Mr. Kosky has provided expert testimony in over 50 Cases. The following provides representative information of the type of proceedings and the nature of the expert/expert witness assistance. He has testified in the following types of proceedings:

- Hearing Officers and Administrative Law Judges (ALJs);
- Public Service Commissions;
- Circuit Court;
- Federal District Court;
- Governor of Florida;
- State and County Environmental Commissions;
- Environmental review Boards;
- County Commissions;
- Land Use Commissions; and
- EPA.

Mr. Kosky has been accepted as an expert in the following areas:

- Power Plant Siting and Licensing
- Air Quality Impact Analyses;
- Air Pollution Control Technology (Design and Engineering);
- Best Available Control Technology;
- Air Pollution Emission Estimates;
- Air Regulation and Compliance; and
- Noise Evaluation and Impact Analyses

Mr. Kosky has testified and been accepted as an expert in Florida, Maryland, Georgia, Louisiana, California and Hawaii.

REPRESENTATIVE PROJECT EXPERIENCE – DOMESTIC

Turkey Point Nuclear Units 6 & 7, FPL
Miami-Dade County, FL

Project Manager for the preparation of licensing documents for the two nominal 1,100-megawatt (MW) nuclear units and associated facilities located at the existing Turkey Point Plant site in Miami-Dade County, Florida. These units are being licensed under Florida's Power Plant Siting Act. Environmental documents prepared include the Site Certification Application (SCA), Federal Aviation Administration (FAA) obstruction to navigation application, U.S. Army Corps of Engineers (USACE) dredge and fill permit application, and air permit application [including prevention of significant deterioration (PSD) application]. The SCA was submitted in July 2009.

Martin Solar Energy Center, Florida Power & Light Company (FPL)
Martin County, FL

Project Manager for the preparation of the environmental licensing of a thermal solar facility located at the FPL Martin Plant. The project involves the installation of 180,000 mirror over 500 acres to generate steam that will be used in a combined cycle plant. The solar generation facility will generate 100,000 MW-hrs per year. The licensing was through Florida's Power Plant Site Certification process as a modification.

Applications for CPCN, Chalk Point, Dickerson, and Morgantown Generating Stations, Constellation Power Source Prince
Georges, Montgomery and Charles Counties , MD

Project Director of the preparation of the environmental analysis for the Certificate of Public Convenience and Necessity (CPCN) Application for the installation of flue gas desulfurization (FGD) systems on seven existing coal-fired units. The projects were designed to meet the requirements of Maryland's Healthy Air Act by reducing emissions of sulfur dioxide and mercury. Projects involved assessment of New Source Review (NSR) for each plant and an analysis of emissions from material handling. An evaluation of air quality impacts performed for new stacks at each plant site. Expert testimony provided before a Public Service Commission (PSC) Hearing Examiner at public hearings.

Applications for Certificate of Public Convenience and Necessity (CPCN), Gould Street and Riverside Generating Stations, Constellation Power Source
Baltimore, MD

Project Manager for the preparation of the CPCN Applications for the reactivation of the Gould Street Generating Station Unit 3 and Riverside Generating Station Unit 5. The Gould Street project involved the refurbishment of an existing 100 MW gas fired steam generating unit. The Riverside project involved the refurbishment of an existing 80 MW oil fired steam generating unit to gas firing. These units are licensed under Maryland's PSC. Environmental documents prepared include the CPCN and air permit application.

Site Certification Applications for St. Lucie and Turkey Point Nuclear Uprate Projects

Project Manager for the preparation of the Site Certification Applications (SCA) for two nuclear uprate projects. Projects involved increasing the nuclear generating capacity at Units 1 and 2 at the FPL St. Lucie Plant and Units 3 and 4 at the Turkey Point Plant. Each uprate project involved an increase of about 200 MW per plant. Applications included environmental evaluations of thermal discharges.

Resumé KENNARD F. KOSKY

FPL Glades Power Park
Palm Beach County, FL

Project Manager for the preparation of licensing documents for the two nominal 980-megawatt (MW) ultra supercritical pulverized coal fired units and associated facilities located on a 4,900 acre site in Glades County, Florida. These units are being licensed under Florida's Power Plant Siting Act. Environmental documents prepared include the Site Certification Application (SCA), Federal Aviation Administration (FAA) obstruction to navigation application, U.S. Army Corps of Engineers (USACE) dredge and fill permit application, and air permit application [including prevention of significant deterioration (PSD) application]. The SCA was submitted in December 2006.

Petroleum Coke Co-Firing St. Johns River Power Park
Jacksonville, FL

Project Manager and engineer-of-record for the FDEP authorization allowing up to 30 percent petroleum coke to be co-fired with coal. The authorization allowed co-firing with petroleum coke from 20 percent to 30 percent.

West County Energy Center Florida Power & Light Company (FPL)
Palm Beach County, FL

Project Manager for the preparation of licensing documents for the 2,450-megawatt (MW) West County Energy Center, Palm Beach County, Florida. This project involved the licensing of two 3-on-1 combined-cycle units using three MHI 501G 250-MW combustion turbines (CTs) with associated heat recovery steam generators (HRSGs), and a 440 MW steam turbine. These units are licensed under Florida's Power Plant Siting Act. Environmental documents prepared include the Site Certification Application (SCA), Federal Aviation Administration (FAA) obstruction to navigation application, U.S. Army Corps of Engineers (USACE) dredge and fill permit application, and air permit application [including prevention of significant deterioration (PSD) application]. Full Governor/Cabinet approval was obtained in December 2006.

Application for CPCN, Brandon Shores Units 4 and 5, Constellation Power Source
Ann Arundel County, MD

Project Manager for the preparation of the Certificate of Public Convenience and Necessity (CPCN) Application for installation of air pollution control systems and associated facilities on the two nominal 670 MW Brandon Shores Units 1 and 2. This project involves the installation of fuel gas desulfurization (FGD) systems, fabric filters, new dual flue stack, and material handling facilities for coal, limestone and FGD byproducts. These units are licensed under Maryland's Public Service Commission (PSC). Environmental documents prepared include the CPCN and air permit application (including PSD application).

Site Certification Application and Licensing For Seminole Generating Station Unit 3 Seminole Electric Cooperative
Putnam County, FL

Technical direction and review for the Site Certification Application and Air Construction/PSD Permit Application for SGS Unit 3, a nominal 750 MW (net) supercritical pulverized coal-fired unit. Provided expert testimony for the local land use hearing and prepared expert testimony for the Site Certification Hearing.

Kenai Blue Sky Coal Gasification Project, Environmental Permitting Feasibility Analysis for Coal-Gasification and Pulverized Coal-Fired Power Plant Agrium U.S., Inc.
Kenai, AK

Project Manager for the preparation of environmental permitting feasibility of coal-gasification and 400-200 MW pulverized coal fired power plant to be located at an existing ammonia/urea production facility. The project would involve the installation of coal gasification to product hydrogen and carbon dioxide as feedstock for the ammonia/urea production facilities. The coal-fired power plant would supply steam and energy for the gasification process and ammonia/urea production facilities, as well as supplying some power to the local grid. The coal gasification process and power plant would utilize Alaskan sub-bituminous coal.

Southwest St. Lucie Power Project Florida Power & Light Company (FPL)
St. Lucie County, FL

Project Manager for the preparation of licensing documents for the 1,700-megawatt (MW) Southwest St. Lucie Power Project to be located in St. Lucie County, Florida. The project involved two nominal 850 MW supercritical pulverized coal fired units and associated facilities. Portions of the SCA was completed but not submitted.

Application for Certificate of Public Convenience and Necessity, Crane Generating Station, Constellation Power Source
Baltimore County, MD

Project Manager for the preparation of the Certificate of Public Convenience and Necessity (CPCN) Application for installation of coal barge unloading facility for the Crane Generating Station. This project involved the refurbishment of an existing oil unloading dock and coal handling equipment. These units are licensed under Maryland's Public Service Commission (PSC). Environmental documents prepared include the CPCN and air permit application.

Site Certification Application and Licensing of the Turkey Point Expansion Project for Florida Power & Light Company (FPL)
Miami-Dade County, FL

Project Manager for the preparation of licensing documents for the 1,150-megawatt (MW) Turkey Point Expansion Project, Miami-Dade County, Florida. This project involved the licensing of 4-on-1 combined-cycle units using four GE Frame 7FA 170-MW combustion turbines (CTs) with associated heat recovery steam generators (HRSGs), and a 440 MW steam turbine. These units are licensed under Florida's Power Plant Siting Act. Environmental documents prepared include the Site Certification Application (SCA), Federal Aviation Administration (FAA) obstruction to navigation application, U.S. Army Corps of Engineers (USACE) dredge and fill permit application, and air permit application [including prevention of significant deterioration (PSD) application]. Full Governor/Cabinet approval was obtained in February 2005.

Burner Replacement for Gerdau-Ameristeel
Baldwin, FL

Obtained a non-PSD determination from the Florida Department of Environmental Protection (FDEP) for a burner replacement project associated with an electric arc furnace. Project involved site visit, technical support, and discussions with FDEP.

Petroleum Coke Co-Firing at the Cedar Bay Cogeneration Project
Jacksonville, FL

Project Manager and engineer-of-record for the FDEP authorization allowing up to 35 percent petroleum coke to be co-fired with coal. The Cedar Bay facility consists of three 75-MW circulating fluidized bed (CFB) boilers fired with coal and located in Jacksonville, Florida. The authorization allowed co-firing with petroleum coke.

Hines Energy Center Power Block 3 for Progress Energy (formerly Florida Power Corporation)
Polk County, FL

Project Manager and engineer-of-record for the air construction and PSD permit application for a 530-MW combined-cycle power project located in Polk County, Florida. Directed preparation of SCA sections related to air emission, best available control technology (BACT), air impacts, and noise impacts. Testified on all air quality and noise aspects at the SCA Hearing.

Air Construction Permits for Tropicana Products, Inc.
Bradenton, FL

Project Manager and engineer-of-record for various projects at Tropicana's Bradenton Citrus Processing Plant. The projects involved replacing the GE LM5000 aero-derivative gas turbine with the larger GE LM6000 turbine, like-kind replacement of the duct burner system on the cogeneration facility, and the installation of a stand-by boiler.

Air Construction Permit for Hydro Aluminum of North America
St. Augustine, FL

Project Manager for the preparation of two air construction permits for secondary aluminum foundry. Project involved physical changes to the melting furnace and increasing production limits. Project was able to net out of PSD review.

Site Certification Application and Licensing of Expansion Projects for Florida Power & Light Company
Martin and Manatee Counties, FL

Project Manager of the preparation of licensing documents for two 1,150-MW Expansion Projects. These projects involved the licensing of 4-on-1 combined-cycle units using four GE Frame 7FA 170-MW CTs with associated HRSGs, and a 440-MW steam turbine. These units were licensed under Florida's Power Plant Siting Act. Environmental documents prepared include the SCA, FAA obstruction to navigation application, and air permit application (including PSD application).

Application for Certificate of Public Convenience and Necessity, Dickerson Units 4 and 5, Mirant Corporation
Montgomery County, MD

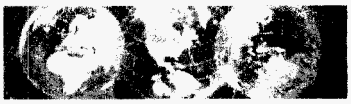
Project Manager for the preparation of the Certificate of Public Convenience and Necessity (CPCN) Application for the 1,100-MW Units 4 and 5 Project. This project involved the licensing of two 2-on-1 combined-cycle units using two existing GE Frame 7F 160-MW CTs and adding two GE Frame 7FA 170 MW CTs, four associated HRSGs, and two 220-MW steam turbines. These units are licensed under Maryland's Public Service Commission (PSC). Environmental documents prepared include the CPCN, FAA obstruction to navigation application, USACE dredge and fill permit application, and air permit application (including PSD application).

Application for Certificate of Public Convenience and Necessity, Chalk Point Units CT7 through CT10, Mirant Corporation
Charles County, MD

Project Manager of the preparation of the CPCN Application for the 320-MW CT Project. This project involved the licensing of four GE Frame 7EA 80-MW simple-cycle units. These units are licensed under Maryland's PSC. Environmental documents prepared include the CPCN, FAA obstruction to navigation application, and air permit application (including PSD application).

Greenhouse Gas Life-Cycle Analysis for Bitor America Corporation
Boca Raton, FL

Project Manager for the preparation of a life-cycle analysis of greenhouse gas (GHG) emissions from various fossil fuels and technologies. The life-cycle analysis compared GHG emissions from the use of coal, natural gas, LNG, oil, and Orimulsion. The technologies evaluated included conventional steam generation, Integrated Gasification Combined-Cycle (IGCC), and combined-cycle.



Odor Evaluations for Sea Ray Boats, Inc.
Palm Coast, FL

Project Manager for the evaluation of odor impacts from styrene emissions associated with an existing fiberglass boat manufacturing facility in Flagler County, Florida. Project involved meteorological monitoring, styrene monitoring using SUMA canisters, air dispersion modeling and conceptual design of exhaust stack. Involved in negotiations with regulatory agency on consent order requirements and made public presentations to citizens group.

Odor Evaluations for Sea Ray Boats, Inc.
Merritt Island, FL

Project Manager for the evaluation of odor impacts from styrene emissions associated with three co-located fiberglass boat manufacturing plants located in Brevard County, Florida. Project involved air dispersion modeling and conceptual design of exhaust stacks for two facilities. Involved in negotiations with regulatory agency and made public presentations to citizens group.

Lone Oak Energy Center for Calpine Eastern Corporation
Lowndes County, MS

Project engineer for the air construction and PSD permit application for an 800-MW combined-cycle power project.

Calhoun County Peaker Project for FPL Energy
Calhoun County, AL

Project Manager for the air construction and PSD permit applications and environmental permits for a 680-MW simple-cycle power project.

Hillabee Energy Center for Calpine Eastern Corporation
Tallapoosa County, AL

Project engineer for the air construction and PSD permit applications for a 700-MW combined-cycle power project.

Auburndale Peaker Project for Calpine Eastern Corporation
Polk County, FL

Project Manager and engineer-of-record for the air construction and PSD permit applications for a 130-MW simple-cycle power project.

Hines Energy Center Power Block 2 for Florida Power Corporation
Polk County, FL

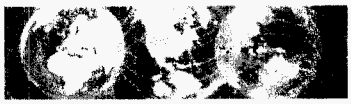
Project Manager and engineer-of-record for the air construction and PSD permit applications for a 530-MW combined-cycle power project.

Osprey Energy Center for Calpine Eastern Corporation
Polk County, FL

Project Manager and engineer-of-record for the air construction and PSD permit applications for a 530-MW combined-cycle power project. Provided technical oversight for the preparation of the SCA.

Simple-Cycle Power Projects for Florida Power & Light Company
Martin and Ft. Myers, FL

Project Manager and engineer-of-record for the air construction and PSD permit applications for two 170-MW simple-cycle units located at the existing FPL Martin and Ft. Myers Power Plant sites. Each project also required an evaluation of the noise impacts. The project at the Martin Plant required a modification of the SCA.



Shady Hills Generating Station for IPS Avon Park Corporation and El Paso Energy Hardee County, FL	Project Manager and engineer-of-record for the air construction and PSD permit applications for a 510-MW simple-cycle power project.
Odor and Air Quality Consulting for the Viera Company Brevard County, FL	Lead technical consultant in providing oversight on the air permitting of a waste scrap shredder. Project involved specifying procedures and reviewing results of source tests and impact analyses.
Installation of Citrus Fruit Extractors for Tropicana Products, Inc. Ft. Pierce, FL	Project manager and engineer-of-record for the air construction and PSD permit applications for the addition of fruit extractors at the Tropicana Plant. Detailed air dispersion modeling was required.
DeSoto Power Project for IPS Avon Park Corporation and Entergy Power Group DeSoto County, FL	Project Manager and engineer-of-record for the air construction and PSD permit applications for a 680-MW simple-cycle power project.
Air Construction Permit Preparation and Review for Solutia, Inc. Pensacola, FL	Preparation of air construction permits for various process additions to the Solutia nylon production plant. This included new adipic acid production intermediates. Assisted Solutia in the review and comments to FDEP on the Title V permit application. Prepared an air permit application for an inlet fogging system for Solutia's cogeneration facility.
Sea Ray Boats, Inc., Cape Canaveral Plant Brevard County, FL	Project Manager for a BACT evaluation and air modeling impact analysis for a new fiberglass boat manufacturing facility. Project involved negotiations with regulatory agency on permit conditions.
Heard County Power Project for Dynergy, Inc. Hardee County, FL	Project engineer for the air construction and PSD permit applications for a 510-MW simple-cycle power project.
Fogger Installation at Combustion Turbine Sites Jacksonville, FL	Project Manager for the preparation of air permit applications for the installation of inlet cooling "foggers" on simple-cycle CTs at Jacksonville Electric Authority's (JEA) Northside and Kennedy Plant sites. Project involved developing strategy for "netting out" of PSD.
Palmetto Power Project for Dynegy, Inc. Hardee County, FL	Project Director and engineer-of-record for the air construction and PSD permit applications for a 510-MW simple-cycle power project.
Vandolah Power Project for IPS Avon Park Corporation and El Paso Energy Hardee County, FL	Project Manager and engineer-of-record for the air construction and PSD permit applications for a 680-MW simple-cycle power project.

Resumé — KENNARD F. KOSKY

Fogger Installation at Combustion Turbine Sites for Florida Power & Light Company
Multiple Sites, FL

Project Manager for the preparation of air permit applications for the installation of inlet cooling "foggers" at the Ft. Myers, Putnam, and Martin Plant sites. Project involved developing strategy for "netting out" of PSD.

Independent Power Projects for Tenaska, Inc.
Multiple Sites

Project Director and engineer-of-record for the preparation of PSD and air permit applications the following projects: Heard County, Georgia – 850-MW simple-cycle; Autauga County, Alabama, Two Projects – an 800-MW combined-cycle and an 8870-MW combined-cycle project located on adjacent sites; Lakefield, Minnesota – 480-MW simple-cycle (BACT); Coosa County, Alabama Project – 540-MW simple-cycle project.

Oleander Power Project for Constellation Energy
Brevard County, FL

Project Manager for the preparation of PSD and Air Permit Applications for the Oleander Power Project. Project consisted of 5 General Electric Frame 7FA simple-cycle CTs (nominal 850 MW). Project involved providing expert testimony.

Repowering Project for Florida Power & Light Company
Sanford, FL

Project Manager for the preparation of air permit applications for conversion of two existing steam electric units (Units 4 and 5) at the FPL Sanford Plant to combined cycle using 8 General Electric Frame 7FA CTs. The repowering would produce a nominal 2,200 MW of gas-fired combined-cycle generation. The project involved the preparation of the PSD and Air Permit Applications, noise evaluation, and FAA Notifications.

Generation Project for Thermal EcoTek, Corporation
Lake Worth, FL

Project Manager for the preparation of the PSD and Air Permit Applications for the Lake Worth Generation Project. Project consisted of the repowering of 2 existing steam units with a nominal capacity of 74 MW using a General Electric Frame 7FA CT (170 MW).

Repowering Project Licensing for Florida Power & Light Company
Ft. Myers, FL

Project Manager for environmental licensing documents for the conversion of the existing steam electric units (Units 1 and 2) at the FPL Ft. Myers Plant to combined cycle using 6 General Electric Frame 7FA CTs. The repowering would produce a nominal 1,500 MW of gas-fired combined-cycle generation. The project involved the preparation of the PSD and Air Permit Applications, Environmental Resource Permit (ERP) Application, Wastewater Discharge Permit Application (i.e., the SPDES), FAA Notifications, and county applications.

Lakeland Electric (City of Lakeland) McIntosh Unit 5
Lakeland, FL

Project Manager for the preparation of the PSD and air permit applications for the McIntosh Unit 5 simple-cycle project. Included preparation of the Modification Request to Site Certification for McIntosh Unit 3. Project consisted of the first Westinghouse 501G CT with a nominal capacity of 250 MW.

Title V Permit Applications for Eagle-Picher Corporation
Multiple Sites

Project Director for the preparation of Title V Permit applications or Federally Enforceable Synthetic Minor Operating Permit applications for 9 facilities in 6 states. The facilities include activities associated with metal coil coating, rubber part manufacturing, and printing. The states where the facilities are located include Connecticut, Florida, Michigan, New Jersey, Pennsylvania, and New York.

Odor and Noise Monitoring for North and South Broward Resource Recovery Facilities
Broward County, FL

Project director for noise and odor studies at two large municipal waste combustors. The studies were based on ASTM methods to demonstrate conformance with requirements of regulatory approvals.

Destin Dome Natural Gas Development Project for Chevron U.S.A. Production Company
Pensacola, FL

Project Manager for the OCS air permit application submitted to the U.S. Environmental Protection Agency (EPA) to develop the natural gas reserves in a 33-square-mile area offshore of Pensacola. The projects involved preparation of permit applications including emission estimates of well drilling and production facilities. Air emission sources included two drilling rigs, one central production facility, and 16 satellite production facilities. The project included PSD evaluations to determine BACT and air impact analysis using the OCD air dispersion model.

Title V Permit Applications for Potomac Electric Power Company
Multiple Sites

Project Manager for the preparation of Title V Permit applications or Federally Enforceable Synthetic Minor Operating (FESOP) Permit applications for 7 facilities in 2 states and 1 jurisdiction. The Title V facilities consist of 6 power plants with coal and oil fossil fuel-fired steam generating units, CTs, and diesel units. The FESOP is for a service facility. The facilities are located in Maryland (3 plants and the service facility), Virginia (1 plant) and the District of Columbia (2 plants).

Air Permitting for Destin Dome Blocks 57 and 96, Chevron U.S.A. Production Company Outer Continental Shelf
Pensacola, FL

Project Manager for the Outer Continental Shelf (OCS) air permits issued by the EPA to conduct well drilling within the U.S. boundary, offshore of Florida. The projects involved preparation of permit applications including emission estimates of well drilling activities. The applications were the first in the Eastern U.S. under 40 Code of Federal Regulation (CFR), Part 55. These regulations were promulgated as a result of the 1990 Amendments of the Clean Air Act (CAA) Amendments. Presented information on the emissions and impacts of the activity at an EPA sponsored public hearing.

Kaiser Aluminum-Gramercy and Baton Rouge Cogeneration Plants
Baton Rouge, LA

Project Manager for obtaining air permits on two cogeneration facilities. The facilities were required to obtain PSD approval and meet NSPS requirements.

PSD Approval for Cogeneration Facility at Borden Chemical
Baton Rouge, LA

Project Director for an 80-MW cogeneration facility constructed for Borden Chemical. The project involved obtaining PSD approval from the state agency.

Site Certification Application for Orimulsion Conversion
Manatee County, FL

Project Director for the licensing of Orimulsion firing at FPL's Manatee Power Plant. The plant consists of two nominal 800-MW units. Technical activities focused on the preparation of BACT evaluation and air pollution control aspects of the project.

Resumé — KENNARD F. KOSKY

Petroleum Coke and Title V Application for City of Lakeland Department of Electric and Water Utilities
Lakeland, FL

Project Manager and engineer-of-record for providing technical assistance to obtain approval for co-firing petroleum coke (20 percent) and coal (80 percent) at McIntosh Power Plant, Unit 3. McIntosh Unit 3 is a 364-MW coal-fired facility. Project Manager and engineer-of-record for preparation of Title V applications.

Coal and Petroleum Coke Co-firing Permit for St. Johns River Power Plant
St. Johns County, FL

Project Manager and engineer-of-record for obtaining approval from the regulatory agencies to co-fire up to 20 percent of petroleum coke by weight with coal in two nominal 700-MW units. Permit application and supporting material prepared. Performed emissions estimates and impact analyses of potentially toxic air emissions (metals). Provided support and presentations to local chapter of Sierra Club who intervened in the permit proceeding. Performed post-test analyses to demonstrate compliance with settlement agreement.

Title V Economic Evaluation for Florida Electric Power Coordinating Group
Tampa, FL

Performed an economic evaluation for Florida Electric Power Coordinating Group (FCG) on the cost to prepare Title V permits as initially proposed by FDEP and presented the results of the evaluation at the FDEP Title V Workshop. The presentation assisted in modifying the FDEP requirements to more closely follow EPA requirements.

Electric Utility Regulatory Requirements for Florida Electric Power Coordinating Group
Tampa, FL

Lead the effort to prepare a comprehensive list of regulatory requirements specific for the electric utility industry. The list, which includes all applicable and non-applicable requirements, forms the basis for compliance statements required of the responsible official.

Title V Permit Recommendations for Florida Electric Power Coordinating Group
Tampa, FL

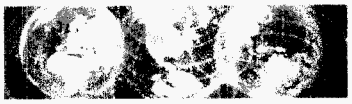
Providing recommendations for preparation of Title V permits for the FCG. This includes interfacing with FDEP and providing comments on insignificant activities and application form submittal. Also provided FDEP comments on data input requirements and suggestions that will make the application form easier to develop.

Florida Power Corporation Title V Applications
Multiple Sites

Project Director and engineer-of-record for Title V applications for 11 facilities. The facilities include coal-, oil-, and gas-fired fossil fuel steam generator units, simple-cycle CT units, combined-cycle unit, and diesel generators. Project involved regulatory requirements, emissions inventories, trivial activity lists and application preparation.

Title V Permits for Florida Power & Light Company Facilities
Multiple Sites

Assisting FPL in the preparation of Title V permit applications for all facilities. This includes 11 power plants and several minor facilities. Engineer-of-record for the applications, and responsible for overseeing the applications' preparation. Also providing input on regulatory requirements and emissions. Currently, one permit application has been completed in draft form.



Title V Permit Implementation Plan for Tennessee Valley Authority
Multiple Sites

Assisted Tennessee Valley Authority (TVA) in developing a comprehensive list of applicable requirements in three states (Tennessee, Kentucky, and Alabama) for 10 facilities. Also performed site visits for four major plants (7,550 MW coal-fired with CTs) to develop a list of major sources and insignificant activities. The result was a comprehensive Title V plan, which is currently being implemented by TVA. Performed reviews of Title V applications for three power facilities.

Gulf Power Company Title V Applications
Multiple Sites

Project Manager and engineer-of-record for Title V applications for three coal-fired facilities. Performed site visits for each facility and developed listing of regulatory requirements.

Title V Database for Various Clients
Multiple Sites

Developed a Title V database built around the FDEP Title V permit application form. The database is designed to manage the data and print out a form identical to the FDEP form. The database will provide a format suitable for electronic submittal to FDEP.

Emissions Inventory and Title V Applications for Potomac Electric Power Company (PEPCO)
Multiple Sites in Maryland

Project Manager for the development of a comprehensive emissions inventory and preparation of Title V applications for all of PEPCO facilities. This includes 6 power plants (4 coal-fired plants, 1 oil/gas plant, and 1 CT plant) located in three regulatory jurisdictions. The inventory will involve the development of an emission inventory management system that will manage the data.

Site Certification Application at Hardee Power Station, Seminole Electric Cooperative Incorporated
Hardee County, FL

Project Director for SCA and environmental assessment (EA) for a 660-MW combined-cycle electric-generating plant. Responsible for the technical, budgetary, and scheduling aspects of the project. The permitting documents prepared were designed to fulfill requirements of the PSC and the U.S. Department of Agriculture (USDA) Rural Electrification Administration (REA). Provided expert testimony for the project.

Transmission Line Corridor Siting at Hardee Power Station for Seminole Electric Cooperative Incorporated
Hardee County, FL

Project Director for siting and licensing of three 230-kilovolt (kV) transmission lines (total of 78 miles) to connect the Hardee Power Station to the Florida transmission grid. Siting of the transmission line corridors was accomplished using the PC ARC/INFO® geographic information system (GIS). Developed all required information and impact analyses for the Florida SCA to be presented to the Florida Department of Environmental Regulation (FDER) and PSC.

Site Certification Application and Licensing of the Lauderdale Repowering Project for Florida Power & Light Company
Ft. Lauderdale, FL

Project Manager for the preparation of licensing documents for the Lauderdale Repowering Project, Broward County, Florida. This project involved replacing two existing steam generators with advanced CTs and HRSGs. The repowered units were designed to have a capacity of approximately 960 MW, approximately 640 MW resulting from the addition of the advanced CTs. Environmental documents prepared include the SCA, National Pollutant *Discharge* Elimination System (NPDES) application, FAA obstruction to navigation application, USACE dredge and fill permit application, and air permit application (including PSD application).

Resumé — KENNARD F. KOSKY

Test Burn of Orimulsion Fuel for Florida Power & Light Company
Sanford, FL

Project Manager for a test burn to discover if Orimulsion fuel had the potential to displace No. 6 fuel oil in steam electric power plants at Sanford Unit 4. Project provided the opportunity to evaluate the technical and operational features associated with burning Orimulsion fuel under utility operating conditions.

Air Construction Permit Application for TransPac, Inc.
Santa Rosa County, FL

Project Manager for project requiring permit to construct an air pollutant source. Developed report supplementing the application to construct a minor-source waste storage and treatment facility. The objective of this report was to evaluate the impact of the facility based on a comparison of the proposed facility's impacts to the FDER's proposed toxic air pollutant guidelines.

Air Quality Impacts of Siting 1,050-MW CTs for Florida Power Corporation
Multiple Sites

Project Manager of air quality impact analyses performed to evaluate locating CTs at six potential sites in Florida: Intercession City, DeBary, Avon Park, Turner, Bartow, and Anclote. The analyses were undertaken to determine compliance with ambient air quality standards (AAQS) and PSD increments for the maximum proposed plant size (i.e., 1,050 MW).

Particulate Matter Air Quality Assessment of Helper Cooling Towers for Florida Power Corporation
Citrus, FL

Project Manager of project to determine the impacts of the proposed cooling towers on ambient particulate matter (PM) levels, considering all PM emissions associated with the CT units, cooling towers, helper cooling towers, and coal- and ash-handlers already existing onsite. Impacts were addressed in regard to allowable PSD increments for PM [as total suspended PM, i.e., PM(TSP)] and AAQS for PM [as particulate with an aerodynamic diameter less than 10 micrometers (μm), i.e., PM10].

Site Evaluation of 1,000-MW CT Project for Florida Power Corporation
Multiple Sites in FL

Project Manager responsible for evaluating the availability of water-supply sources, raw water treatment requirements, and wastewater disposal options at six facilities for the 1,000-MW CT siting project. Water supply sources were evaluated to determine their feasibility for use and included existing permitted groundwater and surface water withdrawals, new groundwater sources, new surface water withdrawals, and secondary effluent from nearby municipal wastewater treatment facilities.

CT Site Evaluation and Chalk Point Environmental Assessment for Potomac Electric Power Company
Chalk Point, MD

Project Manager of project to provide alternative site and environmental information required under the Maryland PSC rules for receiving a CPCN for a new generation facility. The two primary objectives of the report were to identify and evaluate suitable sites for accommodating approximately four CTs and to evaluate the environmental baseline information and potential impacts of locating the CTs at the preferred site.

Gator Power Cogeneration Facility PSD Review for Florida Power Corporation
Gainesville, FL

Project Manager for PSD review for a cogeneration facility consisting of a CT and HRSG. The report addressed the new source review (NSR) requirements contained in air quality regulations on both the state and federal levels.

Fog Visibility Study for Parsons, Brinkerhoff, Quade, and Douglas, Inc.
Charleston, SC

Project Manager responsible for study designed to obtain meteorological and fog/visibility data on the I-526 Cooper River Crossing in North Charleston. Objectives of the program were to document the frequency and duration of fog and the meteorological conditions during which it occurs; to identify and differentiate the fog plume created by the cooling towers from that of other sources; and to correlate the data collected with data observed at the National Weather Service (NWS) station in Charleston.

Site-Specific Environmental Evaluation for Potomac Electric Power Company
Multiple Sites in Maryland

Project Manager responsible for presenting the methodology and results of a site-specific environmental evaluation. The objective of the site environmental evaluation was to determine the environmental suitability of CT units with projected early 1990s in-service dates. The candidate site environmental evaluation consisted of analyzing candidate sites based on six environmental factors.

PSD Permit Application for Environmental Incineration Systems, Inc.
Duval County, FL

Project Manager of permitting activities for proposed municipal solid waste recycling/volume reduction facility. The facility was designed to reduce the amount of solid waste input to landfills in Duval County by up to 175,200 tons per year (TPY). The proposed facility was classified as a "major" source under federal and state air pollution control regulations and was subject to the PSD provisions of the regulations.

PSD Permit Application for Cogeneration Project for Tropicana Products, Inc.
Bradenton, FL

Project Manager responsible for permitting a cogeneration facility consisting of a CT, a HRSG, and an associated auxiliary steam generator. The report addressed the NSR requirements contained in the state and federal regulations.

Crystal River PSD Analysis for Florida Power Corporation
Crystal River, FL

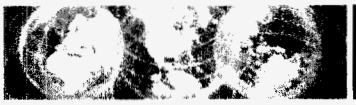
Project Manager of air dispersion modeling analyses performed to determine the TSP impacts of PM emissions from the cooling towers at FPC's Crystal River facility. A modeling protocol was prepared by KBN and reviewed and commented upon by the EPA.

EMSoft II®, Permit Manager for Manatee County Public Health Unit
Manatee County, FL

Designed and developed the EMSoft II®, a software package for micro-computers designed to assist end users in managing environmental permits and requirements through a relational database capable of generating a series of specific reports.

Agrico Chemical Company Mine
Hillsborough County, FL

Project Manager for the EA for a phosphate mine located in eastern Hillsborough County, Florida. The project involved the development of baseline conditions including monitoring of air, water, and ecological conditions. Impact analyses involving various environmental disciplines were conducted using approved regulatory techniques.



REPRESENTATIVE PROJECT EXPERIENCE – INTERNATIONAL

Best Available Control Technology Assessment and Toxic Air Emission Evaluation for Coleson Cove Refurbishment Project, New Brunswick Power Corporation
New Brunswick, Canada

Senior consulting engineer for developing a best available control technology (BACT) assessment and toxic air emission inventory for the conversion of the 1,050-MW Coleson Cove plant from residual oil to Orimulsion. Project involved a detailed assessment of control equipment for sulfur dioxide (SO2), PM, nitrogen oxides (NOx) and sulfuric acid mist (SAM). Develop a toxic air emissions inventory. Provided presentations at multi l agency meetings and public hearings.

Combined-Cycle Projects for Southern Energy, Inc.
Multiple Sites in Italy

Provided technical review and assistance for two 370-MW combined-cycle projects to be located in east central Italy. Reviewed the designs and impact methodologies to provide senior oversight of projects.

Environmental Due Diligence
Campeche, Mexico

Project Director for the environmental due diligence for the Cantarell Nitrogen Project located near Campeche, Mexico. Project is the largest nitrogen plant in the world with an associated 400-MW power complex to provide power for the nitrogen plant. Review licensing reports and documents for conformance with Mexican regulations and "world norms". Review being conducted for international financial institutions.

Environmental Benchmarking of Power Facilities, Worldwide, Confidential Client
Multiple Sites

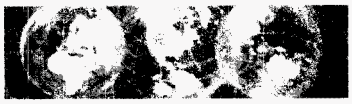
Project Manager assisting an international energy company in the evaluation of their environmental conformance with international accepted norms of all of their facilities worldwide. This involved evaluating over 10,000 MWs at approximately 12 different power facilities including hydro. These plants were located in Asia, South America, North America, and Europe. Evaluation was to assist with the development of an environmental management system for all of the company's facilities.

Shanghai Municipal Electric Power Company Waigaoqiao Environmental Assessment
Shanghai, China

Project Manager for World Bank EA of the addition of two 1,000-MW coal-fired super-critical units to the Waigaoqiao Power Plant site. This was referred to as Phase II, while Phase I, the existing plant, consists of four 300-MW units. The EA also considered the addition of a Phase III which would be identical to Phase II (i.e., another two 1,000-MW units). The EA was prepared to meet World Bank guidelines and involved developing information and performing analyses for Phases I, II, and III.

Baley Gold Mine Project
Western Russia

Task Manager for the environmental assessments relating to the potential air and noise impacts from a gold mine project located in Eastern Russia. The task involved developing emissions and impact estimates for mining 25 million tonnes of material from an open pit mine. Impacts were determined using EPA dispersion models. Noise impacts from mine activities were determined using the NOISECALC model.



Nickel and Cobalt Mine Project
Cupey, Cuba

Working through Golder's Mississauga Office provided air impact analyses for a nickel and cobalt mine located in Cupey, Cuba. The major emissions from the project were from the ore processing, which contained PM and SO2. The EPA dispersion model ISC3ST was used to estimate impacts using a 1-year meteorological data base. Impacts were compared to the World Bank ambient guidelines.

Ambient Air Monitoring Laboratories and Training Program for the Electricity Generating Authority of Thailand
Bangkok, Thailand

Project Director responsible for designing and constructing two mobile laboratories as well as providing air quality and meteorological equipment. Equipment will be installed in specialty l designed cubicles, and mounted on a Nino truck chassis. The intensive training program will consist of 2 months training in the United States for three EGAT engineers.

Air Resources Studies, Mae Moh Power Plant and Lignite Mine for the Electric Generating Authority of Thailand
Mae Moh Valley, Thailand

General Consultant for Air Quality/Project Manager managing activities within an environmental program for proposed plant and mine development in Mae Moh Valley, Northern Thailand.

Environmental Licensing Studies for the Electricity Generating Authority of Thailand
Bangkok, Thailand

Air Resources, Subproject Manager, responsible for studies of coal-fired power plant. Managed air resources investigations as part of overall environmental studies of proposed coal-fired power plant to be located on the Gulf of Thailand, 70 kilometers (km) southeast of Bangkok.

Ambient Monitoring Network for the Electricity Generating Authority of Thailand
Gulf of Thailand

Project Director/Air Resources, Subproject Manager, performing environmental licensing studies for a 2400-MW, coal-fired plant.

Environmental Assessment of Gas Turbine Electrical Generating Facility, World Bank
Hunts Bay, Jamaica

Air Engineer responsible for developing mitigation and monitoring measures based on the results of air modeling to reduce the impacts from SO2 and NOx in the Hunts Bay area.

Development of Air Quality Standards for the Government of Mauritius for the World Bank
Mauritius

Project Manager tasked with assisting the government of Mauritius in developing air quality standards and designing appropriate monitoring programs required for regulatory enforcement.

Environmental Assessment for 60-MW Diesel-Powered Facility
Rockfort, Jamaica

Air Engineer responsible for developing mitigation and monitoring measures based on the results of air modeling to reduce the impacts from sulfur dioxide and nitrogen oxides in the Rockfort project area.

Environmental Assessment of the Gas/Coal Electrical Generating Facility in Mauritius for the World Bank
St. Aubin, Mauritius

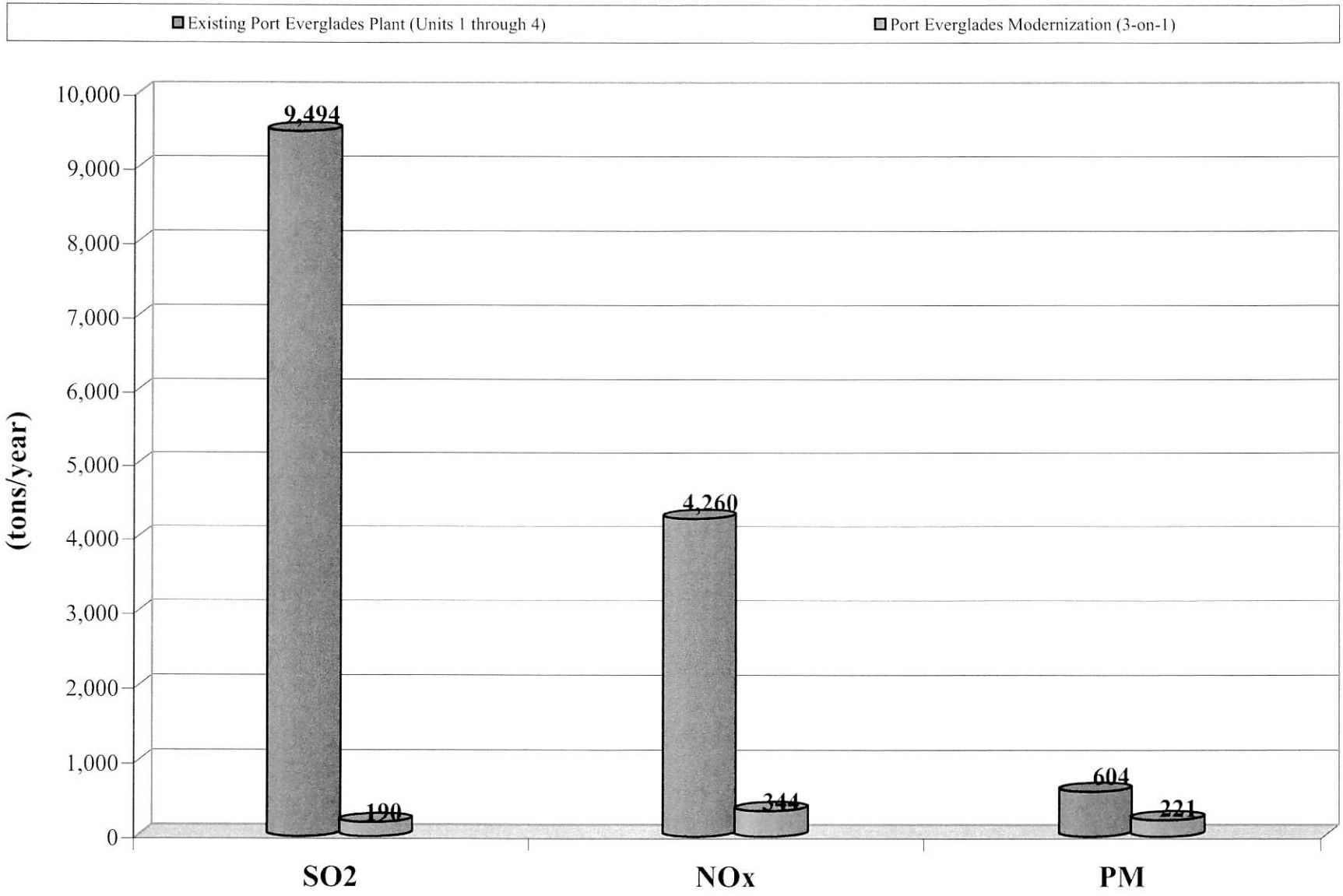
Project Director responsible for conducting all field work for the environmental assessment of a coal- and gas-fired electrical generating facility at St. Aubin in air quality, water quality, and ecology.

PROFESSIONAL REGISTRATIONS

Registered Professional Engineer, State of Florida, No. 14996

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 23
PARTY Florida Power & Light (FPL)
DESCRIPTION Kennard Kosky (KFK-2)
DATE 02/20/12

Exhibit KFK-2. SO_2, NO_X, and PM_{10} Air Emissions (tons/year)

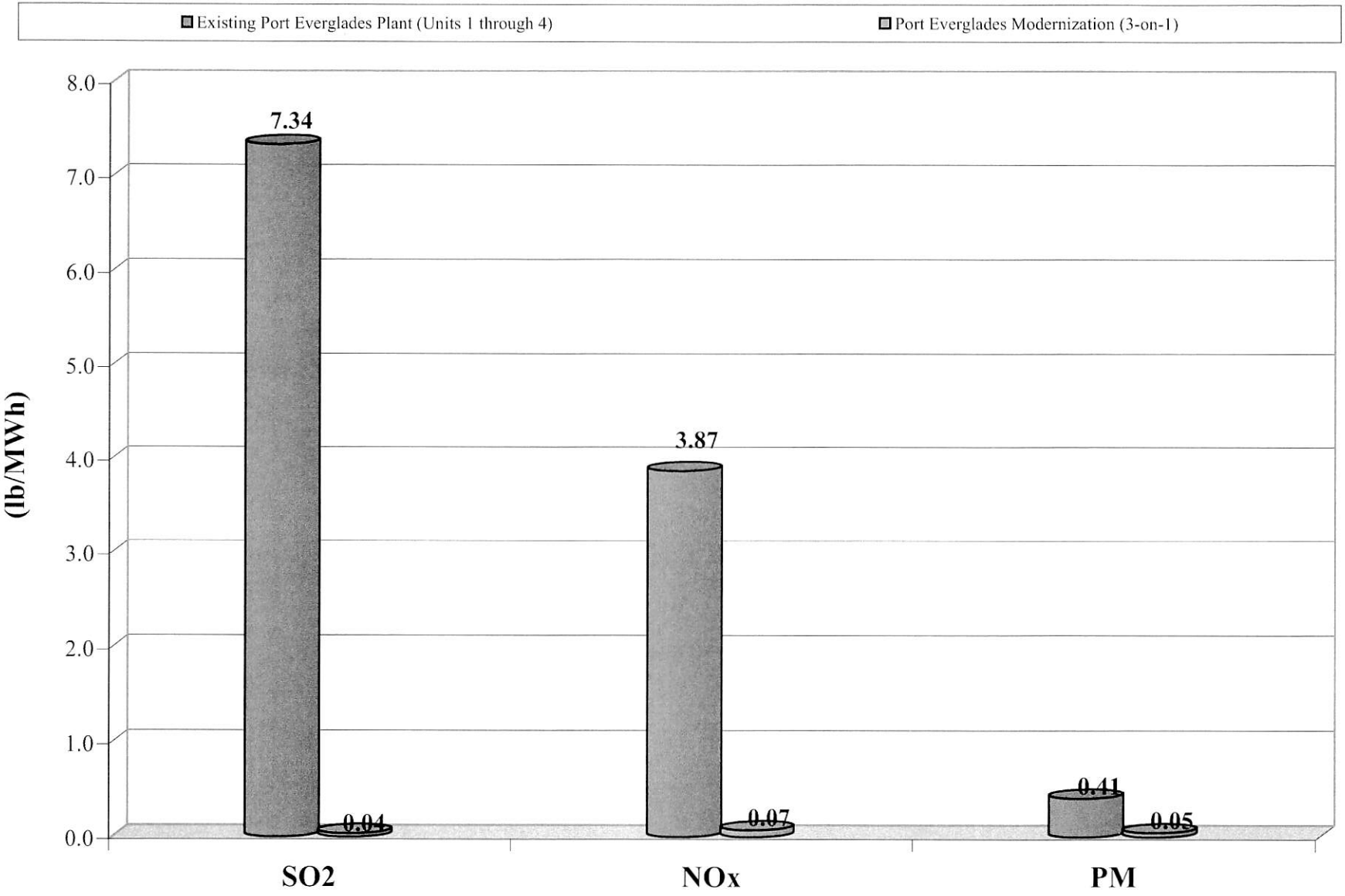


Docket No. 11____-EI
Existing and PEEC Emissions
KFK-2, Page 1 of 1

Notes :Existing Port Everglades based on 2006 and 2007 with an approximate capacity factor of 29%.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 24
PARTY Florida Power & Light (FPL)
DESCRIPTION Kennard Kosky (KFK-3)
DATE 02/20/12

Exhibit KFK-3. SO_2, NO_X, and PM Air Emissions (lb/MWh)

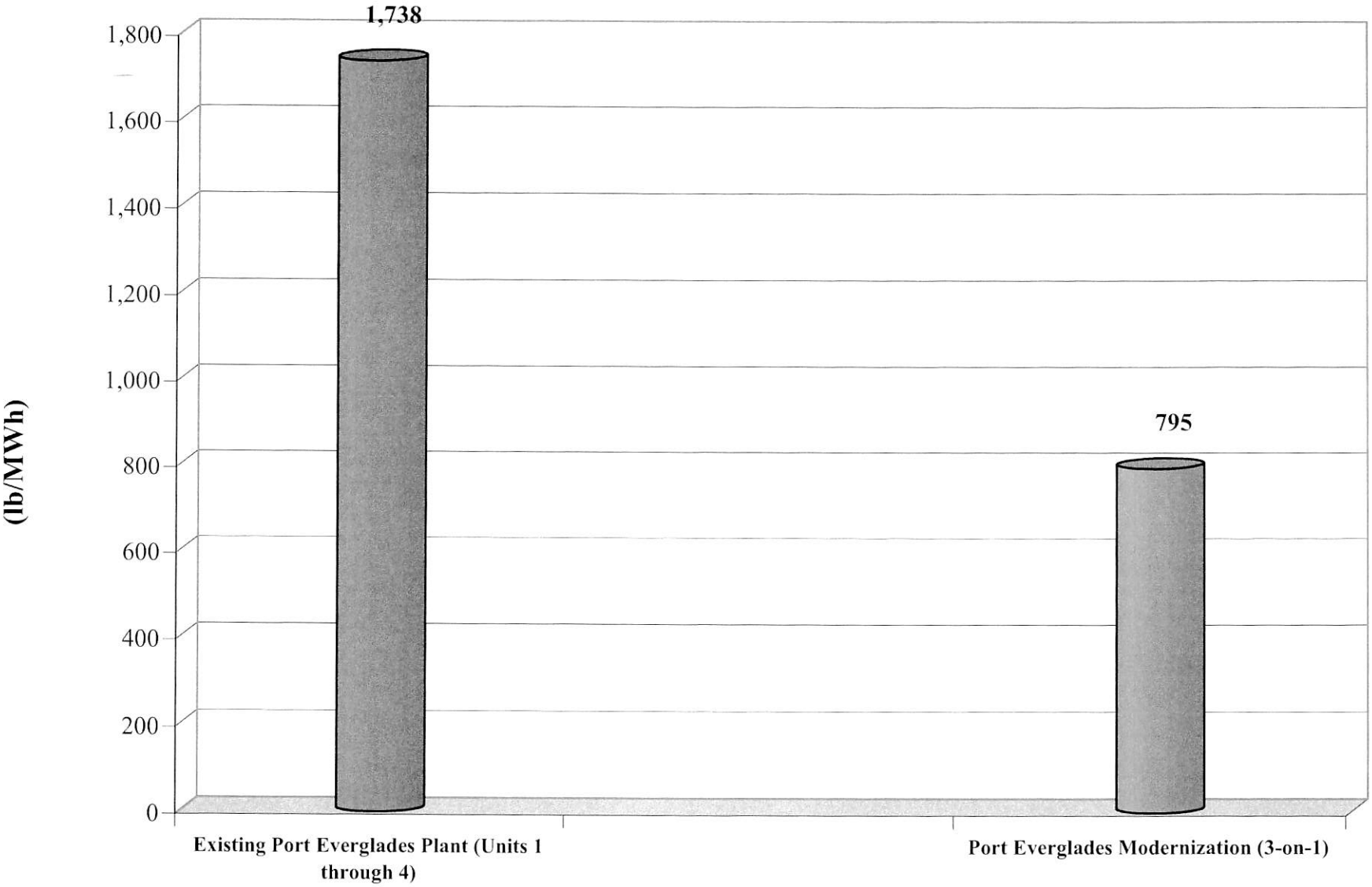


Notes: Existing Port Everglades based on 2007 eGrid Data form EPA (2010).
Modernization based on 90% capacity factor on natural gas and light oil;

Docket No. 11____-EI
Existing and PEEC Emission Rates
KFK-3, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 25
PARTY Florida Power & Light (FPL)
DESCRIPTION Kennard Kosky (KFK-4)
DATE 02/20/12

Exhibit KFK-4. CO_2 Air Emissions (lb/MWh)

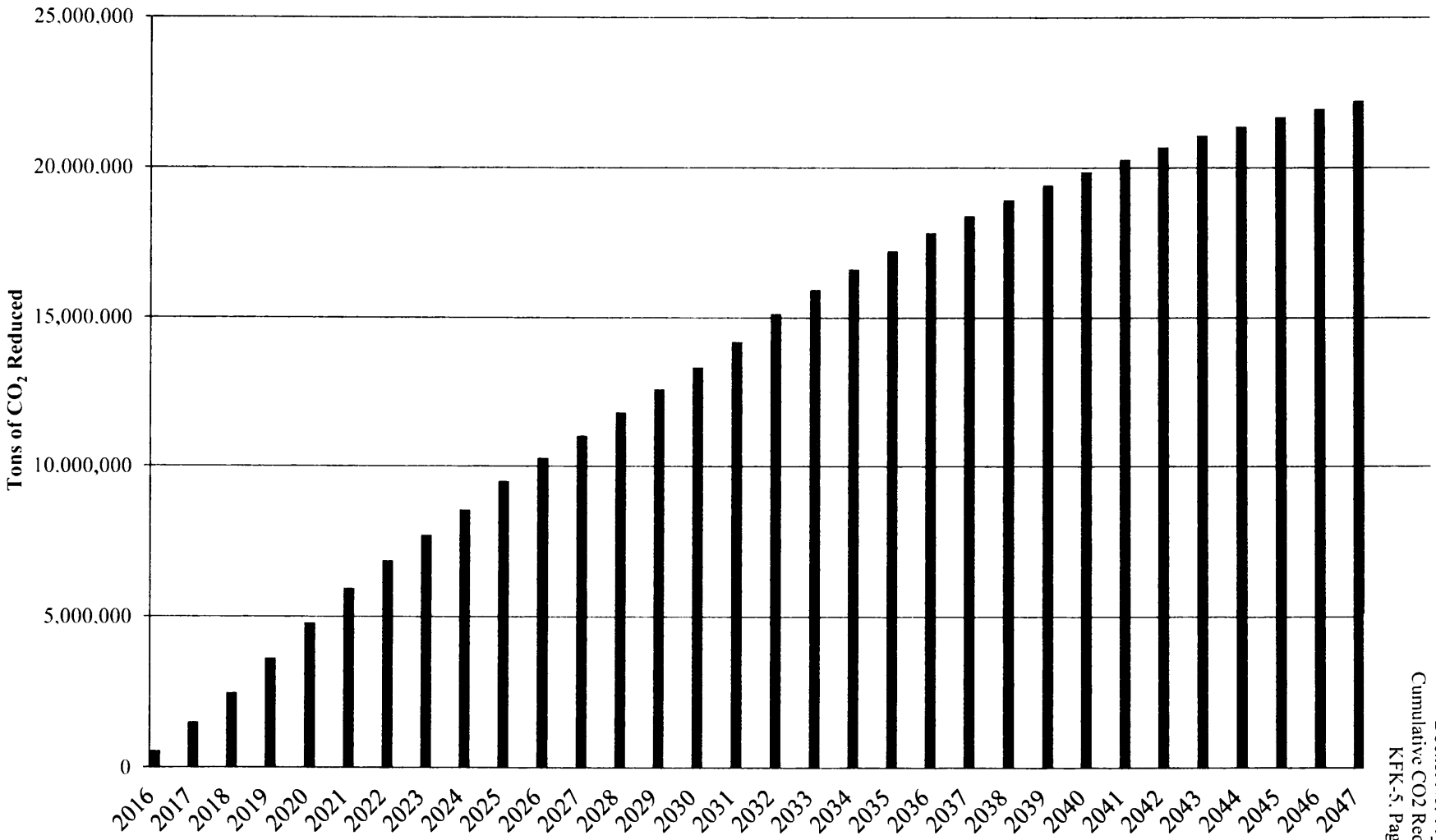


Notes: Existing Port Everglades based on 2007 eGrid Data form EPA (2010).
Modernization based on 90% capacity factor on natural gas and light oil;

Docket No. 11____-EI
Existing and PEEC CO2 Emission Rates
KFK-4, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 26
PARTY Florida Power & Light (FPL)
DESCRIPTION Kennard Kosky (KFK-5)
DATE 02/20/12

Exhibit KFK-5. Cumulative CO_2 Reductions* in FPL's System with Port Everglades Modernization



Docket No. 11____-EI
Cumulative CO2 Reductions
KFK-5, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 27
PARTY Florida Power & Light (FPL)
DESCRIPTION Pedro Modia (PM-1)
DATE 02/20/12

Summary of Required Facilities for PEEC

Transmission Facility Item #	Voltage Level (kV)	Description		Cost 2016$ (000s)		
PEEC TF - 1	138	2-138 kV String Buses w/ fiber optic to connect generators A and B to Port Everglades switchyard	$	1,074		
PEEC TF - 2	230	2-230 kV String Buses w/ fiber optic to connect generators C and STM to Port Everglades switchyard	$	1,074		
PEEC TF - 3	138/230	Port Everglades System Yard - Upgrade 2-138 kV, 2-230 kV terminals, associated equipment	$	4,777		
		Subtotal Interconnection			$	6,924
PEEC TF - 4	138	Port Everglades 138 kV System Yard - Replace 10 - 138 kV breakers w/ 63 kA, 2-cycle	$	6,509		
PEEC TF - 5	230	Port Everglades 230 kV System Yard - Replace 8 - 230 kV breakers w/ 63 kA, 2-cycle	$	5,377		
PEEC TF - 6	138	Port Sub - Upgrade Port Tap terminal to 2000 amps	$	737		
PEEC TF - 7	230	Port Everglades System Yard - Upgrade 230 kV bus due to fault current	$	1,957		
PEEC TF - 8	138	Port Everglades System Yard - Upgrade 138 kV bus due to fault current	$	828		
PEEC TF - 9	138	Hollywood Substation - Upgrade terminal to Port Everglades circuit	$	122		
PEEC TF - 10	138	Dania Substation - Upgrade terminal to Port Everglades circuit	$	557		
PEEC TF - 11	138	Transmission circuits - Upgrade Port Tap1-Dania - Hollywood to 1695 amps	$	7,201		
PEEC TF - 12	138	Transmission circuits - Upgrade Port-Port Tap-Port Tap 2 to 1905 amps	$	1,581		
PEEC TF - 13	138/230	OHGW Replacements due to Fault Current	$	719		
		Subtotal Integration			$	25,588
			Total	$ 32,513		

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 28
PARTY Florida Power & Light (FPL)
DESCRIPTION Juan Enjamio (JEE-1)
DATE 02/20/12

Projection of FPL's Resource Needs through 2021
(Assuming Unit Additions through 2015 Only)

	(1)	(2)	(3)	(4) = (1) + (2) - (3)	(5)	(6)	(7) = (5) - (6)	(8) = (4) - (7)	(9) = (8) / (7)	(10) = ((7)*1.20)-(4)
August of the Year	Projected FPL Unit Summer Capability (MW)	Projected Firm Capacity Summer Purchases (MW)	Projected Scheduled Maintenance * (MW)	Projected Total Summer Capacity (MW)	Projected Summer Peak Load (MW)	Projected Summer DSM Capability (MW)	Projected Summer Firm Peak Load (MW)	Projected Summer Reserves (MW)	Projected Summer Reserve Margin w/o Additions (%)	**Projected MW Needed to Meet 20% Reserve Margin ** (MW)**
2011	22,474	2,056	0	24,530	21,618	1,856	19,762	4,767	24.1%	(815)
2012	23,437	1,956	714	24,679	21,623	1,986	19,637	5,042	25.7%	(1,115)
2013	24,164	1,956	826	25,294	21,931	2,109	19,822	5,472	27.6%	(1,507)
2014	25,467	1,956	826	26,597	23,243	2,272	20,971	5,626	26.8%	(1,432)
2015	25,507	2,046	0	27,553	23,786	2,404	21,382	6,170	28.9%	(1,894)
2016	25,111	740	0	25,851	24,315	2,536	21,779	4,071	18.7%	284
2017	25,111	740	0	25,851	24,529	2,667	21,862	3,989	18.2%	384
2018	25,111	740	0	25,851	24,674	2,799	21,875	3,975	18.2%	400
2019	25,111	740	0	25,851	25,041	2,930	22,111	3,740	16.9%	683
2020	25,111	740	0	25,851	25,499	3,062	22,437	3,413	15.2%	1,074
2021	25,111	740	0	25,851	25,960	3,194	22,766	3,085	13.6%	1,468

* MW values shown in Column (3) represent 714 MW out-of-service during the Summer of 2012 (St. Lucie 2), and 826 MW out-of-service during the Summer of 2013 and 2014 due to the installation of electrostatic precipitators at FPL's 800 MW generating units.

** MW values shown in Column (10) represent new generating capacity needed to meet the 20% reserve margin criterion.

Projection of FPL's Resource Needs through 2021
(Assuming PEEC Addition in 2016)

	(1)	(2)	(3)	(4) = (1) + (2) - (3)	(5)	(6)	(7) = (5) - (6)	(8) = (4) - (7)	(9) = (8) / (7)	(10) = ((7)*1.20)-(4)
August of the Year	Projected FPL Unit Summer Capability (MW)	Projected Firm Capacity Summer Purchases (MW)	Projected Scheduled Maintenance * (MW)	Projected Total Summer Capacity (MW)	Projected Summer Peak Load (MW)	Projected Summer DSM Capability (MW)	Projected Summer Firm Peak Load (MW)	Projected Summer Reserves (MW)	Projected Summer Reserve Margin w/o Additions (%)	**Projected MW Needed to Meet 20% Reserve Margin ** (MW)**
2011	22,474	2,056	0	24,530	21,618	1,856	19,762	4,767	24.1%	(815)
2012	23,437	1,956	714	24,679	21,623	1,986	19,637	5,042	25.7%	(1,115)
2013	24,164	1,956	826	25,294	21,931	2,109	19,822	5,472	27.6%	(1,507)
2014	25,467	1,956	826	26,597	23,243	2,272	20,971	5,626	26.8%	(1,432)
2015	25,507	2,046	0	27,553	23,786	2,404	21,382	6,170	28.9%	(1,894)
2016	26,388	740	0	27,128	24,315	2,536	21,779	5,348	24.6%	(993)
2017	26,388	740	0	27,128	24,529	2,667	21,862	5,266	24.1%	(893)
2018	26,388	740	0	27,128	24,674	2,799	21,875	5,252	24.0%	(877)
2019	26,388	740	0	27,128	25,041	2,930	22,111	5,017	22.7%	(594)
2020	26,388	740	0	27,128	25,499	3,062	22,437	4,690	20.9%	(203)
2021	26,388	740	0	27,128	25,960	3,194	22,766	4,362	19.2%	191

* MW values shown in Column (3) represent 714 MW out-of-service during the Summer of 2012 (St. Lucie 2), and 826 MW out-of-service during the Summer of 2013 and 2014 due to the installation of electrostatic precipitators at FPL's 800 MW generating units.

** MW values shown in Column (10) represent new generating capacity needed to meet the 20% reserve margin criterion.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 29
PARTY Florida Power & Light (FPL)
DESCRIPTION Juan Enjamio (JEE-2)
DATE 02/20/12

Resource Plans Utilized in the Analyses

Resource Plan	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
PEEC	PEEC					3X1 CC	TP6	TP7			
Return to Service	PE3			PE4	PE1	PE2 3X1 CC	TP6	TP7			
Greenfield Combined Cycle (GFCC)	3X1 CC					3X1 CC	TP6	TP7			
Greenfield Combustion Turbine (GFCT)	2 - SC CT			PEEC			TP6	TP7			3X1 CC

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 30
PARTY Florida Power & Light (FPL)
DESCRIPTION Juan Enjamio (JEE-3)
DATE 02/20/12

Results of the Economic Analysis Relative to PEEC

(millions, CPVRR, 2011$, 2011-2047)

Resource Plan	System Costs			Difference from Lowest Cost Plan
	Fixed Costs*	Variable Costs**	Total Costs	
PEEC	14,578	128,333	142,911	--
Return to Service	13,501	129,879	143,380	469
Greenfield Combined Cycle (GFCC)	15,270	128,479	143,749	838
Greenfield Combustion Turbine (GFCT)	14,199	129,137	143,336	425

* Generation system fixed costs include: capital, capacity payments, fixed O&M, capital replacement, and firm gas transportation. (Note that Turkey Point 6 & 7 generation and transmission capital costs are assumed to be zero in this analysis for all resource plans.)

** Generation system variable costs include: variable O&M, plant fuel, FPL system fuel, and environmental compliance costs.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 31
PARTY Florida Power & Light (FPL)
DESCRIPTION Juan Enjamio (JEE-4)
DATE 02/20/12

Projection of Approximate Bill Impacts: PEEC vs. Return To Service Resource Plans

Year	(1) Plan with Port Everglades Modernization Annual Total Revenue Requirements ($millions, Nominal $)	(2) Plan Returning Inactive Reserve Units PPE 1-4 to Service Annual Total Revenue Requirements ($millions, Nominal $)	(3) =(1)-(2) Differential in Annual Total Revenue Requirements ($millions, Nominal $)	(4) Projected Total Sales After DSM (GWh at the meter)	(5) =((3)x100)/(4) Differential in System Average Electric Rates (cents/kWh)	(6) =(5)x10 Differential in Customer Bill of 1,000 kWh ($)
2016	4,794	4,748	46	109,787	$0.04	$0.42
2017	5,291	5,251	39	111,105	$0.04	$0.35
2018	6,927	6,941	-14	112,313	-$0.01	-$0.12
2019	7,470	7,522	-52	113,670	-$0.05	-$0.46
2020	8,240	8,294	-54	116,014	-$0.05	-$0.47
2021	9,111	9,197	-86	118,800	-$0.07	-$0.72
2022	9,561	9,552	9	121,725	$0.01	$0.07
2023	9,490	9,509	-20	124,286	-$0.02	-$0.16
2024	10,224	10,277	-53	126,776	-$0.04	-$0.42
2025	11,182	11,246	-63	129,260	-$0.05	-$0.49
2026	11,830	11,926	-96	131,782	-$0.07	-$0.73
2027	12,609	12,706	-97	134,088	-$0.07	-$0.72
2028	13,230	13,315	-85	136,356	-$0.06	-$0.62
2029	13,996	14,089	-93	138,542	-$0.07	-$0.67
2030	14,956	15,007	-51	140,654	-$0.04	-$0.36
2031	15,824	15,902	-78	143,001	-$0.05	-$0.55
2032	17,143	17,223	-80	145,378	-$0.05	-$0.55
2033	19,320	19,403	-82	147,808	-$0.06	-$0.56
2034	20,763	20,832	-69	150,273	-$0.05	-$0.46
2035	21,759	21,832	-74	152,778	-$0.05	-$0.48
2036	24,103	24,170	-66	155,325	-$0.04	-$0.43
2037	25,618	25,700	-83	157,912	-$0.05	-$0.52
2038	26,878	26,957	-79	160,542	-$0.05	-$0.49
2039	28,542	28,599	-56	163,216	-$0.03	-$0.35
2040	30,044	30,094	-50	165,929	-$0.03	-$0.30
2041	31,584	31,637	-53	168,692	-$0.03	-$0.31
2042	33,561	33,640	-79	171,497	-$0.05	-$0.46
2043	36,309	36,378	-69	174,349	-$0.04	-$0.39
2044	38,787	38,831	-44	177,247	-$0.02	-$0.25
2045	40,918	40,965	-46	180,192	-$0.03	-$0.26
2046	43,259	43,323	-64	183,186	-$0.04	-$0.35
2047	45,749	45,826	-77	186,229	-$0.04	-$0.41
					Average 2016-2047	-$0.38

Notes: (1) This projection assumes instantaneous adjustment to electric rates and is for illustrative purposes only.
(2) The values presented in Columns (1), (2), and (3) are total system revenue requirements and include all costs: capital, system fuel, etc.

Projection of Approximate Bill Impacts: PEEC vs. GFCC Resource Plans

Year	(1) Plan with Port Everglades Modernization Annual Total Revenue Requirements ($millions, Nominal $)	(2) Plan with Greenfield Site Combined Cycle Annual Total Revenue Requirements ($millions, Nominal $)	(3) =(1)-(2) Differential in Annual Total Revenue Requirements ($millions, Nominal $)	(4) Projected Total Sales After DSM (GWh at the meter)	(5) =((3)x100)/(4) Differential in System Average Electric Rates (cents/kWh)	(6) =(5)x10 Differential in Customer Bill of 1,000 kWh ($)
2016	4,794	4,818	-24	109,787	-$0.02	-$0.22
2017	5,291	5,332	-42	111,105	-$0.04	-$0.37
2018	6,927	6,972	-44	112,313	-$0.04	-$0.39
2019	7,470	7,521	-51	113,670	-$0.04	-$0.45
2020	8,240	8,351	-111	116,014	-$0.10	-$0.96
2021	9,111	9,264	-153	118,800	-$0.13	-$1.29
2022	9,561	9,699	-138	121,725	-$0.11	-$1.13
2023	9,490	9,622	-132	124,286	-$0.11	-$1.06
2024	10,224	10,353	-129	126,776	-$0.10	-$1.02
2025	11,182	11,305	-123	129,260	-$0.10	-$0.95
2026	11,830	11,949	-120	131,782	-$0.09	-$0.91
2027	12,609	12,725	-116	134,088	-$0.09	-$0.86
2028	13,230	13,340	-110	136,356	-$0.08	-$0.80
2029	13,996	14,105	-109	138,542	-$0.08	-$0.78
2030	14,956	15,061	-105	140,654	-$0.07	-$0.75
2031	15,824	15,925	-101	143,001	-$0.07	-$0.70
2032	17,143	17,240	-97	145,378	-$0.07	-$0.67
2033	19,320	19,415	-94	147,808	-$0.06	-$0.64
2034	20,763	20,854	-92	150,273	-$0.06	-$0.61
2035	21,759	21,847	-88	152,778	-$0.06	-$0.58
2036	24,103	24,188	-85	155,325	-$0.05	-$0.55
2037	25,618	25,702	-84	157,912	-$0.05	-$0.53
2038	26,878	26,960	-82	160,542	-$0.05	-$0.51
2039	28,542	28,623	-81	163,216	-$0.05	-$0.50
2040	30,044	30,123	-79	165,929	-$0.05	-$0.48
2041	31,584	31,664	-79	168,692	-$0.05	-$0.47
2042	33,561	33,639	-78	171,497	-$0.05	-$0.45
2043	36,309	36,384	-75	174,349	-$0.04	-$0.43
2044	38,787	38,862	-75	177,247	-$0.04	-$0.42
2045	40,918	40,991	-73	180,192	-$0.04	-$0.41
2046	43,259	43,330	-71	183,186	-$0.04	-$0.39
2047	45,749	45,813	-64	186,229	-$0.03	-$0.34
					Average 2016-2047	-$0.64

Notes: (1) This projection assumes instantaneous adjustment to electric rates and is for illustrative purposes only.
(2) The values presented in Columns (1), (2), and (3) are total system revenue requirements and include all costs: capital, system fuel, etc.

Projection of Approximate Bill Impacts: PEEC vs. GFCT Resource Plans

Year	(1) Plan with Port Everglades Modernization Annual Total Revenue Requirements ($millions, Nominal $)	(2) Plan with Simple Cycle Combustion Turbine (CT) Annual Total Revenue Requirements ($millions, Nominal $)	(3) =(1)-(2) Differential in Annual Total Revenue Requirements ($millions, Nominal $)	(4) Projected Total Sales After DSM (GWh at the meter)	(5) =((3)x100)/(4) Differential in System Average Electric Rates (cents/kWh)	(6) =(5)x10 Differential in Customer Bill of 1,000 kWh ($)
2016	4,794	4,784	10	109,787	$0.01	$0.09
2017	5,291	5,273	18	111,105	$0.02	$0.16
2018	6,927	6,931	-3	112,313	$0.00	-$0.03
2019	7,470	7,519	-49	113,670	-$0.04	-$0.43
2020	8,240	8,338	-98	116,014	-$0.08	-$0.84
2021	9,111	9,155	-44	118,800	-$0.04	-$0.37
2022	9,561	9,533	27	121,725	$0.02	$0.23
2023	9,490	9,442	47	124,286	$0.04	$0.38
2024	10,224	10,195	29	126,776	$0.02	$0.23
2025	11,182	11,195	-12	129,260	-$0.01	-$0.10
2026	11,830	11,893	-64	131,782	-$0.05	-$0.48
2027	12,609	12,735	-126	134,088	-$0.09	-$0.94
2028	13,230	13,352	-121	136,356	-$0.09	-$0.89
2029	13,996	14,110	-114	138,542	-$0.08	-$0.82
2030	14,956	15,064	-108	140,654	-$0.08	-$0.76
2031	15,824	15,929	-105	143,001	-$0.07	-$0.73
2032	17,143	17,244	-101	145,378	-$0.07	-$0.69
2033	19,320	19,423	-103	147,808	-$0.07	-$0.70
2034	20,763	20,861	-99	150,273	-$0.07	-$0.66
2035	21,759	21,854	-95	152,778	-$0.06	-$0.62
2036	24,103	24,197	-93	155,325	-$0.06	-$0.60
2037	25,618	25,705	-87	157,912	-$0.06	-$0.55
2038	26,878	26,964	-86	160,542	-$0.05	-$0.54
2039	28,542	28,624	-81	163,216	-$0.05	-$0.50
2040	30,044	30,121	-77	165,929	-$0.05	-$0.46
2041	31,584	31,659	-75	168,692	-$0.04	-$0.44
2042	33,561	33,634	-73	171,497	-$0.04	-$0.43
2043	36,309	36,378	-68	174,349	-$0.04	-$0.39
2044	38,787	38,850	-63	177,247	-$0.04	-$0.36
2045	40,918	40,977	-59	180,192	-$0.03	-$0.33
2046	43,259	43,330	-70	183,186	-$0.04	-$0.38
2047	45,749	45,831	-82	186,229	-$0.04	-$0.44
					Average 2016-2047	-$0.42

Notes: (1) This projection assumes instantaneous adjustment to electric rates and is for illustrative purposes only.
(2) The values presented in Columns (1), (2), and (3) are total system revenue requirements and include all costs: capital, system fuel, etc.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 32
PARTY Florida Power & Light (FPL)
DESCRIPTION Juan Enjamio (JEE-5)
DATE 02/20/12

Non-Economic Analysis Results: Emission Reductions Compared to PEEC Resource Plan

	Return to Service			GFCC			GFCT		
	SO_2 (Tons)	NO_X (Tons)	CO_2 (Tons)	SO_2 (Tons)	NO_X (Tons)	CO_2 (Tons)	SO_2 (Tons)	NO_X (Tons)	CO_2 (Tons)
2016	1,375	1,151	548,000	4	7	11,000	1,346	1,015	551,000
2017	2,259	1,782	956,000	25	5	21,000	2,227	1,565	952,000
2018	2,230	1,677	983,000	105	32	125,000	2,161	1,517	978,000
2019	2,403	1,970	1,138,000	163	106	283,000	608	429	372,000
2020	2,744	2,340	1,177,000	90	96	246,000	-26	-50	-6,000
2021	2,532	2,004	1,140,000	55	73	182,000	1,551	953	552,000
2022	1,799	1,273	925,000	22	14	25,000	1,802	1,200	906,000
2023	1,401	1,006	845,000	10	9	24,000	1,393	951	829,000
2024	1,516	1,093	846,000	6	16	39,000	1,470	1,017	816,000
2025	1,981	1,304	952,000	-3	9	19,000	1,919	1,191	918,000
2026	1,656	1,339	778,000	-22	2	9,000	658	540	413,000
2027	1,632	1,450	750,000	-29	2	19,000	424	292	179,000
2028	1,630	1,371	774,000	-35	-2	9,000	384	284	202,000
2029	1,520	1,125	787,000	-15	-1	11,000	372	248	178,000
2030	1,262	1,017	745,000	-15	-2	12,000	247	211	137,000
2031	1,263	1,066	856,000	-8	1	20,000	336	268	260,000
2032	1,281	1,016	939,000	-26	-3	9,000	286	218	186,000
2033	1,229	975	812,000	-9	0	16,000	291	229	201,000
2034	1,076	844	683,000	-6	0	17,000	269	194	155,000
2035	1,001	780	612,000	-9	0	16,000	238	177	132,000
2036	921	788	599,000	-4	0	17,000	201	172	137,000
2037	882	659	566,000	-6	0	16,000	181	145	120,000
2038	844	653	531,000	-6	0	17,000	152	146	109,000
2039	691	566	492,000	0	0	17,000	190	137	118,000
2040	611	511	433,000	-1	0	17,000	150	119	83,000
2041	571	527	417,000	-2	0	17,000	109	107	79,000
2042	506	454	401,000	1	0	17,000	122	112	95,000
2043	524	452	380,000	0	1	18,000	128	107	74,000
2044	392	397	305,000	1	0	17,000	80	94	69,000
2045	380	375	320,000	1	0	18,000	82	87	73,000
2046	253	336	264,000	1	0	18,000	65	81	59,000
2047	296	334	278,000	1	0	17,000	81	88	74,000
Total	40,661	32,635	22,232,000	289	365	1,319,000	19,497	13,844	10,001,000

(+) Refers to a reduction in emissions to the PEEC plan when compared to all resource plans.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 33
PARTY Florida Power & Light (FPL)
DESCRIPTION Juan Enjamio (JEE-6)
DATE 02/20/12

Non-Economic Analysis Results: Reduction in Fuel Use
Compared to PEEC Resource Plan

	Return to Service		GFCC		GFCT	
	Oil Bbl (000)	Gas MMBtu million	Oil Bbl (000)	Gas MMBtu million	Oil Bbl (000)	Gas MMBtu million
2016	386	4	-3	0	377	4
2017	588	6	5	0	579	6
2018	560	5	-17	-1	538	5
2019	600	4	-13	-2	124	2
2020	711	6	-29	-2	-20	0
2021	671	5	-8	-1	458	3
2022	450	5	6	0	464	4
2023	352	4	2	0	350	3
2024	375	4	-2	0	379	4
2025	496	4	-8	0	520	3
2026	475	5	-20	1	184	2
2027	467	5	-27	0	123	1
2028	466	5	-32	1	108	1
2029	422	3	-17	0	95	0
2030	348	3	-15	0	71	1
2031	332	1	-14	0	81	-1
2032	316	0	-21	0	71	0
2033	301	1	-9	0	70	0
2034	261	1	-8	0	66	0
2035	252	2	-10	0	58	0
2036	233	2	-6	0	46	0
2037	217	1	-6	0	43	0
2038	209	2	-7	0	42	0
2039	163	1	-1	0	44	0
2040	149	1	-1	0	39	0
2041	139	1	-3	0	27	0
2042	119	1	0	0	29	0
2043	125	1	-1	0	33	0
2044	97	2	0	0	18	0
2045	87	1	0	0	17	0
2046	53	1	0	0	12	0
2047	64	1	0	0	16	0
Total	10,484	90	-265	5	5,062	40

(+) Refers to a reduction in fuel to the PEEC plan when compared to all resource plans.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 34
PARTY Florida Power & Light (FPL)
DESCRIPTION Juan Enjamio (JEE-7)
DATE 02/20/12

Forecasted Cost of Air Emissions

	ENV II *$/ton nominal*		
Year	CO_2	SO_2	NO_X
2011	0	53	473
2012	0	104	485
2013	0	113	497
2014	0	57	509
2015	0	58	522
2016	0	59	535
2017	0	61	548
2018	27	62	562
2019	29	64	576
2020	32	66	590
2021	34	67	605
2022	37	69	620
2023	40	71	636
2024	44	72	652
2025	47	74	668
2026	51	76	685
2027	55	78	702
2028	59	80	719
2029	64	82	737
2030	68	84	756
2031	70	86	775
2032	72	88	794
2033	74	90	814
2034	75	93	834
2035	77	95	855
2036	79	97	877
2037	81	100	898
2038	83	102	921
2039	85	105	944
2040	88	108	968
2041	90	110	992
2042	92	113	1,016
2043	94	116	1,042
2044	97	119	1,068
2045	99	122	1,095
2046	102	125	1,122
2047	104	128	1,150

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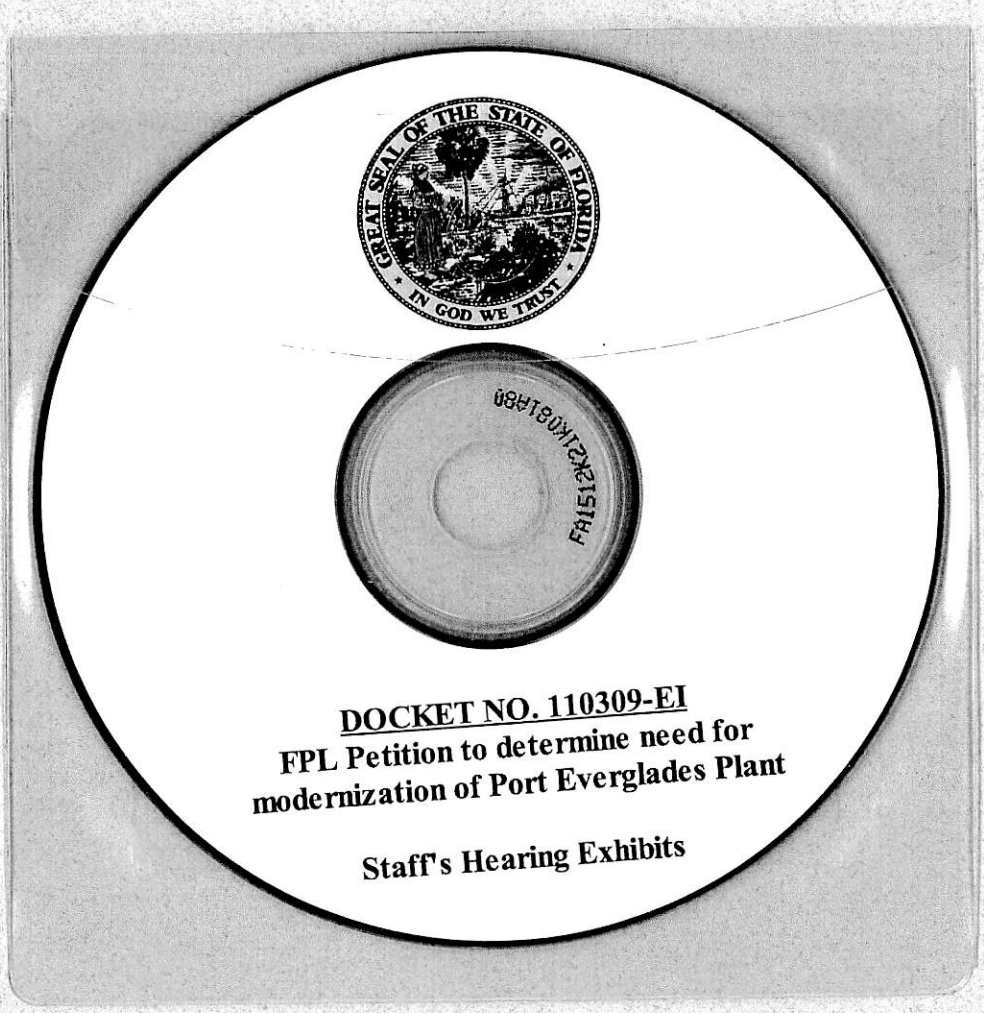
110309.Hearing Exhibit35.bates.pdf - This is a 138-page document, Bates-stamped, that contains Hearing Exhibit 35 which is a Staff exhibit.

110309.Hearing Exhibit36-40.bates.pdf - This is a 101-page document, Bates-stamped, that contains Hearing Exhibits 36-40 which are Staff exhibits.



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FPL's Responses to Staff's First Set of Interrogatories (Nos. 1-61) (including the original and corrected responses to Nos. 34 and 59)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 35
PARTY Florida Public Service Commission Staff
DESCRIPTION Staffs Exhibit #35
DATE 02/20/12

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition To Determine Need for Modernization of Port Everglades Plant	Docket No. 110309-EI Dated: January 4, 2012

FLORIDA POWER & LIGHT COMPANY'S RESPONSES TO STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-61) AND FIRST REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 1-6)

Florida Power & Light Company ("FPL"), pursuant to Rules 1.340 and 1.350, Florida Rules of Civil Procedure, Rule 28-106.206, Florida Administrative Code, and this Commission's Order Establishing Procedure PSC-11-0565-PCO-EI, submits the following responses to the Staff of the Florida Public Service Commission's First Set of Interrogatories (Nos. 1-61) and First Request for Production of Documents (Nos. 1-6).

1. FPL adopts and incorporates by reference, as though fully restated herein, all objections listed in FPL's Objections to Staff's First Set of Interrogatories (1-61) and First Request for Production of Documents (Nos. 1-6) dated December 29, 2011. FPL's responses are without waiver of those prior objections.

2. Attached hereto are FPL's answers to Staff's First Set of Interrogatories (Nos. 1-61), together with the affidavits of the persons providing the answers.

3. FPL will deliver to Staff contemporaneously with this response a CD-Rom containing all non-confidential documents responsive to Staff's First Request for Production of Documents (Nos. 1-6), as well as hard copies of non-confidential documents where specifically requested by Staff. Confidential documents will be available for review at FPL's offices at 215 South Monroe Street, Tallahassee, Florida during regular business hours, 8 a.m. to 5 p.m., Monday through Friday, upon reasonable notice to FPL's counsel. If Staff wishes to remove any

confidential documents from FPL's office, FPL will undertake the necessary steps, pursuant to Florida Statutes and applicable rules, to protect the confidentiality of those documents.

Respectfully submitted this 4th day of January, 2012.

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By: *s/ Maria J. Moncada*
Maria Moncada
Florida Bar No. 0773301

CERTIFICATE OF SERVICE
DOCKET NO. 110309-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing Responses to Staff's First Set of Interrogatories (Nos. 1-61) and Staff's First Request for Production of Documents (Nos. 1-6) was served electronically and by U.S. mail this 4th day of January, 2012 to the following:

Charles W. Murphy, Esq.
Office of the General Counsel
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850
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By: *s/ Maria J. Moncada*
Maria J. Moncada
Florida Bar No. 0773301

Q.

At page 2, lines 21-22, witness Morley testifies that FPL's September 2011 forecasts have replaced the forecasts that were presented in FPL's 2011 Ten Year Site Plan.

a. Were the forecasts identified in 1, above, relied upon to determine generating capacity needs, supporting the modernization of Port Everglades Plant? Please explain.
b. Are the forecasts identified in 1, above, still the most recent?

A.

a. Yes. FPL's September 2011 forecast, which replaced the 2011 Ten Year Site Plan forecast, was relied upon to support the generation plan and the need for the Port Everglades modernization.
b. Yes. The forecasts used in the Port Everglades modernization docket is FPL's most recent forecast.

Q.
Please refer to page 13, lines 4-6, of witness Kosky's direct testimony.

a. What is the EPA Prevention of Significant Deterioration (PSD) review threshold for CO2 emission rates?

b. What are the projected CO2 emission rates for FPL's proposed PEEC?

c. Please explain the statement that, "the net CO2 emissions increase is higher than the EPA PSD review threshold solely due to the capacity factor difference between the existing plant and PEEC."

d. If the CO2 emissions from FPL's proposed PEEC are higher than the EPA PSD review threshold, will this affect FPL's ability to obtain environmental approval from the EPA?

e. If the response to 2.d. is negative, please explain why.

f. If the response to 2.d. is affirmative, please describe the possible outcome(s) and FPL's regulatory plans.

A.

a. The EPA PSD review thresholds for greenhouse gas emissions are 100,000 tons/year of CO2 equivalents (CO2e) for new stationary sources and 75,000 tons/year CO2e for modifications of existing sources that have current CO2e emissions above 100,000 tons/year. CO2e consists primarily of CO2 and minor amounts of methane (CH4) and nitrous oxide (N2O) when combusting natural gas and light oil. (See also witness Kosky's testimony at Page 5, lines 4 through 6). The EPA PSD threshold of 75,000 tons/year CO2e applies to PEEC.

b. The maximum potential CO2e emissions for PEEC are about 4.5 million tons/year.

c. EPA regulations require a comparison of the maximum CO2e potential emissions of PEEC to the baseline actual CO2e emissions of the existing Port Everglades Units 1 through 4. If the maximum potential emissions exceed the baseline actual emissions by more than the PSD threshold, then PSD review is required. EPA rules require the maximum potential CO2e emissions for PEEC be based on its operation at 100 percent capacity for every hour of the year (8,760) including the maximum use of light oil (1,000 hours of the 8,760 hours per year). EPA rules define baseline actual emissions as the actual annual emissions during the last 5-years using the highest average over 24 consecutive months. The baseline actual CO2e emissions for the existing Port Everglades Units 1 through 4 were about 2.6 million tons/year of CO2e with a capacity factor of less than 30 percent. The maximum potential CO2e emissions currently authorized of Port Everglades Units 1 through 4 is about 9.6 million tons/year of CO2e. As a result, the EPA PSD threshold is exceeded due to the low capacity factor of the existing units over the last five years.

d. No.

e. Exceeding the PSD threshold only requires PEEC to undergo PSD review by EPA. PSD review of the PEEC project will involve a determination of Best Available Control Technology (BACT) for CO2e emissions. In its BACT guidance for CO2e emissions, EPA stressed energy efficiency as the basis for determining BACT. PEEC will be highly efficient with a heat rate of approximately 6,330 btu/kWh that results in very low CO2e emissions. When compared to other projects in the United States for which BACT has been approved by EPA, the PEEC CO2e emission rate is one of the lowest.

f. Not applicable.

Q.
Please refer to page 14, lines 3-11 of witness Kosky's direct testimony and Exhibit JEE-3 of witness Enjamio's direct testimony.

a. What emission compliance equipment will be installed at the PEEC for controlling the NOx emissions?
b. What will be the capital costs and O&M costs associated with the equipment described in 3.a.?
c. What emission compliance equipment will be installed at the PEEC for controlling emissions?
d. What will be the capital costs and O&M costs associated with the equipment described in your response to 3.c.?
e. Have the costs discussed in your response to 3.b. and 3.d. been included in Exhibit JEE-3?
f. If the response to 3.e. is negative, please explain why, and provide a revised Exhibit JEE-3 which includes these potential environmental compliance costs.

A.

a. The combustion turbines will be equipped with dry low-NOx combustion system to minimize NOx formation when combusting natural gas and a water injection system to minimize NOx formation when combusting light oil. In addition, selective catalytic reduction (SCR) will be installed in the heat recovery steam generators to further reduce NOx emissions. PEEC's NOx emissions will comply with the Cross State Air Pollution Rule (CSAPR).

b. The Capital Cost associated with the equipment described above is approximately $33 million (2016 dollars). The O&M Cost associated with the equipment described above is approximately $60 million (2016 dollars) over the life of the project.

c. Compliance equipment is not required for controlling SO2 emissions from PEEC. Natural gas is the cleanest fossil fuel with extremely low amounts of sulfur. The backup fuel, light oil, will have a maximum sulfur content of 0.0015 percent that is equivalent to the sulfur in natural gas. PEEC's SO2 emissions will comply with CSAPR.

d. There are no capital or O&M costs associated with controlling SO2 emissions from PEEC.

e. Yes.

f. Not applicable.

Q.
Please refer to page 18, lines 4-13, of witness Gnecco IV's direct testimony and Exhibit JEE-3 of witness Enjamio's direct testimony.

a. Referring to lines 4-6, will PEEC need to run a scrubber to control the SO2 emission when using its primary fuels?
b. Referring to lines 10-13, is PEEC subject to the regulation of the MACT standard when it uses back-up light fuel oil? If not, please explain why not.
c. If the response to 4.b. is affirmative, please provide an estimate of the compliance costs.
d. If the response to 4.b. is affirmative, has FPL included these costs in Exhibit JEE-3? If not, why not?

A.

a. No, PEEC will not need a scrubber to control SO2 emissions. See also answer to Interrogatory 3.c.

b. PEEC is not subject to the proposed MACT standard applicable to coal and oil fired Electric Utility Steam Generating Units (EUGs) as described in witness Kosky's testimony at page 14 lines 12 to 23. The MACT standards applicable to oil-fired combustion turbines are potentially applicable to PEEC if the aggregate use of oil is more than 1,000 hours in any year. The combustion turbines considered for the project will meet the MACT standards for combustion turbines.

c. If the combustion turbine MACT standards become applicable, the combustion turbines proposed for PEEC will meet the combustion MACT standards as part of their original design. There are no compliance costs.

d. There are no separate compliance costs to include.

Q.
Please refer to page 15, lines 1-13 of witness Kosky's direct testimony and Exhibit JEE-3 of witness Enjamio's direct testimony.

a. Referring to lines 10-11, how many design options is FPL evaluating?
b. What is the major driver of the costs associated with each of the design options?
c. Does Exhibit JEE-3 include any costs related to compliance with the EPA's proposed regulation under Section 316(b)?
d. If the response to 5.c. is affirmative, please specify the amount included.
e. If the response to 5.c. is negative, please explain why it is not included.

A.

a. Based on the proposed regulation and recent statements by EPA regarding this regulation, FPL has considered a primary and two alternatives for meeting the 316(b) regulation as it may be promulgated in final form. The primary and two alternatives have a common intake design with alternative routes for meeting Section 316(b).

b. The major cost drivers for 316(b) compliance are the intake structures including modified Ristroph-type screens and an aquatic organism return system. The main reasons for the cost differential between each design option are the final discharge route and location that would be necessary to meet the regulation. However, the primary and alternate routes are similar in length, which minimizes cost differentials.

c. Yes.

d. FPL has estimated approximately $10 million as capital costs for 316(b) compliance.

e. Not applicable.

Q.
Referring to page 16, line 23, through page 17, line 2, of witness Kosky's testimony:

a. Please provide a list of all the components of the "state-of-the-art air pollution control equipment" to be installed at the PEEC.
b. Please elaborate on how the state-of-the-art air pollution control equipment at the PEEC is related to GHGs emission control.

A.

a. The state-of-the-art air pollution control equipment to be installed at PEEC includes a dry low-NOx combustion system in the combustion turbines to minimize NOx formation when combusting natural gas and a water injection system to minimize NOx formation when combusting light oil. In addition, selective catalytic reduction (SCR) will be installed in the heat recovery steam generators to further reduce NOx emissions.

b. PEEC's advanced combined cycle technology is, by design, state-of-the-art pollution control for limiting GHG emissions during operation. PEEC will be highly efficient with a heat rate of approximately 6,330 btu/kWh that results in very low CO2e emissions as described in witness Kosky's testimony at Page 13, lines 9 through 14.

Q.
Please refer to page 18, lines 1-14, of witness Kosky's direct testimony, and Exhibits JEE-3 and JEE-7 of witness Enjamio's direct testimony.

a. Referring to lines 6-9 of witness Kosky's testimony, please clarify whether FPL's modeling result shown in Exhibit JEE-3 incorporates Florida's state-specific environmental compliance requirements, or if FPL just used the ICF Report data as the inputs for Exhibit JEE-3?
b. Referring to Exhibit JEE-7, it appears that FPL chose to use scenario ENV II of the Emission Price Projections from the 2011 ICF Report in developing its economic analysis which resulted in the cost matrix presented in Exhibit JEE-3. Please explain what warrants the selection of the ENV II over the other existing scenarios in the ICF Reports.
c. What are the other scenarios included in the 2011 ICF Report? Please provide a brief summary of the differences between ENV II and each of the other scenarios.
d. Has FPL tried to use other scenarios, rather than the ENV II, as the inputs to formulate the cost matrix in Exhibit JEE-3? If so, what are the results? If not, why not?
e. Please describe each scenario in the 2011 ICF Report affecting emission price projections.
f. For each scenario identified in response to 7.e., please provide FPL's emission price projection in a format similar to Exhibit JEE-7 of witness Enjamio's direct testimony.
g. Has FPL considered the emission price projections produced by sources other than the ICF report in performing the economic analysis of PEEC? If so, what are the results? If not, why not?

A.
a. PEEC's design complies with all Florida's state-specific environmental compliance requirements, and resulting fixed costs are included in the cost of the project and reflected in the economic analyses as shown in the testimony of Witness Enjamio. In addition to these fixed costs, FPL included a system cost for air emissions for SO2, NOx and CO2. The cost of air emissions was based on FPL's ENV II Emission Price Forecast.

b. FPL has developed three emission price forecast scenarios -- labeled ENV I, ENV II, and ENV III -- based on forecast developed by ICF. These three emission price forecasts were used in FPL's feasibility analyses in the NCRC 2011 docket. Of the three scenarios, the ENV II scenario represents the mid-range forecast and is most appropriate for use in the PEEC economic analysis.

c. FPL's three emission price forecasts are based on reports produced by ICF. These three emission price forecasts are described below.

   CO2 price projections
   For its "ENV II," or mid-price scenario for CO2, FPL adopted the ICF national price forecast as reported in the Q4 Report.

The Q4 Report did not provide low and high emission price scenarios. In order to update the high and low CO2 price scenarios, FPL retained its previous "ENV III" (high) and "ENV I" (low) forecasts, but delayed the start of CO2 prices for three years in both scenarios. This delay was based on the view that national CO2 legislation is to be delayed from what was previously expected.

SO2 price projections
For its ENV II, or mid price scenario for SO2, FPL adopted the "ICF Transport Rule SO2 - Group 2 Regional Price Forecast" as reported in the Q4 Report. FPL does not expect that SO2 prices could be reduced significantly from this forecast, so it has also adopted this forecast as its ENV I, or low, forecast. In other words, the new ENV I and ENV II forecasts are the same.

Since ICF did not provide a new high band forecast in the Q4 report, for the ENV III high scenario FPL decided to continue to use the same price projections as before for ENV III. FPL believes that this price scenario continues to provide a reasonable high band for SO2 prices.

NOx price projections
For its ENV II, or mid price scenario for NOx, FPL adopted the "ICF CAIR/Transport Rule Forecast" as reported in the Q4 Report. FPL does not expect that NOx prices could be reduced significantly from this forecast, so it has also adopted this forecast as its ENV I, or low, forecast. In other words, the new ENV I and ENV II forecasts are the same.

Since ICF did not provide a new high band forecast in the Q4 report, for the ENV III high scenario FPL decided to continue to use the same price projections as before. FPL believes that this price scenario still provides a reasonable high band for NOx prices.

Escalation
ICF's forecasts are provided in real dollars. FPL applied an escalation rate to the nominal price forecast to convert the values into nominal prices.

d. FPL has not used its other two emission price forecast scenarios in the economic analysis of PEEC. However, in response to Staff's Interrogatory 30, from this docket, FPL conducted economic analyses of the four resource plans assuming no CO2 costs. As shown in the response to that Interrogatory, the PEEC Resource Plan continues to be the plan with lowest CPVRR even if CO2 costs are assumed to be zero.

e. Please refer to the response to part (c) above.

f. See attached Table 7-1.

g. FPL did not use emission price projections from sources other than ICF. FPL believes that the emission price studies produced by ICF are the most complete and widely accepted emission price forecasts available.

Table 7-1

short tons (2000#)

	ENV I *$/ton nominal*			ENV II *$/ton nominal*			ENV III *$/ton nominal*		
	CO2	SO2	NOX	CO2	SO2	NOX	CO2	SO2	NOX
2012	0	104	485	0	104	485	0	2,027	2,532
2013	0	113	497	0	113	497	0	2,199	2,746
2014	0	57	509	0	57	509	0	2,384	2,979
2015	0	58	522	0	58	522	0	2,585	3,231
2016	0	59	535	0	59	535	36	2,802	3,502
2017	0	61	548	0	61	548	39	3,037	3,797
2018	0	62	562	27	62	562	42	3,292	4,115
2019	0	64	576	29	64	576	46	3,568	4,461
2020	0	66	590	32	66	590	50	3,867	4,835
2021	23	67	605	34	67	605	54	4,194	5,240
2022	25	69	620	37	69	620	58	4,549	3,750
2023	27	71	636	40	71	636	63	4,933	2,683
2024	30	72	652	44	72	652	69	5,350	1,920
2025	32	74	668	47	74	668	74	5,802	1,373
2026	35	76	685	51	76	685	80	5,797	983
2027	38	78	702	55	78	702	87	5,795	1,008
2028	41	80	719	59	80	719	95	5,791	1,033
2029	44	82	737	64	82	737	102	5,788	1,059
2030	48	84	756	68	84	756	111	5,784	1,085
2031	52	86	775	74	86	775	120	5,614	1,112
2032	57	88	794	79	88	794	130	5,450	1,140
2033	61	90	814	85	90	814	141	5,290	1,169
2034	67	93	834	91	93	834	153	5,135	1,198
2035	72	95	855	98	95	855	166	4,983	1,228
2036	78	97	877	106	97	877	179	4,837	1,259
2037	85	100	898	113	100	898	194	4,696	1,290
2038	92	102	921	122	102	921	210	4,557	1,322
2039	100	105	944	131	105	944	228	4,423	1,355
2040	108	108	968	141	108	968	247	4,292	1,389
2041	117	110	992	152	110	992	267	4,166	1,424
2042	127	113	1,016	163	113	1,016	288	4,043	1,460
2043	137	116	1,042	175	116	1,042	311	3,923	1,496
2044	148	119	1,068	188	119	1,068	336	3,807	1,533
2045	160	122	1,095	202	122	1,095	363	3,695	1,572
2046	173	125	1,122	218	125	1,122	392	3,586	1,611
2047	186	128	1,150	234	128	1,150	423	3,480	1,651

Q.
Please refer to item 24 of FPL's Petition, Exhibit JEE-3 of witness Enjamio's direct testimony, and page 13, lines 7-8, of witness Kosky's direct testimony.

a. Is FPL obligated to provide a warm water refuge for manatees during the winter months at Plant Port Everglades?
b. If the response to 8.a. is affirmative, what will be FPL's plan to continuously provide the warm water for the manatees during those winter months after the existing generating units are taken out-of-service and before the new PEEC is in commercial operation in 2016?
c. What will be the estimated total costs associated with the plan discussed in 8.b.?
d. Have the costs discussed in 8.c. been included in Exhibit JEE-3?
e. If the response to 8.d. is negative, please explain why the costs are not included.

A.

a. Yes, the Manatee Protection plan provision of the current FDEP Industrial Wastewater Facility Permit for the Port Everglades Plant requires FPL to provide warm water during the winter months after the existing generating units are taken out-of-service and before the new PEEC is in commercial operation in 2016.

b. FPL is proposing to install a temporary heating system that will provide a manatee refuge during construction of PEEC. Warm water will be discharged from the heating system in compliance with the Manatee Protection Plan.

c. The total cost estimate of the plan described in 8.b is approximately $4.6 million (including Capital and O&M Costs).

d. No.

e. No costs are included as FPL intends to seek Environmental Cost Recovery Clause eligibility for the Port Everglades manatee temporary heating system (MTHS) as has been approved for similar systems associated with the ongoing modernizations of Cape Canaveral and Riviera Beach.

Q.
On page 12, lines 18-19, of his direct testimony, witness Kosky testifies that, "[t]he EPA adopted a regulation on June 10, 2010, that requires PSD review of greenhouse gases emitted from the project, which are primarily CO2." Please provide a citation to this regulation.

A.
The citation for the EPA Rule is 40 C.F.R. Section 52.21(b)(49), which is part of EPA's Prevention of Significant Deterioration of Air Quality regulations. This section defines Greenhouse Gases (GHGs) under the definition of "Subject of Regulation."

Q.
On page 18 of his testimony, Witness Enjamio testifies that, "[t]he PMAREA production costing model was used to determine the . . . difference in FPL's system fuel costs between the four resource plans."

a. Has FPL used the PMAREA production costing model in other Florida Public Service Commission dockets? Please describe.
b. Is PMAREA used by other electric utilities in Florida?

A.

a. FPL has used the PMAREA model, in the current version or previous versions, since the early 1990s. This model was referred to previously as the POWERSYM model; PMAREA is the name of its current version. (The name PMAREA is derived from PWRSYM, multi-area version.)

   Since the 1990s, this model has been used by FPL for almost all production costing analyses presented to the FPSC in numerous dockets, including Petitions for Need Determination and annual Fuel-cost Recovery filings. Some examples of its use in recent FPSC Dockets are the 2011 Fuel Cost Recovery Docket and the recent Mid-course Correction filing, and the Cape Canaveral and Riviera Modernization Need Determination dockets as well as the West County Energy Center Need Determination docket.

b. FPL is unaware of any other utility in Florida that uses the PMAREA model.

Q.
On page 6 of his testimony, Witness Enjamio testifies that Internal Revenue Services regulations limit the total amount of energy that can be received by FPL from the SJRPP purchase. Please provide a legal citation to the referenced Internal Revenue Services regulation(s).

A.
The limitation placed on the amount of capacity FPL can receive from SJRPP Units 1 and 2 is derived from Section 103 of the Internal Revenue Code of 1954 (26 U.S.C. § 103) and related U.S. Treasury Regulations sections 26 C.F.R. 1.103-7(b)(3)(iii), 26 C.F.R. 1.103-7(b)(5)(i) and 26 C.F.R. 1.103-7(b)(5)(ii)(b).

Q.
On page 14 of his testimony, Witness Enjamio testifies that FPL is "conducting reliability studies to determine if the 20% reserve margin criterion should be supplemented with a minimum reserve margin contribution from generation-only resources." Please describe the current status and any results of the referenced ongoing studies.

A.
The reliability studies remain a work in progress, and additional analyses and review are required. FPL intends to present the results of its work to the Commission Staff in 2012.

The analyses examine the projected frequency of use of FPL's load control (LC) resources (approximately 1,900 MW) over the remainder of this decade. A key part of the analysis consists of examining a number of scenarios involving load levels that may differ from the forecasted load, potential generating unit outage levels, and various dispatch orders for FPL's various LC programs (i.e., which LC program is dispatched first, which is dispatched second, etc). The resulting frequency of use of FPL's LC programs is then being evaluated versus expected tolerance levels of LC program participants to having their load controlled.

Please note that FPL's Petition for determination of need for the Port Everglades modernization project is based on FPL's current 20% total minimum reserve margin criterion. As such, FPL's request for approval of the modernization project is not based on a potential "generation-only" supplement to FPL's current reliability criterion.

Q.
On page 19 of his testimony, Witness Enjamio testifies that, "quantifying losses for generation resources at unspecified sites is somewhat speculative." Please explain why such quantification is somewhat speculative.

A.
The quantification of transmission losses is a calculation of the amount of generation needed to serve a given amount of load which varies depending on the electrical location and characteristics of the generation resources serving that load. Such calculation for generation resources at unspecified sites is speculative because a site location must be assumed in order to perform the calculation, an assumption that is speculative.

Although FPL has not quantified the level of the transmission losses, the fact that these sites would be located outside of South Florida and further away from the load center (compared to PEEC) indicates that transmission losses at these unspecified sites would be higher relative to generation located at Port Everglades. As stated in the testimony of Mr. Enjamio, FPL believes that not quantifying losses benefits the economics of the other resource plans relative to PEEC, thus understating the economic advantage of PEEC.

Q.
For each Resource Plan, other than the PEEC Resource Plan, please complete a table in the format used in page 1 and 2 of Exhibit JEE-1.

A.
See attached Tables 14-1, 14-2 and 14-3.

Table 14-1
Projection of FPL's Resource Needs through 2021
(Assuming Return to Service Plan)

August of the Year	(1) Projected FPL Unit Summer Capability (MW)	(2) Projected Firm Capacity Summer Purchases (MW)	(3) Projected Scheduled Maintenance * (MW)	(4) = (1) + (2) - (3) Projected Total Summer Capacity (MW)	(5) Projected Summer Peak Load (MW)	(6) Projected Summer DSM Capability (MW)	(7) = (5) - (6) Projected Summer Firm Peak Load (MW)	(8) = (4) - (7) Projected Summer Reserves (MW)	(9) = (8) / (7) Projected Summer Reserve Margin w/o Additions (%)	(10) = ((7)*1.20)-(4) **Projected MW Needed to Meet 20% Reserve Margin ** (MW)**
2011	22,474	2,056	0	24,530	21,618	1,856	19,762	4,767	24.1%	(815)
2012	23,437	1,956	714	24,679	21,623	1,986	19,637	5,042	25.7%	(1,115)
2013	24,164	1,956	826	25,294	21,931	2,109	19,822	5,472	27.6%	(1,507)
2014	25,467	1,956	826	26,597	23,243	2,272	20,971	5,626	26.8%	(1,432)
2015	25,507	2,046	0	27,553	23,786	2,404	21,382	6,170	28.9%	(1,894)
2016	25,498	740	0	26,238	24,315	2,536	21,779	4,458	20.5%	(103)
2017	25,498	740	0	26,238	24,529	2,667	21,862	4,376	20.0%	(3)
2018	25,498	740	0	26,238	24,674	2,799	21,875	4,362	19.9%	13
2019	25,872	740	0	26,612	25,041	2,930	22,111	4,501	20.4%	(78)
2020	26,085	740	0	26,825	25,499	3,062	22,437	4,387	19.6%	100
2021	26,298	740	0	27,038	25,960	3,194	22,766	4,272	18.8%	281

* MW values shown in Column (3) represent 714 MW out-of-service during the Summer of 2012 (St. Lucie 2), and 826 MW out-of-service during the Summer of 2013 and 2014 due to the installation of electrostatic precipitators at FPL's 800 MW generating units.

** MW values shown in Column (10) represent new generating capacity needed to meet the 20% reserve margin criterion.

Table 14-2
Projection of FPL's Resource Needs through 2021
(Assuming GFCC Plan)

August of the Year	(1) Projected FPL Unit Summer Capability (MW)	(2) Projected Firm Capacity Summer Purchases (MW)	(3) Projected Scheduled Maintenance * (MW)	(4) = (1) + (2) - (3) Projected Total Summer Capacity (MW)	(5) Projected Summer Peak Load (MW)	(6) Projected Summer DSM Capability (MW)	(7) = (5) - (6) Projected Summer Firm Peak Load (MW)	(8) = (4) - (7) Projected Summer Reserves (MW)	(9) = (8) / (7) Projected Summer Reserve Margin w/o Additions (%)	(10) = ((7)*1.20)-(4) **Projected MW Needed to Meet 20% Reserve Margin ** (MW)**
2011	22,474	2,056	0	24,530	21,618	1,856	19,762	4,767	24.1%	(815)
2012	23,437	1,956	714	24,679	21,623	1,986	19,637	5,042	25.7%	(1,115)
2013	24,164	1,956	826	25,294	21,931	2,109	19,822	5,472	27.6%	(1,507)
2014	25,467	1,956	826	26,597	23,243	2,272	20,971	5,626	26.8%	(1,432)
2015	25,507	2,046	0	27,553	23,786	2,404	21,382	6,170	28.9%	(1,894)
2016	26,373	740	0	27,113	24,315	2,536	21,779	5,333	24.5%	(978)
2017	26,373	740	0	27,113	24,529	2,667	21,862	5,251	24.0%	(878)
2018	26,373	740	0	27,113	24,674	2,799	21,875	5,237	23.9%	(862)
2019	26,373	740	0	27,113	25,041	2,930	22,111	5,002	22.6%	(579)
2020	26,373	740	0	27,113	25,499	3,062	22,437	4,675	20.8%	(188)
2021	26,373	740	0	27,113	25,960	3,194	22,766	4,347	19.1%	206

* MW values shown in Column (3) represent 714 MW out-of-service during the Summer of 2012 (St. Lucie 2), and 826 MW out-of-service during the Summer of 2013 and 2014 due to the installation of electrostatic precipitators at FPL's 800 MW generating units.

** MW values shown in Column (10) represent new generating capacity needed to meet the 20% reserve margin criterion.

Table 14-3
Projection of FPL's Resource Needs through 2021
(Assuming GFCT Plan)

August of the Year	(1) Projected FPL Unit Summer Capability (MW)	(2) Projected Firm Capacity Summer Purchases (MW)	(3) Projected Scheduled Maintenance * (MW)	(4) = (1) + (2) - (3) Projected Total Summer Capacity (MW)	(5) Projected Summer Peak Load (MW)	(6) Projected Summer DSM Capability (MW)	(7) = (5) - (6) Projected Summer Firm Peak Load (MW)	(8) = (4) - (7) Projected Summer Reserves (MW)	(9) = (8) / (7) Projected Summer Reserve Margin w/o Additions (%)	(10) = ((7)*1.20)-(4) **Projected MW Needed to Meet 20% Reserve Margin ** (MW)**
2011	22,474	2,056	0	24,530	21,618	1,856	19,762	4,767	24.1%	(815)
2012	23,437	1,956	714	24,679	21,623	1,986	19,637	5,042	25.7%	(1,115)
2013	24,164	1,956	826	25,294	21,931	2,109	19,822	5,472	27.6%	(1,507)
2014	25,467	1,956	826	26,597	23,243	2,272	20,971	5,626	26.8%	(1,432)
2015	25,507	2,046	0	27,553	23,786	2,404	21,382	6,170	28.9%	(1,894)
2016	25,435	740	0	26,175	24,315	2,536	21,779	4,395	20.2%	(40)
2017	25,435	740	0	26,175	24,529	2,667	21,862	4,313	19.7%	60
2018	25,435	740	0	26,175	24,674	2,799	21,875	4,299	19.7%	76
2019	26,712	740	0	27,452	25,041	2,930	22,111	5,341	24.2%	(918)
2020	26,712	740	0	27,452	25,499	3,062	22,437	5,014	22.3%	(527)
2021	26,712	740	0	27,452	25,960	3,194	22,766	4,686	20.6%	(133)

* MW values shown in Column (3) represent 714 MW out-of-service during the Summer of 2012 (St. Lucie 2), and 826 MW out-of-service during the Summer of 2013 and 2014 due to the installation of electrostatic precipitators at FPL's 800 MW generating units.

** MW values shown in Column (10) represent new generating capacity needed to meet the 20% reserve margin criterion.

Q.
On pages 4 and 5 of his testimony, Witness Gnecco testifies that the Port Everglades Site, "will be able to receive back-up fuel from waterborne deliveries."

a. Have waterborne fuel deliveries been made to the Port Everglades site in the past?
b. If the answer to 15.a. is "yes," please provide an estimate of the number of such deliveries and the total quantity delivered.

A.

a. Yes, waterborne fuel deliveries have been made to the Port Everglades site in the past.

b. The table below sets forth the number of waterborne fuel deliveries and the total volumes for the past 12 years (2000-2011).

	# Deliveries	Volume (bbl)
2000	32	6,162,668
2001	37	6,926,842
2002	30	5,634,469
2003	32	6,485,595
2004	26	5,937,715
2005	36	6,402,632
2006	19	2,805,938
2007	20	3,064,967
2008	11	1,576,231
2009	13	1,249,046
2010	16	1,123,810
2011	2	412,454
Total	274	47,782,367

Q.
In deciding to modernize the Port Everglades Plant, please identify each potential site FPL considered for new fossil fuel generation.

a. For each site identified in your response to Interrogatory 16, please provide information similar to that contained in IV.F.2 of FPL's 2011 Ten-Year Site Plan.
b. For each site identified in your response to Interrogatory 16, please describe the potential for receiving waterborne fuel delivery.

A.
a. The potential sites FPL considered and is considering for future new fossil fuel generation are consistent with those identified in the section IV.F.2 of FPL's 2011 Ten-Year Site Plan. Specifically, those sites are identified in FPL's 2011 Ten-Year Site Plan as Northeast Okeechobee County, Palatka Site in Putnam County, Putnam County, Southwest Indian River County, and West Broward in Broward County. For ease of reference the pertinent pages of FPL's 2011 Ten-Year Site Plan are attached.

b.

Potential Site # 1: Northeast Okeechobee County
No access to waterborne deliveries.

Potential Site # 2: Palatka Site, Putnam County
Waterborne deliveries could potentially be made at this site.

Potential Site # 3: Putnam County
No access to waterborne deliveries.

Potential Site # 4: Southwest Indian River County
No access to waterborne deliveries.

Potential Site # 5: West Broward, Broward County
No access to waterborne deliveries.

e. **Supply Sources**

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the solar panels in the absence of sufficient rainfall. Any such water would be brought to the site by truck.

Potential Site # 4: Hendry County

FPL is currently evaluating potential sites in Hendry County for a future PV facility or fossil generation. Sites currently under investigation are approximately 1,500 acres. No specific locations have been selected at this time.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the county has been included at the end of this chapter.

b. **Land Uses**

Hendry County has predominantly agricultural land use.

c. **Environmental Features**

This information is not available because a specific site has not been selected at this time.

d. **Water Quantities**

Minimal amounts of water would be required for a PV facility. Fossil generation would require approximately up to 150 gallons per minute (gpm) for process water and up to 7.5 million gallons per day (mgd) per unit for cooling water (assuming a cooling tower is utilized).

e. **Supply Sources**

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the solar panels in the absence of sufficient rainfall. The supply of water for fossil generation would be dependent upon the selection of a specific site.

Potential Site # 5: Manatee Plant Site, Manatee County

The existing FPL Manatee Plant 9,500-acre site is located in unincorporated north-central Manatee County. The existing power generating facilities are located in all or portions of Sections 18 and 19 of Township 33S, Range 20-E. The plant site lies approximately 5

c. **Environmental Features**

This information is not available because a specific site has not been selected at this time.

d. **Water Quantities**

Minimal amounts of water would be required for a PV facility.

e. **Supply Sources**

Minimal water would be required for a PV facility. A small amount may be needed to occasionally clean the solar panels in the absence of sufficient rainfall.

Potential Site # 7: Northeast Okeechobee County

FPL is currently evaluating potential sites in Northeast Okeechobee County for a future PV facility or fossil generation. Sites currently under investigation are approximately 1,500 acres. No specific locations have been selected at this time.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the county has been included at the end of this chapter.

b. **Land Uses**

Northeast Okeechobee County has predominantly agricultural land use.

c. **Environmental Features**

This information is not available because a specific site has not been selected at this time.

d. **Water Quantities**

As previously discussed, needed water quantities for fossil generation would be up to 150 gallons per minute (gpm) for process water and up to 7.5 million gallons per day (mgd) per unit for cooling water (assuming a cooling tower would be utilized). Needed water quantities would be significantly less for a PV facility.

e. **Supply Sources**

Existing groundwater and/or regional water supply initiatives are potential water sources.

Potential Site # 8: Palatka Site, Putnam County

FPL is currently evaluating a site adjacent to the FPL Putnam Plant in Putnam County for future fossil generation. The approximately 170 acre site was the location of the former FPL Palatka Plant which was dismantled in the 1990s.

a. **U.S. Geological Survey (USGS) Map**
A map of the site is found at the end of this chapter.

b. **Land Uses**
The site has a land use designation of Industrial.

c. **Environmental Features**
The majority of site has been previously impacted by past power plant operations. No significant environmental features have been identified at this time.

d. **Water Quantities**
As previously discussed, needed water quantities would be up to 150 gallons per minute (gpm) for process water and up to 7.5 million gallons per day (mgd) per unit for cooling water (assuming cooling tower).

e. **Supply Sources**
The St John's River, existing groundwater, and/or regional water supply initiatives are potential water sources.

Potential Site # 9: Port Everglades Plant, Broward County

The 94-acre FPL Port Everglades plant site is located at Port Everglades in Broward County. The site has convenient access to State Road (S.R.) 84 and I-595. Rail line is located near the plant. The existing plant consists of four steam boiler generating units: two 200 MW (approximate) and two 400 MW (approximate) sized units. The four steam boilers are capable of firing residual fuel oil, natural gas, or a combination of both. The site is also home to 12 simple cycle gas turbine (GT) peaking units of 35 MW (approximate) each. The GTs are capable of firing either natural gas or liquid fuel. This site is being considered for a potential modernization.

a. **U.S. Geological Survey (USGS) Map**
A map of the site is found at the end of this chapter.

b. **Land Uses**

The land on this site is primarily industrial. The adjacent land uses are port facilities and associated industrial activities, oil storage, cruise ships, and light commercial.

c. **Environmental Features**

The shoreline of the intake and discharge canal banks are vegetated with fringing mangrove, with some open, maintained grass areas on the side.

d. **Water Quantities**

Water quantities would be up to 150 gallons per minute (gpm) for process water and up to 7.5 million gallons per day (mgd) per unit for cooling water (assuming cooling tower).

e. **Supply Sources**

Existing groundwater or the municipal water supply could be used for industrial process and makeup water. Industrial cooling water needs could be met using the existing once-through cooling water system.

Potential Site # 10: Putnam County

FPL is currently evaluating potential sites in Putnam County for a future PV facility or fossil generation. Sites currently under investigation are approximately 2,800 acres. No specific locations have been selected at this time.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the county has been included at the end of this chapter.

b. **Land Uses**

Not available because a specific site has not been selected at this time.

c. **Environmental Features**

This information is not available because a specific site has not been selected at this time.

d. **Water Quantities**

Minimal amounts of water would be required for a PV facility. Fossil generation would require approximately up to 150 gallons per minute (gpm) for process water and up to

7.5 million gallons per day (mgd) per unit for cooling water (assuming a cooling tower is utilized).

e. **Supply Sources**

Existing groundwater is a potential water source.

Potential Site # 11: Southwest Indian River County

FPL is currently evaluating potential sites in Southwest Indian River County for a future PV facility or fossil generation. Sites currently under investigation are approximately 1,500 acres. No specific locations have been selected at this time.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the county has been included at the end of this chapter.

b. **Land Uses**

Southwestern Indian River County has predominantly agricultural land use.

c. **Environmental Features**

Not available because a specific site has not been selected at this time.

d. **Water Quantities**

As previously discussed, needed water quantities for fossil generation would be up to 150 gallons per minute (gpm) for process water and up to 7.5 million gallons per day (mgd) per unit for cooling water (assuming a cooling tower is utilized). Needed water quantities would be significantly less for a PV facility.

e. **Supply Sources**

Existing groundwater is a potential water source.

Potential Site # 12: Space Coast Solar Expansion, Brevard County

The Space Coast site is located at NASA's Kennedy Space Center property in Brevard County. This site currently consists of a 10 MW PV facility with the potential to expand by another 10 MW. Also, FPL is evaluating the potential for further expansion beyond the existing site, within the Space Center property.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the site has been included at the end of this chapter.

b. **Land Uses**

NASA, a federal agency, has approved use of the land at the site for PV generation.

c. **Environmental Features**

There are no significant environmental features on this site.

d. **Water Quantities**

Minimal amounts of water would be required for an expansion of the PV facility.

e. **Supply Sources**

No water would be required for an expansion of the PV facility except the small amount that may be needed to occasionally clean the solar panels in the absence of sufficient rainfall. Any such water would be brought to the site by truck or would come from existing onsite wells.

Potential Site # 13: West Broward, Broward County

FPL has identified its Andytown Substation property in western unincorporated Broward County as a potential site for the addition of new fossil generating capacity and FPL refers to this potential site as the West Broward site. Current facilities on-site include an electric substation. The existing site is an area accessible to both natural gas and electrical transmission through existing structures or through additional lateral connections.

a. **U.S. Geological Survey (USGS) Map**

A USGS map of the county has been included at the end of this chapter.

b. **Land Uses**

The land uses for the site are designated as agricultural use.

c. **Environmental Features**

Extensive low-quality wetlands are present on the site. Known presence of listed species nearby, e.g. wood storks, will require further investigation.

d. **Water Quantities**

As previously discussed, needed water quantities for fossil generation would be up to 150 gallons per minute (gpm) for process water and up to 7.5 million gallons per day (mgd) per unit for cooling water (assuming a cooling tower is utilized).

e. **Supply Sources**

Groundwater from the shallow aquifer or a local source of reclaimed (reuse) water has been identified as potential water sources. The Floridan Aquifer has also been identified as a potential cooling water source. FPL will also consider the potential for alternative water development options at this site.

Q.
For each of FPL's previously completed, or currently on-going conversion projects, please identify and discuss any budget or schedule overruns.

A.

Modernizations of Cape Canaveral and Riviera Units

Cost Category	Cape Canaveral Estimate Approved In Need Determination (2013 $MM)	Cape Canaveral Actual-to-Date Costs as of July 31, 2011 ($MM)	Cape Canaveral Estimated Total In-Service Cost as of July 31, 2011 (2013 $MM)
Power Block	963.0	277.2	992.4
Land	0.0	0.0	0.0
Transmission, Interconnection and Integration	33.0	0.9	33.0
AFUDC	119.0	9.0	89.6
Total Plant Cost	1,115.0	287.1	1,115.0

Cost Category	Riviera Estimate Approved In Need Determination (2014 $MM)	Riviera Actual-to-Date Costs as of July 31, 2011 ($MM)	Riviera Estimated Total In-Service Cost as of July 31, 2011 (2014 $MM)
Power Block	997.0	80.4	1,027.5
Land	0.0	0.0	0.0
Transmission, Interconnection and Integration	132.0	18.7	132.0
AFUDC	147.0	2.0	116.5
Total Plant Cost	1,276.0	101.1	1,276.0

Q.
On page 11 of his testimony, Witness Gnecco testifies that, "an advantage of the multi-train CC arrangement is that it allows for flexibility in matching unit output to generation requirements over time." Please provide the summer capacity of the PEEC assuming each possible configuration of the unit.

A.
Assuming "J" technology CTs are utilized at PEEC, the summary capacity at 95 degrees Fahrenheit would be:

3 x 1 "J" combined cycle with all three CTs operating @ 100% load Output = 1277 MW
3 x 1 "J" combined cycle with two of three CTs operating @ 100% load Output = 844 MW
3 x 1 "J" combined cycle with one of three CTs operating @ 100% load Output = 404 MW

Q.
On page 21 of his testimony, Witness Gnecco testifies that if the proposed project is delayed, "FPL's customers would . . . incur the impacts from generation shortfalls that affect service reliability." Please describe the specific impacts that are expected if the proposed project is delayed.

A.
If the Port Everglades modernization project were delayed, and no other resource was added to take its place, FPL would be serving its customers with a system that has less than a 20% reserve margin level. The extent to which FPL's system Summer reserve margin would degrade to less than 20% during 2016 through 2021 under such a scenario, and the amount of MW that would be needed to return the FPL system to a Summer reserve margin of 20%, is presented in Exhibit JEE-1, page 1 of 2, of FPL Witness Enjamio's direct testimony.

Such a decrease in FPL's system reserve margin level will increase the likelihood that FPL will be unable to continue to reliably serve its customers at peak load periods. This concern is illustrated in the example shown in attached Table 19-1. In this table, a single year (2017) in the 2016 through 2020 time frame is examined using recent levels of deviation from forecast in key reserve margin calculation assumptions such as future load and available generation, plus DSM levels.

On page 1 of 2 of Table 19-1, the PEEC modernization is assumed to have gone in service in 2016 as proposed by FPL. In this case, even after accounting for recently experienced levels of generating unit unavailability, higher-than-forecasted load, use of all load control, and lower-than-forecasted energy efficiency, FPL is still projected to have generating reserves on the Summer peak day. However, as shown on page 2 of 2 of Table 19-1, a decision not to proceed with the PEEC modernization project given the same situation would result in FPL not having sufficient reserves to meet load even with implementing 100% of its load control reserves even if all of the forecasted energy efficiency materialized. A lower-than-forecasted energy efficiency level would further worsen the projected results.

In addition, if the modernization project were delayed as described above, FPL's customers would experience higher costs and higher emission levels than will be the case if the modernization project is approved for a 2016 in-service date.

Table 19-1

POSSIBLE OUTCOMES IN 2017 With PEEC Added in 2016

Year	Month	FPL Generating Capacity (MW)	Purchased Generating Capacity (MW)	Total Generating Capacity (MW)	Unavailable Generation Capacity (MW)	Available Generating Capacity (MW)	Projected Peak Load for 2017 (MW)	Projected Reduction in Load Due to Energy Efficiency (EE) (MW)	Variance Due To Higher Than Forecasted Peak Load (MW)	Actual Peak Load (MW)	Generating Capacity Reserves above/(below) Peak Load (MW)	Projected Load Control (LC) Available for Use (MW)	Remaining LC Reserves above/ (below) need (MW)	Total Remaining Reserves on Peak Day (MW)
2017	August	26,388	740	27,128	0	27,128	24,529	(599)	0	23,930	3,198	2,068	2,068	**5,266**
	The above outcome assumes everything (installed capacity, peak load, DSM additions) occurs in 2017 exactly as projected 6 years earlier with no plant unavailabilities.													
2017	August	26,388	740	27,128	(1,800)	25,328	24,529	(599)	0	23,930	1,398	2,068	2,068	**3,466**
	The above outcome assumes that 1,800 MW of generation are unavailable; all else is as projected. This outage estimate is based on the possibility that one of FPL's largest units is unavailable and that 1/2 of another unit is also unavailable, a not uncommon situation.													
2017	August	26,388	740	27,128	(1,800)	25,328	24,529	(599)	2,216	26,146	(818)	2,068	1,250	**1,250**
	The above outcome **also** assumes that the actual peak load before DSM is approximately 9% higher than the forecasted load for this year. This variance is consistent with an upper band on the projected variance for a 6-year-ahead forecast based on historical data.													
2017	August	26,388	740	27,128	(1,800)	25,328	24,529	(300)	2,216	26,446	(1,118)	2,068	951	**951**
	The above outcome **also** assumes that only 50% of the FPL incremental EE materializes.													

Notes:

The results above assume that all generating capacity, except as explicitly assumed above as unplanned unavailable, is operating at maximum capacity (i.e., no other partial or full outages), and that there are no fuel supply interruptions or transmission interruptions, and that all projected Load Control is available and exerciseable, and that FPL is not providing assistance to any other utility.

As used here, the term "unplanned" means not reflected in FPL's long term plan, such as the Ten Year Site Plan.

On the other hand, the above results assume that there is no short-term capacity available for FPL to purchase.

Table 19-1

POSSIBLE OUTCOMES IN 2017 Without PEEC

Year	Month	FPL Generating Capacity (MW)	Purchased Generating Capacity (MW)	Total Generating Capacity (MW)	Unavailable Generation Capacity (MW)	Available Generating Capacity (MW)	Projected Peak Load for 2017 (MW)	Projected Reduction in Load Due to Energy Efficiency (EE) (MW)	Variance Due To Higher Than Forecasted Peak Load (MW)	Actual Peak Load (MW)	Generating Capacity Reserves above/(below) Peak Load (MW)	Projected Load Control (LC) Available for Use (MW)	Remaining LC Reserves above/ (below) need (MW)	Total Remaining Reserves on Peak Day (MW)
2017	August	25,111	740	25,851	0	25,851	24,529	(599)	0	23,930	1,921	2,068	2,068	**3,989**
	The above outcome assumes everything (installed capacity, peak load, DSM additions) occurs in 2017 exactly as projected 6 years earlier with no plant unavailabilities (except the omission of PEEC).													
2017	August	25,111	740	25,851	(1,800)	24,051	24,529	(599)	0	23,930	121	2,068	2,068	**2,189**
	The above outcome assumes that 1,800 MW of generation are unavailable; all else is as projected. This outage estimate is based on the possibility that one of FPL's largest units is unavailable and that 1/2 of another unit is also unavailable, a not uncommon situation.													
2017	August	25,111	740	25,851	(1,800)	24,051	24,529	(599)	2,216	26,146	(2,095)	2,068	(27)	(27) **UNSERVED LOAD EVEN WITH LC**
	The above outcome **also** assumes that the actual peak load before DSM is approximately 9% higher than the forecasted load for this year. This variance is consistent with an upper band on the projected variance for a 6-year-ahead forecast based on historical data.													
2017	August	25,111	740	25,851	(1,800)	24,051	24,529	(300)	2,216	26,446	(2,395)	2,068	(327)	(327) **UNSERVED LOAD EVEN WITH LC**
	The above outcome **also** assumes that only 50% of the FPL incremental EE materializes.													

Notes:

The results above assume that all generating capacity, except as explicitly assumed above as unplanned unavailable, is operating at maximum capacity (i.e., no other partial or full outages), and that there are no fuel supply interruptions or transmission interruptions, and that all projected Load Control is available and exerciseable, and that FPL is not providing assistance to any other utility.

As used here, the term "unplanned" means not reflected in FPL's long term plan, such as the Ten Year Site Plan.

On the other hand, the above results assume that there is no short-term capacity available for FPL to purchase.

Q.
On pages 21 and 22 of his testimony, Witness Gnecco testifies that, "the cost of building PEEC later would likely be greater than currently projected." What is the basis for this statement?

A.
Building PEEC after 2016 could result in higher costs due to material cost escalation, labor cost escalation, increased global demand for raw material and other commodity costs due to an improved global economy.

Q.
On page 24 of his testimony, Witness Enjamio testifies that, "by reducing the height of the smokestacks and building a lower profile than the existing units, the Project will significantly improve the aesthetics of the site." Has FPL received comments from local government or members of the public regarding the appearance of the Port Everglades Plant? If "yes," please describe.

A.
Yes, during public presentations and individual briefings with local governmental and business leaders, FPL received numerous positive comments regarding the plans to lower the stack height. By way of example, (1) Margaret Kempel, Executive Director of the Port Everglades Association, commented that the lower profile of the new stacks would improve the overall appearance of the Port; and (2) Dan Lindblade, President and CEO, of the Greater Fort Lauderdale Chamber of Commerce, congratulated FPL on the new modern design of the Port Everglades Plant, specifically the improved aesthetics achieved with the low profile stacks.

Q.
In Exhibit JCG-9, the total plant cost for the PEEC does not include demolition of the existing facility. Why was the cost of demolition not included in this exhibit?

a. Did the CPVRR analysis consider the costs associated with the demolition of the existing facility?
b. Please provide a cost estimate for the demolition of the existing facility.
c. What is the salvage value of the existing facility?
d. How much has, or will, FPL receive for salvage of the existing facility?

A.
Demolition costs for the existing Port Everglades facility are not included in the construction cost estimate for PEEC because FPL accrues demolition costs based on its approved dismantlement studies, and demolition would be required at the Port Everglades site within a reasonable period of time regardless of whether PEEC is built. Thus, demolition cannot be considered an incremental cost incurred as a result of the modernization project.

a. No, consistent with the above statement, demolition costs were not considered in the CPVRR analysis.

b. As reflected in FPL's 2009 dismantlement study and approved by the FPSC in Order No. PSC-10-0153-FOF-EI, Docket Nos. 080677-EI and 090130-EI, the estimated total cost to dismantle the existing Port Everglades facility, excluding the salvage value that is addressed in part c below, is approximately $71.6 million. This cost estimate will be updated when FPL completes its next dismantlement study, which must be filed with the FPSC no later than March 2013. As required in FPSC Rule No. 25-6.04364, Electric Utilities Dismantlement Studies, FPL must file a dismantlement study every four years in recognition that cost estimates and the assumptions upon which they are based can change over time. As such, any revisions to FPL's cost estimates and assumptions for Port Everglades will be determined when a full evaluation is completed and filed with the FPSC in FPL's next dismantlement study.

c. As reflected in FPL's 2009 dismantlement study and approved by the FPSC, the estimated salvage value is $10.7 million. This value will also be updated to reflect current market conditions when FPL files its next dismantlement study in March 2013.

d. FPL has not received any salvage value for the existing Port Everglades facility at this time. The estimated salvage value FPL expects to receive is $10.7 million, as noted in the response to part c.

Q.
On pages 2 of her testimony, Witness Morley indicates that she has, "received designation as a certified professional forecaster." Please describe the criteria for receiving such a designation.

A.
The designation of Certified Professional Forecaster (CPF) is awarded by the Institute of Business Forecasting and Planning. In order to receive designation as a CPF from the Institute of Business Forecasting and Planning a candidate must receive a passing score of 70% on three individual exams covering different aspects of business forecasting. Forecasters are eligible to take the CPF exams if they have a bachelors degree and one year of professional experience.

Q.
On page 5 of her testimony, witness Morley describes several industry experts that were relied upon by FPL for certain projections.

a. Has FPL relied on these industry experts for forecasting customer growth, net energy for load, or peak demand in the past? If "yes," please describe.
b. Please identify, and explain the reason for, any adjustments made by FPL to the information provided by the industry experts identified by witness Morley.

A.

a. Yes. FPL has relied upon industry experts for the projections of a number of our independent variables in the past. Population forecasts have been produced by the University of Florida's Bureau of Economic and Demographic Research in conjunction with the Office of Economic and Demographic Research of the state legislature. Economic assumptions have been provided by IHS Global.

b. No adjustments have been made to any projections provided by industry experts identified in witness Morley's testimony.

Q.
Exhibit RM-6 provides a forecasted real price of electricity.

a. Was a base rate increase assumed in the real price of electricity forecast contained in RM-6?

b. Please describe the reason for the projected increase in the real price of electricity beginning in 2017.

A.

a. The real price of electricity forecast in RM-6 does not assume particular base rate increases, but is intended to reflect the long-term cost of new generation.

b. The primary reason for the increase in the real price of electricity beginning in 2017 is rising fuel costs. The recovery of pre-construction costs for Turkey Point Nuclear Units 6 and 7 in 2017 is also a contributing factor. Additionally, beginning in 2018 the price forecast incorporates the estimated cost impact associated with CO2 emissions legislation.

Q.
On page 7 of her testimony, witness Morley testifies that, "[g]rowth in FPL's peak demand has been a function of a larger customer base, weather conditions, economic growth, energy efficiency standards, and changing patterns of customer behavior." Please describe the changing patterns of customer behavior which affect FPL's peak demand.

A.
Each of the coefficients in the summer peak model reflects how customer behavior interacts with an independent variable (e.g. the economy, price, etc.) and thereby affects FPL's peak demand. For example, the coefficient on energy efficiency standards in the summer peak model addresses the behavioral changes resulting from energy efficiency standards. As energy efficiency standards change, there is a behavioral response on the part of electric customers. While new appliances may have improved energy efficiency ratings based on engineering estimates, the actual impact on the summer peak will depend on how customers modify their electric consumption given that energy savings.

Q.
On page 13-14 of his testimony, witness Modia testifies that power flow studies are performed as part of the evaluation process for transmission interconnection and integration of new generation resources.

a. Please describe how these studies are performed.
b. Are there industry-accepted programs or standards for such studies?
c. If the answer to 27.b. is "yes," please identify and describe.

A.
a. As part of the evaluation process for transmission interconnection and integration of any new generation resource, FPL performs a Feasibility Study which includes load flow and short-circuit fault analysis, a System Impact Study which refines the Feasibility Study and adds dynamic stability analysis, and a Facilities Study which details the specific requirements for interconnection and integration of the generating facility.

b. Yes.

c. The generator interconnection and integration studies that FPL performs are in accordance with North American Electric Reliability Corporation (NERC) Standards for Transmission Planning, conform to the Federal Energy Regulatory Commission's (FERC) Large Generator Interconnection Procedures which are incorporated in FPL's Open Access Transmission Tariff, and are approved/accepted by the Florida Reliability Coordinating Council (FRCC). These standards and procedures are common throughout the electric utility industry. In addition, FPL uses Siemens Power System Simulator/Engineering PSS/e) software and related programs, which are the industry accepted standard for transmission studies in the Eastern Interconnection transmission system of the United States.

Q.
Please provide the total miles of new transmission associated with each resource plan described in the testimony of witness Enjamio.

A.
The PEEC Resource Plan has 0 miles of new transmission lines and the Return to Service Resource Plan has 0 miles of new transmission lines. The GFCT and GFCC Resource Plans have an unknown number of miles of transmission lines, as the exact location of the greenfield units included in those plans is unknown. The economic evaluation assumed that the GFCT and GFCC Resource Plans would be located such that minimal new transmission would be necessary for the interconnection of the resources. As witness Enjamio states in his direct testimony, the GFCC resource plan does, however, include approximately $638 million worth of new transmission lines and/or transmission line upgrades which would be needed to continue to reliably serve the Southeast Florida area in any resource plan where no generation is added or returned to service at the Port Everglades site. This cost estimate is based on approximately 100 miles of new lines.

Q.
How were transmission costs estimated for each resource plan evaluated by witness Enjamio?

A.
The transmission costs for each resource plan were estimated by engineers who utilized Transmission & Substation's internal estimating system, PUR (Project Updating & Reporting system). PUR uses recent project costs – labor, material, and other costs – to generate estimates. These costs were then escalated by the CPI (consumer price index) based on the in-service date year. A Transmission & Substation cross functional team then vetted the estimates for accuracy and completeness prior to their submittal.

Q.
Please complete the table below assuming no CO2 costs. Please provide this information for the four resource plans discussed in witness Enjamio's testimony.

A.
See attached Tables 30-1, 30-2, 30-3, and 30-4.

PEEC Resource Plan- Revenue Requirements Assuming no CO2 Costs

	(1)	(2)	(3)	(4)	(5)	(6)
	Annual Revenue Requirements (Generation Capital) ($millions, 2011 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2011 $)	Annual Revenue Requirements (O&M) ($millions, 2011 $)	Annual Revenue Requirements (Fuel) ($millions, 2011 $)	Annual Revenue Requirements (Environmental) ($millions, 2011 $)	Total ($millions, 2011 $)
2011	0	0	0	3,250	-11	3,239
2012	0	0	1	3,434	-5	3,430
2013	0	0	1	3,433	-8	3,426
2014	0	0	1	3,665	-7	3,659
2015	0	0	1	3,972	-8	3,966
2016	115	3	33	4,651	-9	4,794
2017	192	5	42	5,059	-9	5,291
2018	185	5	43	5,491	-9	5,716
2019	179	5	45	5,916	-9	6,135
2020	172	5	46	6,550	-9	6,764
2021	303	15	73	7,081	-10	7,462
2022	388	21	97	7,324	-11	7,820
2023	374	20	97	7,262	-12	7,741
2024	360	19	100	7,849	-12	8,316
2025	346	19	106	8,655	-12	9,114
2026	421	18	122	9,032	-12	9,580
2027	466	17	137	9,500	-12	10,109
2028	532	16	157	9,817	-12	10,510
2029	744	16	205	10,117	-13	11,070
2030	927	15	252	10,578	-13	11,758
2031	1,045	14	288	11,045	-14	12,379
2032	1,259	14	344	11,740	-14	13,342
2033	1,636	13	435	12,876	-15	14,945
2034	1,879	13	506	13,561	-15	15,943
2035	1,979	12	553	14,023	-16	16,552
2036	2,295	11	642	15,156	-16	18,089
2037	2,541	11	728	15,765	-16	19,028
2038	2,632	11	781	16,288	-17	19,696
2039	2,841	10	862	16,955	-17	20,652
2040	3,012	10	944	17,501	-18	21,450
2041	3,100	10	1,007	18,105	-18	22,203
2042	3,317	9	1,099	18,842	-19	23,249
2043	3,624	9	1,213	19,913	-19	24,741
2044	3,931	9	1,333	20,779	-19	26,033
2045	4,097	8	1,434	21,482	-19	27,001
2046	4,283	8	1,546	22,236	-20	28,054
2047	4,434	8	1,656	23,038	-20	29,115
CPVRR	8,410	108	2,522	103,144	-146	114,038

Return To Service Resource Plan: Revenue Requirements Assuming no CO2 Costs

	(1)	(2)	(3)	(4)	(5)	(6)
	Annual Revenue Requirements (Generation Capital) ($millions, 2011 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2011 $)	Annual Revenue Requirements (O&M) ($millions, 2011 $)	Annual Revenue Requirements (Fuel) ($millions, 2011 $)	Annual Revenue Requirements (Environmental) ($millions, 2011 $)	Total ($millions, 2011 $)
2011	0	0	0	3,250	-11	3,239
2012	0	0	1	3,434	-5	3,430
2013	0	0	1	3,433	-8	3,426
2014	0	0	42	3,665	-7	3,699
2015	0	0	42	3,972	-8	4,006
2016	0	0	17	4,739	-8	4,748
2017	0	0	52	5,207	-8	5,251
2018	0	0	80	5,631	-8	5,703
2019	0	0	98	6,064	-8	6,154
2020	0	0	60	6,728	-8	6,781
2021	137	10	115	7,254	-8	7,508
2022	229	17	75	7,466	-10	7,776
2023	220	16	117	7,384	-11	7,727
2024	212	15	135	7,981	-11	8,332
2025	204	15	111	8,812	-11	9,132
2026	296	14	146	9,191	-11	9,636
2027	355	14	147	9,659	-11	10,164
2028	426	13	151	9,971	-11	10,550
2029	644	13	216	10,252	-12	11,112
2030	831	12	229	10,699	-12	11,758
2031	955	12	294	11,147	-13	12,394
2032	1,174	11	351	11,826	-13	13,348
2033	1,556	10	433	12,972	-14	14,958
2034	1,804	10	497	13,653	-15	15,950
2035	1,910	9	545	14,116	-15	16,565
2036	2,230	9	618	15,249	-15	18,092
2037	2,480	9	726	15,848	-16	19,047
2038	2,574	8	769	16,374	-16	19,710
2039	2,787	8	836	17,029	-17	20,643
2040	2,960	8	912	17,575	-17	21,439
2041	3,050	8	976	18,176	-17	22,193
2042	3,270	7	1,093	18,910	-18	23,262
2043	3,580	7	1,194	19,981	-18	24,744
2044	3,889	7	1,295	20,848	-19	26,020
2045	4,057	7	1,394	21,545	-19	26,983
2046	4,272	6	1,505	22,297	-20	28,060
2047	4,441	6	1,604	23,096	-20	29,127
CPVRR	7,244	74	2,645	104,314	-137	114,140

GFCC Resource Plan: Revenue Requirements Assuming no CO2 Costs

	(1)	(2)	(3)	(4)	(5)	(6)
	Annual Revenue Requirements (Generation Capital) ($millions, 2011 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2011 $)	Annual Revenue Requirements (O&M) ($millions, 2011 $)	Annual Revenue Requirements (Fuel) ($millions, 2011 $)	Annual Revenue Requirements (Environmental) ($millions, 2011 $)	Total ($millions, 2011 $)
2011	0	0	0	3,250	-11	3,239
2012	0	0	1	3,434	-5	3,430
2013	0	0	1	3,433	-8	3,426
2014	0	0	1	3,665	-7	3,659
2015	0	0	1	3,972	-8	3,966
2016	118	10	33	4,665	-9	4,818
2017	197	17	42	5,084	-9	5,332
2018	190	22	43	5,510	-9	5,757
2019	183	26	45	5,933	-9	6,177
2020	176	90	46	6,564	-9	6,867
2021	307	142	73	7,096	-10	7,608
2022	392	143	97	7,335	-11	7,957
2023	378	138	97	7,272	-11	7,872
2024	363	132	100	7,860	-12	8,444
2025	350	127	106	8,665	-12	9,236
2026	426	122	122	9,041	-12	9,700
2027	473	118	138	9,507	-12	10,223
2028	538	113	158	9,823	-12	10,620
2029	750	108	206	10,126	-13	11,177
2030	932	103	252	10,588	-13	11,863
2031	1,051	99	289	11,054	-14	12,478
2032	1,264	94	345	11,750	-14	13,439
2033	1,641	90	435	12,887	-15	15,038
2034	1,883	85	507	13,573	-15	16,033
2035	1,984	81	554	14,035	-16	16,638
2036	2,299	79	643	15,167	-16	18,172
2037	2,545	76	729	15,777	-16	19,110
2038	2,636	74	782	16,300	-17	19,775
2039	2,845	72	863	16,968	-17	20,730
2040	3,016	70	945	17,514	-18	21,526
2041	3,103	67	1,008	18,120	-18	22,280
2042	3,320	65	1,100	18,857	-19	23,324
2043	3,627	63	1,214	19,927	-19	24,813
2044	3,934	61	1,334	20,795	-19	26,104
2045	4,099	58	1,435	21,498	-19	27,071
2046	4,285	56	1,547	22,252	-20	28,120
2047	4,435	50	1,657	23,054	-20	29,175
CPVRR	8,450	757	2,525	103,268	-146	114,854

GFCT Resource Plan: Revenue Requirements Assuming no CO2 Costs

	(1)	(2)	(3)	(4)	(5)	(6)
	Annual Revenue Requirements (Generation Capital) ($millions, 2011 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2011 $)	Annual Revenue Requirements (O&M) ($millions, 2011 $)	Annual Revenue Requirements (Fuel) ($millions, 2011 $)	Annual Revenue Requirements (Environmental) ($millions, 2011 $)	Total ($millions, 2011 $)
2011	0	0	0	3,250	-11	3,239
2012	0	0	1	3,434	-5	3,430
2013	0	0	1	3,433	-8	3,426
2014	0	0	1	3,665	-7	3,659
2015	0	0	1	3,972	-8	3,966
2016	33	4	14	4,741	-8	4,784
2017	56	7	7	5,210	-8	5,273
2018	53	7	8	5,633	-8	5,693
2019	177	10	32	5,962	-9	6,173
2020	259	12	51	6,548	-9	6,862
2021	249	12	53	7,182	-9	7,487
2022	240	11	57	7,460	-10	7,758
2023	231	11	56	7,374	-11	7,660
2024	222	10	57	7,973	-11	8,251
2025	213	10	62	8,808	-11	9,083
2026	411	21	99	9,103	-11	9,623
2027	540	28	130	9,537	-11	10,225
2028	604	27	150	9,851	-12	10,620
2029	813	26	198	10,147	-13	11,172
2030	994	25	244	10,607	-13	11,856
2031	1,110	24	280	11,064	-14	12,465
2032	1,323	23	336	11,761	-14	13,428
2033	1,699	22	426	12,898	-15	15,031
2034	1,941	21	497	13,583	-15	16,027
2035	2,041	20	544	14,044	-16	16,634
2036	2,356	20	633	15,175	-16	18,167
2037	2,599	19	718	15,782	-16	19,102
2038	2,688	18	771	16,308	-17	19,769
2039	2,895	17	852	16,971	-17	20,718
2040	3,064	16	933	17,518	-18	21,515
2041	3,150	16	996	18,122	-18	22,266
2042	3,365	15	1,088	18,857	-18	23,307
2043	3,669	15	1,202	19,930	-19	24,797
2044	3,972	14	1,321	20,794	-19	26,083
2045	4,135	14	1,421	21,495	-19	27,046
2046	4,337	13	1,533	22,247	-20	28,111
2047	4,498	13	1,643	23,047	-20	29,180
CPVRR	8,189	134	2,338	103,795	-142	114,314

Q.
On page 12 of his testimony, witness Enjamio testifies that approximately $300 million in savings will result from placing Turkey Point Unit 1 in inactive reserve. Please describe and quantify each source of these savings.

A.
FPL compared the PEEC Resource Plan with Turkey Point 1 in inactive reserve to a resource plan in which Turkey Point 1 remained in active generation service. Under the resource plan that includes Turkey Point 1 in active service, PEEC is delayed from 2016 to 2019 and the greenfield combined cycle that follows PEEC is then delayed from 2021 to 2026.

The PEEC Resource Plan with Turkey Point Unit 1 in inactive reserve results in total system variable O&M and fuel cost savings of $886 million (CPVRR, 2011$) compared to the resource plan in which Turkey Point 1 remains in service. These variable cost savings are offset by higher total system fixed costs of $588 million (CPVRR, 2011$) compared to the resource plan in which Turkey Point 1 remains in service. The resulting net savings amounts to $298 million (CPVRR, 2011$).

Q.
Please provide FPL's LOLP analysis for the four resource plans discussed in witness Enjamio's testimony.

A.
Table 32-1, attached, shows the annual LOLP values for the four resource plans from 2016 to 2021.

Table 32-1
Loss-of-Load Probabilities (LOLP) for the four Resource Plans

PEEC Resource Plan	
	LOLP(Days/Year)
2016	0.000271
2017	0.000332
2018	0.000416
2019	0.000852
2020	0.001473
2021	0.000245

Return to Service Resource Plan	
	LOLP(Days/Year)
2016	0.001556
2017	0.001935
2018	0.002474
2019	0.002084
2020	0.002189
2021	0.000212

GFCC Resource Plan	
	LOLP(Days/Year)
2016	0.000277
2017	0.000339
2018	0.000425
2019	0.000871
2020	0.001507
2021	0.000250

GFCT Resource Plan	
	LOLP(Days/Year)
2016	0.001827
2017	0.002276
2018	0.002810
2019	0.000409
2020	0.000692
2021	0.001532

FPL's LOLP reliability criterion is a maximum of 0.1 day/year. The projected LOLP values shown above are significantly lower than this criterion.

FPL's need for resources is driven by its Summer Reserve Margin criterion of 20%.

Q.
Please explain the reason for the difference in the fixed costs for the PEEC Resource Plan and the GFCC Resource Plan set forth in Exhibit JEE-3.

A.
There is a difference in fixed costs of $692 million (CPVRR, 2011$) between the PEEC Resource Plan and the GFCC Resource Plan. The main reason is due to the difference in transmission costs between the two plans which is approximately $649 million (CPVRR, 2011$). In addition, there are approximately $40 million (CPVRR, 2011$) in generation capital costs due to the difference in generation capital costs of PEEC, the GFCC units and the filler units used in the plans. The direct testimonies of FPL witnesses Modia and Enjamio address transmission investments which are approximately $638 million in overnight capital costs (in 2016 dollars) which are included in the GFCC Resource Plan. The difference in generation capital costs between PEEC and the GFCC are due mainly to the use of cooling towers in the GFCC which are not planned for PEEC.

Q.
Please complete the table below for the PEEC, the 2016 Greenfield Combined Cycle Units and the 2016 Greenfield Combustion Turbine.

Generation Technology	
Net Generation MW, Summer)	
Installed Cost	
Capital $/kw	
Fixed O&M ($/kw-yr) 2011$	
Variable O&M ($/MWh) 2011$	
Heat Rate (BTU/kwh)	
Equivalent Availability (%)	
Capacity Factor	
Water Usage (million gal/day)	

A.
Please see attached Table 34-1.

Table 34-1

PEEC (assuming 2016 in-service date)

Generation Technology	3x1 MHI J
Net Generation MW, Summer	1,277
Installed Cost $ Millions	1,185.2
Capital $/kW, summer	928
Fixed O&M ($/kW-yr) 2011$	7.99
Variable O&M ($/MWh) 2011$	0.09
Heat Rate (BTU/kWh) (75°F case)	6,330
Equivalent Availability (%)	95.4
Capacity Factor	95
Water Usage (million gal/day) (once through seawater)	635

Greenfield Combined Cycle (assuming 2016 in-service date)

Generation Technology	3x1 MHI J
Net Generation MW, Summer	1,262
Installed Cost $ Millions	1,271.1
Capital $/kW, summer	1,007
Fixed O&M ($/kW-yr) 2011$	8.08
Variable O&M ($/MWh) 2011$	0.51
Heat Rate (BTU/kWh) (75°F case)	6,369
Equivalent Availability (%)	95.4
Capacity Factor	84
Water Usage (million gal/day) (Cooling Tower makeup)	7 to 8

Greenfield Combustion Turbine (assuming 2016 in-service date)

Generation Technology	1x0 GE 7FA.03
Net Generation MW, Summer	162
Installed Cost $ Millions	178.3
Capital $/kW, summer	1,100.6
Fixed O&M ($/kW-yr) 2011$	7.9
Variable O&M ($/MWh) 2011$	0.27
Heat Rate (BTU/kWh) (75°F case)	10,410
Equivalent Availability (%)	95.4
Capacity Factor	1
Water Usage (million gal/day)	0.07

Notes:

Installed cost includes AFUDC.

Capacity factor is based on average from 2016 to 2025.

The analysis was performed assuming "J" technology CTs for the combined cycles. FPL is considering a number of advanced combustion turbine designs and has not yet made a final decision for the PEEC project.

Q.
Please complete the table below for the PEEC, the 2016 Greenfield Combined Cycle Units and the 2016 Greenfield Combustion Turbine.

Generation Technology	
Net Generation MW, Summer)	
Installed Cost	
Capital $/kw	
Fixed O&M ($/kw-yr) 2011$	
Variable O&M ($/MWh) 2011$	
Heat Rate (BTU/kwh)	
Equivalent Availability (%)	
Capacity Factor	
Water Usage (million gal/day)	

A.
Please see attached corrected table.

Table 34-1 Corrected

PEEC (assuming 2016 in-service date)

Generation Technology	3x1 MHI J
Net Generation MW, Summer	1,277
Installed Cost $ Millions	1,185.2
Capital $/kw, summer	928
Fixed O&M ($/kw-yr) 2016$	7.99
Variable O&M ($/MWh) 2016$	0.10
Heat Rate (BTU/kwh) (75°F case)	6,330
Equivalent Availability (%)	95.4
Capacity Factor	95
Water Usage (million gal/day) (once through seawater)	635

Greenfield Combined Cycle (assuming 2016 in-service date)

Generation Technology	3x1 MHI J
Net Generation MW, Summer	1,262
Installed Cost $ Millions	1,271.1
Capital $/kw, summer	1,007
Fixed O&M ($/kw-yr) 2016$	8.08
Variable O&M ($/MWh) 2016$	0.58
Heat Rate (BTU/kwh) (75°F case)	6,369
Equivalent Availability (%)	95.4
Capacity Factor	84
Water Usage (million gal/day) (Cooling Tower makeup)	7 to 8

Greenfield Combustion Turbine (assuming 2016 in-service date)

Generation Technology	1x0 GE 7FA.03
Net Generation MW, Summer	162
Installed Cost $ Millions	178.3
Capital $/kw, summer	1,100.6
Fixed O&M ($/kw-yr) 2016$	7.9
Variable O&M ($/MWh) 2016$	0.30
Heat Rate (BTU/kwh) (75°F case)	10,410
Equivalent Availability (%)	95.4
Capacity Factor	1
Water Usage (million gal/day)	0.07

Notes:

Installed cost includes AFUDC

Capacity factor is based on average from 2016 to 2025.

The analysis was performed assuming "J" technology CTs for the combined cycles. FPL is considering a number of advanced combustion turbine designs and has not yet made a final decision for the PEEC project.

Q.
Please identify and quantify any savings that have resulted from placing the four steam units at FPL's Port Everglades Site in inactive reserve.

A.
Port Everglades Units 1 & 2: FPL classified Port Everglades Units 1 & 2 as inactive reserve in May 2009, and plans to retire those units at the end of January 2013, pending Public Service Commission approval of unit modernization.

Actual O&M expenditures for the five year period 2004-2008 were approximately $33 million and were forecasted to be $6 million for 2009-2013, a $27 million reduction over the prior period.
Actual Capital expenditures for the five year period 2004-2008 were approximately $40 million and were forecasted to be $7 million for 2009-2013, a $33 million reduction over the prior period.

Port Everglades Units 3 & 4: FPL temporarily classified Port Everglades Units 3 & 4 as inactive reserve in August 2011, and plans to return to those units to active service in January 2012 until their retirement at the end of January 2013, pending Public Service Commission approval of unit modernization.
Looking at the same five year periods as Units 1 & 2, actual O&M expenditures were approximately $45 million for 2004-2008 and were forecasted to be $31 million for 2009-2013, a $14 million reduction over the prior period.

Actual Capital expenditures for the period 2004-2008 were approximately $79 million and were forecasted to be $12 million for 2009-2013, a $67 million reduction over the prior period.
Planning for the units to go inactive and for modernization has reduced O&M and Capital expenditures for the period 2009-2013.

In summary, the total five year O&M and Capital cost savings ($41 million and $100 million respectively) associated with the four steam units are estimated to total $141 million.

Q.
Witness Silva testifies that several FPL units have been placed in inactive reserve. Has placing these units in inactive reserve resulted in cost savings to FPL's customers?

a. If the answer to 36 is "yes," please identify and quantify the savings.
b. When were the four steam units at FPL's Port Everglades Site placed in inactive reserve?

A.
a. Yes, placing units in inactive reserve status has resulted in cost savings to FPL's customers. These inactive reserve-based savings for FPL units, including the Port Everglades site referenced in Interrogatory No. 35, were estimated by comparing the O&M and Capital costs for two adjoining five year periods: 2004-2008 versus 2009-2013 as shown in the table below.

FPL Inactive Reserve Unit Savings in Millions					
Site	**Year Inactive**	**Costs**	**5 Year Period 2004 - 2008**	**5 Year Period 2009 - 2013**	**Savings**
Sanford Unit 3	May 09	O&M	$10	$0	($10)
		Capital	$14	$1	($13)
		SubTotal	$24	$1	($23)
Cutler Units 5 & 6	May 09	O&M	$16	$2	($14)
		Capital	$11	$1	($10)
		SubTotal	$27	$3	($24)
Port Everglades Unis 1 & 2	May 09	O&M	$33	$6	($27)
		Capital	$40	$7	($33)
		SubTotal	$73	$13	($60)
Port Everglades Units 3 & 4 (Units returned to service Jan 2012 through Jan 2013)	Aug 11	O&M	$45	$31	($14)
		Capital	$79	$12	($67)
		SubTotal	$124	$43	($81)
Turkey Point Unit 2	Feb 11	O&M	$25	$11	($14)
		Capital	$36	$10	($26)
		SubTotal	$61	$21	($40)
Total Inactive Reserve Units		O&M	$129	$50	($79)
		Capital	$180	$31	($149)
		Total	$309	$81	($228)

Actual O&M expenditures for these inactive reserve units over this timeframe were approximately $129 million for 2004-2008 and are forecasted to be $50 million for 2009-2013. Actual Capital expenditures for the period 2004-2008 were approximately $180 million and are forecasted to be $31 million for 2009-2013.

The resulting savings for FPL's inactive reserve units are estimated to total approximately $228 million for the five year period from 2009-2013, including approximately $79 million of O&M costs and $149 million in Capital costs.

b. Port Everglades Units 1&2 were classified as inactive reserve in May 2009, and are planned to be retired at the end of January 2013, pending Public Service Commission approval of unit modernization.

Port Everglades Units 3&4 were temporarily classified as inactive reserve in August 2011, and are scheduled to return to active service in January 2012 until their retirement at the end of January 2013, pending Public Service Commission approval of unit modernization.

Q.
For each of the four resource plans discussed in witness Enjamio's testimony, please provide the following information for the years 2012-2025:

a. The net generation for each generating unit on FPL's system.
b. The capacity factor for each generating unit on FPL's system.

A.
See attached Tables 37-1, 37-2, 37-3, and 37-4.

Florida Power & Light Company
Docket No. 110309-EI
Staff's First Set of Interrogatories
Interrogatory No. 37
Attachment No. 1
Page 1 of 4

PEEC Resource Plan
Table 37-1

	2012		2013		2014		2015		2016		2017		2018		2019		2020		2021		2022		2023		2024		2025	
	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF
CEDAR BAY	1,849	84.18	1,837	83.88	1,837	83.90	1,823	83.26	1,833	83.48	1,795	81.95	1,792	81.83	1,828	83.49	1,837	83.66	1,816	82.94	1,832	83.65	1,818	83.03	1,822	82.99	0	0.00
COG OFFPK	560	76.23	560	76.16	560	76.16	560	76.16	562	76.23	560	76.26	560	76.16	560	76.16	561	76.14	560	76.16	560	76.26	560	76.26	561	76.14	560	76.16
COG ONPK	280	23.77	280	23.84	280	23.84	280	23.84	280	23.77	279	23.74	280	23.84	280	23.84	281	23.86	280	23.84	279	23.74	279	23.74	281	23.86	280	23.84
EVERGLADES 1-12	0	0.00	0	0.01	0	0.00	0	0.00	1	0.03	2	0.06	2	0.08	4	0.14	6	0.20	1	0.04	0	0.00	0	0.00	0	0.00	3	0.08
EVERGLADES 3	119	3.62	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
EVERGLADES 4	68	2.08	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
FORT MYERS 1-12	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
FORT MYERS 2	10,131	83.74	8,790	73.01	7,281	60.28	8,431	68.38	8,879	71.46	8,383	67.76	8,741	70.63	8,785	71.00	9,104	73.21	8,346	67.34	6,678	53.89	6,032	48.72	5,876	47.39	6,250	50.48
FORT MYERS 3A_B	24	0.93	12	0.45	6	0.23	11	0.41	14	0.52	17	0.66	20	0.78	26	0.99	40	1.52	20	0.78	4	0.16	1	0.02	5	0.19	17	0.65
FRANKLIN	254	16.00	117	7.40	84	5.30	87	5.50	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
GREENFIELD CC	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4,690	40.93	11,099	95.40	11,082	95.26	11,037	94.64	11,043	94.95
HARRIS	1,171	22.67	596	11.58	427	8.30	415	8.05	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
INDIANTOWN	90	3.11	239	8.28	200	6.92	293	10.15	347	11.97	515	17.82	354	12.23	393	13.61	476	16.41	387	13.39	292	10.10	234	8.11	300	10.36	431	14.92
LAUDERDALE 1-24	3	0.05	1	0.01	0	0.00	1	0.01	4	0.06	7	0.11	9	0.16	11	0.19	17	0.27	10	0.16	0	0.00	0	0.00	0	0.01	6	0.10
LAUDERDALE 4	1,157	29.92	777	20.16	659	17.10	480	12.49	420	10.89	406	10.58	363	9.45	351	9.14	520	13.49	459	11.96	261	6.80	192	5.01	199	5.16	259	6.75
LAUDERDALE 5	1,354	35.06	937	24.32	783	20.29	658	17.12	556	14.42	500	13.01	495	12.90	527	13.72	627	16.26	541	14.08	350	9.11	239	6.22	265	6.89	347	9.04
MANATEE 1	497	7.16	98	1.42	124	1.80	68	0.98	127	1.83	187	2.70	161	2.34	187	2.71	251	3.63	193	2.80	46	0.67	21	0.31	55	0.80	111	1.61
MANATEE 2	497	7.19	253	3.66	222	3.21	141	2.04	284	4.10	277	4.02	277	4.01	345	5.00	496	7.17	375	5.43	108	1.57	59	0.85	104	1.50	192	2.78
MANATEE 3	7,593	80.41	5,266	55.93	5,369	55.89	4,660	48.12	4,907	50.50	4,511	46.58	4,475	46.12	4,632	47.83	4,986	51.19	4,884	50.40	4,199	43.42	3,739	38.75	3,715	38.37	3,940	40.80
MARTIN 1	1,032	14.64	197	2.80	440	6.26	281	4.00	480	6.81	430	6.13	489	6.96	444	6.31	716	10.16	455	6.48	237	3.37	136	1.93	191	2.71	335	4.77
MARTIN 2	1,261	17.89	660	9.38	28	0.40	505	7.19	462	6.55	668	9.51	508	7.23	708	10.08	889	12.62	731	10.40	374	5.33	233	3.32	300	4.26	472	6.71
MARTIN 3	1,523	39.59	1,069	27.97	787	20.48	767	20.20	660	17.33	637	16.83	626	16.50	589	15.51	822	21.55	706	18.58	446	11.74	329	8.71	343	9.04	438	11.59
MARTIN 4	1,668	43.36	1,227	32.05	1,093	28.52	924	24.31	798	20.95	732	19.29	727	19.16	797	20.98	1,004	26.33	833	21.90	575	15.18	422	11.15	437	11.51	538	14.21
MARTIN 8	7,599	78.71	6,750	69.71	6,193	64.04	5,409	55.96	3,717	38.40	4,655	48.22	4,488	46.45	4,414	45.66	4,579	47.24	4,194	43.47	3,373	35.10	2,814	29.39	2,881	30.01	3,142	32.76
OLEANDER CT	1	0.04	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
PCC3	0	0.00	6,117	55.82	9,696	87.57	10,283	92.54	9,611	86.50	9,628	86.60	10,200	91.84	9,263	83.59	10,428	93.55	9,211	82.87	9,995	90.14	9,389	84.91	9,190	82.95	9,458	85.49
PEEC	0	0.00	0	0.00	0	0.00	0	0.00	6,458	55.68	11,192	95.36	11,195	95.38	11,198	95.40	11,230	95.40	11,198	95.40	11,198	95.40	11,194	95.37	11,214	95.27	11,187	95.32
PRV5	0	0.00	0	0.00	6,112	55.84	9,680	87.56	10,450	93.96	9,712	87.83	10,130	91.27	10,465	94.36	9,087	82.32	10,491	94.57	10,156	91.72	9,862	89.18	9,735	87.84	9,876	89.28
PUTNAM 1	377	17.81	206	9.78	164	7.78	114	5.43	170	8.07	172	8.20	156	7.46	170	8.11	202	9.60	181	8.62	105	5.00	81	3.88	84	4.02	126	6.01
PUTNAM 2	327	15.44	187	8.85	137	6.52	118	5.62	146	6.92	151	7.22	136	6.49	151	7.18	192	9.16	137	6.52	94	4.49	65	3.08	75	3.56	110	5.25
SANFORD 4	4,338	51.38	3,402	39.56	3,437	39.84	2,945	34.30	2,547	29.64	2,385	27.85	2,217	25.93	2,242	26.21	3,046	35.41	2,639	30.82	2,204	25.74	1,672	19.61	1,683	19.71	2,011	23.55
SANFORD 5	3,578	43.79	3,712	45.24	3,136	38.03	2,589	31.56	2,358	28.66	2,634	32.13	2,523	30.75	2,684	32.64	3,158	38.19	2,858	34.78	2,374	28.92	1,873	22.93	1,965	23.98	2,233	27.24
SCHERER 3	1,309	92.00	1,306	92.00	1,306	92.00	1,301	91.65	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
SCHERER 4	4,191	75.54	5,409	97.77	4,868	88.03	5,406	97.72	4,887	88.06	5,406	97.72	4,783	86.52	4,566	82.54	4,213	76.00	4,935	89.22	5,028	90.90	4,824	87.22	5,053	91.11	5,064	91.56
ST JOHNS 1O	874	80.26	941	86.60	1,032	95.05	965	88.85	1,052	96.61	964	88.75	790	72.69	793	73.04	950	87.23	920	84.67	1,019	93.80	990	91.14	1,001	91.94	1,010	93.00
ST JOHNS 1P	1,309	80.11	1,413	86.75	1,547	94.95	1,454	89.22	917	56.12	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
ST JOHNS 2O	857	78.71	1,033	95.12	953	87.75	1,053	96.89	976	89.62	1,050	96.62	712	65.55	934	85.97	895	82.19	1,030	94.84	1,022	94.10	1,013	93.24	1,018	93.43	1,012	93.20
ST JOHNS 2P	1,277	78.15	1,544	94.75	1,426	87.52	1,582	97.09	795	48.65	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
ST LUCIE 1	6,102	72.99	7,404	87.35	7,400	87.35	8,259	97.50	7,652	90.04	7,629	90.02	8,259	97.50	7,629	90.02	7,652	90.04	8,259	97.50	7,629	90.02	7,629	90.02	8,282	97.50	7,629	90.02
ST LUCIE 2	4,556	67.40	6,334	87.35	7,077	97.50	6,344	87.35	6,550	90.04	7,077	97.50	6,537	90.02	6,530	90.02	7,096	97.50	6,537	90.02	6,530	90.02	7,077	97.50	6,557	90.04	6,530	90.02
TURKEY POINT 1	7	0.21	3	0.08	1	0.04	3	0.08	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
TURKEY POINT 3	3,843	54.88	6,279	88.15	6,936	97.50	6,394	90.02	6,429	90.04	6,936	97.50	6,397	90.02	6,410	90.02	6,955	97.50	6,397	90.02	6,410	90.02	6,936	97.50	6,416	90.04	6,410	90.02
TURKEY POINT 4	5,081	82.58	5,505	77.73	6,262	88.15	6,274	88.15	6,955	97.50	6,410	90.02	6,410	90.02	6,936	97.50	6,429	90.04	6,410	90.02	6,936	97.50	6,410	90.02	6,429	90.04	6,936	97.50
TURKEY POINT 5	5,823	61.78	4,058	42.88	4,954	51.01	4,021	41.56	4,066	41.95	3,705	38.26	4,474	46.35	4,724	48.91	5,085	52.46	4,931	51.05	3,840	39.87	3,310	34.46	3,371	34.99	3,625	37.66
TURKEY POINT 6	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4,914	50.63	9,358	95.75	8,854	90.26	8,814	90.24
TURKEY POINT 7	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	5,463	56.14	8,835	90.26	9,358	95.75
WCEC_01	9,637	90.94	8,791	83.20	7,681	72.64	8,357	79.13	8,129	76.76	7,284	69.00	7,597	72.00	8,442	79.92	7,540	71.07	8,534	80.83	7,886	74.74	6,797	64.42	6,728	63.62	7,109	67.39
WCEC_02	9,389	88.47	8,929	84.43	7,987	75.68	7,851	74.39	7,479	70.70	7,506	71.15	7,763	73.51	7,863	74.49	7,514	71.03	7,031	66.59	6,714	63.62	5,994	56.82	5,925	56.02	6,208	58.84
WCEC_03	9,433	89.07	9,910	93.71	8,971	84.99	8,811	83.30	9,160	86.44	8,056	76.33	9,114	86.26	9,369	88.66	8,916	84.23	9,481	89.73	8,890	84.22	8,144	77.22	8,011	75.76	8,256	78.27

Return Units to Service Resource Plan
Table 37-2

	2012		2013		2014		2015		2016		2017		2018		2019		2020		2021		2022		2023		2024		2025	
	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF
CEDAR BAY	1,849	84.18	1,837	83.88	1,837	83.90	1,823	83.26	1,837	83.65	1,795	81.96	1,828	83.47	1,831	83.61	1,837	83.65	1,828	83.46	1,828	83.47	1,829	83.50	1,830	83.33	0	0.00
COG OFFPK	560	76.23	560	76.16	560	76.16	560	76.16	562	76.23	560	76.26	560	76.16	560	76.16	561	76.14	560	76.16	560	76.26	560	76.26	561	76.14	560	76.16
COG ONPK	280	23.77	280	23.84	280	23.84	280	23.84	280	23.77	279	23.74	280	23.84	280	23.84	281	23.86	280	23.84	279	23.74	279	23.74	281	23.86	280	23.84
EVERGLADES 1	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	29	1.60	15	0.82	2	0.13	1	0.03	3	0.14	10	0.56
EVERGLADES 1-12	0	0.00	0	0.01	0	0.00	0	0.00	8	0.27	12	0.39	14	0.46	11	0.36	10	0.35	6	0.19	0	0.00	0	0.00	0	0.00	3	0.10
EVERGLADES 2	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	12	0.70	6	0.34	3	0.16	3	0.17	11	0.64
EVERGLADES 3	119	3.62	0	0.00	0	0.00	0	0.00	74	2.27	107	3.27	83	2.53	106	3.24	123	3.76	116	3.53	25	0.76	17	0.52	27	0.83	45	1.37
EVERGLADES 4	68	2.08	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	81	2.46	129	3.91	80	2.45	19	0.58	10	0.31	19	0.58	39	1.19
FORT MYERS 1-12	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	1	0.02	2	0.03	1	0.02	1	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
FORT MYERS 2	10,131	83.74	8,790	73.01	7,281	60.28	8,431	68.38	9,333	75.05	9,314	75.09	9,816	79.06	9,950	80.12	10,027	80.40	9,467	76.25	7,783	62.76	6,995	56.43	6,905	55.58	7,193	58.02
FORT MYERS 3A_B	24	0.93	12	0.45	6	0.23	11	0.41	38	1.48	54	2.08	46	1.77	39	1.50	67	2.57	35	1.33	6	0.22	2	0.07	11	0.42	24	0.91
FRANKLIN	254	16.00	117	7.40	84	5.30	87	5.50	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
GREENFIELD CC	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4,730	41.27	11,100	95.40	11,100	95.40	11,119	95.29	11,100	95.40
HARRIS	1,171	22.67	596	11.58	427	8.30	415	8.05	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
INDIANTOWN	90	3.11	239	8.28	200	6.92	293	10.15	449	15.49	774	26.78	531	18.36	595	20.59	723	24.94	575	19.88	526	18.21	374	12.95	461	15.90	636	22.01
LAUDERDALE 1-24	3	0.05	1	0.01	0	0.00	1	0.01	24	0.40	32	0.54	32	0.53	29	0.49	35	0.58	15	0.24	0	0.01	0	0.00	1	0.02	7	0.12
LAUDERDALE 4	1,157	29.92	777	20.16	659	17.10	480	12.49	570	14.79	639	16.62	582	15.14	543	14.13	829	21.48	685	17.80	445	11.56	319	8.30	334	8.69	407	10.59
LAUDERDALE 5	1,354	35.06	937	24.32	783	20.29	658	17.12	733	19.01	743	19.32	786	20.46	800	20.80	964	24.97	796	20.68	621	16.15	388	10.10	421	10.94	506	13.18
LOAD-CC1	0	0.00	0	0.00	0	0.00	0	0.00	1	0.03	3	0.08	3	0.09	0	0.00	1	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
LOAD-CC2	0	0.00	0	0.00	0	0.00	0	0.00	2	0.03	4	0.08	5	0.09	0	0.00	2	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
LOAD-CR1	0	0.00	0	0.00	0	0.00	0	0.00	1	0.03	3	0.08	4	0.09	0	0.00	1	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
LOAD-CR2	0	0.00	0	0.00	0	0.00	0	0.00	2	0.03	4	0.08	5	0.09	0	0.00	2	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
MANATEE 1	497	7.16	98	1.42	124	1.80	68	0.98	265	3.83	464	6.72	377	5.46	415	6.01	532	7.68	471	6.82	169	2.45	95	1.38	129	1.87	252	3.64
MANATEE 2	497	7.19	253	3.66	222	3.21	141	2.04	484	7.00	569	8.23	593	8.59	671	9.72	867	12.52	719	10.41	302	4.38	223	3.23	272	3.94	441	6.39
MANATEE 3	7,593	80.41	5,266	55.93	5,369	55.89	4,660	48.12	5,365	55.23	5,527	57.01	5,257	54.09	5,661	58.39	6,123	62.84	5,841	60.24	4,995	51.53	4,496	46.43	4,384	45.17	4,631	47.84
MARTIN 1	1,032	14.64	197	2.80	440	6.26	281	4.00	752	10.68	810	11.52	861	12.26	784	11.15	1,220	17.31	842	11.98	562	7.99	402	5.72	462	6.56	664	9.45
MARTIN 2	1,261	17.89	660	9.38	28	0.40	505	7.19	692	9.82	1,060	15.08	845	12.03	1,148	16.33	1,309	18.56	1,221	17.38	777	11.05	551	7.84	658	9.33	862	12.27
MARTIN 3	1,523	39.59	1,069	27.97	787	20.48	767	20.20	812	21.33	934	24.60	915	24.08	903	23.70	1,196	31.21	1,006	26.38	776	20.37	552	14.55	575	15.13	689	18.11
MARTIN 4	1,668	43.36	1,227	32.05	1,093	28.52	924	24.31	982	25.77	1,046	27.44	1,059	27.81	1,177	30.85	1,349	35.20	1,167	30.52	914	24.01	694	18.32	704	18.51	866	22.75
MARTIN 8	7,599	78.71	6,750	69.71	6,193	64.04	5,409	55.96	4,491	46.44	5,709	59.13	5,392	55.78	5,099	52.72	5,418	55.88	4,847	50.19	4,050	42.02	3,572	37.16	3,635	37.69	3,813	39.60
OLEANDER CT	1	0.04	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
PCC3	0	0.00	6,117	55.82	9,696	87.57	10,283	92.54	9,811	88.24	10,079	90.49	10,552	94.88	9,507	85.68	10,621	95.21	9,397	84.47	10,335	93.06	10,082	90.90	9,969	89.69	10,084	90.92
PRV5	0	0.00	0	0.00	6,112	55.84	9,680	87.56	10,537	94.72	9,945	89.85	10,307	92.82	10,566	95.24	9,172	83.07	10,604	95.59	10,349	93.40	10,227	92.33	10,138	91.33	10,235	92.41
PUTNAM 1	377	17.81	206	9.78	164	7.78	114	5.43	235	11.16	281	13.38	251	11.96	276	13.14	315	14.93	288	13.71	182	8.65	139	6.62	148	7.02	183	8.72
PUTNAM 2	327	15.44	187	8.85	137	6.52	118	5.62	207	9.85	242	11.54	219	10.42	235	11.19	298	14.16	230	10.94	156	7.43	119	5.68	133	6.32	165	7.87
SANFORD 4	4,338	51.38	3,402	39.56	3,437	39.84	2,945	34.30	3,016	35.03	3,140	36.52	2,935	34.19	2,949	34.33	3,741	43.35	3,338	38.85	2,998	34.90	2,368	27.69	2,405	28.05	2,690	31.38
SANFORD 5	3,578	43.79	3,712	45.24	3,136	38.03	2,589	31.56	2,709	32.86	3,271	39.73	3,192	38.72	3,325	40.28	3,771	45.47	3,457	41.93	3,039	36.90	2,616	31.83	2,669	32.39	2,925	35.51
SCHERER 3	1,309	92.00	1,306	92.00	1,306	92.00	1,301	91.65	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
SCHERER 4	4,191	75.54	5,409	97.77	4,868	88.03	5,406	97.72	4,887	88.06	5,406	97.72	4,810	87.00	4,769	86.21	4,348	78.43	5,150	93.11	5,177	93.59	5,054	91.37	5,230	94.29	5,241	94.76
ST JOHNS 1O	874	80.26	941	86.60	1,032	95.05	965	88.85	1,052	96.61	972	89.50	879	80.97	869	79.99	984	90.36	945	86.98	1,025	94.34	1,013	93.24	1,030	94.55	1,032	95.03
ST JOHNS 1P	1,309	80.11	1,413	86.75	1,547	94.95	1,454	89.22	917	56.12	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
ST JOHNS 2O	857	78.71	1,033	95.12	953	87.75	1,053	96.89	976	89.62	1,058	97.37	761	70.03	987	90.90	911	83.62	1,048	96.46	1,027	94.52	1,022	94.05	1,035	95.06	1,037	95.44
ST JOHNS 2P	1,277	78.15	1,544	94.75	1,426	87.52	1,582	97.09	795	48.65	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
ST LUCIE 1	6,102	72.99	7,404	87.35	7,400	87.35	8,259	97.50	7,652	90.04	7,629	90.02	8,259	97.50	7,629	90.02	7,652	90.04	8,259	97.50	7,629	90.02	7,629	90.02	8,282	97.50	7,629	90.02
ST LUCIE 2	4,556	67.40	6,334	87.35	7,077	97.50	6,344	87.35	6,550	90.04	7,077	97.50	6,537	90.02	6,530	90.02	7,096	97.50	6,537	90.02	6,530	90.02	7,077	97.50	6,557	90.04	6,530	90.02
TURKEY POINT 1	7	0.21	3	0.08	1	0.04	3	0.08	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
TURKEY POINT 3	3,843	54.88	6,279	88.15	6,936	97.50	6,394	90.02	6,429	90.04	6,936	97.50	6,397	90.02	6,410	90.02	6,955	97.50	6,397	90.02	6,410	90.02	6,936	97.50	6,416	90.04	6,410	90.02
TURKEY POINT 4	5,081	82.58	5,505	77.73	6,262	88.15	6,274	88.15	6,955	97.50	6,410	90.02	6,410	90.02	6,936	97.50	6,429	90.04	6,410	90.02	6,936	97.50	6,410	90.02	6,429	90.04	6,936	97.50
TURKEY POINT 5	5,823	61.78	4,058	42.88	4,954	51.01	4,021	41.56	4,428	45.66	4,288	44.24	5,587	57.90	5,830	60.39	6,029	62.16	6,062	62.72	4,638	48.01	4,081	42.33	4,055	41.96	4,321	44.78
TURKEY POINT 6	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4,914	50.63	9,358	95.75	8,854	90.26	8,814	90.24
TURKEY POINT 7	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	5,463	56.14	8,835	90.26	9,358	95.75
WCEC_01	9,637	90.94	8,791	83.20	7,681	72.64	8,357	79.13	8,610	81.29	8,127	76.94	8,555	80.99	9,135	86.44	8,130	76.61	9,331	88.29	8,860	83.91	8,102	76.80	7,920	74.89	8,250	78.18
WCEC_02	9,389	88.47	8,929	84.43	7,987	75.68	7,851	74.39	8,104	76.58	8,522	80.69	8,523	80.65	8,784	83.14	8,365	79.00	7,957	75.26	8,085	76.61	7,025	66.57	6,964	65.82	7,335	69.52
WCEC_03	9,433	89.07	9,910	93.71	8,971	84.99	8,811	83.30	9,488	89.54	8,631	81.74	9,710	91.86	9,827	92.95	9,345	88.26	9,940	94.01	9,623	91.07	9,089	86.09	8,934	84.42	9,112	86.31

Florida Power & Light Company
Docket No. 110309-EI
Staff's First Set of Interrogatories
Interrogatory No. 37
Attachment No. 1
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GFCC Resource Plan
Table 37-3

	2012		2013		2014		2015		2016		2017		2018		2019		2020		2021		2022		2023		2024		2025	
	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF
CEDAR BAY	1,849	84.18	1,837	83.88	1,837	83.90	1,823	83.26	1,834	83.50	1,796	81.99	1,824	83.30	1,828	83.47	1,838	83.70	1,817	82.95	1,828	83.47	1,818	83.03	1,822	82.99	0	0.00
COG OFFPK	560	76.23	560	76.16	560	76.16	560	76.16	562	76.23	560	76.26	560	76.16	560	76.16	561	76.14	560	76.16	560	76.26	560	76.26	561	76.14	560	76.16
COG ONPK	280	23.77	280	23.84	280	23.84	280	23.84	280	23.77	279	23.74	280	23.84	280	23.84	281	23.86	280	23.84	279	23.74	279	23.74	281	23.86	280	23.84
EVERGLADES 1-12	0	0.00	0	0.01	0	0.00	0	0.00	1	0.03	2	0.06	3	0.11	4	0.14	6	0.20	2	0.05	0	0.00	0	0.00	0	0.00	3	0.09
EVERGLADES 3	119	3.62	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
EVERGLADES 4	68	2.08	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
FORT MYERS 1-12	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
FORT MYERS 2	10,131	83.74	8,790	73.01	7,281	60.28	8,431	68.38	8,975	72.23	8,516	68.83	8,892	71.86	8,940	72.26	9,269	74.54	8,451	68.20	6,690	53.99	6,039	48.78	5,887	47.48	6,256	50.52
FORT MYERS 3A_B	24	0.93	12	0.45	6	0.23	11	0.41	14	0.55	17	0.65	21	0.80	24	0.92	41	1.57	20	0.78	4	0.16	1	0.02	5	0.18	17	0.66
FRANKLIN	254	16.00	117	7.40	84	5.30	87	5.50	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
GREENFIELD CC	0	0.00	0	0.00	0	0.00	0	0.00	4,767	41.49	8,195	70.47	8,195	70.48	8,149	70.08	8,352	71.54	9,292	79.95	11,100	95.40	11,096	95.37	11,105	95.18	11,088	95.30
GREENFIELD CC	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4,691	40.94	11,099	95.40	11,082	95.26	11,036	94.63	11,043	94.94
HARRIS	1,171	22.67	596	11.58	427	8.30	415	8.05	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
INDIANTOWN	90	3.11	239	8.28	200	6.92	293	10.15	345	11.91	512	17.71	359	12.40	395	13.66	479	16.51	386	13.36	295	10.21	236	8.17	301	10.37	428	14.79
LAUDERDALE 1-24	3	0.05	1	0.01	0	0.00	1	0.01	4	0.06	7	0.12	9	0.15	15	0.24	17	0.28	10	0.17	0	0.01	0	0.00	1	0.01	6	0.09
LAUDERDALE 4	1,157	29.92	777	20.16	659	17.10	480	12.49	423	10.98	410	10.66	365	9.50	353	9.20	532	13.81	460	11.98	260	6.76	194	5.04	205	5.31	258	6.71
LAUDERDALE 5	1,354	35.06	937	24.32	783	20.29	658	17.12	562	14.58	501	13.04	502	13.08	533	13.89	636	16.50	543	14.14	345	8.97	243	6.32	265	6.88	350	9.13
MANATEE 1	497	7.16	98	1.42	124	1.80	68	0.98	131	1.89	187	2.71	162	2.35	201	2.91	251	3.63	198	2.87	46	0.67	21	0.30	55	0.80	111	1.61
MANATEE 2	497	7.19	253	3.66	222	3.21	141	2.04	285	4.12	290	4.20	282	4.08	353	5.12	486	7.03	378	5.48	109	1.58	59	0.86	103	1.49	192	2.79
MANATEE 3	7,593	80.41	5,266	55.93	5,369	55.89	4,660	48.12	4,924	50.67	4,599	47.46	4,542	46.79	4,708	48.59	5,068	52.02	4,968	51.26	4,206	43.49	3,743	38.79	3,720	38.42	3,940	40.80
MARTIN 1	1,032	14.64	197	2.80	440	6.26	281	4.00	480	6.81	434	6.17	486	6.91	446	6.34	713	10.12	453	6.45	245	3.48	136	1.93	189	2.69	344	4.90
MARTIN 2	1,261	17.89	660	9.38	28	0.40	505	7.19	466	6.61	677	9.64	510	7.26	710	10.10	897	12.73	741	10.55	381	5.42	236	3.35	302	4.29	477	6.79
MARTIN 3	1,523	39.59	1,069	27.97	787	20.48	767	20.20	665	17.47	638	16.86	623	16.43	589	15.52	833	21.86	717	18.87	455	11.97	327	8.65	344	9.08	446	11.78
MARTIN 4	1,668	43.36	1,227	32.05	1,093	28.52	924	24.31	801	21.02	734	19.34	736	19.40	801	21.08	1,012	26.53	834	21.94	575	15.20	429	11.34	447	11.78	547	14.43
MARTIN 8	7,599	78.71	6,750	69.71	6,193	64.04	5,409	55.96	3,750	38.75	4,805	49.76	4,583	47.41	4,473	46.26	4,642	47.88	4,261	44.16	3,373	35.10	2,828	29.54	2,881	30.00	3,138	32.72
OLEANDER CT	1	0.04	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
PCC3	0	0.00	6,117	55.82	9,696	87.57	10,283	92.54	9,814	88.27	10,036	90.12	10,501	94.45	9,454	85.24	10,592	94.97	9,323	83.83	9,997	90.16	9,403	85.02	9,202	83.05	9,471	85.60
PRV5	0	0.00	0	0.00	6,112	55.84	9,680	87.56	10,527	94.63	9,903	89.49	10,247	92.29	10,526	94.89	9,145	82.83	10,537	94.99	10,157	91.73	9,860	89.17	9,736	87.85	9,877	89.29
PUTNAM 1	377	17.81	206	9.78	164	7.78	114	5.43	169	8.03	173	8.26	158	7.54	170	8.11	202	9.62	182	8.67	106	5.06	81	3.87	85	4.05	124	5.93
PUTNAM 2	327	15.44	187	8.85	137	6.52	118	5.62	148	7.04	151	7.22	138	6.58	150	7.17	196	9.33	140	6.67	96	4.58	66	3.15	76	3.62	109	5.21
SANFORD 4	4,338	51.38	3,402	39.56	3,437	39.84	2,945	34.30	2,557	29.75	2,394	27.95	2,222	25.99	2,244	26.23	3,062	35.59	2,649	30.93	2,212	25.85	1,675	19.65	1,691	19.80	2,019	23.64
SANFORD 5	3,578	43.79	3,712	45.24	3,136	38.03	2,589	31.56	2,357	28.65	2,633	32.12	2,537	30.92	2,689	32.70	3,171	38.33	2,855	34.75	2,381	29.01	1,879	23.00	1,971	24.05	2,245	27.38
SCHERER 3	1,309	92.00	1,306	92.00	1,306	92.00	1,301	91.65	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
SCHERER 4	4,191	75.54	5,409	97.77	4,868	88.03	5,406	97.72	4,887	88.06	5,406	97.72	4,846	87.66	4,850	87.68	4,476	80.75	5,147	93.06	5,029	90.93	4,826	87.27	5,077	91.54	5,066	91.60
ST JOHNS 1O	874	80.26	941	86.60	1,032	95.05	965	88.85	1,052	96.61	964	88.77	826	76.02	842	77.49	994	91.29	930	85.58	1,019	93.79	990	91.17	1,001	91.88	1,009	92.90
ST JOHNS 1P	1,309	80.11	1,413	86.75	1,547	94.95	1,454	89.22	917	56.12	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
ST JOHNS 2O	857	78.71	1,033	95.12	953	87.75	1,053	96.89	976	89.62	1,050	96.62	743	68.40	993	91.37	927	85.11	1,038	95.58	1,022	94.11	1,013	93.27	1,021	93.76	1,010	92.99
ST JOHNS 2P	1,277	78.15	1,544	94.75	1,426	87.52	1,582	97.09	795	48.65	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
ST LUCIE 1	6,102	72.99	7,404	87.35	7,400	87.35	8,259	97.50	7,652	90.04	7,629	90.02	8,259	97.50	7,629	90.02	7,652	90.04	8,259	97.50	7,629	90.02	7,629	90.02	8,282	97.50	7,629	90.02
ST LUCIE 2	4,556	67.40	6,334	87.35	7,077	97.50	6,344	87.35	6,550	90.04	7,077	97.50	6,537	90.02	6,530	90.02	7,096	97.50	6,537	90.02	6,530	90.02	7,077	97.50	6,557	90.04	6,530	90.02
TURKEY POINT 1	7	0.21	3	0.08	1	0.04	3	0.08	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
TURKEY POINT 3	3,843	54.88	6,279	88.15	6,936	97.50	6,394	90.02	6,429	90.04	6,936	97.50	6,397	90.02	6,410	90.02	6,955	97.50	6,397	90.02	6,410	90.02	6,936	97.50	6,416	90.04	6,410	90.02
TURKEY POINT 4	5,081	82.58	5,505	77.73	6,262	88.15	6,274	88.15	6,955	97.50	6,410	90.02	6,410	90.02	6,936	97.50	6,429	90.04	6,410	90.02	6,936	97.50	6,410	90.02	6,429	90.04	6,936	97.50
TURKEY POINT 5	5,823	61.78	4,058	42.88	4,954	51.01	4,021	41.56	4,074	42.03	3,749	38.70	4,565	47.28	4,830	50.01	5,208	53.75	5,039	52.17	3,851	39.98	3,314	34.50	3,377	35.04	3,634	37.76
TURKEY POINT 6	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4,914	50.63	9,358	95.75	8,854	90.26	8,814	90.24
TURKEY POINT 7	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	5,463	56.14	8,835	90.26	9,358	95.75
WCEC_01	9,637	90.94	8,791	83.20	7,681	72.64	8,357	79.13	8,580	81.05	7,975	75.56	8,210	77.83	9,216	87.24	8,187	77.16	9,005	85.29	7,898	74.85	6,804	64.49	6,738	63.71	7,120	67.50
WCEC_02	9,389	88.47	8,929	84.43	7,987	75.68	7,851	74.39	7,820	73.95	8,159	77.36	8,457	80.08	8,523	80.77	8,154	77.10	7,309	69.23	6,724	63.72	6,002	56.89	5,928	56.06	6,217	58.93
WCEC_03	9,433	89.07	9,910	93.71	8,971	84.99	8,811	83.30	9,592	90.51	8,656	81.99	9,775	92.47	9,896	93.60	9,437	89.11	9,839	93.08	8,895	84.27	8,156	77.33	8,014	75.78	8,264	78.34

Florida Power & Light Company
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GFCT Resource Plan
Table 37-4

	2012		2013		2014		2015		2016		2017		2018		2019		2020		2021		2022		2023		2024		2025	
	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF	GWH	CF
CEDAR BAY	1,849	84.18	1,837	83.88	1,837	83.90	1,823	83.26	1,837	83.65	1,795	81.96	1,828	83.47	1,828	83.49	1,837	83.66	1,824	83.27	1,832	83.66	1,829	83.50	1,830	83.33	0	0.00
COG OFFPK	560	76.23	560	76.16	560	76.16	560	76.16	562	76.23	560	76.26	560	76.16	560	76.16	561	76.14	560	76.16	560	76.26	560	76.26	561	76.14	560	76.16
COG ONPK	280	23.77	280	23.84	280	23.84	280	23.84	280	23.77	279	23.74	280	23.84	280	23.84	281	23.86	280	23.84	279	23.74	279	23.74	281	23.86	280	23.84
CT_2016	0	0.00	0	0.00	0	0.00	0	0.00	37	1.31	54	1.89	43	1.50	13	0.45	16	0.56	36	1.26	11	0.37	5	0.17	12	0.42	27	0.96
EVERGLADES 1-12	0	0.00	0	0.01	0	0.00	0	0.00	10	0.32	11	0.38	14	0.47	1	0.03	4	0.12	6	0.20	2	0.07	0	0.00	4	0.12	9	0.29
EVERGLADES 3	119	3.62	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
EVERGLADES 4	68	2.08	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
FORT MYERS 1-12	0	0.00	0	0.00	0	0.00	0	0.00	1	0.02	2	0.03	2	0.04	0	0.00	0	0.00	1	0.02	0	0.00	0	0.00	0	0.00	1	0.02
FORT MYERS 2	10,131	83.74	8,790	73.01	7,281	60.28	8,431	68.38	9,333	75.05	9,316	75.11	9,816	79.06	9,319	75.17	9,104	73.21	8,865	71.51	7,761	62.58	6,989	56.38	6,898	55.51	7,185	57.95
FORT MYERS 3A_B	24	0.93	12	0.45	6	0.23	11	0.41	56	2.17	74	2.86	62	2.41	27	1.05	40	1.52	63	2.44	18	0.71	12	0.45	19	0.74	34	1.29
FRANKLIN	254	16.00	117	7.40	84	5.30	87	5.50	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
HARRIS	1,171	22.67	596	11.58	427	8.30	415	8.05	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
INDIANTOWN	90	3.11	239	8.28	200	6.92	293	10.15	450	15.53	777	26.88	532	18.41	483	16.71	476	16.41	499	17.27	519	17.96	376	13.00	457	15.76	635	21.95
LAUDERDALE 1-24	3	0.05	1	0.01	0	0.00	1	0.01	26	0.43	33	0.55	32	0.54	6	0.09	9	0.15	21	0.35	6	0.10	2	0.03	7	0.12	21	0.35
LAUDERDALE 4	1,157	29.92	777	20.16	659	17.10	480	12.49	571	14.83	646	16.82	587	15.27	446	11.59	520	13.49	584	15.20	440	11.45	316	8.23	337	8.75	419	10.92
LAUDERDALE 5	1,354	35.06	937	24.32	783	20.29	658	17.12	731	18.97	750	19.50	790	20.56	616	16.03	627	16.26	713	18.55	624	16.21	393	10.25	427	11.10	514	13.37
LOAD-CC1	0	0.00	0	0.00	0	0.00	0	0.00	1	0.03	4	0.10	5	0.13	0	0.00	0	0.00	0	0.01	0	0.00	0	0.00	0	0.00	4	0.10
LOAD-CC2	0	0.00	0	0.00	0	0.00	0	0.00	2	0.03	5	0.10	6	0.13	0	0.00	0	0.00	1	0.01	0	0.00	0	0.00	0	0.00	6	0.10
LOAD-CR1	0	0.00	0	0.00	0	0.00	0	0.00	1	0.03	6	0.15	5	0.13	0	0.00	0	0.00	0	0.01	0	0.00	0	0.00	0	0.00	4	0.10
LOAD-CR2	0	0.00	0	0.00	0	0.00	0	0.00	2	0.03	8	0.15	7	0.13	0	0.00	0	0.00	1	0.01	0	0.00	0	0.00	0	0.00	6	0.10
MANATEE 1	497	7.16	98	1.42	124	1.80	68	0.98	268	3.86	465	6.73	377	5.46	216	3.13	247	3.57	395	5.73	188	2.72	96	1.39	132	1.90	252	3.66
MANATEE 2	497	7.19	253	3.66	222	3.21	141	2.04	489	7.06	571	8.26	596	8.63	403	5.83	496	7.16	617	8.94	303	4.38	215	3.12	269	3.89	433	6.28
MANATEE 3	7,593	80.41	5,266	55.93	5,369	55.89	4,660	48.12	5,365	55.23	5,527	57.01	5,256	54.09	5,101	52.60	4,986	51.19	5,322	54.94	4,989	51.46	4,483	46.31	4,382	45.15	4,626	47.78
MARTIN 1	1,032	14.64	197	2.80	440	6.26	281	4.00	752	10.67	807	11.48	860	12.24	571	8.12	716	10.16	672	9.56	564	8.02	401	5.70	438	6.22	664	9.45
MARTIN 2	1,261	17.89	660	9.38	28	0.40	505	7.19	694	9.85	1,058	15.06	845	12.03	866	12.33	889	12.62	1,043	14.85	764	10.87	548	7.80	648	9.19	850	12.10
MARTIN 3	1,523	39.59	1,069	27.97	787	20.48	767	20.20	811	21.31	936	24.65	916	24.09	711	18.66	822	21.55	862	22.68	769	20.19	552	14.56	582	15.30	682	17.93
MARTIN 4	1,668	43.36	1,227	32.05	1,093	28.52	924	24.31	982	25.77	1,046	27.42	1,058	27.80	963	25.26	1,004	26.33	1,009	26.49	908	23.86	686	18.10	711	18.69	860	22.58
MARTIN 8	7,599	78.71	6,750	69.71	6,193	64.04	5,409	55.96	4,491	46.44	5,704	59.07	5,392	55.78	4,696	48.54	4,579	47.24	4,494	46.57	4,046	41.97	3,566	37.09	3,629	37.64	3,812	39.60
OLEANDER CT	1	0.04	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
PCC3	0	0.00	6,117	55.82	9,696	87.57	10,283	92.54	9,811	88.24	10,079	90.49	10,552	94.88	9,438	85.08	10,428	93.55	9,202	82.80	10,334	93.05	10,080	90.88	9,965	89.65	10,080	90.88
PEEC	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	6,458	55.84	11,230	95.40	11,198	95.40	11,198	95.40	11,198	95.40	11,218	95.30	11,197	95.40
PRV5	0	0.00	0	0.00	6,112	55.84	9,680	87.56	10,537	94.72	9,946	89.85	10,307	92.82	10,537	94.98	9,087	82.32	10,519	94.82	10,350	93.40	10,225	92.31	10,135	91.30	10,231	92.38
PUTNAM 1	377	17.81	206	9.78	164	7.78	114	5.43	238	11.33	284	13.54	255	12.16	208	9.92	202	9.60	246	11.71	185	8.80	139	6.65	147	6.99	183	8.74
PUTNAM 2	327	15.44	187	8.85	137	6.52	118	5.62	210	9.99	248	11.84	220	10.49	179	8.52	192	9.16	182	8.67	157	7.47	121	5.75	136	6.50	167	7.96
SANFORD 4	4,338	51.38	3,402	39.56	3,437	39.84	2,945	34.30	3,016	35.03	3,139	36.51	2,935	34.19	2,549	29.74	3,046	35.41	3,013	35.15	2,990	34.80	2,360	27.59	2,398	27.98	2,667	31.12
SANFORD 5	3,578	43.79	3,712	45.24	3,136	38.03	2,589	31.56	2,709	32.86	3,269	39.70	3,192	38.72	2,978	36.14	3,158	38.19	3,167	38.50	3,030	36.78	2,608	31.74	2,670	32.41	2,926	35.53
SCHERER 3	1,309	92.00	1,306	92.00	1,306	92.00	1,301	91.65	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
SCHERER 4	4,191	75.54	5,409	97.77	4,868	88.03	5,406	97.72	4,887	88.06	5,406	97.72	4,810	87.00	4,624	83.58	4,213	76.00	4,914	88.83	5,177	93.59	5,060	91.49	5,229	94.27	5,241	94.76
ST JOHNS 1O	874	80.26	941	86.60	1,032	95.05	965	88.85	1,052	96.61	972	89.50	880	80.98	810	74.58	950	87.23	922	84.85	1,025	94.32	1,014	93.39	1,030	94.53	1,030	94.85
ST JOHNS 1P	1,309	80.11	1,413	86.75	1,547	94.95	1,454	89.22	917	56.12	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
ST JOHNS 2O	857	78.71	1,033	95.12	953	87.75	1,053	96.89	976	89.62	1,058	97.37	761	70.03	950	87.46	895	82.19	1,028	94.64	1,027	94.51	1,023	94.20	1,035	94.99	1,037	95.44
ST JOHNS 2P	1,277	78.15	1,544	94.75	1,426	87.52	1,582	97.09	795	48.65	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
ST LUCIE 1	6,102	72.99	7,404	87.35	7,400	87.35	8,259	97.50	7,652	90.04	7,629	90.02	8,259	97.50	7,629	90.02	7,652	90.04	8,259	97.50	7,629	90.02	7,629	90.02	8,282	97.50	7,629	90.02
ST LUCIE 2	4,556	67.40	6,334	87.35	7,077	97.50	6,344	87.35	6,550	90.04	7,077	97.50	6,537	90.02	6,530	90.02	7,096	97.50	6,537	90.02	6,530	90.02	7,077	97.50	6,557	90.04	6,530	90.02
TURKEY POINT 1	7	0.21	3	0.08	1	0.04	3	0.08	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
TURKEY POINT 3	3,843	54.88	6,279	88.15	6,936	97.50	6,394	90.02	6,429	90.04	6,936	97.50	6,397	90.02	6,410	90.02	6,955	97.50	6,397	90.02	6,410	90.02	6,936	97.50	6,416	90.04	6,410	90.02
TURKEY POINT 4	5,081	82.58	5,505	77.73	6,262	88.15	6,274	88.15	6,955	97.50	6,410	90.02	6,410	90.02	6,936	97.50	6,429	90.04	6,410	90.02	6,936	97.50	6,410	90.02	6,429	90.04	6,936	97.50
TURKEY POINT 5	5,823	61.78	4,058	42.88	4,954	51.01	4,021	41.56	4,428	45.66	4,288	44.24	5,587	57.90	5,100	52.78	5,085	52.46	5,594	57.95	4,623	47.87	4,078	42.30	4,040	41.82	4,327	44.84
TURKEY POINT 6	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4,914	50.63	9,358	95.75	8,854	90.26	8,814	90.24
TURKEY POINT 7	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	5,463	56.14	8,835	90.26	9,358	95.75
WCEC_01	9,637	90.94	8,791	83.20	7,681	72.64	8,357	79.13	8,610	81.29	8,126	76.93	8,555	80.99	8,796	83.23	7,540	71.07	8,561	81.03	8,853	83.83	8,093	76.71	7,909	74.79	8,241	78.10
WCEC_02	9,389	88.47	8,929	84.43	7,987	75.68	7,851	74.39	8,104	76.58	8,524	80.70	8,523	80.65	8,360	79.13	7,514	71.03	7,239	68.49	8,082	76.59	7,011	66.43	6,963	65.81	7,327	69.45
WCEC_03	9,433	89.07	9,910	93.71	8,971	84.99	8,811	83.30	9,488	89.54	8,634	81.77	9,710	91.86	9,651	91.30	8,916	84.23	9,405	89.00	9,629	91.13	9,078	85.99	8,927	84.35	9,107	86.26

Q.
On pages 14 and 15 of his testimony, witness Silva testifies that for the purpose of FPL's analyses, projected costs and operating characteristics are consistent with a 3x1 combined cycle unit with "J" CT technology. Please describe FPL's experience with "J" CT technology.

A.
FPL does not have any direct experience with "J" technology CTs, as that technology only recently became commercially available. However, FPL currently operates "G" technology CTs at the West County Energy Center, which are predecessors to the "J" technology. Vendors have supplied preliminary design and operating specifications for the "J" technology CTs to FPL.

Q.
Please provide the following information regarding the power purchase agreements FPL is pursuing with biomass renewable resources as described on page 21 of witness Silva's testimony.

a. Have negotiations with any of these resources started?
b. If negotiations have started, what is the current status of those negotiations?
c. What "avoided cost" is FPL using to evaluate the cost-effectiveness of these resources?

A.

a. Yes.

b. Detailed negotiations concerning contract language, terms and conditions are ongoing.

c. FPL is currently using an avoided cost that is consistent with the Standard Offer Contract proposed in Docket No. 110312-EQ. Should FPL and the counterparty successfully negotiate a mutually acceptable contract, FPL's submission for approval will be based on the most recent forecast of avoided costs for FPL's system.

Q.
Please complete the table below for each of the four resource plans discussed in witness Enjamio's testimony.

	Unit Additions	Incremental MW Added	Cumulative MW Added	Cumulative Gas Dependent MW Added	Cumulative Gas Requirements (Bcf/day)
2012					
2013					
2014					
2015					
2016					
2017					
2018					
2019					
2020					
2021					
2022					
2023					
2024					
2025					
2026					
2027					
2028					
2029					
2030					
2031					
2032					
2033					
2034					
2035					
2036					
2037					
2038					
2039					
2040					
2041					
2042					
2043					
2044					
2045					
2046					
2047					
Total					

A.
Please see attached Tables 40-1, 40-2, 40-3, and 40-4.

PEEC Resource Plan

Table 40-1

	Unit Additions	Incremental MW Added	Cumulative MW Added	Cumulative Gas Dependent MW Added	Cumulative Gas Requirements-Summer (MMcf/day)
2012			0	0	1,969
2013	PCC3	1,210	1,210	1,210	1,969
2014	PRV5	1,212	2,422	2,422	1,969
2015			2,422	2,422	1,969
2016	PEEC	1,277	3,699	3,699	2,369
2017			3,699	3,699	2,369
2018			3,699	3,699	2,369
2019			3,699	3,699	2,369
2020			3,699	3,699	2,569
2021	GFCC	1,262	4,961	4,961	2,569
2022	TP 6	1,100	4,961	4,961	2,569
2023	TP 7	1,100	4,961	4,961	2,569
2024			4,961	4,961	2,569
2025			4,961	4,961	2,569
2026	2x1-CC	698	5,659	5,659	2,569
2027			5,659	5,659	2,569
2028	1- 2x1-CC	631	6,290	6,290	2,569
2029	2- 2x1-CC	1,262	7,552	7,552	2,569
2030	1- 2x1-CC	631	8,183	8,183	2,569
2031	1- 2x1-CC	631	8,814	8,814	2,569
2032	2- 2x1-CC	1,262	10,076	10,076	2,569
2033	3- 2x1-CC	1,893	11,969	11,969	2,569
2034	1- 2x1-CC	631	12,600	12,600	2,569
2035	1- 2x1-CC	631	13,231	13,231	2,569
2036	3- 2x1-CC	1,893	15,124	15,124	2,569
2037	1- 2x1-CC	631	15,755	15,755	2,569
2038	1- 2x1-CC	631	16,386	16,386	2,569
2039	2- 2x1-CC	1,262	17,648	17,648	2,569
2040	1- 2x1-CC	631	18,279	18,279	2,569
2041	1- 2x1-CC	631	18,910	18,910	2,569
2042	2- 2x1-CC	1,262	20,172	20,172	2,569
2043	2- 2x1-CC	1,262	21,434	21,434	2,569
2044	2- 2x1-CC	1,262	22,696	22,696	2,569
2045	1- 2x1-CC	631	23,327	23,327	2,569
2046	2- 2x1-CC	1,262	24,589	24,589	2,569
2047	1- 2x1-CC	631	25,220	25,220	2,569

Notes:

- Values shown indicate the summer volume of gas.
- This table shows the cumulative gas requirements used in economic analyses of the resource plans.
- Starting in 2026, an unlimited amount of gas was made available to the filler combined cycle units. This volume is not added to the cumulative gas requirements shown above. This assumption was made across all resource plans.
- System requirements reflect existing contractual commitments plus 400 MMcf per day added in 2016 and an additional 200 MMcf per day added in 2020 to serve system needs.

Return to Service Resource Plan

Table 40-2

	Unit Additions	Incremental MW Added	Cumulative MW Added	Cumulative Gas Dependent MW Added	Cumulative Gas Requirements-Summer (MMcf/day)
2012			0	0	1,969
2013	PCC3	1,210	1,210	1,210	1,969
2014	PRV5	1,212	2,422	2,422	1,969
2015			2,422	2,422	1,969
2016	PE 3	387	2,809	2,809	2,369
2017			2,809	2,809	2,369
2018			2,809	2,809	2,369
2019	PE 4	374	3,183	3,183	2,369
2020	PE 1	213	3,396	3,396	2,569
2021	PE 2 & GFCC	1,475	4,871	4,871	2,569
2022	TP 6	1,100	4,871	4,871	2,569
2023	TP 7	1,100	4,871	4,871	2,569
2024			4,871	4,871	2,569
2025			4,871	4,871	2,569
2026	2X1	788	5,659	5,659	2,569
2027			5,659	5,659	2,569
2028	1- 2X1	631	6,290	6,290	2,569
2029	2- 2X1	1,262	7,552	7,552	2,569
2030	1- 2X1	631	8,183	8,183	2,569
2031	1- 2X1	631	8,814	8,814	2,569
2032	2- 2X1	1,262	10,076	10,076	2,569
2033	3- 2X1	1,893	11,969	11,969	2,569
2034	1- 2X1	631	12,600	12,600	2,569
2035	1- 2X1	631	13,231	13,231	2,569
2036	3- 2X1	1,893	15,124	15,124	2,569
2037	1- 2X1	631	15,755	15,755	2,569
2038	1- 2X1	631	16,386	16,386	2,569
2039	2- 2X1	1,262	17,648	17,648	2,569
2040	1- 2X1	631	18,279	18,279	2,569
2041	1- 2X1	631	18,910	18,910	2,569
2042	2- 2X1	1,262	20,172	20,172	2,569
2043	2- 2X1	1,262	21,434	21,434	2,569
2044	2- 2X1	1,262	22,696	22,696	2,569
2045	1- 2X1	631	23,327	23,327	2,569
2046	2- 2X1	1,262	24,589	24,589	2,569
2047	1- 2X1	631	25,220	25,220	2,569

Notes:

- Values shown indicate the summer volume of gas.
- This table shows the cumulative gas requirements used in economic analyses of the resource plans.
- Starting in 2026, an unlimited amount of gas was made available to the filler combined cycle units. This volume is not added to the cumulative gas requirements shown above. This assumption was made across all resource plans.
- System requirements reflect existing contractual commitments plus 400 MMcf per day added in 2016 and an additional 200 MMcf per day added in 2020 to serve system needs.

GFCC Resource Plan

Table 40-3

	Unit Additions	Incremental MW Added	Cumulative MW Added	Cumulative Gas Dependent MW Added	Cumulative Gas Requirements- Summer (MMcf/day)
2012			0	0	1,969
2013	PCC3	1,210	1,210	1,210	1,969
2014	PRV5	1,212	2,422	2,422	1,969
2015			2,422	2,422	1,969
2016	GFCC	1,262	3,684	3,684	2,369
2017			3,684	3,684	2,369
2018			3,684	3,684	2,369
2019			3,684	3,684	2,369
2020			3,684	3,684	2,569
2021	GFCC	1,262	4,946	4,946	2,569
2022	TP 6	1,100	4,946	4,946	2,569
2023	TP 7	1,100	4,946	4,946	2,569
2024			4,946	4,946	2,569
2025			4,946	4,946	2,569
2026	2X1	713	5,659	5,659	2,569
2027			5,659	5,659	2,569
2028	1- 2X1	631	6,290	6,290	2,569
2029	2- 2X1	1,262	7,552	7,552	2,569
2030	1- 2X1	631	8,183	8,183	2,569
2031	1- 2X1	631	8,814	8,814	2,569
2032	2- 2X1	1,262	10,076	10,076	2,569
2033	3- 2X1	1,893	11,969	11,969	2,569
2034	1- 2X1	631	12,600	12,600	2,569
2035	1- 2X1	631	13,231	13,231	2,569
2036	3- 2X1	1,893	15,124	15,124	2,569
2037	1- 2X1	631	15,755	15,755	2,569
2038	1- 2X1	631	16,386	16,386	2,569
2039	2- 2X1	1,262	17,648	17,648	2,569
2040	1- 2X1	631	18,279	18,279	2,569
2041	1- 2X1	631	18,910	18,910	2,569
2042	2- 2X1	1,262	20,172	20,172	2,569
2043	2- 2X1	1,262	21,434	21,434	2,569
2044	2- 2X1	1,262	22,696	22,696	2,569
2045	1- 2X1	631	23,327	23,327	2,569
2046	2- 2X1	1,262	24,589	24,589	2,569
2047	1- 2X1	631	25,220	25,220	2,569

Notes:

- Values shown indicate the summer volume of gas.
- This table shows the cumulative gas requirements used in economic analyses of the resource plans.
- Starting in 2026, an unlimited amount of gas was made available to the filler combined cycle units. This volume is not added to the cumulative gas requirements shown above. This assumption was made across all resource plans.
- System requirements reflect existing contractual commitments plus 400 MMcf per day added in 2016 and an additional 200 MMcf per day added in 2020 to serve system needs.

GFCT Resource Plan

Table 40-4

	Unit Additions	Incremental MW Added	Cumulative MW Added	Cumulative Gas Dependent MW Added	Cumulative Gas Requirements- Summer (MMcf/day)
2012			0	0	1,969
2013	PCC3	1,210	1,210	1,210	1,969
2014	PRV5	1,212	2,422	2,422	1,969
2015			2,422	2,422	1,969
2016	2- GFCT	324	2,746	2,746	2,369
2017			2,746	2,746	2,369
2018			2,746	2,746	2,369
2019	PEEC	1,277	4,023	4,023	2,369
2020			4,023	4,023	2,569
2021			4,023	4,023	2,569
2022	TP 6	1,100	4,023	4,023	2,569
2023	TP 7	1,100	4,023	4,023	2,569
2024			4,023	4,023	2,569
2025			4,023	4,023	2,569
2026	2X1 & GFCC	1,637	5,660	5,660	2,569
2027			5,660	5,660	2,569
2028	1- 2X1	631	6,291	6,291	2,569
2029	2- 2X1	1,262	7,553	7,553	2,569
2030	1- 2X1	631	8,184	8,184	2,569
2031	1- 2X1	631	8,815	8,815	2,569
2032	2- 2X1	1,262	10,077	10,077	2,569
2033	3- 2X1	1,893	11,970	11,970	2,569
2034	1- 2X1	631	12,601	12,601	2,569
2035	1- 2X1	631	13,232	13,232	2,569
2036	3- 2X1	1,893	15,125	15,125	2,569
2037	1- 2X1	631	15,756	15,756	2,569
2038	1- 2X1	631	16,387	16,387	2,569
2039	2- 2X1	1,262	17,649	17,649	2,569
2040	1- 2X1	631	18,280	18,280	2,569
2041	1- 2X1	631	18,911	18,911	2,569
2042	2- 2X1	1,262	20,173	20,173	2,569
2043	2- 2X1	1,262	21,435	21,435	2,569
2044	2- 2X1	1,262	22,697	22,697	2,569
2045	1- 2X1	631	23,328	23,328	2,569
2046	2- 2X1	1,262	24,590	24,590	2,569
2047	1- 2X1	631	25,221	25,221	2,569

Notes:

- Values shown indicate the summer volume of gas.
- This table shows the cumulative gas requirements used in economic analyses of the resource plans.
- Starting in 2026, an unlimited amount of gas was made available to the filler combined cycle units. This volume is not added to the cumulative gas requirements shown above. This assumption was made across all resource plans.
- System requirements reflect existing contractual commitments plus 400 MMcf per day added in 2016 and

Q.

Please complete the table below for each of the four resource plans discussed in witness Enjamio's testimony. Please assume FPL's fuel forecast which led to its recent mid-course filing.

A.

The fuel forecast that led to the recent mid-course correction of FPL's 2012 Fuel Cost Recovery factors is a short-term (one-year) forecast. In contrast, the four resource plans evaluated by FPL witness Enjamio address generation additions in 2016 and beyond. Thus, re-evaluating the resource plans based on the "fuel forecast which led to [FPL's] recent mid-course filing" would not be meaningful. However, FPL has a long-term fuel forecast that was prepared in the same time frame (mid-November 2011) as the short-term forecast used for the mid-course correction. For the purpose of responding to this interrogatory, FPL has completed the attached Tables 41-1, 41-2, 41-3 and 41-4 using the mid-November long-term fuel forecast. See attached Tables.

Table 41-1
PEEC Resource Plan- Revenue Requirements Assuming Fuel Forecast used in mid-course filing

	(1)	(2)	(3)	(4)	(5)	(6)
	Annual Revenue Requirements (Generation Capital) ($millions, 2011 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2011 $)	Annual Revenue Requirements (O&M) ($millions, 2011 $)	Annual Revenue Requirements (Fuel) ($millions, 2011 $)	Annual Revenue Requirements (Environmental) ($millions, 2011 $)	Total ($millions, 2011 $)
2011	0	0	0	3,133	-11	3,122
2012	0	0	1	2,891	-5	2,887
2013	0	0	1	3,020	-8	3,013
2014	0	0	1	3,353	-8	3,347
2015	0	0	1	3,605	-8	3,599
2016	115	3	33	4,277	-9	4,420
2017	192	5	42	4,654	-9	4,886
2018	185	5	43	5,082	1,176	6,492
2019	179	5	45	5,506	1,271	7,006
2020	172	5	46	6,167	1,438	7,828
2021	303	15	73	6,670	1,614	8,674
2022	388	21	97	6,906	1,708	9,121
2023	374	20	97	6,876	1,718	9,085
2024	360	19	100	7,315	1,879	9,672
2025	346	19	106	8,027	2,042	10,539
2026	421	18	122	8,377	2,219	11,156
2027	466	17	137	8,816	2,458	11,894
2028	532	16	157	9,120	2,659	12,485
2029	744	16	205	9,411	2,841	13,217
2030	927	15	252	9,882	3,056	14,132
2031	1,045	14	288	10,311	3,298	14,957
2032	1,259	14	344	10,910	3,682	16,209
2033	1,636	13	435	11,877	4,302	18,263
2034	1,879	13	506	12,469	4,774	19,640
2035	1,979	12	553	12,880	5,178	20,602
2036	2,295	11	642	13,891	5,988	22,828
2037	2,541	11	728	14,435	6,566	24,281
2038	2,632	11	781	14,907	7,161	25,493
2039	2,841	10	862	15,510	7,865	27,089
2040	3,012	10	944	16,006	8,570	28,543
2041	3,100	10	1,007	16,555	9,361	30,032
2042	3,317	9	1,099	17,220	10,292	31,938
2043	3,624	9	1,213	18,185	11,545	34,577
2044	3,931	9	1,333	18,969	12,732	36,973
2045	4,097	8	1,434	19,607	13,895	39,041
2046	4,283	8	1,546	20,291	15,182	41,311
2047	4,434	8	1,656	21,018	16,610	43,725
CPVRR	8,410	108	2,522	95,094	28,448	134,582

Table 41-2
Return to Service Resource Plan- Revenue Requirements Assuming Fuel Forecast used in mid-course filing

	(1)	(2)	(3)	(4)	(5)	(6)
	Annual Revenue Requirements (Generation Capital) ($millions, 2011 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2011 $)	Annual Revenue Requirements (O&M) ($millions, 2011 $)	Annual Revenue Requirements (Fuel) ($millions, 2011 $)	Annual Revenue Requirements (Environmental) ($millions, 2011 $)	Total ($millions, 2011 $)
2011	0	0	0	3,133	-11	3,122
2012	0	0	1	2,891	-5	2,887
2013	0	0	1	3,020	-8	3,013
2014	0	0	42	3,353	-8	3,387
2015	0	0	42	3,605	-8	3,639
2016	0	0	17	4,359	-8	4,368
2017	0	0	52	4,793	-8	4,837
2018	0	0	80	5,214	1,208	6,502
2019	0	0	98	5,641	1,322	7,061
2020	0	0	60	6,330	1,488	7,878
2021	137	10	115	6,828	1,663	8,753
2022	229	17	75	7,034	1,751	9,105
2023	220	16	117	6,987	1,758	9,098
2024	212	15	135	7,437	1,920	9,719
2025	204	15	111	8,175	2,091	10,596
2026	296	14	146	8,521	2,264	11,241
2027	355	14	147	8,957	2,507	11,980
2028	426	13	151	9,252	2,720	12,562
2029	644	13	216	9,531	2,903	13,306
2030	831	12	229	9,984	3,122	14,178
2031	955	12	294	10,410	3,366	15,036
2032	1,174	11	351	11,006	3,743	16,284
2033	1,556	10	433	11,980	4,362	18,342
2034	1,804	10	497	12,563	4,832	19,706
2035	1,910	9	545	12,969	5,236	20,670
2036	2,230	9	618	13,979	6,050	22,887
2037	2,480	9	726	14,515	6,629	24,359
2038	2,574	8	769	14,988	7,226	25,566
2039	2,787	8	836	15,580	7,930	27,141
2040	2,960	8	912	16,074	8,630	28,585
2041	3,050	8	976	16,621	9,423	30,078
2042	3,270	7	1,093	17,282	10,356	32,008
2043	3,580	7	1,194	18,246	11,609	34,636
2044	3,889	7	1,295	19,025	12,788	37,003
2045	4,057	7	1,394	19,662	13,958	39,077
2046	4,272	6	1,505	20,340	15,242	41,365
2047	4,441	6	1,604	21,064	16,675	43,790
CPVRR	7,244	74	2,645	96,174	28,861	134,998

Table 41-3
GFCC Resource Plan- Revenue Requirements Assuming Fuel Forecast used in mid-course filing

	(1)	(2)	(3)	(4)	(5)	(6)
	Annual Revenue Requirements (Generation Capital) ($millions, 2011 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2011 $)	Annual Revenue Requirements (O&M) ($millions, 2011 $)	Annual Revenue Requirements (Fuel) ($millions, 2011 $)	Annual Revenue Requirements (Environmental) ($millions, 2011 $)	Total ($millions, 2011 $)
2011	0	0	0	3,133	-11	3,122
2012	0	0	1	2,891	-5	2,887
2013	0	0	1	3,020	-8	3,013
2014	0	0	1	3,353	-8	3,347
2015	0	0	1	3,605	-8	3,599
2016	118	10	33	4,289	-9	4,442
2017	197	17	42	4,677	-9	4,925
2018	190	22	43	5,097	1,184	6,537
2019	183	26	45	5,526	1,277	7,057
2020	176	90	46	6,184	1,446	7,942
2021	307	142	73	6,685	1,621	8,828
2022	392	143	97	6,916	1,709	9,258
2023	378	138	97	6,885	1,719	9,216
2024	363	132	100	7,325	1,880	9,800
2025	350	127	106	8,038	2,043	10,663
2026	426	122	122	8,385	2,219	11,274
2027	473	118	138	8,821	2,459	12,008
2028	538	113	158	9,126	2,660	12,594
2029	750	108	206	9,419	2,841	13,325
2030	932	103	252	9,891	3,057	14,236
2031	1,051	99	289	10,320	3,299	15,057
2032	1,264	94	345	10,919	3,683	16,305
2033	1,641	90	435	11,888	4,303	18,357
2034	1,883	85	507	12,480	4,776	19,731
2035	1,984	81	554	12,890	5,179	20,688
2036	2,299	79	643	13,903	5,990	22,914
2037	2,545	76	729	14,447	6,568	24,365
2038	2,636	74	782	14,919	7,163	25,575
2039	2,845	72	863	15,523	7,868	27,170
2040	3,016	70	945	16,020	8,573	28,623
2041	3,103	67	1,008	16,569	9,364	30,110
2042	3,320	65	1,100	17,234	10,295	32,014
2043	3,627	63	1,214	18,199	11,548	34,651
2044	3,934	61	1,334	18,984	12,735	37,047
2045	4,099	58	1,435	19,622	13,898	39,113
2046	4,285	56	1,547	20,306	15,186	41,380
2047	4,435	50	1,657	21,034	16,614	43,789
CPVRR	8,450	757	2,525	95,213	28,473	135,417

Table 41-4
GFCT Resource Plan- Revenue Requirements Assuming Fuel Forecast used in mid-course filing

	(1)	(2)	(3)	(4)	(5)	(6)
	Annual Revenue Requirements (Generation Capital) ($millions, 2011 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2011 $)	Annual Revenue Requirements (O&M) ($millions, 2011 $)	Annual Revenue Requirements (Fuel) ($millions, 2011 $)	Annual Revenue Requirements (Environmental) ($millions, 2011 $)	Total ($millions, 2011 $)
2011	0	0	0	3,133	-11	3,122
2012	0	0	1	2,891	-5	2,887
2013	0	0	1	3,020	-8	3,013
2014	0	0	1	3,353	-8	3,347
2015	0	0	1	3,605	-8	3,599
2016	33	4	14	4,362	-8	4,405
2017	56	7	7	4,796	-8	4,859
2018	53	7	8	5,215	1,207	6,491
2019	177	10	32	5,544	1,290	7,054
2020	259	12	51	6,166	1,437	7,926
2021	249	12	53	6,759	1,640	8,712
2022	240	11	57	7,029	1,750	9,087
2023	231	11	56	6,976	1,757	9,030
2024	222	10	57	7,430	1,919	9,638
2025	213	10	62	8,173	2,089	10,547
2026	411	21	99	8,440	2,242	11,213
2027	540	28	130	8,849	2,469	12,017
2028	604	27	150	9,148	2,674	12,603
2029	813	26	198	9,438	2,853	13,329
2030	994	25	244	9,905	3,070	14,238
2031	1,110	24	280	10,336	3,312	15,063
2032	1,323	23	336	10,933	3,694	16,309
2033	1,699	22	426	11,903	4,314	18,364
2034	1,941	21	497	12,491	4,788	19,738
2035	2,041	20	544	12,899	5,191	20,696
2036	2,356	20	633	13,911	6,002	22,921
2037	2,599	19	718	14,452	6,579	24,368
2038	2,688	18	771	14,928	7,175	25,580
2039	2,895	17	852	15,527	7,881	27,171
2040	3,064	16	933	16,023	8,582	28,620
2041	3,150	16	996	16,571	9,371	30,104
2042	3,365	15	1,088	17,236	10,307	32,012
2043	3,669	15	1,202	18,201	11,559	34,645
2044	3,972	14	1,321	18,984	12,744	37,035
2045	4,135	14	1,421	19,619	13,907	39,097
2046	4,337	13	1,533	20,302	15,193	41,379
2047	4,498	13	1,643	21,027	16,625	43,806
CPVRR	8,189	134	2,338	95,697	28,618	134,975

Q.
Please complete the table below describing the availability of natural gas to FPL. Please assume only the currently-planned expansion of existing pipelines.

A.

	FPL Committed (1) (Bcf/day)	Un-committed (2) (Bcf/day)
2012	1.969	.214
2013	1.969	.214
2014	1.969	.214
2015	1.969	.214
2016	1.969	.214
2017	1.969	.214
2018	1.969	.214
2019	1.969	.214
2020	1.969	.214
2021	1.969	.214
2022	1.969	.214
2023	1.969	.214
2024	1.969	.214
2025	1.969	.214
2026	1.969	.214
2027	1.969	.214
2028	1.969	.214
2029	1.969	.214
2030	1.969	.214
2031	1.969	.214
2032	1.969	.214
2033	1.969	.214
2034	1.969	.214
2035	1.969	.214
2036	1.969	.214
2037	1.969	.214
2038	1.969	.214
2039	1.969	.214
2040	1.969	.214
2041	1.969	.214
2042	1.969	.214
2043	1.969	.214
2044	1.969	.214
2045	1.969	.214
2046	1.969	.214
2047	1.969	.214
Total	1.969	.214

(1) The 1.969 Bcf/day is FPL's current committed summer transportation capacity; FPL's actual transportation capacity varies by season. For the purpose of completing the table through 2047, FPL assumed that it will extend the current contracts through 2047. The response does not include any assumptions for the gas transportation quantities that will be requested in FPL's planned Request for Proposals (as directed by the Commission in Order No. 09-0715-FOF-EI) or any other future transportation requirements.

(2) FPL has interpreted "Un-committed" to mean the unsubscribed transportation capacity on the Florida Gas Transmission (FGT) and Gulfstream Natural Gas pipelines. Currently, Gulfstream is fully subscribed; FGT has 0.214 Bcf/day of capacity available. This capacity is likely to be contracted for over the next few years, but since the actual contract date cannot be determined, this quantity is included for the term. Neither pipeline has announced any future plans for expansion.

Q.
On page 2 of her testimony, Witness Stubblefield testifies that additional compression will be required "to meet the delivery pressure requirements of the plant." Were the costs associated with this additional compression considered in the economic evaluation of the PEEC?

A.
Yes, the costs of additional compression have been included in the overall cost of the project and considered in the economic evaluation of PEEC.

Q.
What is the current status of FPL's EnergySecure pipeline?

A.
FPL assumes that this interrogatory refers to the Florida EnergySecure Line, which is the pipeline project for which the Commission denied FPL's petition for a determination of need in Order No. 09-0715-FOF-EI on October 28, 2009. The certification application under the Natural Gas Pipeline Siting Act (NGPSA) for the Florida EnergySecure Pipeline is currently in abeyance at the Division of Administrative Hearings. FPL intends to terminate the abeyance and withdraw the application effective January 2012.

FPL is currently in the process of evaluating the gas transport requirements for the modernizations of Riviera Beach and Cape Canaveral, as well as PEEC and beyond. Consistent with Order No. 09-0715-FOF-EI, FPL is preparing a Request for Proposals (RFP) to procure additional gas transportation to serve those facilities, as well as the rest of FPL's gas transportation needs.

Q.
Would delay of the PEEC impact the status of FPL's EnergySecure pipeline? Please explain.

A.
As discussed in the response to Interrogatory No. 44, FPL assumes that "FPL's Energy Secure Line" refers to the Florida Energy Secure Line, as to which the Commission denied FPL's need petition in 2009 and FPL intends to withdraw in January 2012 the certification application that is presently in abeyance. More generally, however, FPL is currently preparing a Request for Proposals (RFP) for gas transport requirements, consistent with the Commission's Order No. 09-0715-FOF-EI. That RFP process would not be impacted by a delay in PEEC. Under FPL's existing rights with Florida Gas Transmission, FPL has the gas transportation capacity needed to serve PEEC. FPL's need for additional gas is driven primarily by increased load and not the addition of new gas-fired generation. Based on the load forecast, new gas transportation (which will be requested under the RFP) will be needed to meet FPL's overall system requirements by 2017 regardless of the status of PEEC.

Q.
Please describe "temporary boost compression" including any limitations with respect to operation.

A.
The effect of gas compression is to raise the natural gas pressure up to the combustion turbine vendors specified range. The natural gas supplied to the Port Everglades site from the Florida Gas Transmission Pipeline is at a lower pressure than is needed to operate the new proposed advanced combustion turbines. Thus, the increased compression is necessary to operate PEEC's combustion turbines. The increased compression does not impose any limitations on PEEC's operation.

Q.
Please update columns 5 and 6 of Exhibit JEE-4 pages 1 through 3 assuming the fuel forecast that led to FPL's recent mid-course filing.

A.
The fuel forecast that led to the recent mid-course correction of FPL's 2012 Fuel Cost Recovery factors is a short-term (one-year) forecast. In contrast, the four resource plans evaluated by FPL witness Enjamio address generation additions in 2016 and beyond. Thus, updating columns 5 and 6 of Exhibit JEE-4 based on the "fuel forecast which led to [FPL's] recent mid-course filing" would not be meaningful. However, FPL has a long-term fuel forecast that was prepared in the same time frame (mid-November 2011) as the short-term forecast used for the mid-course correction. For the purpose of responding to this interrogatory, FPL has completed the attached Tables 47-1, 47-2 and 47-3 using the mid-November long-term fuel forecast. See attached Tables.

Table 47-1
Projection of Approximate Bill Impacts:
PEEC vs. Return To Service Resource Plans
Assuming Fuel Forecast from Mid-course Filing

Year	(1) Plan with Port Everglades Modernization Annual Total Revenue Requirements ($millions, Nominal $)	(2) Plan Returning Inactive Reserve Units PPE 1-4 to Service Annual Total Revenue Requirements ($millions, Nominal $)	(3) =(1)-(2) Differential in Annual Total Revenue Requirements ($millions, Nominal $)	(4) Projected Total Sales After DSM (GWh at the meter)	(5) =((3)x100)/(4) Differential in System Average Electric Rates (cents/kwh)	(6) =(5)x10 Differential in Customer Bill of 1,000 kwh ($)
2016	4,420	4,368	52	109,787	$0.05	$0.47
2017	4,886	4,837	48	111,105	$0.04	$0.43
2018	6,492	6,502	-10	112,313	-$0.01	-$0.09
2019	7,006	7,061	-56	113,670	-$0.05	-$0.49
2020	7,828	7,878	-51	116,014	-$0.04	-$0.44
2021	8,674	8,753	-79	118,800	-$0.07	-$0.67
2022	9,121	9,105	16	121,725	$0.01	$0.13
2023	9,085	9,098	-14	124,286	-$0.01	-$0.11
2024	9,672	9,719	-47	126,776	-$0.04	-$0.37
2025	10,539	10,596	-57	129,260	-$0.04	-$0.44
2026	11,156	11,241	-86	131,782	-$0.06	-$0.65
2027	11,894	11,980	-86	134,088	-$0.06	-$0.64
2028	12,485	12,562	-77	136,356	-$0.06	-$0.56
2029	13,217	13,306	-89	138,542	-$0.06	-$0.64
2030	14,132	14,178	-46	140,654	-$0.03	-$0.33
2031	14,957	15,036	-79	143,001	-$0.06	-$0.55
2032	16,209	16,284	-75	145,378	-$0.05	-$0.52
2033	18,263	18,342	-79	147,808	-$0.05	-$0.54
2034	19,640	19,706	-66	150,273	-$0.04	-$0.44
2035	20,602	20,670	-68	152,778	-$0.04	-$0.44
2036	22,828	22,887	-59	155,325	-$0.04	-$0.38
2037	24,281	24,359	-78	157,912	-$0.05	-$0.49
2038	25,493	25,566	-73	160,542	-$0.05	-$0.46
2039	27,089	27,141	-52	163,216	-$0.03	-$0.32
2040	28,543	28,585	-42	165,929	-$0.03	-$0.26
2041	30,032	30,078	-46	168,692	-$0.03	-$0.28
2042	31,938	32,008	-71	171,497	-$0.04	-$0.41
2043	34,577	34,636	-59	174,349	-$0.03	-$0.34
2044	36,973	37,003	-29	177,247	-$0.02	-$0.17
2045	39,041	39,077	-36	180,192	-$0.02	-$0.20
2046	41,311	41,365	-54	183,186	-$0.03	-$0.29
2047	43,725	43,790	-65	186,229	-$0.03	-$0.35
					Average 2016-2047	-$0.34

Notes: (1) This projection assumes instantaneous adjustment to electric rates and is for illustrative purposes only.
(2) The values presented in Columns (1), (2), and (3) are total system revenue requirements and include all costs: capital, system fuel, etc.

Table 47-2
Projection of Approximate Bill Impacts:
PEEC vs. GFCC Resource Plans
Assuming Fuel Forecast from Mid-course Filing

Year	(1) Plan with Port Everglades Modernization Annual Total Revenue Requirements ($millions, Nominal $)	(2) Plan with Greenfield Site Combined Cycle Annual Total Revenue Requirements ($millions, Nominal $)	(3) =(1)-(2) Differential in Annual Total Revenue Requirements ($millions, Nominal $)	(4) Projected Total Sales After DSM (GWh at the meter)	(5) =((3)x100)/(4) Differential in System Average Electric Rates (cents/kwh)	(6) =(5)x10 Differential in Customer Bill of 1,000 kwh ($)
2016	4,420	4,442	-22	109,787	-$0.02	-$0.20
2017	4,886	4,925	-39	111,105	-$0.04	-$0.36
2018	6,492	6,537	-45	112,313	-$0.04	-$0.40
2019	7,006	7,057	-51	113,670	-$0.05	-$0.45
2020	7,828	7,942	-115	116,014	-$0.10	-$0.99
2021	8,674	8,828	-154	118,800	-$0.13	-$1.30
2022	9,121	9,258	-137	121,725	-$0.11	-$1.13
2023	9,085	9,216	-132	124,286	-$0.11	-$1.06
2024	9,672	9,800	-128	126,776	-$0.10	-$1.01
2025	10,539	10,663	-124	129,260	-$0.10	-$0.96
2026	11,156	11,274	-119	131,782	-$0.09	-$0.90
2027	11,894	12,008	-113	134,088	-$0.08	-$0.85
2028	12,485	12,594	-109	136,356	-$0.08	-$0.80
2029	13,217	13,325	-108	138,542	-$0.08	-$0.78
2030	14,132	14,236	-105	140,654	-$0.07	-$0.74
2031	14,957	15,057	-100	143,001	-$0.07	-$0.70
2032	16,209	16,305	-96	145,378	-$0.07	-$0.66
2033	18,263	18,357	-94	147,808	-$0.06	-$0.64
2034	19,640	19,731	-91	150,273	-$0.06	-$0.60
2035	20,602	20,688	-86	152,778	-$0.06	-$0.56
2036	22,828	22,914	-86	155,325	-$0.06	-$0.55
2037	24,281	24,365	-84	157,912	-$0.05	-$0.53
2038	25,493	25,575	-82	160,542	-$0.05	-$0.51
2039	27,089	27,170	-81	163,216	-$0.05	-$0.50
2040	28,543	28,623	-80	165,929	-$0.05	-$0.48
2041	30,032	30,110	-78	168,692	-$0.05	-$0.46
2042	31,938	32,014	-77	171,497	-$0.04	-$0.45
2043	34,577	34,651	-75	174,349	-$0.04	-$0.43
2044	36,973	37,047	-74	177,247	-$0.04	-$0.42
2045	39,041	39,113	-72	180,192	-$0.04	-$0.40
2046	41,311	41,380	-70	183,186	-$0.04	-$0.38
2047	43,725	43,789	-64	186,229	-$0.03	-$0.34
					Average 2016-2047	-$0.64

Notes: (1) This projection assumes instantaneous adjustment to electric rates and is for illustrative purposes only.
(2) The values presented in Columns (1), (2), and (3) are total system revenue requirements and include all costs: capital, system fuel, etc.

Table 47-3
Projection of Approximate Bill Impacts:
PEEC vs. GFCT Resource Plans
Assuming Fuel Forecast from Mid-course Filing

Year	(1) Plan with Port Everglades Modernization Annual Total Revenue Requirements ($millions, Nominal $)	(2) Plan with Simple Cycle Combustion Turbine (CT) Annual Total Revenue Requirements ($millions, Nominal $)	(3) =(1)-(2) Differential in Annual Total Revenue Requirements ($millions, Nominal $)	(4) Projected Total Sales After DSM (GWh at the meter)	(5) =((3)x100)/(4) Differential in System Average Electric Rates (cents/kwh)	(6) =(5)x10 Differential in Customer Bill of 1,000 kwh ($)
2016	4,420	4,405	15	109,787	$0.01	$0.14
2017	4,886	4,859	27	111,105	$0.02	$0.24
2018	6,492	6,491	2	112,313	$0.00	$0.02
2019	7,006	7,054	-48	113,670	-$0.04	-$0.43
2020	7,828	7,926	-99	116,014	-$0.09	-$0.85
2021	8,674	8,712	-38	118,800	-$0.03	-$0.32
2022	9,121	9,087	34	121,725	$0.03	$0.28
2023	9,085	9,030	55	124,286	$0.04	$0.44
2024	9,672	9,638	34	126,776	$0.03	$0.27
2025	10,539	10,547	-8	129,260	-$0.01	-$0.06
2026	11,156	11,213	-57	131,782	-$0.04	-$0.44
2027	11,894	12,017	-122	134,088	-$0.09	-$0.91
2028	12,485	12,603	-118	136,356	-$0.09	-$0.87
2029	13,217	13,329	-112	138,542	-$0.08	-$0.81
2030	14,132	14,238	-106	140,654	-$0.08	-$0.75
2031	14,957	15,063	-106	143,001	-$0.07	-$0.74
2032	16,209	16,309	-100	145,378	-$0.07	-$0.69
2033	18,263	18,364	-101	147,808	-$0.07	-$0.69
2034	19,640	19,738	-98	150,273	-$0.07	-$0.65
2035	20,602	20,696	-94	152,778	-$0.06	-$0.61
2036	22,828	22,921	-93	155,325	-$0.06	-$0.60
2037	24,281	24,368	-87	157,912	-$0.06	-$0.55
2038	25,493	25,580	-87	160,542	-$0.05	-$0.54
2039	27,089	27,171	-82	163,216	-$0.05	-$0.50
2040	28,543	28,620	-77	165,929	-$0.05	-$0.47
2041	30,032	30,104	-72	168,692	-$0.04	-$0.43
2042	31,938	32,012	-74	171,497	-$0.04	-$0.43
2043	34,577	34,645	-68	174,349	-$0.04	-$0.39
2044	36,973	37,035	-62	177,247	-$0.03	-$0.35
2045	39,041	39,097	-56	180,192	-$0.03	-$0.31
2046	41,311	41,379	-68	183,186	-$0.04	-$0.37
2047	43,725	43,806	-81	186,229	-$0.04	-$0.43
					Average 2016-2047	-$0.40

Notes: (1) This projection assumes instantaneous adjustment to electric rates and is for illustrative purposes only.
(2) The values presented in Columns (1), (2), and (3) are total system revenue requirements and include all costs: capital, system fuel, etc.

Q.
Please complete the table below, describing FPL's generation by fuel type, for each of the four resource plans discussed in witness Enjamio's testimony.

Generation by Fuel Type (%)					
	NG	Oil	Coal	Nuclear	Renewable
2012					
2013					
2014					
2015					
2016					
2017					
2018					
2019					
2020					
2021					
2022					
2023					
2024					
2025					

A.
See attached Tables 48-1, 48-2, 48-3, and 48-4.

Table 48-1
PEEC Resource Plan

Generation by Fuel Type %					
	NG	Oil	Coal	Nuclear	Renewable
2012	69.87%	0.84%	10.54%	17.44%	1.30%
2013	63.61%	0.30%	12.17%	22.56%	1.37%
2014	63.96%	0.20%	11.15%	23.39%	1.31%
2015	64.03%	0.25%	11.49%	22.59%	1.64%
2016	66.52%	0.33%	8.82%	22.52%	1.80%
2017	67.33%	0.37%	7.86%	22.66%	1.78%
2018	69.09%	0.35%	6.74%	22.06%	1.76%
2019	69.41%	0.41%	6.73%	21.72%	1.74%
2020	69.48%	0.55%	6.48%	21.78%	1.71%
2021	70.14%	0.40%	6.88%	20.91%	1.67%
2022	67.39%	0.16%	6.81%	24.01%	1.63%
2023	60.71%	0.09%	6.45%	31.15%	1.60%
2024	59.36%	0.14%	6.56%	32.37%	1.57%
2025	60.94%	0.23%	5.27%	32.01%	1.54%

Table 48-2
Return to Service Resource Plan

Generation by Fuel Type %					
	NG	Oil	Coal	Nuclear	Renewable
2012	69.87%	0.84%	10.54%	17.44%	1.30%
2013	63.61%	0.30%	12.17%	22.56%	1.37%
2014	63.96%	0.20%	11.15%	23.39%	1.31%
2015	64.03%	0.25%	11.49%	22.59%	1.64%
2016	66.22%	0.54%	8.91%	22.52%	1.80%
2017	66.78%	0.70%	8.08%	22.66%	1.78%
2018	68.48%	0.65%	7.04%	22.06%	1.76%
2019	68.66%	0.73%	7.15%	21.72%	1.74%
2020	68.76%	0.93%	6.82%	21.78%	1.71%
2021	69.45%	0.75%	7.23%	20.91%	1.67%
2022	66.87%	0.39%	7.10%	24.01%	1.63%
2023	60.23%	0.27%	6.75%	31.15%	1.60%
2024	58.90%	0.32%	6.84%	32.37%	1.57%
2025	60.40%	0.48%	5.57%	32.01%	1.54%

Table 48-3
GFCC Resource Plan

Generation by Fuel Type %					
	NG	Oil	Coal	Nuclear	Renewable
2012	69.87%	0.84%	10.54%	17.44%	1.30%
2013	63.61%	0.30%	12.17%	22.56%	1.37%
2014	63.96%	0.20%	11.15%	23.39%	1.31%
2015	64.03%	0.25%	11.49%	22.59%	1.64%
2016	66.53%	0.32%	8.82%	22.52%	1.80%
2017	67.33%	0.38%	7.85%	22.66%	1.78%
2018	68.97%	0.34%	6.87%	22.06%	1.76%
2019	69.10%	0.40%	7.03%	21.72%	1.74%
2020	69.22%	0.54%	6.75%	21.78%	1.71%
2021	69.97%	0.40%	7.06%	20.91%	1.67%
2022	67.39%	0.17%	6.81%	24.01%	1.63%
2023	60.70%	0.09%	6.46%	31.15%	1.60%
2024	59.34%	0.14%	6.58%	32.37%	1.57%
2025	60.95%	0.23%	5.27%	32.01%	1.54%

Table 48-4
GFCT Resource Plan

Generation by Fuel Type %					
	NG	Oil	Coal	Nuclear	Renewable
2012	69.87%	0.84%	10.54%	17.44%	1.30%
2013	63.61%	0.30%	12.17%	22.56%	1.37%
2014	63.96%	0.20%	11.15%	23.39%	1.31%
2015	64.03%	0.25%	11.49%	22.59%	1.64%
2016	66.22%	0.54%	8.91%	22.52%	1.80%
2017	66.78%	0.70%	8.08%	22.66%	1.78%
2018	68.49%	0.64%	7.04%	22.06%	1.76%
2019	69.19%	0.48%	6.87%	21.72%	1.74%
2020	69.48%	0.55%	6.48%	21.78%	1.71%
2021	69.83%	0.63%	6.96%	20.91%	1.67%
2022	66.87%	0.40%	7.09%	24.01%	1.63%
2023	60.22%	0.27%	6.76%	31.15%	1.60%
2024	58.90%	0.32%	6.84%	32.37%	1.57%
2025	60.39%	0.48%	5.57%	32.02%	1.54%

Q.
Does operating a unit as a synchronous condenser cause any damage to a generating unit? Please explain.

A.
No. Operating a generating unit as a synchronous condenser does not cause any damage to the generating unit. The reason is twofold. First, when the generating unit operates as a synchronous condenser, the majority of the unit's equipment is not used because the prime mover and its associated equipment are not needed for operation. Second, the equipment that is being used -- the synchronous generator, the excitation system, generator lubricating oil systems, and generator cooling systems -- all operate within their normal design ratings when the unit operates as a synchronous condenser.

Q.
Please describe the O&M costs associated with a unit being operated as a synchronous condenser and then contrast such costs with the costs of the same unit being operated for generation purposes.

A.
The O&M cost of operating Turkey Point Unit 2 as a synchronous condenser is estimated to average approximately $1.2 million annually versus $4.1 million annually over the most recent five year period (2006-2010) when operating the unit for generation purposes.

Q.
On page 4 of his testimony, witness Gnecco testifies that the PEEC will result in "the creation of an estimated 650 direct jobs at its peak." How many permanent jobs will be created as a result of the PEEC project?

A.
The PEEC project will require approximately 40 full time employees under normal operating conditions.

Q.
Please provide a timeline comparing the PEEC project with FPL's other modernization projects, including projected regulatory and construction milestones.

A.
See Attachment No. 1.

Plant Modernization Schedules

	Project Milestone Schedule		
	Cape Canaveral Energy Center	Riviera Beach Energy Center	Port Everglades Energy Center
Need Determination	September 2008	September 2008	April 2012
Site Certification Final Order	October 2009	November 2009	March 2013
Start Demolition	June 2010	March 2011	March 2013
Demolition Complete	February 2011	November 2011	April 2014
Construction Start	March 2011	November 2011	April 2014
Commissioning - 1st Fire	December 2012	December 2013	December 2015
Commercial Operation	June 2013	June 2014	June 2016

Q.
On page 8 of his testimony, witness Gnecco testifies that, "[b]ringing traditional oil or natural gas fired steam generator technologies out of Inactive Reserve was removed from consideration for multiple reasons, including the initial capital cost." What is the initial capital cost associated with bringing such a unit out of inactive reserve?

A.
The initial capital cost associated with bring Port Everglades units 1-4 out of inactive reserve is estimated to be approximately $235 million. To keep the facility operational for an additional 30 years would require an estimated $587 million of capital expenditures in addition to the $235 million initial capital costs and an estimated $838 million in O&M costs.

Q.
What technology CTs are being used at FPL's other conversion projects?

A.
The modernizations at Cape Canaveral and Riviera Beach will be deploying Siemens "H" technology combustion turbines.

Q.
In his testimony, witness Modia discusses the load to generation imbalance in the Southeast Florida area.

a. Please describe the consequences of not building new generation near FPL's load centers.
b. Please describe the consequences of not building new generation near FPL's load centers and not upgrading transmission.
c. Please illustrate graphically the location of FPL's load centers and the location of its generation.

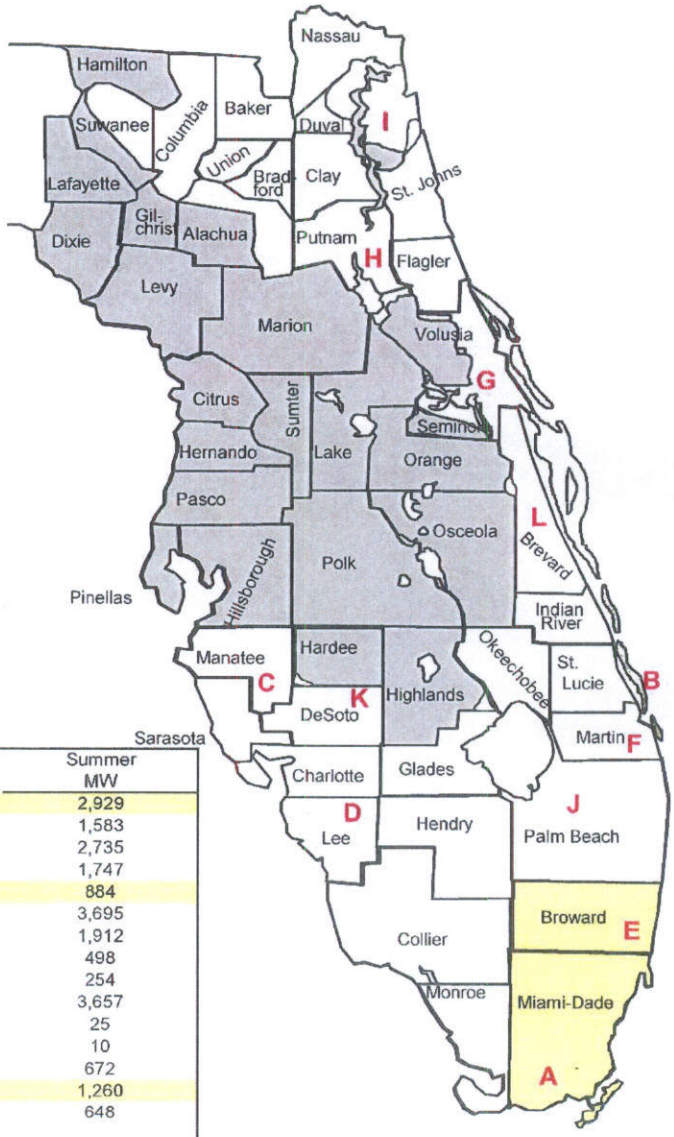
A.
a. The consequence of not building new generation near FPL load is that the load would become more dependent upon the transmission system to deliver generation from distant locales and upgraded and/or additional transmission facilities will be required to reliably serve customer loads as they increase over time. Such upgraded and/or additional transmission facilities would be planned and constructed to meet NERC Reliability Standards and prescribed performance criteria. Despite adherence to such standards and criteria, reliance upon long-distance transmission lines is inherently more risky than reliance upon generation that is positioned close to load. Damage to one long-distance transmission line due to extreme weather, for example, would potentially impact a large number of customers. The ultimate consequence, therefore, would be less reliable service.

b. The consequences of not building new generation near FPL load and not upgrading transmission facilities are that as customer loads increase, the loads could not be served reliably, resulting in possible curtailment of electric service to FPL's customers (i.e., brownouts or blackouts). Additionally, such inaction could violate NERC Reliability Standards, subjecting FPL to penalties and fines of up to one million dollars per day, per violation.

c. See attached Table 55 - C.

Table 55 - C

FPL Generating Resources and Peak Load by Location



Location/ Map Key	Plant Name	Number of Units	Summer MW
A	Turkey Point	4	2,929
B	St. Lucie	2	1,583
C	Manatee	3	2,735
D	Fort Myers	2	1,747
E	Lauderdale	2	884
F	Martin	5	3,695
G	Sanford	2	1,912
H	Putnam	2	498
I	SJRPP	2	254
J	West County	3	3,657
K	DeSoto (non-firm)	1	25
L	Space Coast (non-firm)	1	10
	Scherer	1	672
	Gas Turbines (Broward County)	36	1,260
	Gas Turbines (Other)	12	648
	Total System Generation =	**78**	**22,509**
	System Firm Generation * =	**76**	**22,474**

Broward and Miami-Dade Generation =	5,073 MW
Broward and Miami-Dade MWs (w/o Gas Turbines) =	3,813 MW
Broward & Miami-Dade % =	**22.6% of Firm Generation**
Broward & Miami-Dade (w/o Gas Turbines) % =	**17.0% of Firm Generation**

* Does not include units in inactive reserve such as Port Everglades Units 1 - 4

FPL August 2011 Peak Load	
System Peak Load =	21,615 MW
Broward & Miami-Dade Peak Load =	9,517 MW
Broward & Miami-Dade % =	**44% of peak load**

Q.
Please list critical milestones for the construction of a new coal plant including a projected timeline for siting and construction.

A.
FPL has not preformed any specific assessments into the timeline associated with the development of a new coal plant. However, the following figures (prepared for the "2006 Ten Year Site Plan Supplemental Data Request") depict the timelines for siting, permitting, and constructing a new super critical pulverized coal unit with and without an RFP.

Figure 4B.1

Timeline of Activities Needed for FPL to Gain Approval for & Construct a New Super Critical Pulverized Coal Unit without conduct of an RFP
(Approximate Times)

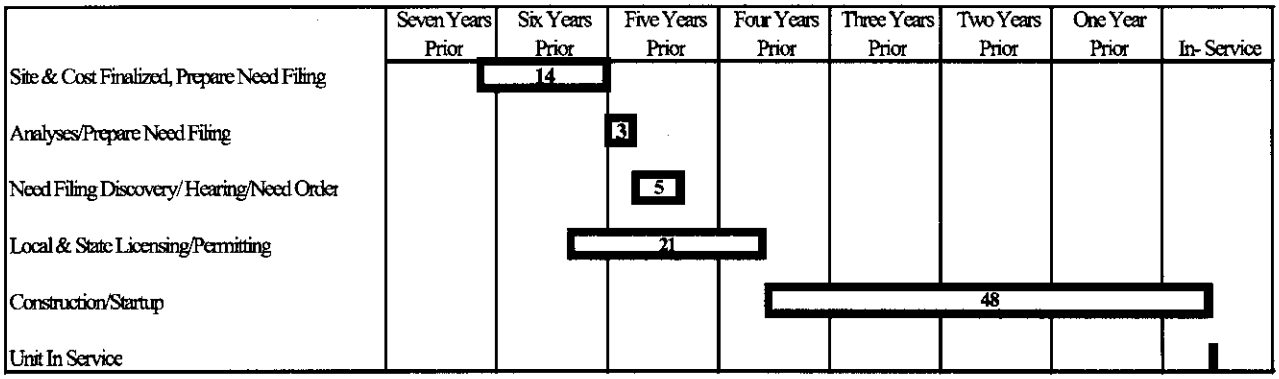
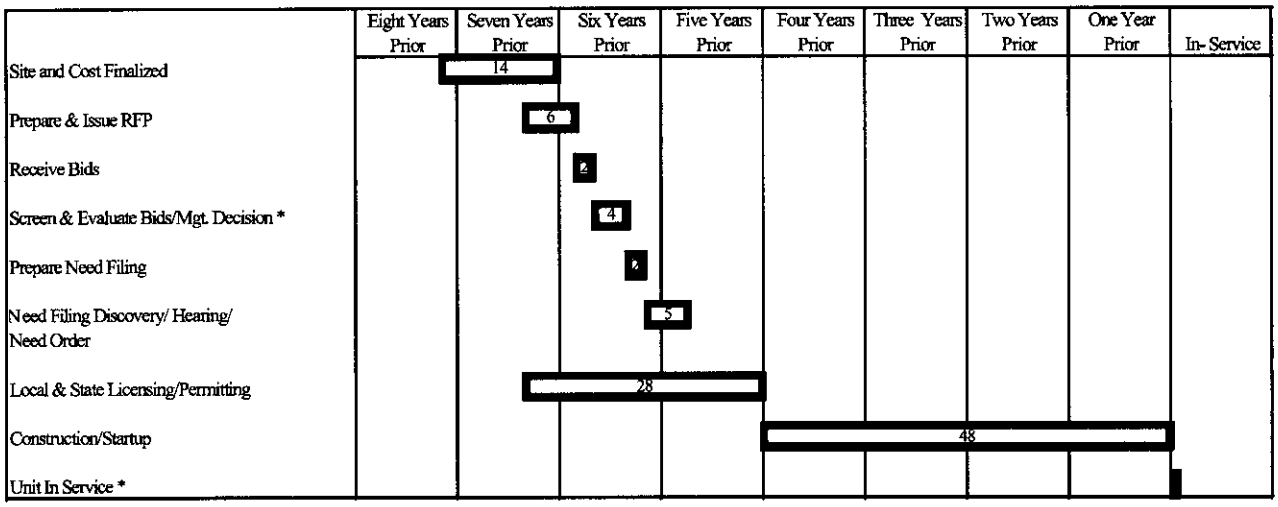


Figure 4B.2

Timeline of Activities Needed for FPL to Gain Approval for & Construct a New Super Critical Pulverized Coal Unit including conduct of an RFP

(Approximate Times, Shortest Possible Time for RFP *)



* If extended negotiations with Bidder(s) are required, at least 3 additional months would be added to the timeline shown.

Q.
Please list and discuss all financial and economic assumptions used in FPL's economic evaluation of the PEEC including without limitation. capital structure, discount rate, general inflation rate, and tax assumptions.

A.
See assumptions below:

Income Tax

STATE INCOME TAX RATE	5.50%
FEDERAL INCOME TAX RATE	35.00%
COMPOSITE INCOME TAX RATE	38.575%

Cost of Capital and Discount Rate

SOURCE	WEIGHT	LONG LIVED ASSETS COST	WTD COST	AFTER TAX
DEBT	40.9%	5.50%	2.25%	1.38%
PREFERRED	0.0%	0.00%	0.0%	0.0%
COMMON	59.1%	10.00%	5.91%	5.91%
TOTAL	100.0%	--	8.16%	7.29%

DISCOUNT RATE:	7.29%

Property Taxes and Insurance

PROPERTY TAXES	1.84%
PROPERTY INSURANCE	0.047%

Escalation Rates

Average capital escalation rate	3.0%
Average O&M escalation rate	2.5%

Q.
Please complete the table below describing FPL's DSM projections.

	Projected Summer DSM (MW)	Commission Goals
2012		
2013		
2014		
2015		
2016		
2017		
2018		
2019		

A.
This information is provided in Table 58. Column (1) presents FPL's projected total Summer DSM MW that were used in FPL's analyses presented in this filing for approval of the PEEC modernization project. Column (2) presents the annual incremental Summer MW values associated with the Column (1) values. Column (3) presents the annual incremental Summer MW from the FPSC's 2009 DSM Goals decision.

The DSM MW values presented in Columns (1) and (2) are consistent with the FPSC's 2011 decision regarding FPL's DSM Plan which instructed FPL to implement previously approved DSM programs.

Table 58

Year	(1) Projected Total Summer DSM (MW at gen)	(2) Projected Incremental Summer DSM (MW at gen)	(3) FPSC Incremental Summer DSM Goals (MW at gen)
2011	1,856	---	---
2012	1,986	130	167
2013	2,109	123	180
2014	2,272	163	184
2015	2,404	132	172
2016	2,536	132	156
2017	2,667	131	140
2018	2,799	132	129
2019	2,930	131	118

Notes:

- Column (1) provides FPL's projection of total Summer MW reduction capability used in FPL's analyses of its generation options for the PEEC modernization filing. (These values were previously provided in Exhibit JEE-1 of FPL Witness Enjamio.

- Column (2) provides the annual incremental DSM Summer MW associated with the values presented in Column (1). (Note that the DSM values shown for the year 2014 include approximately 40 MW of Lee County load control capability that will become available once FPL begins to serve all of Lee County's load in 2014.) These total MW values represent both cumulative load control plus incremental energy conservation and load control.

- **The DSM values shown in Columns (1) and (2) are consistent with the Commission's order in the DSM Plan docket that directed FPL to implement previously approved DSM programs.**

- Column (3) provides the total Summer MW DSM goals for FPL from the FPSC's 2009 DSM Goals order.

Q.
Please complete the table below assuming the following changes to Resource Plan GFCT:

a. Removal of the two CTs in 2016.
b. Removal of the two CTs in 2016. Addition of a Short Term 600 MW Power Purchase Agreement beginning in 2016 and ending in 2019. Please provide the basis for the cost of the Power Purchase Agreement.
c. Removal of the two CTs in 2016. Addition of three CTs at the Port Everglades Site in 2016. Addition of Heat Return Steam Generator at the Port Everglades Site in 2019.

	Annual Revenue Requirements (Generation Capital) ($millions, 2011 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2011 $)	Annual Revenue Requirements (O&M) ($millions, 2011 $)	Annual Revenue Requirements (Fuel) ($millions, 2011 $)	Annual Revenue Requirements (Environmental) ($millions, 2011 $)	Total ($millions, 2011 $)
2012						
2013						
2014						
2015						
2016						
2017						
2018						
2019						
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2023						
2024						
2025						
2026						
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2028						
2029						
2030						
2031						
2032						
2033						
	Annual Revenue Requirements (Generation Capital) ($millions, 2011 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2011 $)	Annual Revenue Requirements (O&M) ($millions, 2011 $)	Annual Revenue Requirements (Fuel) ($millions, 2011 $)	Annual Revenue Requirements (Environmental) ($millions, 2011 $)	Total ($millions, 2011 $)
2034						
2035						
2036						
2037						
2038						
2039						
2040						
2041						
2042						
2043						
2044						
2045						
2046						
2047						
Total						

A.
Please see attached tables for answer to subparts (a) and (b).

c. FPL does not have the information required to perform the economic analysis requested regarding the phased construction of PEEC. To develop the required cost and performance information, FPL would need to conduct detailed engineering feasibility and cost estimating studies, as well as additional transmission reliability studies. FPL has not conducted these studies, as it expects that building PEEC in two phases that are separated by multiple years would result in a substantial increase in the overall cost of the project to the detriment of FPL's customers. The increase in overall costs would be due to several factors, including the following: (1) a larger power block footprint to accommodate the CT exhaust stack and a safe working distances to allow simple cycle operation during HRSG and steam turbine construction; (2) an increase in constructions costs due to de-moblizing EPC contractors following construction of the CTs in 2016 and then re-mobilizing those contractors in 2018-2019 for the HRSG and steam turbine construction; (3) escalation in equipment and labor costs in 2018-19 due to an improved global economy; and (4) significantly higher fuel costs and higher air emissions during the 2016-2019 period when compared to the PEEC Resource Plan due to the delay in completing the full combined cycle unit.

In addition to the factors identified above, phased construction would also require a construction outage of approximately 6-9 months to integrate the combustion turbines and the HRSG into combined cycle operation. This lengthy outage could significantly increase costs to customers as well. During this outage the new CTs would not be able to operate, so the only generation available at the site would be the existing gas turbines. Due to transmission reliability concerns, during the construction outages these gas turbines would likely be required to operate out of the normal economic dispatch, further increasing system fuel costs. Additional transmission remediation measures might be required which could result in transmission costs due to the phased approach.

Finally, from an environmental standpoint, FPL would have considerable difficulty obtaining authorization from FDEP to operate the CTs that are in consideration for PEEC in simple cycle configuration. FDEP permits for simple cycle CT projects typically require a NOx emission rate of 9 ppmvd for natural gas firing. The advanced CTs in consideration for PEEC are designed and optimized for combined cycle application, and they would have simple-cycle NOx emission rates up to three or more times the FDEP authorized simple cycle emissions rate (in combined cycle operation, NOx emissions are controlled as the exhaust gases from the advanced CTs pass through an SCR in the HRSG). Further engineering studies would be needed to evaluate the use of these advanced CTs in simple cycle operation. FPL expects that the advanced CTs would require additional equipment and controls (such as selective catalytic reduction (SCR), or other equipment modifications) to achieve the FDEP authorized NOx emission rates in simple-cycle operation. There are, however, major technical challenges to using SCR in simple cycle configuration due to the very high exhaust temperatures from the CTs being considered. Please note that there are CT designs that can achieve the FDEP's authorized NOx emission rates in simple-cycle configuration, but those CT designs have a higher heat rate (lower efficiency) and are less effective in a combined cycle plant than the advanced CTs in consideration for PEEC. The use of less efficient CTs would increase PEEC's fuel costs and emissions, to the detriment of

FPL's customers and the state of Florida.

Based on these reasons, FPL believes that the two-stage construction of this project would measurably increase capital costs and fuel costs when compared to constructing PEEC in full combined cycle mode by the summer of 2016 (the PEEC Resource Plan).

Florida Power & Light Company
Docket No. 110309-EI
Staff's First Set of Interrogatories
Interrogatory No. 59
Attachment No. 1
Page 1 of 2

GFCT Resource Plan- Revenue Requirements
Assuming the removal of the two CTs In 2016

	(1)	(2)	(3)	(4)	(5)	(6)
	Annual Revenue Requirements (Generation Capital) ($millions, 2011 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2011 $)	Annual Revenue Requirements (O&M) ($millions, 2011 $)	Annual Revenue Requirements (Fuel) ($millions, 2011 $)	Annual Revenue Requirements (Environmental) ($millions, 2011 $)	Total ($millions, 2011 $)
2011	0	0	0	3,250	-11	3,239
2012	0	0	1	3,434	-5	3,430
2013	0	0	1	3,433	-8	3,426
2014	0	0	1	3,665	-7	3,659
2015	0	0	1	3,972	-8	3,966
2016	0	0	11	4,741	-8	4,744
2017	0	0	3	5,207	-8	5,202
2018	0	0	3	5,630	1,229	6,863
2019	126	4	27	5,963	1,337	7,457
2020	210	6	46	6,550	1,467	8,279
2021	203	6	47	7,182	1,660	9,097
2022	195	5	52	7,462	1,765	9,479
2023	188	5	50	7,375	1,771	9,389
2024	181	5	51	7,975	1,933	10,145
2025	174	5	56	8,811	2,102	11,148
2026	374	16	93	9,103	2,259	11,845
2027	505	24	124	9,535	2,499	12,686
2028	571	23	143	9,850	2,720	13,306
2029	782	22	191	10,148	2,925	14,069
2030	964	21	237	10,608	3,194	15,024
2031	1,083	20	273	11,064	3,451	15,891
2032	1,296	19	329	11,761	3,801	17,207
2033	1,674	18	419	12,899	4,378	19,388
2034	1,917	18	489	13,584	4,819	20,827
2035	2,018	17	536	14,046	5,205	21,822
2036	2,333	16	625	15,176	6,014	24,164
2037	2,578	16	710	15,783	6,587	25,674
2038	2,668	15	763	16,310	7,179	26,935
2039	2,875	14	843	16,972	7,889	28,594
2040	3,046	14	925	17,518	8,589	30,091
2041	3,133	13	987	18,122	9,376	31,631
2042	3,348	12	1,079	18,857	10,309	33,606
2043	3,653	12	1,192	19,930	11,562	36,350
2044	3,957	12	1,312	20,793	12,748	38,822
2045	4,121	11	1,411	21,494	13,912	40,950
2046	4,332	11	1,523	22,247	15,199	43,312
2047	4,498	11	1,632	23,047	16,630	45,818
CPVRR	7,846	88	2,282	103,797	28,880	142,893

GFCT Resource Plan- Revenue Requirements
Assuming the removal of the two CTs in 2016 and a Short Term Purchase (600MW) 2016-2019

	(1)	(2)	(3)	(4)	(5)	(6)
	Annual Revenue Requirements (Generation Capital) ($millions, 2011 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2011 $)	Annual Revenue Requirements (O&M) ($millions, 2011 $)	Annual Revenue Requirements (Fuel) ($millions, 2011 $)	Annual Revenue Requirements (Environmental) ($millions, 2011 $)	Total ($millions, 2011 $)
2011	0	0	0	3,250	-11	3,239
2012	0	0	0	3,434	-5	3,429
2013	0	0	0	3,433	-8	3,425
2014	0	0	0	3,665	-7	3,658
2015	0	0	0	3,972	-8	3,964
2016	0	0	14	4,738	-8	4,744
2017	0	0	25	5,208	-8	5,226
2018	0	0	26	5,632	1,230	6,888
2019	126	4	35	5,963	1,337	7,465
2020	210	6	43	6,550	1,467	8,277
2021	203	6	44	7,182	1,660	9,094
2022	195	5	46	7,462	1,765	9,473
2023	188	5	47	7,375	1,771	9,386
2024	181	5	48	7,975	1,933	10,142
2025	174	5	50	8,811	2,102	11,141
2026	374	16	90	9,103	2,259	11,842
2027	505	24	120	9,535	2,499	12,683
2028	571	23	140	9,850	2,720	13,303
2029	782	22	188	10,148	2,925	14,065
2030	964	21	233	10,608	3,194	15,021
2031	1,083	20	270	11,064	3,451	15,887
2032	1,296	19	325	11,761	3,801	17,203
2033	1,674	18	415	12,899	4,378	19,384
2034	1,917	18	485	13,584	4,819	20,823
2035	2,018	17	532	14,046	5,205	21,818
2036	2,333	16	621	15,176	6,014	24,160
2037	2,578	16	702	15,783	6,587	25,666
2038	2,668	15	759	16,310	7,179	26,930
2039	2,875	14	839	16,972	7,889	28,589
2040	3,046	14	917	17,518	8,589	30,083
2041	3,133	13	982	18,122	9,376	31,626
2042	3,348	12	1,074	18,857	10,309	33,601
2043	3,653	12	1,187	19,930	11,562	36,345
2044	3,957	12	1,306	20,793	12,748	38,817
2045	4,121	11	1,406	21,494	13,912	40,945
2046	4,332	11	1,517	22,247	15,199	43,306
2047	4,498	11	1,627	23,047	16,630	45,812
CPVRR	7,846	88	2,285	103,797	28,881	142,896

Q.
Please complete the table below assuming the following changes to Resource Plan GFCT:

a. Removal of the two CTs in 2016.
b. Removal of the two CTs in 2016. Addition of a Short Term 600 MW Power Purchase Agreement beginning in 2016 and ending in 2019. Please provide the basis for the cost of the Power Purchase Agreement.
c. Removal of the two CTs in 2016. Addition of three CTs at the Port Everglades Site in 2016. Addition of Heat Return Steam Generator at the Port Everglades Site in 2019.

	Annual Revenue Requirements (Generation Capital) ($millions, 2011 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2011 $)	Annual Revenue Requirements (O&M) ($millions, 2011 $)	Annual Revenue Requirements (Fuel) ($millions, 2011 $)	Annual Revenue Requirements (Environmental) ($millions, 2011 $)	Total ($millions, 2011 $)
2012						
2013						
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2032						
2033						
	Annual Revenue Requirements (Generation Capital) ($millions, 2011 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2011 $)	Annual Revenue Requirements (O&M) ($millions, 2011 $)	Annual Revenue Requirements (Fuel) ($millions, 2011 $)	Annual Revenue Requirements (Environmental) ($millions, 2011 $)	Total ($millions, 2011 $)
2034						
2035						
2036						
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2038						
2039						
2040						
2041						
2042						
2043						
2044						

2045						
2046						
2047						
Total						

A.
Please see attached corrected Tables 59-A and 59-B for answers to subparts (a) and (b).

c. FPL does not have the information required to perform the economic analysis requested regarding the phased construction of PEEC. To develop the required cost and performance information, FPL would need to conduct detailed engineering feasibility and cost estimating studies, as well as additional transmission reliability studies. FPL has not conducted these studies, as it expects that building PEEC in two phases that are separated by multiple years would result in a substantial increase in the overall cost of the project to the detriment of FPL's customers. The increase in overall costs would be due to several factors, including the following: (1) a larger power block footprint to accommodate the CT exhaust stack and a safe working distances to allow simple cycle operation during HRSG and steam turbine construction; (2) an increase in constructions costs due to de-moblizing EPC contractors following construction of the CTs in 2016 and then re-mobilizing those contractors in 2018-2019 for the HRSG and steam turbine construction; (3) escalation in equipment and labor costs in 2018-19 due to an improved global economy; and (4) significantly higher fuel costs and higher air emissions during the 2016-2019 period when compared to the PEEC Resource Plan due to the delay in completing the full combined cycle unit.

In addition to the factors identified above, phased construction would also require a construction outage of approximately 6-9 months to integrate the combustion turbines and the HRSG into combined cycle operation. This lengthy outage could significantly increase costs to customers as well. During this outage the new CTs would not be able to operate, so the only generation available at the site would be the existing gas turbines. Due to transmission reliability concerns, during the construction outages these gas turbines would likely be required to operate out of the normal economic dispatch, further increasing system fuel costs. Additional transmission remediation measures might be required which could result in transmission costs due to the phased approach.

Finally, from an environmental standpoint, FPL would have considerable difficulty obtaining authorization from FDEP to operate the CTs that are in consideration for PEEC in simple cycle configuration. FDEP permits for simple cycle CT projects typically require a NOx emission rate of 9 ppmvd for natural gas firing. The advanced CTs in consideration for PEEC are designed and optimized for combined cycle application, and they would have simple-cycle NOx emission rates up to three or more times the FDEP authorized simple cycle emissions rate (in combined cycle operation, NOx emissions are controlled as the exhaust gases from the advanced CTs pass through an SCR in the HRSG). Further engineering studies would be needed to evaluate the use of these advanced CTs in simple cycle operation. FPL expects that the advanced CTs would require additional equipment and controls (such as selective catalytic reduction (SCR), or other equipment modifications) to achieve the FDEP authorized NOx emission rates in simple-cycle operation. There are, however, major technical challenges to using SCR in simple cycle

configuration due to the very high exhaust temperatures from the CTs being considered. Please note that there are CT designs that can achieve the FDEP's authorized NOx emission rates in simple-cycle configuration, but those CT designs have a higher heat rate (lower efficiency) and are less effective in a combined cycle plant than the advanced CTs in consideration for PEEC. The use of less efficient CTs would increase PEEC's fuel costs and emissions, to the detriment of FPL's customers and the state of Florida.

Based on these reasons, FPL believes that the two-stage construction of this project would measurably increase capital costs and fuel costs when compared to constructing PEEC in full combined cycle mode by the summer of 2016 (the PEEC Resource Plan).

Table 59-A Corrected

GFCT Resource Plan- Revenue Requirements
Assuming the removal of the two CTs in 2016

	(1)	(2)	(3)	(4)	(5)	(6)
	Annual Revenue Requirements (Generation Capital) ($millions, 2011 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2011 $)	Annual Revenue Requirements (O&M) ($millions, 2011 $)	Annual Revenue Requirements (Fuel) ($millions, 2011 $)	Annual Revenue Requirements (Environmental) ($millions, 2011 $)	Total ($millions, 2011 $)
2011	0	0	0	3,250	-11	3,239
2012	0	0	1	3,434	-5	3,430
2013	0	0	1	3,433	-8	3,426
2014	0	0	1	3,665	-7	3,659
2015	0	0	1	3,972	-8	3,966
2016	0	0	11	4,741	-8	4,744
2017	0	0	3	5,207	-8	5,202
2018	0	0	3	5,630	1,229	6,863
2019	126	4	27	5,963	1,337	7,457
2020	210	6	46	6,550	1,467	8,279
2021	203	6	47	7,182	1,660	9,097
2022	195	5	52	7,462	1,765	9,479
2023	188	5	50	7,375	1,771	9,389
2024	181	5	51	7,975	1,933	10,145
2025	174	5	56	8,811	2,102	11,148
2026	374	16	93	9,103	2,259	11,845
2027	505	24	124	9,535	2,499	12,686
2028	571	23	143	9,850	2,720	13,306
2029	782	22	191	10,148	2,925	14,069
2030	964	21	237	10,608	3,194	15,024
2031	1,083	20	273	11,064	3,451	15,891
2032	1,296	19	329	11,761	3,801	17,207
2033	1,674	18	419	12,899	4,378	19,388
2034	1,917	18	489	13,584	4,819	20,827

Table 59-A Corrected

GFCT Resource Plan- Revenue Requirements
Assuming the removal of the two CTs in 2016

	(1)	(2)	(3)	(4)	(5)	(6)
	Annual Revenue Requirements (Generation Capital) ($millions, 2011 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2011 $)	Annual Revenue Requirements (O&M) ($millions, 2011 $)	Annual Revenue Requirements (Fuel) ($millions, 2011 $)	Annual Revenue Requirements (Environmental) ($millions, 2011 $)	Total ($millions, 2011 $)
2035	2,018	17	536	14,046	5,205	21,822
2036	2,333	16	625	15,176	6,014	24,164
2037	2,578	16	710	15,783	6,587	25,674
2038	2,668	15	763	16,310	7,179	26,935
2039	2,875	14	843	16,972	7,889	28,594
2040	3,046	14	925	17,518	8,589	30,091
2041	3,133	13	987	18,122	9,376	31,631
2042	3,348	12	1,079	18,857	10,309	33,606
2043	3,653	12	1,192	19,930	11,562	36,350
2044	3,957	12	1,312	20,793	12,748	38,822
2045	4,121	11	1,411	21,494	13,912	40,950
2046	4,332	11	1,523	22,247	15,199	43,312
2047	4,498	11	1,632	23,047	16,630	45,818
CPVRR	7,846	88	2,282	103,797	28,880	142,893

Table 59-B Corrected

GFCT Resource Plan- Revenue Requirements
Assuming the removal of the two CTs in 2016 and a Short Term Purchase (600MW) 2016-2019

	(1)	(2)	(3)	(4)	(5)	(6)
	Annual Revenue Requirements (Generation Capital) ($millions, 2011 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2011 $)	Annual Revenue Requirements (O&M) ($millions, 2011 $)	Annual Revenue Requirements (Fuel) ($millions, 2011 $)	Annual Revenue Requirements (Environmental) ($millions, 2011 $)	Total ($millions, 2011 $)
2011	0	0	0	3,250	-11	3,239
2012	0	0	1	3,434	-5	3,430
2013	0	0	1	3,433	-8	3,426
2014	0	0	1	3,665	-7	3,659
2015	0	0	1	3,972	-8	3,966
2016	0	0	25	4,738	-8	4,755
2017	0	0	28	5,208	-8	5,228
2018	0	0	29	5,632	1,230	6,891
2019	126	4	38	5,963	1,337	7,468
2020	210	6	46	6,550	1,467	8,279
2021	203	6	47	7,182	1,660	9,097
2022	195	5	52	7,462	1,765	9,479
2023	188	5	50	7,375	1,771	9,389
2024	181	5	51	7,975	1,933	10,145
2025	174	5	56	8,811	2,102	11,148
2026	374	16	93	9,103	2,259	11,845
2027	505	24	124	9,535	2,499	12,686
2028	571	23	143	9,850	2,720	13,306
2029	782	22	191	10,148	2,925	14,069
2030	964	21	237	10,608	3,194	15,024
2031	1,083	20	273	11,064	3,451	15,891
2032	1,296	19	329	11,761	3,801	17,207
2033	1,674	18	419	12,899	4,378	19,388
2034	1,917	18	489	13,584	4,819	20,827

Table 59-B Corrected

GFCT Resource Plan- Revenue Requirements
Assuming the removal of the two CTs in 2016 and a Short Term Purchase (600MW) 2016-2019

	(1)	(2)	(3)	(4)	(5)	(6)
	Annual Revenue Requirements (Generation Capital) ($millions, 2011 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2011 $)	Annual Revenue Requirements (O&M) ($millions, 2011 $)	Annual Revenue Requirements (Fuel) ($millions, 2011 $)	Annual Revenue Requirements (Environmental) ($millions, 2011 $)	Total ($millions, 2011 $)
2035	2,018	17	536	14,046	5,205	21,822
2036	2,333	16	625	15,176	6,014	24,164
2037	2,578	16	710	15,783	6,587	25,674
2038	2,668	15	763	16,310	7,179	26,935
2039	2,875	14	843	16,972	7,889	28,594
2040	3,046	14	925	17,518	8,589	30,091
2041	3,133	13	987	18,122	9,376	31,631
2042	3,348	12	1,079	18,857	10,309	33,606
2043	3,653	12	1,192	19,930	11,562	36,350
2044	3,957	12	1,312	20,793	12,748	38,822
2045	4,121	11	1,411	21,494	13,912	40,950
2046	4,332	11	1,523	22,247	15,199	43,312
2047	4,498	11	1,632	23,047	16,630	45,818
CPVRR	7,846	88	2,330	103,797	28,881	142,941

Q.
Please complete tables similar to the ones contained in JEE-1 assuming the following changes to Resource Plan GFCT.

a. Removal of the two CTs in 2016.
b. Removal of the two CTs in 2016. Addition of a Short Term 600 MW Power Purchase Agreement beginning in 2016 and ending in 2019.
c. Removal of the two CTs in 2016. Addition of three CTs at the Port Everglades Site in 2016. Addition of Heat Return Steam Generator at the Port Everglades Site in 2019.

A.
Please see attached tables for responses to subparts (a) and (b).

For the answer to subpart (c), please refer to FPL's response to Staff's First Set of Interrogatories No. 59.

Table 60-A
Projection of FPL's Resource Needs through 2021
Interrogatory # 60 (A)- GFCT plan with no CTs in 2016

August of the Year	(1) Projected FPL Unit Summer Capability (MW)	(2) Projected Firm Capacity Summer Purchases (MW)	(3) Projected Scheduled Maintenance * (MW)	(4) = (1) + (2) - (3) Projected Total Summer Capacity (MW)	(5) Projected Summer Peak Load (MW)	(6) Projected Summer DSM Capability (MW)	(7) = (5) - (6) Projected Summer Firm Peak Load (MW)	(8) = (4) - (7) Projected Summer Reserves (MW)	(9) = (8) / (7) Projected Summer Reserve Margin w/o Additions (%)	(10) = ((7)*1.20)-(4) **Projected MW Needed to Meet 20% Reserve Margin ** (MW)**
2011	22,474	2,056	0	24,530	21,618	1,856	19,762	4,767	24.1%	(815)
2012	23,437	1,956	714	24,679	21,623	1,986	19,637	5,042	25.7%	(1,115)
2013	24,164	1,956	826	25,294	21,931	2,109	19,822	5,472	27.6%	(1,507)
2014	25,467	1,956	826	26,597	23,243	2,272	20,971	5,626	26.8%	(1,432)
2015	25,507	2,046	0	27,553	23,786	2,404	21,382	6,170	28.9%	(1,894)
2016	25,111	740	0	25,851	24,315	2,536	21,779	4,071	18.7%	284
2017	25,111	740	0	25,851	24,529	2,667	21,862	3,989	18.2%	384
2018	25,111	740	0	25,851	24,674	2,799	21,875	3,975	18.2%	400
2019	26,388	740	0	27,128	25,041	2,930	22,111	5,017	22.7%	(594)
2020	26,388	740	0	27,128	25,499	3,062	22,437	4,690	20.9%	(203)
2021	26,388	740	0	27,128	25,960	3,194	22,766	4,362	19.2%	191

* MW values shown in Column (3) represent 714 MW out-of-service during the Summer of 2012 (St. Lucie 2), and 826 MW out-of-service during the Summer of 2013 and 2014 due to the installation of electrostatic precipitators at FPL's 800 MW generating units.

** MW values shown in Column (10) represent new generating capacity needed to meet the 20% reserve margin criterion.

Table 60-B
Projection of FPL's Resource Needs through 2021
Interrogatory # 60 (B)- GFCT plan with no CTs in 2016 and a Short Term Purchase (600MW) 2016-2019

August of the Year	(1) Projected FPL Unit Summer Capability (MW)	(2) Projected Firm Capacity Summer Purchases (MW)	(3) Projected Scheduled Maintenance * (MW)	(4) = (1) + (2) - (3) Projected Total Summer Capacity (MW)	(5) Projected Summer Peak Load (MW)	(6) Projected Summer DSM Capability (MW)	(7) = (5) - (6) Projected Summer Firm Peak Load (MW)	(8) = (4) - (7) Projected Summer Reserves (MW)	(9) = (8) / (7) Projected Summer Reserve Margin w/o Additions (%)	(10) = ((7)*1.20)-(4) **Projected MW Needed to Meet 20% Reserve Margin ** (MW)**
2011	22,474	2,056	0	24,530	21,618	1,856	19,762	4,767	24.1%	(815)
2012	23,437	1,956	714	24,679	21,623	1,986	19,637	5,042	25.7%	(1,115)
2013	24,164	1,956	826	25,294	21,931	2,109	19,822	5,472	27.6%	(1,507)
2014	25,467	1,956	826	26,597	23,243	2,272	20,971	5,626	26.8%	(1,432)
2015	25,507	2,046	0	27,553	23,786	2,404	21,382	6,170	28.9%	(1,894)
2016	25,711	740	0	26,451	24,315	2,536	21,779	4,671	21.4%	(316)
2017	25,711	740	0	26,451	24,529	2,667	21,862	4,589	21.0%	(216)
2018	25,711	740	0	26,451	24,674	2,799	21,875	4,575	20.9%	(200)
2019	26,388	740	0	27,128	25,041	2,930	22,111	5,017	22.7%	(594)
2020	26,388	740	0	27,128	25,499	3,062	22,437	4,690	20.9%	(203)
2021	26,388	740	0	27,128	25,960	3,194	22,766	4,362	19.2%	191

* MW values shown in Column (3) represent 714 MW out-of-service during the Summer of 2012 (St. Lucie 2), and 826 MW out-of-service during the Summer of 2013 and 2014 due to the installation of electrostatic precipitators at FPL's 800 MW generating units.

** MW values shown in Column (10) represent new generating capacity needed to meet the 20% reserve margin criterion.

Q.
Please complete an LOLP analysis for the three resource plans posed by staff in Interrogatory 60.

A.
The table below shows the results of the requested analysis for the first two resource plans listed in Interrogatory 60. FPL has not conducted LOLP analysis for the third plan listed in Interrogatory 60. See response to Interrogatory 59 (c) for further explanation.

Table 61-1
Loss-of-Load Probabilities (LOLP) for the four Resource Plans

(a)

	No CTs in 2016; PEEC in 2019 LOLP(Days/Year)
2012	0.000510
2013	0.000100
2014	0.000127
2015	0.000061
2016	0.003723
2017	0.004659
2018	0.005664
2019	0.000871
2020	0.001473
2021	0.003170

(b)

	No CTs in 2016, 600MW PPA 2016-2019; PEEC-2019 LOLP(Days/Year)
2012	0.000510
2013	0.000100
2014	0.000127
2015	0.000061
2016	0.000884
2017	0.001099
2018	0.001380
2019	0.000871
2020	0.001473
2021	0.003170

FPL's LOLP reliability criterion is a maximum of 0.1 day/year. The projected LOLP values shown above are significantly lower than this criterion.

FPL's need for resources is driven by its Summer Reserve Margin criterion of 20%.

AFFIDAVIT

John Bulich
John Bulich

State of Florida)

County of Palm Beach)

I hereby certify that on this 30th day of December, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared John Bulich, who is personally known to me, and he acknowledged before me that he sponsored or cosponsored the answers to Interrogatory Nos. 3(b), 8(c), 34, 46 and 52 from Staff's First Set of Interrogatories to Florida Power & Light Company in Docket No. 110309-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 30th day of December, 2011.

Traci D. Goldwire
Notary Public, State of Florida

Notary Stamp:

AFFIDAVIT

John Butler

State of Florida)

County of Palm Beach)

I hereby certify that on this 30 day of January, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared John Butler, who is personally known to me, and he acknowledged before me that he sponsored the answer to Interrogatory No. 11 from Staff's First Set of Interrogatories to Florida Power & Light Company in Docket No. 110309-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 31st day of January, 2012.

Notary Public, State of Florida

Notary Stamp:

Pamela L. Springer
COMMISSION # EE085473
EXPIRES: APR. 18, 2015
www.AARONNOTARY.com

AFFIDAVIT

Juan E. Enjamio

State of Florida)

County of Miami-Dade)

I hereby certify that on this 3rd day of January, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Juan E. Enjamio, who is personally known to me, and he acknowledged before me that he sponsored or cosponsored the answers to Interrogatory Nos. 7, 10, 12-14, 19, 30-33, 34, 37, 40, 41, 43, 47, 48, 55c, and 57-61 from Staff's First Set of Interrogatories to Florida Power & Light Company in Docket No. 110309-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 3rd day of January, 2012.

Notary Public, State of Florida

Notary Stamp:

Notary Public State of Florida
Lily A Rodriguez
My Commission DD854399
Expires 02/13/2013

AFFIDAVIT

Thomas. L Hartman

State of Florida)

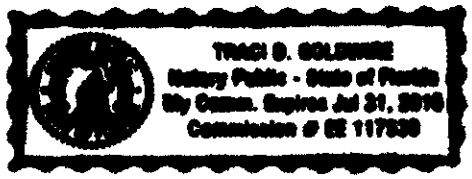
County of Palm Beach)

I hereby certify that on this 28th day of December, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Thomas L. Hartman**, who is personally known to me, and he acknowledged before me that he sponsored the answer to Interrogatory No. 39 from Staff's First Set of Interrogatories to Florida Power & Light Company in Docket No. 110309-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 28th day of December, 2011.

Traci D. Goldwire
Notary Public, State of Florida

Notary Stamp:



AFFIDAVIT

Roxane R. Kennedy

State of Florida)

County of Palm Beach)

I hereby certify that on this 29 day of December, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Roxane R. Kennedy, who is personally known to me, and she acknowledged before me that she sponsored or cosponsored the answers to Interrogatory Nos. 3(b), 35, 36, 49 and 50 from Staff's First Set of Interrogatories to Florida Power & Light Company in Docket No. 110309-EI, and that the responses are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 29 day of December, 2011.

Notary Public, State of Florida

Notary Stamp:

JAYNE LORING DAVIS
MY COMMISSION # DD908031
EXPIRES September 14, 2013
(407) 398-0153 FloridaNotaryService.com

AFFIDAVIT

Kennard F. Kosky

State of Florida)

County of Alachua)

I hereby certify that on this 30 day of December, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Kennard F. Kosky, who is personally known to me, and he acknowledged before me that he sponsored or cosponsored the answers to Interrogatory Nos. 2, 3 (a) (c) (d) (e) (f), 4, 5, 6, 8 (a) (b) (d) (e), and 9 from Staff's First Set of Interrogatories to Florida Power & Light Company in Docket No. 110309-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 30 day of December, 2011.

Notary Public, State of Florida

Notary Stamp:

STACIE G. FOWLER
MY COMMISSION # EE 58916
EXPIRES: January 26, 2015
Bonded Thru Pichard Insurance Agency

STATE OF FLORIDA
COUNTY OF Alachua

The foregoing instrument was acknowledged before me this 30 day of Dec., 2011 by Kennard F. Kosky

Personally Known ____ or produced Identification type FL Drivel License

Signature of Notary Seal

AFFIDAVIT

Pedro Modia

State of Florida)

County of Miami Dade)

I hereby certify that on this 28th day of December 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Pedro Modia**, who is personally known to me, and he acknowledged before me that he sponsored the answers to Interrogatory Nos. 27, 28, 29, and 55 (a) (b) from Staff's First Set of Interrogatories to Florida Power & Light Company in Docket No. 110309-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 28th day of December, 2011.

Mary F. Shoemaker
Notary Public, State of Florida

Notary Stamp:

Notary Public State of Florida
Mary F Shoemaker
My Commission EE106465
Expires 09/30/2015

AFFIDAVIT

Rosemary Morley

State of Florida)

County of Palm Beach)

I hereby certify that on this 4th day of January, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Rosemary Morley, who is personally known to me, and she acknowledged before me that she sponsored the answers to Interrogatory Nos. 1, 23, 24, 25, 26 from Staff's First Set of Interrogatories to Florida Power & Light Company in Docket No. 110309-EI, and that the responses are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 4th day of January, 2012.

Traci D. Goldwire
Notary Public, State of Florida

Notary Stamp:

TRACI D. GOLDWIRE
Notary Public - State of Florida
My Comm. Expires Jul 31, 2015
Commission # EE 117539

AFFIDAVIT

Juliet Murphy Roulhac

State of Florida)

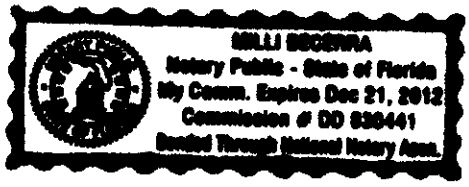
County of Miami-Dade)

I hereby certify that on this 3rd day of January, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Juliet Murphy Roulhac, who is personally known to me, and she acknowledged before me that she sponsored the answer to Interrogatory No. 21 from Staff's First Set of Interrogatories to Florida Power & Light Company in Docket No. 110309-EI, and that the response is true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 3rd day of January, 2012.

Notary Public, State of Florida

Notary Stamp:



AFFIDAVIT

Justin J. Sobol

State of Florida)

County of Palm Beach)

I hereby certify that on this 4th day of January, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Justin J. Sobol, who is personally known to me, and he acknowledged before me that he sponsored or cosponsored the answers to Interrogatory Nos. 15-18, 20, 38, 51, 52, 53, 54 and 56 from Staff's First Set of Interrogatories to Florida Power & Light Company in Docket No. 110309-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 4th day of January, 2012.

Traci D. Goldwire
Notary Public, State of Florida

Notary Stamp:

TRACI D. GOLDWIRE
Notary Public - State of Florida
My Comm. Expires Jul 31, 2015
Commission # EE 117830

AFFIDAVIT

Sol L. Stamm

State of Florida)

County of Miami Dade)

I hereby certify that on this 3rd day of January, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Sol L. Stamm, who is personally known to me, and he acknowledged before me that he sponsored the answer to Interrogatory No. 22 from Staff's First Set of Interrogatories to Florida Power & Light Company in Docket No. 110309-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 3rd day of January, 2012.

Notary Public, State of Florida

Notary Stamp:

NOTARY PUBLIC-STATE OF FLORIDA
Iwanda S. Jenkins
Commission # DD827829
Expires: NOV. 19, 2012
BONDED THRU ATLANTIC BONDING CO., INC.

AFFIDAVIT

Heather C. Stubblefield

State of Florida)

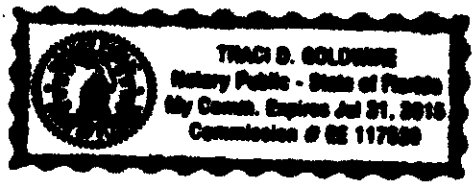
County of Palm Beach)

I hereby certify that on this 28th day of December, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Heather C. Stubblefield**, who is personally known to me, and she acknowledged before me that she sponsored the answers to Interrogatory Nos. 42, 44, and 45 from Staff's First Set of Interrogatories to Florida Power & Light Company in Docket No. 110309-EI, and that the responses are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 28th day of December, 2011.

Notary Public, State of Florida

Notary Stamp:



36

FPL's Responses to Staff's Second Set of Interrogatories (Nos. 62-71)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 36
PARTY Florida Public Service Commission Staff
DESCRIPTION Staffs Exhibit #36
DATE 02/20/12

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition To Determine Need for Modernization of Port Everglades Plant	Docket No. 110309-EI Dated: January 18, 2012

FLORIDA POWER & LIGHT COMPANY'S RESPONSES TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 62-71) AND SECOND REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 7-10)

Florida Power & Light Company ("FPL"), pursuant to Rules 1.340 and 1.350, Florida Rules of Civil Procedure, Rule 28-106.206, Florida Administrative Code, and this Commission's Order Establishing Procedure PSC-11-0565-PCO-EI, submits the following responses to the Staff of the Florida Public Service Commission's Second Set of Interrogatories (Nos. 62-71) and Second Request for Production of Documents (Nos. 7-10).

1. FPL adopts and incorporates by reference, as though fully restated herein, all objections listed in FPL's Objections to Staff's Second Set of Interrogatories (62-71) and Second Request for Production of Documents (Nos. 7-10) dated January 12, 2012. FPL's responses are without waiver of those prior objections.

2. Attached hereto are FPL's non-confidential answers to Staff's Second Set of Interrogatories (Nos. 62-71), together with the affidavits of the persons providing the answers.

3. FPL will deliver to Staff contemporaneously with this response a CD-Rom containing all non-confidential documents responsive to Staff's Second Request for Production of Documents (Nos. 7-10).

4. Confidential answers and documents will be available for review at FPL's offices at 215 South Monroe Street, Suite 810, Tallahassee, Florida during regular business hours, 8 a.m. to 5 p.m., Monday through Friday, upon reasonable notice to FPL's counsel. If Staff wishes to remove any confidential answers or documents from FPL's office, FPL will undertake the

necessary steps, pursuant to Florida Statutes and applicable rules, to protect the confidentiality of those materials.

Respectfully submitted this 18th day of January, 2012.

John T. Butler
Will P. Cox
Maria J. Moncada
Attorneys for Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408-0420
(561) 304-5795
(561) 691-7135 (fax)

By: *s/ Maria J. Moncada*
Maria Moncada
Florida Bar No. 0773301

CERTIFICATE OF SERVICE
DOCKET NO. 110309-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing Responses to Staff's Second Set of Interrogatories (Nos. 62-71) and Second Request for Production of Documents (Nos. 7-10) was served electronically and by U.S. mail this 18th day of January, 2012 to the following:

Charles W. Murphy, Esq.
Office of the General Counsel
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850
cmurphy@psc.state.fl.us

By: *s/ Maria J. Moncada*
Maria J. Moncada
Florida Bar No. 0773301

Q.
On page 4 of witness Stubblefield's testimony, starting at line 22, the witness testifies that, FPL's long-term fossil fuel price forecast "is reasonable," and that the forecasts "reflect projected supply, demand and price for light fuel oil, natural gas and coal." Please explain why each forecasted price is reasonable for each fuel type.

A.
FPL's fuel price forecast utilizes forward curve commodity prices from the New York Mercantile Exchange (NYMEX) and Over-the-Counter (OTC) brokers, escalation rates provided by the Energy Information Administration (EIA), and long-term price projections from both The PIRA Energy Group (PIRA) and JD Energy, Inc. (JD Energy). 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-term and long-term projections for future prices of oil and natural gas. JD Energy, a consulting firm retained by many utilities, including Florida utilities and coal suppliers and with extensive expertise in all aspects of the coal and petroleum coke industry, supplies FPL with an extensive database to support its short-term and long-term projections for future prices of coal and petroleum coke. Because FPL utilizes inputs from renowned energy consultants, exchanges and industry-accepted rates of escalation, FPL's forecast is reasonable.

Q.
Referring to the price forecasts on pp. 1 and 4 of HCS-1.

a. Do the forecasts reflect delivered prices?
b. Do the forecasts reflect commodity-only prices?
c. Do the forecasts reflect some other type of pricing?
d. Please provide a separate transportation cost forecast for each fuel type.
e. Please explain how the transportation cost forecasts were developed.
f. Please explain why each transportation forecast is reasonable.

A.

a. Yes. The forecasts reflect delivered dispatch prices. The dispatch prices include commodity costs and variable transport charges. These are the prices that FPL utilizes to economically dispatch its generation system. Fixed demand charges for transport are not included in the dispatch prices as these charges are incurred regardless of whether FPL uses the transport, it would not be appropriate to take the charges into account in FPL's dispatch decision.

b. No

c. No, see answer to subpart (a).

d. FPL is providing an Excel spreadsheet which provides a separate transportation cost forecast for the fuel types on pages 1 and 4 of HCS - 1. The document provided in response to this part is confidential and will be made available for inspection at FPL's Tallahassee Office at 215 South Monroe Street, Suite 810, Tallahassee, Florida, during regular business hours, 8 a.m. to 5 p.m., Monday through Friday, upon reasonable notice to FPL's counsel.

e. For natural gas (Page 1), the transportation costs reflect the current posted tariffs for Florida Gas Transmission (FGT), Gulfstream Natural Gas System (Gulfstream), Southeast Supply Header (SESH), and Transco 4A lateral, adjusted for any FPL negotiated rates. For light oil (Page 4), the transport costs to FPL plants are based on current market information and actual transportation costs that FPL has incurred for light oil deliveries.

f. These transportation forecasts are reasonable, as they reflect current market rates and are based on actual transport charges that FPL incurs to deliver fuel to its generation facilities.

Q.
At page 3 of witness Stubblefield's testimony, beginning at line 7, she testifies that light fuel "can be resupplied with both waterborne and truck deliveries."

a Are the delivery costs for each method (ship and truck) commensurate with one another? Please explain.
b. If the answer to 64 a is negative, please compare the relative transportation costs and discuss any variables.
c. If the answer to 64 a is negative, how do the transportation cost estimates for light oil account for the difference, i.e., what assumptions for transportation were used in the cost model.

A.

a. Yes. Although delivery rates for each method can and will vary at times, FPL estimates that the delivery costs for each method (waterborne and truck) are commensurate with one another.

b. N/A.

c. N/A.

Q.
Referring to the column headings on page 1 of HCS-1, please explain what the heading "Future Gas Pipeline" means.

A.
The column headed "Future Gas Pipeline" contains the projected dispatch prices for incremental pipeline capacity (either from a new pipeline or from an expansion of an existing pipeline) that will be required to meet FPL's gas transportation needs beginning in 2016. As stated in FPL's response to Staff's Second Set of Interrogatories No. 63, the dispatch prices include commodity costs and variable transport charges and are utilized to economically dispatch FPL's generation system.

Q.
At page 4 of witness Stubblefield's testimony, lines 11-13, she testifies that the methodology used for developing FPL's fuel forecast in this docket "is consistent with the approach to fuel forecasting used in previous filings, including FPL's 2011 Ten Year Site Plan." Please identify each such previous FPL filing.

A.
FPL's fuel price forecast methodology has been used by FPL for many years and the forecast results, based on this methodology, have been filed in numerous dockets. Examples of recent dockets are:

- Docket No. 110009-EI Nuclear Cost Recovery Clause.
- Docket No. 110018-EI Joint petition for modification to determination of need for expansion of an existing renewable energy electrical power plant in Palm Beach County by Solid Waste Authority of Palm Beach County and Florida Power and Light Company, and approval of associated regulatory accounting and purchase power agreement cost recovery.
- Docket No. 100009-EI Nuclear Cost Recovery 2010.
- Docket No. 090009-EI Nuclear Cost Recovery 2009.

Q.
Please refer to page 4 of witness Stubblefield's testimony, lines 5 and 6.

a. Please identify the escalation rate from the Energy Information Administration that FPL used for forecasts beyond the year 2025.
b. What is the date of the Energy Information Administration forecast relied upon by FPL for fuel price escalations beyond 2025?

A.
a. The following are the annual average rates of escalation from the Energy Information Administration used by FPL for forecasts values beyond the year 2025:

Light Oil:	0.750%
Heavy Oil:	0.274%
Natural Gas:	1.706%

b. The 2011 Annual Energy Outlook, published by the Energy Information Administration on April 26, 2011, was the source of the rates of escalation used by FPL for forecast values beyond the year 2025. FPL used the average rate of escalation over the 2025 through 2035 period.

Q.
Please refer to the fuel price forecasts (Exhibit HCS-1).

a. To what other published contemporary fuel price forecasts did FPL compare its fuel price forecasts? How were any such comparisons made?
b. Please explain how FPL reviewed or tested its fuel price forecasts for reasonableness.
c. Please compare FPL's natural gas price forecast for PEEC with FPL's natural gas price forecast in its 2011 Ten Year Site Plan and explain differences, if any between the forecasts.

d. Please identify any differences between the 10 price points from the current Ten Year Site Plan (2011 through 2020) and the yearly averages for the same period from the PEEC gas price forecast and explain the reason for such differences.

A.
a. FPL did not compare its fuel price forecasts to other published contemporary forecasts. As explained in FPL's response to Staff's Second Set of Interrogatories No. 62, FPL's forecast utilizes forward curve commodity prices, escalation rates and long-term price projections provided by recognized, independent subject matter experts. Therefore, FPL does not believe that comparisons against additional independent forecasts are necessary.

b. As stated in FPL's response to subpart (a) above and FPL's response to Staff's Second Set of Interrogatories No. 62, FPL's fuel price forecast is based on independent forecasts from widely recognized energy consulting firms and rates of escalation from widely recognized firms and the Energy Information Administration. Therefore, additional tests or reviews were not necessary. FPL believes its projections are reasonable.

c. As shown on the spreadsheet that FPL will provide, the two natural gas price forecasts differ by less than $0.60/MMBTU in each year even though they are based on a different forward curve for the earlier years, a slightly different forecast from The PIRA Energy Group and a slightly different rate of escalation from the Energy Information Administration. The spreadsheet provided in response to this Interrogatory is confidential and will be made available for inspection at FPL's Tallahassee Office at 215 South Monroe Street, Suite 810, Tallahassee, Florida, during regular business hours, 8 a.m. to 5 p.m., Monday through Friday, upon reasonable notice to FPL's counsel.

d. As shown on the spreadsheet to be provided in response to subpart (c.) above, the differences in years 2011 through 2013 are based on the differences in the August 1, 2011 and January 14, 2011 forward curves. The differences in 2014 and 2015 are based on the differences in the forward curves and The PIRA Energy Group's forecast. The differences in 2016 through 2020 are based on the differences in The PIRA Energy Group's forecast.

Q.
Is FPL's recent mid-course correction reflected in the natural gas forecast filed in this docket? Please explain why or why not.

A.
FPL has addressed the revised long-term forecast and re-evaluated the data in FPL's response to Staff's First Set of Interrogatories No. 41. Please see FPL's response to Staff's First Set of Interrogatories No. 41.

Q.
If the answer to Interrogatory 69 is negative, please update the natural gas forecast filed in this docket using the November 14 forward curves and explain how this change affects the CPVRR.

A.
FPL has addressed the revised long-term forecast and re-evaluated the data in FPL's response to Staff's First Set of Interrogatories No. 41. Please see FPL's response to Staff's First Set of Interrogatories No. 41.

Q.
Please provide the annual estimated transportation costs in real and nominal terms for the forecast horizon.

A.
FPL is providing the annual estimated transportation costs in real and nominal terms for each fuel for the forecast horizon. The document provided in response to this request is confidential and will be made available for inspection at FPL's Tallahassee Office at 215 South Monroe Street, Suite 810, Tallahassee, Florida, during regular business hours, 8 a.m. to 5 p.m., Monday through Friday, upon reasonable notice to FPL's counsel.

AFFIDAVIT

Juan E. Enjamio

State of Florida)

County of Miami-Dade)

I hereby certify that on this 11th day of January, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Juan E. Enjamio, who is personally known to me, and he acknowledged before me that he sponsored the answer to Interrogatory No. 70 from Staff's Second Set of Interrogatories to Florida Power & Light Company in Docket No. 110309-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 11th day of January, 2012.

Notary Public, State of Florida

Notary Stamp:

Notary Public State of Florida
Lily A Rodriguez
My Commission DD854399
Expires 02/13/2013

AFFIDAVIT

Heather C. Stubblefield

Heather C. Stubblefield

State of Florida)

County of Palm Beach)

I hereby certify that on this 11 day of Jan, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Heather C. Stubblefield**, who is personally known to me, and she acknowledged before me that she sponsored the answers to Interrogatory Nos. 62, 63, 64, 65, 66, 67, 68, 69, & 71 from Staff's First Set of Interrogatories to Florida Power & Light Company in Docket No. 110309-EI, and that the responses are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 11 day of January, 2012.

Maritza Miranda-Wise

Notary Public, State of Florida

Notary Stamp:

MARITZA MIRANDA-WISE
MY COMMISSION # DD 870958
EXPIRES: May 30, 2013
Bonded Thru Notary Public Underwriters

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FPL's Responses to Staff's Third Set of Interrogatories (Nos. 72-99)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 37
PARTY Florida Public Service Commission Staff
DESCRIPTION Staffs Exhibit #37
DATE 02/20/12

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition To Determine Need for Modernization of Port Everglades Plant	Docket No. 110309-EI Dated: January 26, 2012

FLORIDA POWER & LIGHT COMPANY'S OBJECTIONS AND RESPONSES TO STAFF'S THIRD SET OF INTERROGATORIES (NOS. 72-99)

Florida Power & Light Company ("FPL"), pursuant to Rule 1.340, Florida Rules of Civil Procedure, Rule 28-106.206, Florida Administrative Code, and this Commission's Order Establishing Procedure PSC-11-0565-PCO-EI, submits the following objections and responses to the Staff of the Florida Public Service Commission's Third Set of Interrogatories (Nos. 72-99).

I. General Objections

FPL objects to each and every request for documents that calls for information protected by the attorney-client privilege, the work product doctrine, the accountant-client privilege, the trade secret privilege, or any other applicable privilege or protection afforded by law, whether such privilege or protection appears at the time response is first made or is later determined to be applicable for any reason. FPL in no way intends to waive such privilege or protection. The nature of the document(s), if any, will be described in a privilege log prepared by FPL.

In certain circumstances, FPL may determine, upon investigation and analysis, that information responsive to certain discovery requests to which objections are not otherwise asserted are confidential and proprietary and should be produced only with provisions in place to protect the confidentiality of the information, if at all. By agreeing to provide such information in response to such request, FPL is not waiving its right to insist upon appropriate protection of confidentiality by means of a protective order or other action to protect the confidential information requested. FPL asserts its right to require such protection of any and all documents

that may qualify for protection under the Florida Rules of Civil Procedure and other applicable statutes, rules and legal principles.

FPL is a large corporation with employees located in many different locations. In the course of its business, FPL creates numerous documents that are not subject to Florida Public Service Commission or other governmental record retention requirements. These documents are kept in numerous locations and frequently are moved from site to site as employees change jobs or as business is reorganized. Therefore, it is possible that not every relevant document may have been consulted in developing FPL's response. Rather, these responses provide all the information that FPL obtained after a reasonable and diligent search conducted in connection with this discovery request. To the extent that the discovery requests propose to require more, FPL objects on the grounds that compliance would impose an undue burden or expense on FPL.

FPL objects to each request to the extent that it seeks information that is not relevant to the subject matter of this docket and is not reasonably calculated to lead to the discovery of admissible evidence.

FPL objects to each request to the extent it is vague, ambiguous, overly broad, imprecise, or utilizes terms that are subject to multiple interpretations but are not properly defined or explained for purposes of such discovery requests.

FPL also objects to these discovery requests to the extent they call for FPL to prepare information in a particular format or perform calculations or analyses not previously prepared or performed as purporting to expand FPL's obligations under applicable law. FPL will comply with its obligations under the applicable rules of procedure.

FPL objects to providing information to the extent that such information is already in the public record before the Florida Public Service Commission and available through normal procedures.

FPL objects to each and every discovery request that calls for the production of documents and/or disclosure of information from NextEra Energy, Inc. and any subsidiaries and/or affiliates of NextEra Energy, Inc. that do not deal with transactions or cost allocations between FPL and either NextEra Energy, Inc. or any subsidiaries and/or affiliates. Such documents and/or information do not affect FPL's rates or cost of service to FPL's customers. Therefore, those documents and/or information are irrelevant and not reasonably calculated to lead to the discovery of admissible evidence. Furthermore, FPL is the party appearing before the Florida Public Service Commission in this docket. To require any non-regulated entities to participate in irrelevant discovery is by its very nature unduly burdensome and overbroad. Subject to, and without waiving, any other objections, FPL will respond to the extent the request pertains to FPL and FPL's rates or cost of service charged to FPL's customers. To the extent any responsive documents contain irrelevant affiliate information as well as information related to FPL and FPL's rates or cost of service charged to its customers, FPL may redact the irrelevant affiliate information from the responsive documents.

FPL objects to each and every discovery request and any instructions that purport to expand FPL's obligations under applicable law.

In addition, FPL reserves its right to count discovery requests and their subparts, as permitted under the applicable rules of procedure, in determining whether it is obligated to respond to additional discovery requests served by any party.

FPL expressly reserves and does not waive any and all objections it may have to the admissibility, authenticity or relevancy of the information provided in its responses.

Notwithstanding any of the foregoing general objections and without waiving these objections, FPL intends in good faith to respond to Staff's discovery requests.

II. Responses

Attached hereto are FPL's answers to Staff's Third Set of Interrogatories (Nos. 72-99), together with the affidavits of the persons providing the answers.

Respectfully submitted this 26th day of January, 2012.

John T. Butler
Will P. Cox
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By: *s/ Maria J. Moncada*
Maria Moncada
Florida Bar No. 0773301

CERTIFICATE OF SERVICE
DOCKET NO. 110309-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing Objections and Responses to Staff's Third Set of Interrogatories (Nos. 72-99) was served electronically and by U.S. mail this 26th day of January, 2012 on the following:

Charles W. Murphy, Esq.
Office of the General Counsel
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850
cmurphy@psc.state.fl.us

By: *s/ Maria J. Moncada*
Maria J. Moncada
Florida Bar No. 0773301

Q.
Please refer to FPL's response to staff Interrogatory No. 12. How does the Company intend to present the results of its reliability studies determining if the 20% reserve margin criterion requires a generation only component to the Commission staff in 2012?

A.
As stated in FPL's response to Staff's First Set of Interrogatories No. 12, the reliability studies remain a work in progress, and additional analyses and review are required. FPL intends to present the results of its analyses to the Commission Staff in 2012, but FPL has not yet determined how or when it will present these results.

However, please note that FPL's filing for approval of the Port Everglades modernization project is based on FPL's current 20% total minimum reserve margin criterion. As such, FPL's request for approval of the modernization project is not based on a potential "generation-only" supplement to FPL's current reliability criterion.

Q.
On page 6 of his testimony, Witness Enjamio testifies that "FPL presently has a long-term Unit Power Sales contract to purchase up to 931 MW of coal fired-generation from Southern Company." Please describe FPL's efforts, if any, to extend the terms of the referenced contract.

A.
The referenced Unit Power Sales (UPS) contract consists of three contracts associated with three individual units – two are gas, Franklin and Harris, the third unit is a 165 MW purchase from the coal-fired Scherer Unit 3.

The Franklin and Harris contracts each contained an option to extend the purchase for two years. These options were required to be exercised by January 31, 2010. FPL determined that extension of the contracts was not cost effective for its customers, and therefore allowed the options to expire.

The purchase from the Scherer unit output is partially from the Georgia Power entitlement, and partially from the Gulf Power entitlement to the unit. This contract contained no option for extension. Discussions were held with Southern Company in 2011 about the potential to extend the Gulf Power portion of the contract. Given the capacity costs associated with the facility and various environmental upgrades, the differential costs between coal and natural gas, as well as the system losses with transmitting the power to FPL's system, FPL determined that extending the contract was not economic for customers.

Q.
Please describe FPL's efforts, if any, to secure purchased power over the Company's interface with Southern Company.

A.
FPL monitors transactions and wholesale pricing in the Southeastern Electric Reliability Council ("SERC") on a regular basis, and periodically transacts both short-term sales and purchases when economics provide a benefit to the customers. At the present time, given prices in SERC, as well as losses associated with transmitting the power to FPL's customers, conditions are not favorable for purchases. As a result, FPL currently has no active efforts to purchase long-term power over the interface.

Q.
FPL's response to staff interrogatory No. 14, Attachment No.1, reflects that FPL's return to service plan falls below the 20% reserve margin by 13 MW. How does FPL determine the timing of new generation when the capacity shortage may be considered relatively small?

A.
When FPL's planning process indicates that there will be a shortfall in reserve margin below the 20% minimum level that FPL considers necessary to provide reliable service, FPL considers alternatives that may be available to raise the reserve margin to at least 20%. Alternatives may include constructing differing types new generation, as well as entering into short or long-term power purchase agreements.

FPL makes each decision to add or acquire new capacity on a case-by-case basis. For each year in which the planning process indicates a shortfall, FPL assesses factors such as the lead time in which new resources could be built or acquired, the economics of the various alternatives, and the projected quality of FPL's reserves. Until such decision is made, FPL continues to update its reserve margin projection each year using the latest load forecast, DSM additions and plant capacity projections. Such updates could result in the decision being deferred or accelerated, and could affect the resource alternative selected.

Q.

On pages 4 and 5 of his testimony, Witness Gnecco testifies that the Port Everglades Site, "will be able to receive back-up fuel from waterborne deliveries."

a. How many consecutive days could the PEEC provide generation relying solely on waterborne deliveries?

b. Does the use of a backup fuel impact the output of the PEEC when compared to operation using natural gas?

A.

a. PEEC has storage on site for up to 72 hours (3 days) of operation on a form of light fuel oil known as ultra low sulfur distillate fuel. The ability to operate beyond the 72 hours requires additional demineralized water (for NOx emissions control) and light fuel oil. With advanced notice, preparation, and approval, the plant can run on light fuel oil indefinitely.

b. Yes, the output while operating on the backup fuel is lower.

Q.
Since 1998, what is the largest amount of generation capacity that has been unavailable during the Company's peak period. Please identify the units that were unavailable as well as the cause of the outage (planned or forced).

A.
Since 1998, the largest amount of FPL owned generation capacity unavailable during the Company's peak period (day/hour) occurred August 16, 2001 from 4:00 p.m. to 5:00 p.m. when 1,516 MW were unavailable due to forced outages at Cape Canaveral Unit 2 (234 MW), Martin Unit 3 (218 MW), Sanford Unit 4 (371 MW) and Turkey Point Unit 3 (693 MW).

Q.
Since 1998, how many times has FPL's forecasted load been exceeded by 9% or greater?

A.
Since 1998, FPL's forecasted summer peak load has been exceed by 9% or greater seven times. The summer peak forecasts exceeded by 9% or more are listed below.

- 1998 Ten Year Site Plan forecast of the 2004 summer peak
- 1998 Ten Year Site Plan forecast of the 2005 summer peak
- 1998 Ten Year Site Plan forecast of the 2006 summer peak
- 1998 Ten Year Site Plan forecast of the 2007 summer peak
- 1999 Ten Year Site Plan forecast of the 2005 summer peak
- 2000 Ten Year Site Plan forecast of the 2005 summer peak
- 2001 Ten Year Site Plan forecast of the 2005 summer peak

Since 1998, FPL's winter peak load has been exceed by 9% or greater three times. The winter peak forecasts exceeded by 9% or more are listed below.

- 2009 Ten Year Site Plan forecast of the 2010 winter peak
- 2009 Ten Year Site Plan forecast of the 2011 winter peak
- 2010 Ten Year Site Plan forecast of the 2010 winter peak

Q.
Please complete the table below for a 2016 "G" technology CT and a 2016 "J" technology CT.

Generation Technology	
Net Generation MW, (Summer)	
Installed Cost	
Capital $/kw	
Fixed O&M ($/kw-yr) 2016$	
Variable O&M ($/MWh) 2016$	
Heat Rate (BTU/kwh)	
Equivalent Availability (%)	
Capacity Factor	
Water Usage (million gal/day)	

A.
See attached table. The figures for the "G" technology are based on work done for the Riviera Beach Energy Center (RBEC) and adjusted by escalation because FPL has not obtained or developed information for "G" technology for the PEEC project.

Table 79

J Technology
(assuming 2016 in-service date)

Generation Technology	3x1 MHI J
Net Generation MW, Summer	1,277
Installed Cost $ Millions	1,185.2
Capital $/kw, summer	928
Fixed O&M ($/kw-yr) 2016$	7.99
Variable O&M ($/MWh) 2016$	0.10
Heat Rate (BTU/kwh) (75°F case)	6,330
Equivalent Availability (%)	95.4
Capacity Factor	95
Water Usage (million gal/day) (once through seawater)	635

G Technology
(assuming 2016 in-service date)

Generation Technology	3x1 MHI G DF
Net Generation MW, Summer	1,207
Installed Cost $ Millions	1,354.1
Capital $/kw, summer	1,122
Fixed O&M ($/kw-yr) 2016$	6.18
Variable O&M ($/MWh) 2016$	0.112
Heat Rate (BTU/kwh) (75°F case)	6,576
Equivalent Availability (%)	96.8
Capacity Factor	95
Water Usage (million gal/day) (once through seawater)	598

Notes:
Installed cost includes AFUDC

Q.
In response to staff Interrogatory No. 40, Attachment No.1, FPL indicates that the capacity of the 2026 CC for the resource plans on pages 1 through 3 varies. Please explain why the projected capacity of this unit is not the same under each resource plan.

A.
FPL elected to use identical resource plans starting in 2026 so that differences in resource plans that occur in the distant future do not impact the near term resource plan analysis at issue. To accomplish this and still reflect differences in the resource plans through 2026, FPL adjusted the incremental additions in 2026 to reach 5,659 MW total cumulative gas-dependent MW in that year for each resource plan. As a result, the capacity of the 2026 CC unit is not the same for each resource plan. See table below.

Resource Plan	2026 Filler MW added	cumulative gas-dependent MW added
PEEC	698 MW	5,659 MW
Return to Service	788 MW	5,659 MW
Greenfield Combined Cycle (GFCC)	713 MW	5,659 MW
Greenfield Combustion Turbine (GFCT)	375 MW	5,659 MW*

* Please note that in the response to Staff Interrogatory 40, the cumulative gas dependent MW capacity for 2026 is shown as 5,660 MW, not 5,659 MW. This 1 MW difference is due to round-off.

Q.
Please provide the basis for the cost of the Power Purchase Agreement assumed in FPL's response to staff Interrogatory No. 59 part b.

A.
The purchased power cost was based on peaking capacity priced at $3.00/kW-month in 2012, escalating at 3% per annum. The pricing was based on recent transactions by FPL.

Q.
In response to staff Interrogatory No. 28, FPL indicates that the transmission cost estimate for resource plans not adding new generation at the Port Everglades site is based on approximately 100 miles of new lines. Why did FPL assume 100 miles of new transmission?

A.
As discussed in FPL's response to Staff's First Set of Interrogatories No. 28 and in witness Modia's direct testimony, significant transmission upgrades would be needed by 2020 to increase the Miami-Dade and Broward County area's ability to import generation to serve load if the Port Everglades generation that will be in Inactive Reserve is not returned to service or replaced with either the PEEC project or generation sited within the Miami-Dade and Broward County area. In order to capture the cost of these upgrades to include them in the economic evaluation of resource plans such as the GFCC plan that does not include such generation, FPL performed a hypothetical analysis to determine potential upgrades needed to maintain reliability that could be constructed to adequately increase the area's import capability. The upgrades identified in the analysis include a combination of transformers (added or replaced) with greater capability, upgraded existing lines and several new lines (approximately 100 miles) to transfer additional electricity into and across the Miami-Dade and Broward area. All of the upgrades, transformers and new lines identified in this analysis are included in the transmission cost estimate for resource plans that do not include generation within the Miami-Dade and Broward County area.

Q.

FPL's response to staff Interrogatory No. 34, Attachment 1, indicates that FPL is proposing a GE 7FA.03 CT for the Greenfield Combustion Turbine resource plan. Why is FPL not considering a "J" or "G" technology combustion turbine in this resource plan?

A.

FPL did not consider the "G" technology combustion turbines evaluated for the Cape Canaveral and Riviera Beach modernization projects or the "J" technology combustion turbines in consideration for PEEC. These turbines are designed and optimized for combined cycle operation, not simple cycle. These turbines would also require steam cooling and a Selective Catalytic Reduction (SCRs) for NOx control, while the GE 7FA.03 combustion turbines would most likely not require this additional equipment. If FPL were to proceed with a simple cycle CT project, viable turbines would be considered and evaluated. The final selection would be based on lowest CPVRR for our customers.

Q.

On page 3 of her testimony, Witness Stubblefield testifies that "FPL is currently preparing a Request for Proposals to meet these future gas transportation needs."

a. What is the amount of the need to be included in the Request for Proposals?

b. What is the timing of the need to be included in the Request for Proposals?

A.

a. For the purposes of the evaluation of PEEC, FPL assumed 400,000 MMBtu/day of incremental gas transportation capacity beginning May 1, 2016 with an additional 200,000 MMBtu/day of transportation capacity beginning May 1, 2020. The same assumption was used for all the different resource plans. FPL is still evaluating the gas transportation quantities that will be included in the Request for Proposals.

b. FPL is still evaluating the timing of the Request for Proposals.

Q.
What is the incremental amount of transportation capacity (Mcf/day) that will be required to serve the PEEC?

A.
PEEC is projected to consume 194,000 Mcf of natural gas per day on average during the first five full years of operation, but this is not incremental gas use to the system. Because the need for gas transportation to the FPL system is driven by the needs of the system, FPL plans incremental gas additions based on incremental system needs, not the needs of a particular unit. As addressed in FPL's response to Staff's Third Set of Interrogatories No. 84, FPL is still in the process of evaluating the quantity and timing of our gas transportation requirements.

Q.
Does FPL currently have sufficient gas transportation to serve its currently certified units through 2020? If no, how does FPL plan to serve its currently certified units during the described timeframe?

A.
No. FPL will need incremental gas transportation for its system before 2020. Once the quantity and timing of the incremental gas transportation requirements are determined, FPL intends to issue a Request for Proposals as stated in FPL's response to Staff's Third Set of Interrogatories No. 84.

Q.
Please refer to FPL's response to staff Interrogatory No. 44. What is the status of FPL's withdrawal of its certification application for the EnergySecure Pipeline?

A.
FPL filed a Motion to Withdraw the EnergySecure Line project with the Administrative Law Judge January 20, 2012. Prior to the filing, FPL conferred with all of the parties and confirmed that none of the Parties objected to the withdrawal. On January 20, 2012, the Administrative Law Judge issued an Order granting FPL's motion and closing the file for the EnergySecure pipeline project.

Q.
In response to staff Interrogatory No. 53, FPL indicates that the initial capital cost associated with bringing Port Everglades units 1-4 out of inactive reserve is estimated to be approximately $235 million. Please provide an annual breakdown of the costs that make up the $235 million.

A.
The capital work required to bring each of the Port Everglades units out of Inactive Reserve status would be substantial. Due to the magnitude and volume of work required to return the units to active status, the work is projected to extend over two years. The initial $235 million of capital cost includes the following major work activities:

NOx controls (reburn)	$97.1 million
Boiler refurbishment	$83.7 million
Balance of plant overhaul (valves, pumps, motors, structural, instruments and controls)	$23.1 million
Generator rewind	$22.8 million
Steam turbine overhaul	$8.3 million

FPL does not have sufficient information on the sequence of work activities to assign specific activities to one of those two years rather than the other. Accordingly, for the purpose of cash flow estimating, FPL split the required $235 million evenly over the two-year period.

Q.
In response to staff Interrogatory No. 35, FPL states "the total five year O&M and Capital cost savings ($41 million and $100 million respectively) associated with the four steam units are estimated to be $141 million."

a. How and when have these savings been passed on to FPL's customers?
b. How and when have the savings associated with placing other units in inactive reserve been passed on to customers?

A.
a. There are cost savings in FPL's current base rates associated with FPL placing units into Inactive Reserve. This is because FPL's 2010 test year forecast, upon which FPL's current base rates were set, included an assumption that certain units would be in Inactive Reserve status and that O&M expenses and capital expenditures would be lower for those units as a result. As explained below, it is not possible to directly trace the cost savings reflected in current base rates to the cost savings that were calculated for FPL's response to Interrogatory Nos. 35 and 36, because the comparisons cover different periods and the units that ultimately were put into Inactive Reserve differed from the assumptions made at the time the 2010 test year forecast was prepared.

In the 2010 test year, FPL assumed that the following units would be placed in Inactive Reserve:

Cutler Units 5 & 6;
Port Everglades Units 1 & 2;
Riviera Units 3 & 4; and
Sanford Unit 3.

The 2010 test year reflected forecasted O&M expenses of $7.2 million and capital expenditures of $3.2 million for those assumed Inactive Reserve units. In contrast, the actual average annual O&M expenses and Capital expenditures for the prior five year period 2004 – 2008 -- when those units were still in active status -- were $18.3 million and $17.7 million, respectively. FPL's forecasted O&M expense and capital expenditures for 2010 likely would have been close to those five-year averages for those units if FPL had not assumed that they would be transferred to Inactive Reserve. Thus, one can reasonably calculate that FPL's current base rates reflect lower annual O&M costs of about $11.1 million and lower Capital expenditures of about $14.5 million as a result of FPL's assumption about transferring units to Inactive Reserve. FPL's current base rates are lower as a result of these differences, which benefits FPL's customers.

In contrast to the above estimate of the savings in base rates as a result of the assumed Inactive Reserve units, the cost savings reflected in Interrogatory Nos. 35 and 36 are based on the following units that were in Inactive Reserve in 2011:

Cutler Units 5 & 6;
Port Everglades Units 1 & 2;
Port Everglades Units 3 & 4;
Sanford Unit 3; and
Turkey Point Unit 2.

For those units, the cost savings were calculated using a comparison between the average annual O&M expenses and Capital expenditures over the five year periods from 2004 - 2008 and from 2009 - 2013 (2009 - 2010 actuals and projections for 2011 - 2013).

b. Refer to Section (a) for response.

Q.
Please update Exhibit JEE-4, Page 1 of 3, and Table 47-1 of FPL's response to staff Interrogatory No. 47, to include years 2013-2015.

A.
See attached tables 90-1 and 90-2.

Projection of Approximate Bill Impacts: PEEC vs. Return To Service Resource Plans

Year	(1) Plan with Port Everglades Modernization Annual Total Revenue Requirements ($millions, Nominal $)	(2) Plan Returning Inactive Reserve Units PPE 1-4 to Service Annual Total Revenue Requirements ($millions, Nominal $)	(3) =(1)-(2) Differential in Annual Total Revenue Requirements ($millions, Nominal $)	(4) Projected Total Sales After DSM (GWh at the meter)	(5) =((3)x100)/(4) Differential in System Average Electric Rates (cents/kwh)	(6) =(5)x10 Differential in Customer Bill of 1,000 kwh ($)
2013	3,426	3,426	0	103,200	0.00	$0.00
2014	3,659	3,699	-40	105,490	-0.04	-$0.38
2015	3,966	4,006	-40	108,127	-0.04	-$0.37
2016	4,794	4,748	46	109,787	0.04	$0.42
2017	5,291	5,251	39	111,105	0.04	$0.35
2018	6,927	6,941	-14	112,313	-0.01	-$0.12
2019	7,470	7,522	-52	113,670	-0.05	-$0.46
2020	8,240	8,294	-54	116,014	-0.05	-$0.47
2021	9,111	9,197	-86	118,800	-0.07	-$0.72
2022	9,561	9,552	9	121,725	0.01	$0.07
2023	9,490	9,509	-20	124,286	-0.02	-$0.16
2024	10,224	10,277	-53	126,776	-0.04	-$0.42
2025	11,182	11,246	-63	129,260	-0.05	-$0.49
2026	11,830	11,926	-96	131,782	-0.07	-$0.73
2027	12,609	12,706	-97	134,088	-0.07	-$0.72
2028	13,230	13,315	-85	136,356	-0.06	-$0.62
2029	13,996	14,089	-93	138,542	-0.07	-$0.67
2030	14,956	15,007	-51	140,654	-0.04	-$0.36
2031	15,824	15,902	-78	143,001	-0.05	-$0.55
2032	17,143	17,223	-80	145,378	-0.05	-$0.55
2033	19,320	19,403	-82	147,808	-0.06	-$0.56
2034	20,763	20,832	-69	150,273	-0.05	-$0.46
2035	21,759	21,832	-74	152,778	-0.05	-$0.48
2036	24,103	24,170	-66	155,325	-0.04	-$0.43
2037	25,618	25,700	-83	157,912	-0.05	-$0.52
2038	26,878	26,957	-79	160,542	-0.05	-$0.49
2039	28,542	28,599	-56	163,216	-0.03	-$0.35
2040	30,044	30,094	-50	165,929	-0.03	-$0.30
2041	31,584	31,637	-53	168,692	-0.03	-$0.31
2042	33,561	33,640	-79	171,497	-0.05	-$0.46
2043	36,309	36,378	-69	174,349	-0.04	-$0.39
2044	38,787	38,831	-44	177,247	-0.02	-$0.25
2045	40,918	40,965	-46	180,192	-0.03	-$0.26
2046	43,259	43,323	-64	183,186	-0.04	-$0.35
2047	45,749	45,826	-77	186,229	-0.04	-$0.41
					Average 2016-2047	-$0.38

Notes: (1) This projection assumes instantaneous adjustment to electric rates and is for illustrative purposes only.
(2) The values presented in Columns (1), (2), and (3) are total system revenue requirements and include all costs: capital, system fuel, etc.

Table 90-2
Projection of Approximate Bill Impacts:
PEEC vs. Return To Service Resource Plans
Assuming Fuel Forecast from Mid-course Filing

Year	(1) Plan with Port Everglades Modernization Annual Total Revenue Requirements ($millions, Nominal $)	(2) Plan Returning Inactive Reserve Units PPE 1-4 to Service Annual Total Revenue Requirements ($millions, Nominal $)	(3) =(1)-(2) Differential in Annual Total Revenue Requirements ($millions, Nominal $)	(4) Projected Total Sales After DSM (GWh at the meter)	(5) =((3)x100)/(4) Differential in System Average Electric Rates (cents/kwh)	(6) =(5)x10 Differential in Customer Bill of 1,000 kwh ($)
2013	3,013	3,013	0	103,200	0.00	$0.00
2014	3,347	3,387	-40	105,490	-0.04	-$0.38
2015	3,599	3,639	-40	108,127	-0.04	-$0.37
2016	4,420	4,368	52	109,787	0.05	$0.47
2017	4,886	4,837	48	111,105	0.04	$0.43
2018	6,492	6,502	-10	112,313	-0.01	-$0.09
2019	7,006	7,061	-56	113,670	-0.05	-$0.49
2020	7,828	7,878	-51	116,014	-0.04	-$0.44
2021	8,674	8,753	-79	118,800	-0.07	-$0.67
2022	9,121	9,105	16	121,725	0.01	$0.13
2023	9,085	9,098	-14	124,286	-0.01	-$0.11
2024	9,672	9,719	-47	126,776	-0.04	-$0.37
2025	10,539	10,596	-57	129,260	-0.04	-$0.44
2026	11,156	11,241	-86	131,782	-0.06	-$0.65
2027	11,894	11,980	-86	134,088	-0.06	-$0.64
2028	12,485	12,562	-77	136,356	-0.06	-$0.56
2029	13,217	13,306	-89	138,542	-0.06	-$0.64
2030	14,132	14,178	-46	140,654	-0.03	-$0.33
2031	14,957	15,036	-79	143,001	-0.06	-$0.55
2032	16,209	16,284	-75	145,378	-0.05	-$0.52
2033	18,263	18,342	-79	147,808	-0.05	-$0.54
2034	19,640	19,706	-66	150,273	-0.04	-$0.44
2035	20,602	20,670	-68	152,778	-0.04	-$0.44
2036	22,828	22,887	-59	155,325	-0.04	-$0.38
2037	24,281	24,359	-78	157,912	-0.05	-$0.49
2038	25,493	25,566	-73	160,542	-0.05	-$0.46
2039	27,089	27,141	-52	163,216	-0.03	-$0.32
2040	28,543	28,585	-42	165,929	-0.03	-$0.26
2041	30,032	30,078	-46	168,692	-0.03	-$0.28
2042	31,938	32,008	-71	171,497	-0.04	-$0.41
2043	34,577	34,636	-59	174,349	-0.03	-$0.34
2044	36,973	37,003	-29	177,247	-0.02	-$0.17
2045	39,041	39,077	-36	180,192	-0.02	-$0.20
2046	41,311	41,365	-54	183,186	-0.03	-$0.29
2047	43,725	43,790	-65	186,229	-0.03	-$0.35
					Average 2016-2047	-$0.34

Notes: (1) This projection assumes instantaneous adjustment to electric rates and is for illustrative purposes only.
(2) The values presented in Columns (1), (2), and (3) are total system revenue requirements and include all costs: capital, system fuel, etc.

Q.
FPL's response to staff Interrogatory No. 34 appears to indicate that the installed cost of the PEEC is approximately $86 million less than the installed cost of a Greenfield Combined Cycle. FPL's response to staff Interrogatory No. 33 reflects that the difference between PEEC and a Greenfield Combined Cycle is approximately $40 million. Please explain this discrepancy.

A.
There is no discrepancy between the responses provided to Staff's First Set of Interrogatories Nos. 33 and 34. The costs reported in FPL's responses to Interrogatories Nos. 33 and 34 are different for two reasons: (i) the values represent different cost comparisons and (ii) the cost values are stated on different economic terms.

FPL's response to Interrogatory No. 33 addresses the difference in fixed costs between the PEEC Resource Plan and the GFCC Resource Plan. The total difference in the fixed costs between the two resource plans is $692 million expressed as cumulative present value of revenue requirements (CPVRR) in 2011 dollars. As stated in the response, of the total $692 difference, approximately $40 million (CPVRR) is the difference in generation capital costs of PEEC and the filler units in the PEEC Resource Plan on one side, and the generation capital costs of the GFCC unit and the filler units in the GFCC Resource Plan on the other. Of this $40 million CPVRR value, approximately $31 million is due to the difference in "generation only" fixed costs between the PEEC and GFCC units. The additional $9 million in CPVRR 2011$ is due to the difference in "generation only" fixed costs between the different sized 2026 filler units in the two resource plans.

By contrast, FPL's response to Interrogatory No. 34 shows the difference between the installed cost of PEEC and the installed cost of GFCC, which is approximately $86 million. These installed costs include generation capital costs, transmission interconnection costs, and AFUDC costs. This value is expressed in 2016 dollars, not in terms of CPVRR.

Q.
Please provide a levelized cost (in $/kwh) for various capacity factors comparing PEEC to each of the following: a biomass facility, a single wind unit, and a roof top PV unit.
a. Please show levelized capital costs and O&M/Fuel costs separately.
b. Please provide the raw data used to answer this question.
c. Please provide a chart graphically depicting this information.

A.
FPL does not believe that the information requested by Staff in this question provides meaningful information for comparing the relative costs and benefits of these different technologies, as such costs and benefits affect FPL and its customers. FPL is nevertheless providing the estimated levelized cost of electricity ($/MWh) for various capacity factors on the following charts and tables.

A levelized cost of electricity approach cannot meaningfully compare the relative economics of dissimilar resource options such as a solar (PV) option and a combined cycle fossil fuel facility. A levelized cost of electricity approach is useful only as a preliminary economic screening tool, and only if the resource options in question are identical, or virtually identical, in, at a minimum, (i) size (MW), (ii) firmness of capacity, (iii) capacity factor, and (iv) operating life. If the resource options in question differ in even one of these attributes, then a levelized cost of electricity approach cannot provide a meaningful assessment regarding the most beneficial option for FPL's customers, even as a preliminary analysis. This is because dissimilar resource options have significantly different impact on the FPL system, which, simply, are not captured in a levelized cost of electricity approach.

The four technologies included in this comparison are dissimilar in all four categories of attributes. For example, a wind unit and rooftop solar PV are non-firm energy (MWh) sources, while PEEC offers firm capacity and energy. Biomass may offer firm capacity and energy, assuming uninterrupted biomass fuel deliveries. PEEC's 1,277 MW gas-fueled combined cycle unit also significantly differs from the other resource options in terms of size (MW), capacity factor, and operating life.

Accordingly, the levelized cost of electricity approach for analyzing these different options does not, and cannot, provide meaningful results, even for a preliminary evaluation. In order for a comparison of the cost of electricity associated with adding resource alternatives to FPL's system to provide meaningful information, the comparison must reflect all system impacts caused by the addition of each alternative as part of FPL's overall system, such as effects to system fuel costs and system environmental costs, as well as capacity deferral effects from resource options that provide firm capacity. In addition, the resource analysis must be based on a system simulation that uses a reasonable projection of the generation provided by each of the alternative resources,

not a pre-determined range of assumed capacity factors.

a. Attached **Table 92-1** displays the total, levelized costs of generation over the first 25 years of operation. The capital, O&M, and fuel costs are broken out in the subsequent tables (92-1a, 92-1b, and 92-1c).

b. The raw data used to answer this question can be found in the attached **Table 92-2**.

c. The attached chart (**GRAPH 92-3**) graphically depicts the levelized total costs of generation at various capacity factors for the various technologies.

TABLE 92-1: Levelized total costs of generation at various capacity factors for various technologies ($/MWH)

Technology	Capacity Factor (%)									
	10%	15%	20%	25%	.....	75%	80%	85%	90%	95%
Wind	346	231	173	138						
Solar (Rooftop)	781	521	391	312						
Biomass						227	206	187	170	156
3x1 CC						93	91	90	89	88

TABLE 92-1a: Levelized capital charges at various capacity factors for various technologies ($/MWH)

Technology	Capacity Factor (%)									
	10%	15%	20%	25%	.....	75%	80%	85%	90%	95%
Wind	305	203	153	122						
Solar (Rooftop)	761	507	380	304						
Biomass						171	159	149	140	132
3x1 CC						18	17	16	15	14

Notes:
1) Capital carrying charges include transmission integration cost.

TABLE 92-1b: Levelized O&M costs at various capacity factors for various technologies ($/MWH)

Technology	Capacity Factor (%)									
	10%	15%	20%	25%	.....	75%	80%	85%	90%	95%
Wind	41	27	20	16						
Solar (Rooftop)	20	14	10	8						
Biomass						156	146	137	130	123
3x1 CC						6	6	5	5	5

Notes:
1) Includes Fixed O&M, Variable O&M, and Capital Replacement charges, where applicable.

TABLE 92-1c: Levelized fuel costs at various capacity factors for various technologies ($/MWH)

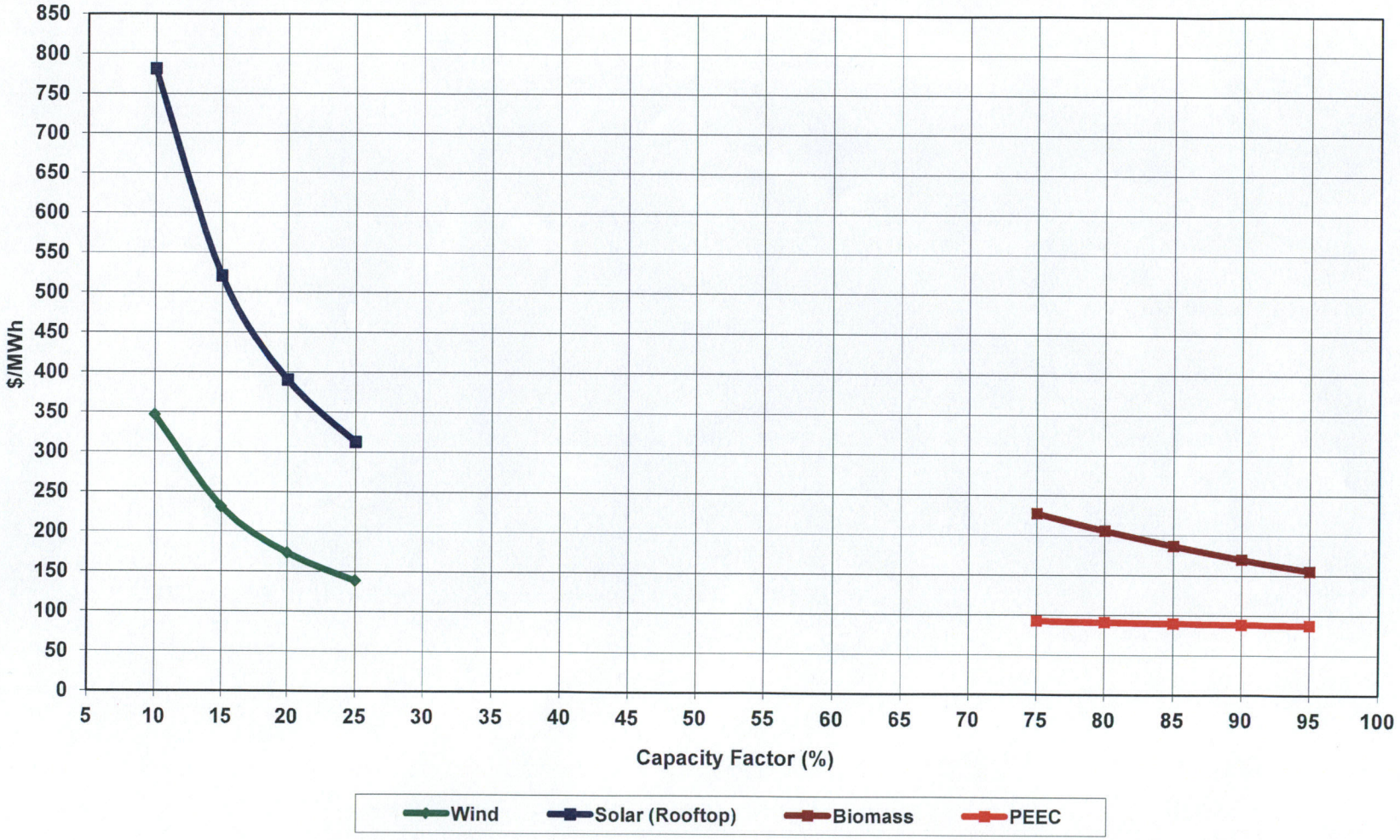
Technology	Capacity Factor (%)									
	10%	15%	20%	25%	.....	75%	80%	85%	90%	95%
Wind	0	0	0	0						
Solar (Rooftop)	0	0	0	0						
Biomass						-100	-100	-100	-100	-100
3x1 CC						69	69	69	69	69

TABLE 92-2: Input Data Assumptions for various technologies

	PEEC Combined Cycle	Wind turbine	Rooftop PV	Biomass (Waste to energy)
In-service date	Jun-16	Jun-16	Jun-16	Jun-16
Rating summer	1277 MW	100 MW	5.2 KW (per installation)	90 MW
Capital cost ($/KW)	841$/KW	2,500 $/KW	6494 $/KW ac	9285 $/KW
Fixed O&M (2016 $s)	7.98 $/KW-yr	27.34 $/kW-yr	0	817.92 $/kW-yr
Variable O&M (2016 $s)	0.10 $/MWH	0	0	0
Capital replacement (2016 $s)	22.10 $/KW	0	1013 $/KW (every ten years)	NA
Heat rate (BTU/KWH)	6330 BTU/KWH	NA	NA	10500 BTU/KWH
Fuel cost ($/MMBTU)	13.25 $/MMBTU	NA	NA	-11.25 $/MMBTU
O&M escalation (%)	2.5%	3.0%	NA	2.5%
Capital escalation (%)	3.0%	3.0%	0.0%	0.0%
Asset Life	30	30	30	50

Notes:
1) Fuel for combined cycle unit listed as average gas price over 30 years.
2) Fuel for biomass unit listed as average price over 30 years. Also, fuel costs are negative as technology, if reliably available, is considered a benefit to customer (energy supplied).

GRAPH 92-3: Levelized Total Costs of Generation at various Capacity Factors for various technologies ($/MWh)



Q.
Please update FPL's response to staff Interrogatory No. 59, assuming no CO2 costs.

A.
See attached tables.

Please note that the Resource Plan requested by Staff's First Set of Interrogatories No. 59 is not acceptable from a reliability perspective because it does not meet FPL's 20% reserve margin criterion, which the Commission has approved as the minimum required reserve to maintain the necessary level of system reliability. Therefore, any comparison between the CPVRR of the resource plan from Interrogatory No. 59 and the other four resource plans listed on the table below does not consider equal levels of system reliability and does not constitute a meaningful economic comparison.

Table 93-A
GFCT Resource Plan- Revenue Requirements
Assuming the removal of the two CTs in 2016
No CO2 Costs

	(1)	(2)	(3)	(4)	(5)	(6)
	Annual Revenue Requirements (Generation Capital) ($millions, 2011 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2011 $)	Annual Revenue Requirements (O&M) ($millions, 2011 $)	Annual Revenue Requirements (Fuel) ($millions, 2011 $)	Annual Revenue Requirements (Environmental) ($millions, 2011 $)	Total ($millions, 2011 $)
2011	0	0	0	3,250	-11	3,239
2012	0	0	1	3,434	-5	3,430
2013	0	0	1	3,433	-8	3,426
2014	0	0	1	3,665	-7	3,659
2015	0	0	1	3,972	-8	3,966
2016	0	0	11	4,741	-8	4,744
2017	0	0	3	5,207	-8	5,202
2018	0	0	3	5,630	-8	5,625
2019	126	4	27	5,963	-9	6,111
2020	210	6	46	6,550	-9	6,803
2021	203	6	47	7,182	-9	7,428
2022	195	5	52	7,462	-10	7,704
2023	188	5	50	7,375	-11	7,607
2024	181	5	51	7,975	-11	8,201
2025	174	5	56	8,811	-11	9,035
2026	374	16	93	9,103	-11	9,575
2027	505	24	124	9,535	-11	10,176
2028	571	23	143	9,850	-12	10,575
2029	782	22	191	10,148	-13	11,131
2030	964	21	237	10,608	-13	11,817
2031	1,083	20	273	11,064	-14	12,426
2032	1,296	19	329	11,761	-14	13,391
2033	1,674	18	419	12,899	-15	14,995
2034	1,917	18	489	13,584	-15	15,993
2035	2,018	17	536	14,046	-16	16,601
2036	2,333	16	625	15,176	-16	18,135
2037	2,578	16	710	15,783	-16	19,070
2038	2,668	15	763	16,310	-17	19,739
2039	2,875	14	843	16,972	-17	20,688
2040	3,046	14	925	17,518	-18	21,485
2041	3,133	13	987	18,122	-18	22,237
2042	3,348	12	1,079	18,857	-18	23,278
2043	3,653	12	1,192	19,930	-19	24,769
2044	3,957	12	1,312	20,793	-19	26,055
2045	4,121	11	1,411	21,494	-19	27,018
2046	4,332	11	1,523	22,247	-20	28,093
2047	4,498	11	1,632	23,047	-20	29,167
CPVRR	7,846	88	2,282	103,797	-141	113,871

Table 93-B
GFCT Resource Plan- Revenue Requirements
Assuming the removal of the two CTs in 2016 and a Short Term Purchase (600MW) 2016-2019
No CO2 Costs

	(1)	(2)	(3)	(4)	(5)	(6)
	Annual Revenue Requirements (Generation Capital) ($millions, 2011 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2011 $)	Annual Revenue Requirements (O&M) ($millions, 2011 $)	Annual Revenue Requirements (Fuel) ($millions, 2011 $)	Annual Revenue Requirements (Environmental) ($millions, 2011 $)	Total ($millions, 2011 $)
2011	0	0	0	3,250	-11	3,239
2012	0	0	1	3,434	-5	3,430
2013	0	0	1	3,433	-8	3,426
2014	0	0	1	3,665	-7	3,659
2015	0	0	1	3,972	-8	3,966
2016	0	0	25	4,738	-8	4,755
2017	0	0	28	5,208	-8	5,228
2018	0	0	29	5,632	-9	5,653
2019	126	4	38	5,963	-9	6,122
2020	210	6	46	6,550	-9	6,803
2021	203	6	47	7,182	-9	7,428
2022	195	5	52	7,462	-10	7,704
2023	188	5	50	7,375	-11	7,607
2024	181	5	51	7,975	-11	8,201
2025	174	5	56	8,811	-11	9,035
2026	374	16	93	9,103	-11	9,575
2027	505	24	124	9,535	-11	10,176
2028	571	23	143	9,850	-12	10,575
2029	782	22	191	10,148	-13	11,131
2030	964	21	237	10,608	-13	11,817
2031	1,083	20	273	11,064	-14	12,426
2032	1,296	19	329	11,761	-14	13,391
2033	1,674	18	419	12,899	-15	14,995
2034	1,917	18	489	13,584	-15	15,993
2035	2,018	17	536	14,046	-16	16,601
2036	2,333	16	625	15,176	-16	18,135
2037	2,578	16	710	15,783	-16	19,070
2038	2,668	15	763	16,310	-17	19,739
2039	2,875	14	843	16,972	-17	20,688
2040	3,046	14	925	17,518	-18	21,485
2041	3,133	13	987	18,122	-18	22,237
2042	3,348	12	1,079	18,857	-18	23,278
2043	3,653	12	1,192	19,930	-19	24,769
2044	3,957	12	1,312	20,793	-19	26,055
2045	4,121	11	1,411	21,494	-19	27,018
2046	4,332	11	1,523	22,247	-20	28,093
2047	4,498	11	1,632	23,047	-20	29,167
CPVRR	7,846	88	2,330	103,797	-142	113,919

Q.
In response to staff Interrogatory No. 40, FPL indicates that the Cumulative gas requirements in 2016 are the same for the PEEC resource plan and the Return to Service Resource Plan. Why are the gas requirements for the two resource plans the same despite the gas dependent generating capacity, in that same year, being different?

A.
The PEEC Resource Plan generates energy more efficiently than the Return to Service Resource Plan. FPL's gas requirements are based on the amount of gas the system would use to generate electricity to meet its customers' projected demand in the most economic manner. Gas is projected to be a more economic fuel choice than oil in both the PEEC Resource Plan and the Return to Service Resource Plan. The projected amount of gas used by the system on the peak day in 2016 with the PEEC Resource Plan is slightly lower than with the Return to Service Resource Plan, despite the fact that the gas generating capacity of the Return to Service Plan is lower in 2016. This is because the FPL system with the PEEC Resource Plan uses natural gas more efficiently to generate electricity than with the Return to Service Plan. The difference between the projected system maximum gas use on the peak day of 2016 for Return to Service Resource Plan compared to the PEEC Resource Plan is only slightly greater than 20 Mcf/day. Because the amount of gas used is approximately the same, the analysis reflects approximately the same projected gas requirement for the two resource plans.

Q.

On page 15 of Witness Enjamio's testimony, he states that the GFCT plan "consists of the construction of two new combustion turbines at a greenfield site which defers the need for PEEC to 2019." Please complete the table below assuming the two new combustion turbines are constructed at FPL's Port Everglades site.

	Annual Revenue Requirements (Generation Capital) ($millions, 2011 $)	Annual Revenue Requirements (Transmission Capital) ($millions, 2011 $)	Annual Revenue Requirements (O&M) ($millions, 2011 $)	Annual Revenue Requirements (Fuel) ($millions, 2011 $)	Annual Revenue Requirements (Environmental) ($millions, 2011 $)	Total ($millions, 2011 $)
2012						
2013						
2014						
2015						
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						
2030						
2031						
2032						
2033						
2034						
2035						
2036						
2037						
2038						
2039						
2040						
2041						
2042						
2043						
2044						
2045						
2046						
2047						
Total						

A.

The addition of PEEC at the Port Everglades Plant site is appropriately sized to take advantage of the existing electrical and natural gas transmission infrastructures that serve the site, upon the removal of the existing 4 steam units. FPL would not want to lose that valuable option, if it were to add stand-alone, simple-cycle combustion turbines at the site. FPL has not performed the engineering and environmental studies necessary to determine the technical feasibility of adding two stand-alone combustion turbines (CTs) and also be able to subsequently build the combined cycle unit which FPL has proposed as the PEEC project. However, based on the information we do have available, the addition of two stand-alone, simple cycle CTs at the Port Everglades site in advance of the PEEC project would, at least, require a substantially greater capital investment for the additional electrical and gas transmission infrastructures than would be required to support the generation of the two CTs, in addition to PEEC. Building two simple-cycle CTs at the Port Everglades Plant site in addition to the PEEC project also could complicate environmental permitting and require lengthy re-permitting of the PEEC project. FPL's preliminary analysis indicates that, because of the substantially greater capital investment as well as the environmental complications that would result from a combined project of two simple-cycle CTs plus PEEC, that approach would render the overall project prohibitively expensive. Therefore, construction of two simple-cycle CTs at the Port Everglades Plant site would effectively preclude proceeding with the PEEC project at that site.

Building two CTs at Port Everglades, instead of building the larger and much more efficient PEEC at this site would result in a far less than optimal use for what is arguably FPL's most beneficially located site, near FPL's areas of highest concentration of customer load (Miami-Dade and Broward Counties). If only two CTs are built at Port Everglades, FPL would be forced to build the combined cycle unit it now plans for that location as PEEC at a greenfield site instead, resulting in higher capital costs to FPL customers. In addition, the construction of two CTs at Port Everglades instead of PEEC would make it necessary to operate these less efficient CTs out of economic merit order to ensure compliance with area transmission import limits into Miami-Dade and Broward counties, which would result in higher system fuel costs.

Alternatively, building two CTs at the Port Everglades site as part of a phased construction (separated by multiple years) of a combined cycle unit, if it could be done, would result in much higher construction costs, as well as raise environmental regulatory issues previously discussed in FPL's response to Staff's First Set of Interrogatories No. 59(c).

PEEC is an ideal and very beneficial fit for the Port Everglades site because its size and fuel efficiency maximizes the capability of the site while incurring minimal transmission and gas transportation costs. For these reasons, it is clear that any alternative that would prevent or defer the addition of PEEC at the Port Everglades site, would be to the detriment of FPL's customers.

Q.
Please complete the table below assuming a 15% increase in natural gas prices. Please provide the results in 2011$ over the period 2011-2047.

Resource Plan	System Costs			
	Fixed Cost	Variable Cost	Total Cost	Difference from PEEC Resource Plan
PEEC				
Return to Service				
GFCC				
GFCT				
Resource Plan from Interrogatory No. 59 part A				

A.
Please note that the Resource Plan requested by Staff in Interrogatory 59 Part A is not acceptable from a reliability perspective because it does not meet FPL's 20% reserve margin criterion, which the Commission has approved as the minimum required reserve to maintain the necessary level of system reliability. Therefore, any comparison between the CPVRR of the resource plan from Interrogatory No. 59 part A and the other four resource plans listed on the table below does not consider equal levels of system reliability and is not a meaningful economic comparison.

Results of the Economic Analysis
Relative to PEEC
Assuming 15% increase in natural gas prices

(millions, CPVRR, 2011$, 2011-2047)

Resource Plan	System Costs			Difference from Lowest Cost Plan
	Fixed Costs*	Variable Costs**	Total Costs	
PEEC	14,578	141,352	155,930	--
Return to Service	13,501	142,962	156,463	533
Greenfield Combined Cycle (GFCC)	15,270	141,501	156,771	841
Greenfield Combustion Turbine (GFCT)	14,199	142,187	156,386	456
Resource Plan from Interrogatory No. 59 part A	13,753	142,188	155,942	12

* Generation system fixed costs include: capital, capacity payments, fixed O&M, capital replacement, and firm gas transportation. (Note that Turkey Point 6 & 7 generation and transmission capital costs are assumed to be zero in this analysis for all resource plans.)

** Generation system variable costs include: variable O&M, plant fuel, FPL system fuel, and environmental compliance costs.

Q.
Please complete the table below assuming a 15% decrease in natural gas prices. Please provide the results in 2011$ over the period 2011-2047.

Resource Plan	System Costs			
	Fixed Cost	Variable Cost	Total Cost	Difference from PEEC Resource Plan
PEEC				
Return to Service				
GFCC				
GFCT				
Resource Plan from Interrogatory No. 59 part A				

A.
Please note that the Resource Plan requested by Staff in Interrogatory No. 59 Part A is not acceptable from a reliability perspective because it does not meet FPL's 20% reserve margin criterion, which the Commission has approved as the minimum required reserve to maintain the necessary level of system reliability. Therefore, any comparison between the CPVRR of the resource plan from Interrogatory No. 59 part A and the other four resource plans listed on the table below does not consider equal levels of system reliability and does not constitute a meaningful economic comparison.

Results of the Economic Analysis
Relative to PEEC
Assuming 15% decrease in natural gas prices

(millions, CPVRR, 2011$, 2011-2047)

Resource Plan	System Costs			Difference from Lowest Cost Plan
	Fixed Costs*	Variable Costs**	Total Costs	
PEEC	14,578	115,111	129,689	--
Return to Service	13,501	116,628	130,129	440
Greenfield Combined Cycle (GFCC)	15,270	115,254	130,523	834
Greenfield Combustion Turbine (GFCT)	14,199	115,900	130,099	410
Resource Plan from Interrogatory No. 59 part A	13,753	115,903	129,657	-32

* Generation system fixed costs include: capital, capacity payments, fixed O&M, capital replacement, and firm gas transportation. (Note that Turkey Point 6 & 7 generation and transmission capital costs are assumed to be zero in this analysis for all resource plans.)

** Generation system variable costs include: variable O&M, plant fuel, FPL system fuel, and environmental compliance costs.

Q.
Please complete the table below describing the oil and gas usage for each resource plan.

Total oil and Gas Usage	
Plan	Usage through 2021 (MMBtu x 1,000)
PEEC	
Return to Service	
GFCC	
GFCT	
Resource Plan from	
Interrogatory No. 59 part A	

A.
See table below. Please note that the Resource Plan requested by Staff in Interrogatory No. 59 Part A is not acceptable from a reliability perspective because it does not meet FPL's 20% reserve margin criterion, which the Commission has approved as the minimum required reserve to maintain the necessary level of system reliability.

Table 98-1
Total Projected Oil & Gas Usage
(Based on Economic Analysis)
2016-2021

Plan	Oil (MMBTU)	Gas (MMBtu)	Total Oil and Gas (MMBtu)
PEEC	28,467	3,553,795	3,582,262
Return to Service	50,970	3,583,575	3,634,545
GFCC	28,102	3,549,499	3,577,601
GFCT	41,599	3,574,180	3,615,779
Resource Plan from Interrogatory #59 A	42,207	3,573,505	3,615,712

Q.
On pages 77-83, of FPL's 2011 Ten-Year Site Plan, the company discusses renewable resources,

a. Is the information still current? If not please update the information.
b. Is the information still accurate? If not please explain why.
c. Is the information reliable for purposes of this docket? Please explain why or why not.
d. If FPL updated the information in response to question 99a above, is the updated information reliable for purposes of this docket. Please explain why or why not.

A.
Response to subparts (a) - (d).

The information from FPL's 2011 Ten Year Site Plan regarding renewable energy resources that pertains to the need for capacity in 2016 and the economic analysis supporting this docket is the information related to the implementation of renewable-based DSM programs for solar water heaters and photovoltaics. The projected MW impacts of those DSM programs were included in FPL's 2011 Site Plan in the reserve margin calculations, and the MW and MWh impacts are also included in FPL's analysis performed in support of this docket. That information is still current, accurate, and reliable for purposes of this docket.

The information presented on pages 77-83 of FPL's 2011 Ten Year Site Plan is historical information through the end of 2010, which remains accurate. FPL has not yet developed the information necessary to update its Ten Year Site Plan. FPL will be providing updated information that includes a narrative of FPL's renewable energy efforts through 2011 in FPL's 2012 Ten Year Site Plan filing. FPL knows of no updates to its renewable energy efforts for the 2012 Ten Year Site Plan filing that would reduce FPL's need for capacity beginning in 2016 or negatively affect the economic analysis supporting this docket.

AFFIDAVIT

John Bulich

John Bulich

State of Florida)

County of Palm Beach)

I hereby certify that on this 23 day of January, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared John Bulich, who is personally known to me, and he acknowledged before me that he sponsored or cosponsored the answers to Interrogatory Nos. 76, 79, 83, 91, and 95 from Staff's Third Set of Interrogatories to Florida Power & Light Company in Docket No. 110309-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 23 day of January, 2012.

Morgan Sabato

Notary Public, State of Florida

Notary Stamp:

AFFIDAVIT

Juan E. Enjamio

State of Florida)

County of Miami-Dade)

I hereby certify that on this 25th day of January, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Juan E. Enjamio, who is personally known to me, and he acknowledged before me that he sponsored or cosponsored the answers to Interrogatory Nos. 72, 73, 75, 80, 81, 85, 86, 88, 90, 91, 92, 93, 94, 95, 96, 97, 98 and 99 from Staff's Third Set of Interrogatories to Florida Power & Light Company in Docket No. 110309-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 25th day of January, 2012.

Notary Public, State of Florida

Notary Stamp:

Notary Public State of Florida
Lily A Rodriguez
My Commission DD854399
Expires 02/13/2013

AFFIDAVIT

Thomas. L Hartman

State of Florida)

County of Palm Beach)

I hereby certify that on this 24 day of January 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Thomas L. Hartman**, who is personally known to me, and he acknowledged before me that he sponsored the answers to Interrogatory Nos. 73, 74 & 81 from Staff's Third Set of Interrogatories to Florida Power & Light Company in Docket No. 110309-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 24th day of January, 2012.

Notary Public, State of Florida

Notary Stamp:

MARITZA MIRANDA-WISE
MY COMMISSION # DD 870958
EXPIRES: May 30, 2013
Bonded Thru Notary Public Underwriters

AFFIDAVIT

Roxane Kennedy

State of Florida)

County of Palm Beach)

I hereby certify that on this 25th day of January, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Roxane Kennedy, who is personally known to me, and she acknowledged before me that she sponsored the answers to Interrogatory Nos. 77, 88 and 89 from Staff's Third Set of Interrogatories to Florida Power & Light Company in Docket No. 110309-EI, and that the responses are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 25th day of January, 2012.

Notary Public, State of Florida

Notary Stamp:

Notary Public State of Florida
Jessica Alexander Johnson
My Commission EE108855
Expires 03/02/2015

AFFIDAVIT

Pedro Modia

State of Florida)

County of Miami Dade)

I hereby certify that on this 26th day of January, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Pedro Modia**, who is personally known to me, and he acknowledged before me that he sponsored the answer to Interrogatory No. 82 from Staff's Third Set of Interrogatories to Florida Power & Light Company in Docket No. 110309-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 26th day of January, 2012.

Notary Public, State of Florida

Notary Stamp:

LOURDES V. WONGDEN
Notary Public - State of Florida
My Comm. Expires Oct 28, 2015
Commission # EE 134330
Bonded Through National Notary Assn.

AFFIDAVIT

Rosemary Morley

State of Florida)

County of Palm Beach)

I hereby certify that on this 23 day of January, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Rosemary Morley, who is personally known to me, and she acknowledged before me that she sponsored the answer to Interrogatory No. 78 from Staff's Third Set of Interrogatories to Florida Power & Light Company in Docket No. 110309-EI, and that the response is true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 23 day of January, 2012.

Notary Public, State of Florida

Notary Stamp:

KAREN PEKSA
Notary Public - State of Florida
My Comm. Expires Oct 23, 2015
Commission # EE 140478

AFFIDAVIT

T.O. Nasby

State of Florida)

County of Palm Beach)

I hereby certify that on this 23rd day of January, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared T.O. Nasby, who is personally known to me, and he acknowledged before me that he sponsored or cosponsored the answers to Interrogatory No. 92 from Staff's Third Set of Interrogatories to Florida Power & Light Company in Docket No. 110309-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 23rd day of January, 2012.

Morgan Sabato
Notary Public, State of Florida

Notary Stamp:

MORGAN A. SABATO
Notary Public - State of Florida
My Comm. Expires Oct 23, 2015
Commission # EE 140489

AFFIDAVIT

Heather C. Stubblefield

State of Florida)

County of Palm Beach)

I hereby certify that on this 25 day of January 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Heather C. Stubblefield**, who is personally known to me, and she acknowledged before me that she sponsored the answers to Interrogatory Nos. 84, 85 86, & 87 from Staff's Third Set of Interrogatories to Florida Power & Light Company in Docket No. 110309-EI, and that the responses are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 25 day of January, 2012.

Notary Public, State of Florida

Notary Stamp:

MARITZA MIRANDA-WISE
MY COMMISSION # DD 870958
EXPIRES: May 30, 2013
Bonded Thru Notary Public Underwriters

38

FPL's Responses to Staff's First Request for Production of Documents (Nos. 1-6)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 38
PARTY Florida Public Service Commission Staff
DESCRIPTION Staffs Exhibit #38
DATE 02/20/12

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition To Determine Need for Modernization of Port Everglades Plant	Docket No. 110309-EI Dated: January 4, 2012

FLORIDA POWER & LIGHT COMPANY'S RESPONSES TO STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1-61) AND FIRST REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 1-6)

Florida Power & Light Company ("FPL"), pursuant to Rules 1.340 and 1.350, Florida Rules of Civil Procedure, Rule 28-106.206, Florida Administrative Code, and this Commission's Order Establishing Procedure PSC-11-0565-PCO-EI, submits the following responses to the Staff of the Florida Public Service Commission's First Set of Interrogatories (Nos. 1-61) and First Request for Production of Documents (Nos. 1-6).

1. FPL adopts and incorporates by reference, as though fully restated herein, all objections listed in FPL's Objections to Staff's First Set of Interrogatories (1-61) and First Request for Production of Documents (Nos. 1-6) dated December 29, 2011. FPL's responses are without waiver of those prior objections.

2. Attached hereto are FPL's answers to Staff's First Set of Interrogatories (Nos. 1-61), together with the affidavits of the persons providing the answers.

3. FPL will deliver to Staff contemporaneously with this response a CD-Rom containing all non-confidential documents responsive to Staff's First Request for Production of Documents (Nos. 1-6), as well as hard copies of non-confidential documents where specifically requested by Staff. Confidential documents will be available for review at FPL's offices at 215 South Monroe Street, Tallahassee, Florida during regular business hours, 8 a.m. to 5 p.m., Monday through Friday, upon reasonable notice to FPL's counsel. If Staff wishes to remove any

confidential documents from FPL's office, FPL will undertake the necessary steps, pursuant to Florida Statutes and applicable rules, to protect the confidentiality of those documents.

Respectfully submitted this 4th day of January, 2012.

John T. Butler
Will P. Cox
Maria J. Moncada
Attorneys for Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408-0420
(561) 304-5795
(561) 691-7135 (fax)

By: *s/ Maria J. Moncada*
Maria Moncada
Florida Bar No. 0773301

CERTIFICATE OF SERVICE
DOCKET NO. 110309-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing Responses to Staff's First Set of Interrogatories (Nos. 1-61) and Staff's First Request for Production of Documents (Nos. 1-6) was served electronically and by U.S. mail this 4th day of January, 2012 to the following:

Charles W. Murphy, Esq.
Office of the General Counsel
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850
cmurphy@psc.state.fl.us

By: *s/ Maria J. Moncada*
Maria J. Moncada
Florida Bar No. 0773301

FPL 000001
PEEC-11

Total Customers

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	-295894.256	356537.802	-0.830	40.74%
Florida Population	0.257	0.020	13.177	0.00%
AR(1)	0.963	0.017	56.532	0.00%
SAR(1)	0.820	0.030	27.747	0.00%

Net Energy for Load

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	1.548	0.088	17.526	0.00%
Calendar Heating Degree Days (Base =45)	0.017	0.003	5.219	0.00%
Calendar Cooling Degree Hours (Base=72)	0.003	0.000	74.874	0.00%
Calendar Winter Heating Degree Days (Base=66)	0.001	0.000	15.191	0.00%
Inactive_Ratio	-2.698	0.725	-3.721	0.03%
Weather Sensitive Energy Efficiency Standards	-1.796	0.297	-6.042	0.00%
Real per Capita Income weighted by Employed Population (Thou 2005$)	0.022	0.005	4.339	0.00%
Dummy March 2003	0.098	0.023	4.317	0.00%
Dummy February	-0.147	0.008	-19.374	0.00%
Dummy April	-0.036	0.008	-4.723	0.00%
Dummy June	-0.055	0.008	-7.197	0.00%
Dummy September	-0.052	0.007	-7.088	0.00%
Dummy May 2004	0.111	0.023	4.933	0.00%
Dummy November	-0.057	0.009	-6.576	0.00%
Dummy November 2005	0.106	0.024	4.503	0.00%
CPI for Energy (1982-1984=100)	-0.000	0.000	-2.544	1.24%
AR(1)	0.323	0.094	3.453	0.08%

Summer Peak

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	-1.3855	0.948	-1.462	15.79%
Real per Capita Income weighted by Employed Population	0.0880	0.010	9.030	0.00%
Real Price of Electricity Lagged 1 Month	-9.3309	1.919	-4.861	0.01%
System Composite Peak Day Maximum Temperature	0.0489	0.010	4.662	0.01%
Cooling Degree Hours Prior Day (Base=72)	0.0030	0.001	4.583	0.01%
Energy Efficiency Standards	-0.4411	0.215	-2.054	5.21%
Dummy 1982	0.2219	0.090	2.476	2.15%
Dummy 1990	-0.2668	0.086	-3.100	0.52%
Dummy 1989	-0.2118	0.086	-2.469	2.18%

Winter Peak

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	6.799533	0.575	11.828	0.00%
System Minimum Temperature on Peak Day	-0.072204	0.012	-5.948	0.00%
Heating Degree Hours Squared	0.000001	0.000	3.074	0.60%
Weekend Winter Peak Dummy	-0.549943	0.143	-3.851	0.10%
AR(1)	0.394120	0.197	2.002	5.90%

FPL 000002
PEEC-11

Net Energy for Load	Coefficient	StdErr	T-Stat	P-Value
CONST	1.5482	0.088	17.526	0.00%
Calendar Heating Degree Days (Base =45)	0.0174	0.003	5.219	0.00%
Calendar Cooling Degree Hours (Base=72)	0.0029	0.000	74.874	0.00%
Calendar Winter Heating Degree Days (Base=66)	0.0012	0.000	15.191	0.00%
Inactive_Ratio	-2.6985	0.725	-3.721	0.03%
Weather Sensitive Energy Efficiency Standards	-1.7963	0.297	-6.042	0.00%
Real per Capita Income weighted by Employed Population (Thou 2005$)	0.0221	0.005	4.339	0.00%
Dummy March 2003	0.0980	0.023	4.317	0.00%
Dummy February	-0.1468	0.008	-19.374	0.00%
Dummy April	-0.0363	0.008	-4.723	0.00%
Dummy June	-0.0546	0.008	-7.197	0.00%
Dummy September	-0.0519	0.007	-7.088	0.00%
Dummy May 2004	0.1115	0.023	4.933	0.00%
Dummy November	-0.0565	0.009	-6.576	0.00%
Dummy November 2005	0.1061	0.024	4.503	0.00%
CPI for Energy (1982-1984=100)	-0.0004	0.000	-2.544	1.24%
AR(1)	0.3233	0.094	3.453	0.08%

Total Customers

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	-295894.256	356537.802	-0.830	40.74%
Population_Data_Monthly.EDR_FL_Population_Aug_2011	0.256993	0.020	13.177	0.00%
AR(1)	0.962961	0.017	56.532	0.00%
SAR(1)	0.819722	0.030	27.747	0.00%

Summer Peak

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	-1.38546	0.948	-1.462	15.79%
Real per Capita Income weighted by Employed Population (Thou 2005$)	0.08798	0.010	9.030	0.00%
Real Price of Electricity Lagged 1 Month	-9.33087	1.919	-4.861	0.01%
System Composite Peak Day Maximum Temperature	0.04891	0.010	4.662	0.01%
Cooling Degree Hours Prior Day (Base=72)	0.00298	0.001	4.583	0.01%
Energy Efficiency Standards	-0.44105	0.215	-2.054	5.21%
Annual.Dummy_1982	0.22191	0.090	2.476	2.15%
Annual.Dummy_1990	-0.26684	0.086	-3.100	0.52%
Annual.Dummy_1989	-0.21183	0.086	-2.469	2.18%

Winter Peak

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	6.799533	0.575	11.828	0.00%
System Minimum Temperature on Peak Day	-0.072204	0.012	-5.948	0.00%
Heating Degree Hours Squared	0.000001	0.000	3.074	0.60%
Annual.Weekend_Winter_Peak	-0.549943	0.143	-3.851	0.10%
AR(1)	0.394120	0.197	2.002	5.90%

FPL 000003
PEEC-11

Net Energy for Load

Model Statistics	
Iterations	14
Adjusted Observations	119
Deg. of Freedom for Error	102
R-Squared	0.995
Adjusted R-Squared	0.994
AIC	-7.380
BIC	-6.983
F-Statistic	1294.760
Prob (F-Statistic)	0.0000
Model Sum of Squares	11.32
Sum of Squared Errors	0.06
Mean Squared Error	0.00
Std. Error of Regression	0.02
Mean Abs. Dev. (MAD)	0.02
Mean Abs. % Err. (MAPE)	0.80%
Durbin-Watson Statistic	2.062
Durbin-H Statistic	#NA

Total Customers

Model Statistics	
Iterations	17
Adjusted Observations	245
Deg. of Freedom for Error	241
R-Squared	1.000
Adjusted R-Squared	1.000
AIC	16.333
BIC	16.390
F-Statistic	1325853.481
Prob (F-Statistic)	0.0000
Model Sum of Squares	48,503,978,137,512
Sum of Squared Errors	2,938,851,312
Mean Squared Error	12,194,403.79
Std. Error of Regression	3,492.05
Mean Abs. Dev. (MAD)	2,538.59
Mean Abs. % Err. (MAPE)	0.06%
Durbin-Watson Statistic	1.718
Durbin-H Statistic	#NA

Summer Peak

Model Statistics	
Iterations	1
Adjusted Observations	31
Deg. of Freedom for Error	22
R-Squared	0.946
Adjusted R-Squared	0.926
AIC	-4.826
BIC	-4.410
F-Statistic	48.257
Prob (F-Statistic)	0.0000
Model Sum of Squares	2.44
Sum of Squared Errors	0.14
Mean Squared Error	0.01
Std. Error of Regression	0.08
Mean Abs. Dev. (MAD)	0.05
Mean Abs. % Err. (MAPE)	1.15%
Durbin-Watson Statistic	2.045
Durbin-H Statistic	#NA

Winter Peak

Model Statistics	
Iterations	8
Adjusted Observations	25
Deg. of Freedom for Error	20
R-Squared	0.835
Adjusted R-Squared	0.802
AIC	-2.775
BIC	-2.531
F-Statistic	25.374
Prob (F-Statistic)	0.0000
Model Sum of Squares	5.30
Sum of Squared Errors	1.05
Mean Squared Error	0.05
Std. Error of Regression	0.23
Mean Abs. Dev. (MAD)	16.79%
Mean Abs. % Err. (MAPE)	0.040
Durbin-Watson Statistic	1.904
Durbin-H Statistic	#NA

Q.
Please provide each forecast assumption and its source(s) used to project the load forecast forecasts referenced in witness Morley's testimony at page 2, lines 21-22.

A.
Please see FPL's response to Staff's First Request for Production of Documents No. 2.

Q.
Please provide the calculations and supporting rationale behind any adjustments made to the output of the econometric models relied upon in the load forecasts referenced in witness Morley's testimony at page 2, lines 21-22.

A.
The forecasts are adjusted for incremental wholesale loads, new load resulting from plug-in electric vehicles, changes to the Economic Development rider, and the addition of the Existing Facilities Economic Development Rider. These adjustments are made in order to include additional load not otherwise reflected in FPL's historical load levels and therefore not captured by our models. Additionally, adjustments are made for current wholesale contracts set to terminate. Since these customers are included in the historical data, the forecast reflects the load of these customers. Adjustments are therefore made to remove this load from FPL's projections.

Please see Attachment No. 1 for the calculations of the adjustments described above.

Summer Peak Adjustments
The adjustments to the summer peak forecast are shown in tab "Summer Peak." The additional load from new or modified wholesale contracts is provided in columns N, O, R and S. The loss of load from terminated wholesale contracts is provided in column Q. The additional load resulting from plug-in electric vehicles is provided in column P. The additional load resulting from the Economic Development Rider and Existing Facilities Economic Development Rider is shown in column T.

Winter Peak Adjustments
The adjustments to the winter peak forecast are shown in tab "Winter Peak." The additional load from new and/or modified wholesale contracts is provided in columns J, K, N and O. The loss of load from terminated wholesale contracts is provided in column M. The additional load resulting from plug-in electric vehicles is provided in column L. The additional load resulting from the Economic Development Rider and Existing Facilities Economic Development Rider is shown in column P. The impact of energy efficiency standards is shown in column I. Note that energy efficiency standards are treated as a model variable in the summer peak and net energy for load models. Hence, an adjustment for energy efficiency standards is only used for the winter peak forecast.

Net Energy for Load Adjustments

The adjustments to the net energy for load forecast are shown in tab "NEL." The additional load from new and/or modified wholesale contracts is provided in columns S, T, W and X. The loss of load from terminated wholesale contracts is provided in column V. The additional load resulting from plug-in electric vehicles is provided in column U. The additional load resulting from the Economic Development Rider and Existing Facilities Economic Development Rider is shown in column Y. In addition, there is a very small decrease in NEL resulting from the implementation of the AMI program. This decrease results from the improved detection of usage by non-paying customers. This adjustment is shown in column AF. The net impact from AMI is shown in column AA.

Q.
If the answer to Interrogatory 1. is "No," please provide the information requested in Requests for Production 1.-5., above, for the forecasts relied upon to determine generating capacity needs supporting the modernization of Port Everglades Plant.

A.
The answer to Interrogatory 1 is yes, this is the most recent forecast and the one used to determine generating capacity needs.

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FPL's Responses to Staff's Second Request for Production of Documents (Nos. 7-10)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 39
PARTY Florida Public Service Commission Staff
DESCRIPTION Staffs Exhibit #39
DATE 02/20/12

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Florida Power & Light Company's Petition To Determine Need for Modernization of Port Everglades Plant	Docket No. 110309-EI Dated: January 18, 2012

FLORIDA POWER & LIGHT COMPANY'S RESPONSES TO STAFF'S SECOND SET OF INTERROGATORIES (NOS. 62-71) AND SECOND REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 7-10)

Florida Power & Light Company ("FPL"), pursuant to Rules 1.340 and 1.350, Florida Rules of Civil Procedure, Rule 28-106.206, Florida Administrative Code, and this Commission's Order Establishing Procedure PSC-11-0565-PCO-EI, submits the following responses to the Staff of the Florida Public Service Commission's Second Set of Interrogatories (Nos. 62-71) and Second Request for Production of Documents (Nos. 7-10).

1. FPL adopts and incorporates by reference, as though fully restated herein, all objections listed in FPL's Objections to Staff's Second Set of Interrogatories (62-71) and Second Request for Production of Documents (Nos. 7-10) dated January 12, 2012. FPL's responses are without waiver of those prior objections.

2. Attached hereto are FPL's non-confidential answers to Staff's Second Set of Interrogatories (Nos. 62-71), together with the affidavits of the persons providing the answers.

3. FPL will deliver to Staff contemporaneously with this response a CD-Rom containing all non-confidential documents responsive to Staff's Second Request for Production of Documents (Nos. 7-10).

4. Confidential answers and documents will be available for review at FPL's offices at 215 South Monroe Street, Suite 810, Tallahassee, Florida during regular business hours, 8 a.m. to 5 p.m., Monday through Friday, upon reasonable notice to FPL's counsel. If Staff wishes to remove any confidential answers or documents from FPL's office, FPL will undertake the

necessary steps, pursuant to Florida Statutes and applicable rules, to protect the confidentiality of those materials.

Respectfully submitted this 18th day of January, 2012.

John T. Butler
Will P. Cox
Maria J. Moncada
Attorneys for Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408-0420
(561) 304-5795
(561) 691-7135 (fax)

By: *s/ Maria J. Moncada*
Maria Moncada
Florida Bar No. 0773301

CERTIFICATE OF SERVICE
DOCKET NO. 110309-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing Responses to Staff's Second Set of Interrogatories (Nos. 62-71) and Second Request for Production of Documents (Nos. 7-10) was served electronically and by U.S. mail this 18th day of January, 2012 to the following:

Charles W. Murphy, Esq.
Office of the General Counsel
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850
cmurphy@psc.state.fl.us

By: *s/ Maria J. Moncada*
Maria J. Moncada
Florida Bar No. 0773301

Q.
Please provide complete copies of all work papers and source documents associated with the testimony and exhibits of Heather Stubblefield.

A.
FPL will provide the complete copies of all work papers and source documents associated with the testimony and exhibits of Heather Stubblefield. The documents provided in response to this request are confidential and will be made available for inspection at FPL's Tallahassee Office at 215 South Monroe Street, Suite 810, Tallahassee, Florida, during regular business hours, 8 a.m. to 5 p.m., Monday through Friday, upon reasonable notice to FPL's counsel.

Q.
FPL's fuel price forecast was prepared on August 1, 2011. If FPL has in its possession a more recent forecast for any fuel type for the forecast horizon in excess of 10 years, please provide.

A.
FPL will provide copies of FPL's November 14, 2011 and January 3, 2012 fuel price forecast. The documents provided in response to this request are confidential and will be made available for inspection at FPL's Tallahassee Office at 215 South Monroe Street, Suite 810, Tallahassee, Florida, during regular business hours, 8 a.m. to 5 p.m., Monday through Friday, upon reasonable notice to FPL's counsel.

Q.

To the extent not provided in response to Request for Production No. 7 above, please provide copies of each contemporary fuel price forecast: (a.) to which FPL compared its fuel price forecast or, (b.) which FPL used in the development of its fuel price forecast.

A.

(a) Please see FPL's response to Staff's Second Set of Interrogatories No. 68.

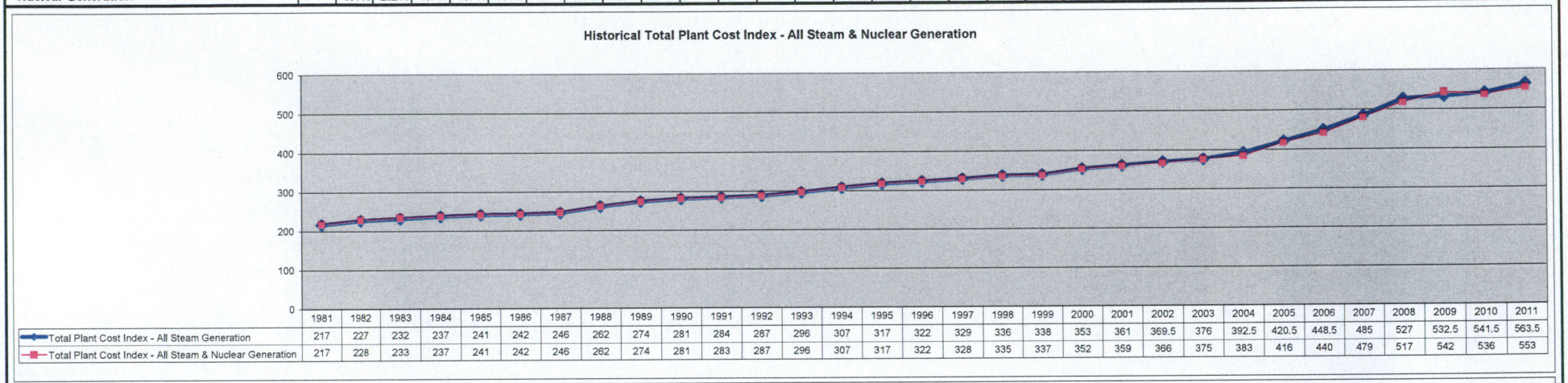
(b) All forecasts used by FPL in the development of its fuel price forecast is included in FPL's response to Staff's Second Request for Production of Documents No. 7.

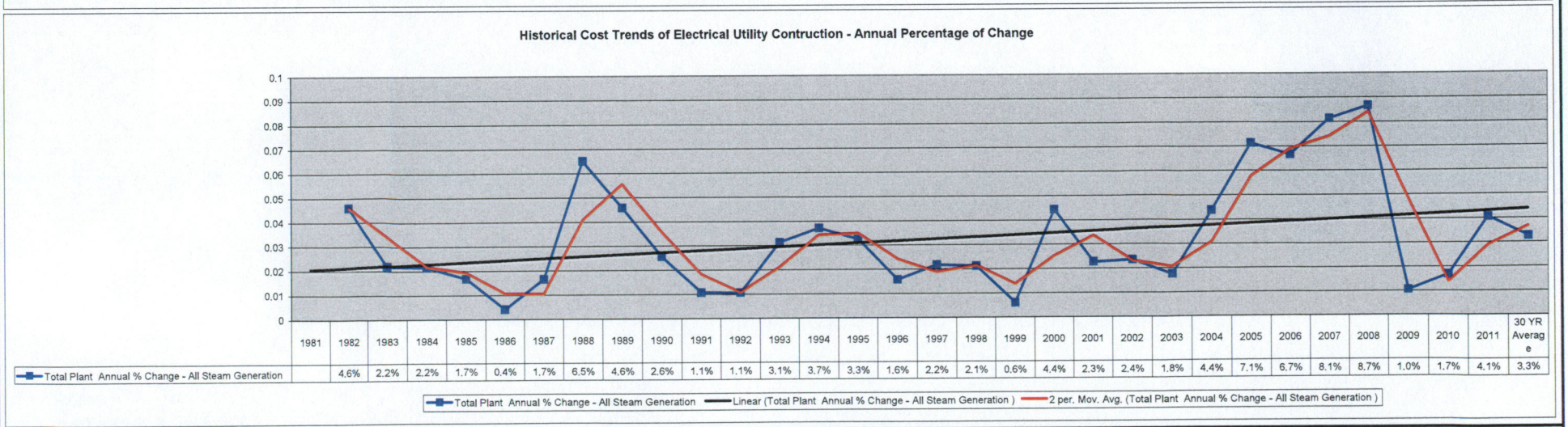
Q.
To the extent not provided in response to Request for Production No. 7 above, please provide complete copies of all documents used to develop the escalation factors and the general inflation rate used by FPL in this docket.

A.
FPL is providing the responsive non-confidential documents. One document provided in response to this request is confidential and will be made available for inspection at FPL's Tallahassee Office at 215 South Monroe Street, Suite 810, Tallahassee, Florida, during regular business hours, 8 a.m. to 5 p.m., Monday through Friday, upon reasonable notice to FPL's counsel.

Historical Cost Trends of Electrical Utility Construction - South Atlantic Region **

Construction and Equipment	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	30 YR Average
Total Plant Cost Index - All Steam Generation	217	227	232	237	241	242	246	262	274	281	284	287	296	307	317	322	329	336	338	353	361	369.5	376	392.5	420.5	448.5	485	527	532.5	541.5	563.5	
Total Plant Annual % Change - All Steam Generation		4.6%	2.2%	2.2%	1.7%	0.4%	1.7%	6.5%	4.6%	2.6%	1.1%	1.1%	3.1%	3.7%	3.3%	1.6%	2.2%	2.1%	0.6%	4.4%	2.3%	2.4%	1.8%	4.4%	7.1%	6.7%	8.1%	8.7%	1.0%	1.7%	4.1%	3.3%
Total Plant Cost Index - All Steam & Nuclear Generation	217	228	233	237	241	242	246	262	274	281	283	287	296	307	317	322	328	335	337	352	359	366	375	383	416	440	479	517	542	536	553	
Total Plant Annual % Change - All Steam & Nuclear Generation		5.1%	2.2%	1.7%	1.7%	0.4%	1.7%	6.5%	4.6%	2.6%	0.7%	1.4%	3.1%	3.7%	3.3%	1.6%	1.9%	2.1%	0.6%	4.5%	2.0%	1.9%	2.5%	2.1%	8.6%	5.8%	8.9%	7.9%	4.8%	-1.1%	3.2%	3.2%





**Handy Whitman Index of Public Utility Construction Cost - Bulletin No. 174

FPL 000138
PEEC-11

Year	CPI	% Change
1980	82.4	
1981	90.9	10.4%
1982	96.5	6.2%
1983	99.6	3.2%
1984	103.9	4.4%
1985	107.6	3.5%
1986	109.7	1.9%
1987	113.6	3.6%
1988	118.3	4.1%
1989	123.9	4.8%
1990	130.7	5.4%
1991	136.2	4.2%
1992	140.3	3.0%
1993	144.5	3.0%
1994	148.2	2.6%
1995	152.4	2.8%
1996	156.9	2.9%
1997	160.5	2.3%
1998	163.0	1.5%
1999	166.6	2.2%
2000	172.2	3.4%
2001	177.0	2.8%
2002	179.9	1.6%
2003	184.0	2.3%
2004	188.9	2.7%
2005	195.3	3.4%
2006	201.6	3.2%
2007	207.3	2.9%
2008	215.3	3.8%
2009	214.5	-0.3%
2010	218.1	1.6%
2011	224.3	2.8%
2012	228.6	1.9%
2013	233.3	2.0%
2014	238.5	2.2%
2015	243.6	2.1%
2016	248.7	2.1%
2017	253.9	2.1%
2018	259.1	2.0%
2019	263.9	1.9%
2020	268.8	1.8%
2021	273.8	1.9%
2022	278.9	1.8%
2023	284.0	1.8%
2024	289.4	1.9%
2025	295.0	1.9%
2026	300.8	2.0%
2027	306.9	2.0%
2028	313.2	2.1%
2029	319.6	2.1%
2030	326.0	2.0%
2031	332.3	1.9%
2032	338.7	1.9%

Avg 20 Yrs 1991-2011 2.5%

FPL 000138
PEEC-11

Year	CPI	% Change
2033	345.3	1.9%
2034	351.9	1.9%
2035	358.6	1.9%
2036	365.6	2.0%
2037	372.9	2.0%
2038	380.5	2.0%
2039	388.4	2.1%
2040	396.4	2.1%
2041	404.4	2.0%
2042	412.5	2.0%
2043	420.7	2.0%

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FPL's Responses to Staff's Request for PEEC Resource Plan

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 40
PARTY Florida Public Service Commission Staff
DESCRIPTION Staffs Exhibit #40
DATE 02/20/12

DOCKET NO. 110309-EI
RESPONSE TO STAFF REQUEST FOR PEEC RESOURCE PLAN
USING 15% RESERVE MARGIN CRITERION
ECONOMIC ANALYSIS

15% RMC vs. 20% RMC

As requested by Staff, below is a resource plan in which capacity is added to satisfy a 15% reserve margin criterion (RMC) rather than the approved 20% RMC. Please note that PEEC is added in 2020, although the 15% RMC would not call for its addition until 2021. This was done to avoid the substantial transmission costs that FPL would have to incur if sufficient capacity is not added in Southeast Florida by 2020. Also attached is an updated PEEC resource plan applying the 20% RMC, to reflect the same assumptions used under the 15% RMC.

Table 1
Comparison of Resource Plans
15% RMC vs. 20% RMC

		15% Reserve Margin							PEEC in 2016 - 20% Reserve Margin				
	Year	Resource Plan	Unit MWs	MWs Over 15% RM	% RM	Gen Only RM %	MWs Over/(Under) 20% RM		Resource Plan	Unit MWs	MWs Over/Under 20% RM	% RM	Gen Only RM %
3x1 CCs added	2016	---		1179	20.4%	7.9%	91		PEEC	1277	1368	26.3%	13.1%
	2017	---		709	18.2%	5.4%	(384)		---		893	24.1%	10.6%
	2018	---		694	18.2%	4.8%	(400)		---		877	24.0%	9.9%
	2019	---		423	16.9%	3.2%	(683)		---		594	22.7%	8.3%
	2020	PEEC	1277	1325	20.9%	6.4%	203		---		203	20.9%	6.4%
	2021	---		947	19.2%	4.5%	(191)		1 - 3x1 J	1262	1071	24.7%	9.4%
	2022	TP6	1100	1586	21.8%	6.6%	428		TP6	1100	1690	27.3%	11.3%
	2023	TP7	1100	2110	23.9%	8.1%	926		TP7	1100	2188	29.2%	12.8%
	2024	---		1623	21.7%	6.0%	418		---		1680	27.0%	10.5%
	2025	---		848	18.5%	2.9%	(379)		---		883	23.6%	7.3%
	2026	1 - 3x1 J	1262	1200	19.8%	3.8%	(52)		1 (698MW)	698	646	22.6%	6.2%
2x1 Filler CCs added	2027	---							---				
	2028	1	631						1	631			
	2029	1	631						2	1262			
	2030	1	631						1	631			
	2031	1	631						1	631			
	2032	2	1262						2	1262			
	2033	3	1893						3	1893			
	2034	1	631						1	631			
	2035	1	631						1	631			
	2036	3	1893						3	1893			
	2037	1	631						1	631			
	2038	1	631						1	631			
	2039	1	631						2	1262			
	2040	2	1262						1	631			
	2041	1	631						1	631			
	2042	1	631						2	1262			
	2043	3	1893						2	1262			
	2044	1	631						2	1262			
	2045	2	1262						1	631			
	2046	1	631						2	1262			
	2047	2	1262						1	631			
	Total MWs		23,669							24,998			

15% RMC

Please refer to companion document labeled "Response to Staff Request for PEEC Resource Plan Using 15% Reserve Margin Criterion" for a full description of FPL's concerns.

The economic analysis is based on the midcourse Fuel Price forecast and assumes that SJRPP suspension is delayed until 2017. The results for this comparison show that using these assumptions the 15% RMC case would result in a decrease in projected CPVRR of $407 MM (as shown in the table that follows). However, this result is very sensitive to long-term assumptions. For example, if natural gas prices were to be only $1.45/MMBtu higher than assumed, there would be no CPVRR difference between the two resource plans.

Table 2
Results of Economic Comparison of 15% RMC vs. 20% RMC

	Capital	O&M and Cap rep	Other	Total Fixed costs	Fuel and Vom	Emissions	Total variable costs	Total
20% RM -	$8,518	$2,477	$3,583	$14,578	$91,538	$28,448	$119,987	$134,564
15% RM -	$7,236	$2,019	$3,583	$12,839	$92,480	$28,838	$121,319	$134,157
Difference	(1,282)	(457)	0	(1,739)	942	390	1,332	(407)

It should also be noted that the cumulative CO2 emissions by 2030 of the 15% RMC resource plan is approximately 13 million tons greater than for the 20% RMC resource plan.

DOCKET NO. 110309-EI
RESPONSE TO STAFF REQUEST FOR PEEC RESOURCE PLAN
USING 15% RESERVE MARGIN CRITERION
ECONOMIC ANALYSIS

15% RMC thru 2024 reverting to 20% RMC 2025 vs. 20% RMC

As an additional response to Staff's request, below is a resource plan in which capacity is added to satisfy a 15% reserve margin criterion (RMC) through 2024, but subsequently added to satisfy a 20% RMC starting in 2025. Please note that PEEC is added in 2020 although the 15% RMC would not call for its addition until 2021. This was done to avoid the substantial transmission costs that FPL would have to incur if sufficient capacity is not added in Southeast Florida by 2020. Also attached is an updated PEEC resource plan applying the 20% RMC for comparison purposes. This comparison results in an equal amount of capacity added by the end of the study period.

Table 1
Comparison of Resource Plans
15% RMC thru 2024 vs. 20% RMC

		15% Reserve Margin to 2024 / 20% Reserve Margin after 2025							PEEC in 2016 - 20% Reserve Margin				
	Year	Resource Plan	Unit MWs	MWs Over 15% RM	% RM	Gen Only RM %	MWs Over/(Under) 20% RM		Resource Plan	Unit MWs	MWs Over/Under 20% RM	% RM	Gen Only RM %
3x1 CCs added	2016	---		1179	20.4%	7.9%	91		PEEC	1277	1368	26.3%	13.1%
	2017	---		709	18.2%	5.4%	(384)		---		893	24.1%	10.6%
	2018	---		694	18.2%	4.8%	(400)		---		877	24.0%	9.9%
	2019	---		423	16.9%	3.2%	(683)		---		594	22.7%	8.3%
	2020	PEEC	1277	1325	20.9%	6.4%	203		---		203	20.9%	6.4%
	2021	---		947	19.2%	4.5%	(191)	15% RMC	1 - 3x1 J	1262	1071	24.7%	9.4%
	2022	TP6	1100	1586	21.8%	6.6%	428		TP6	1100	1690	27.3%	11.3%
	2023	TP7	1100	2110	23.9%	8.1%	926		TP7	1100	2188	29.2%	12.8%
	2024	---		1623	21.7%	6.0%	418		---		1680	27.0%	10.5%
	2025	1 - 3x1 J	1262	2110	23.6%	7.3%	883		---		883	23.6%	7.3%
	2026	1 (698MW)	698	1898	22.6%	6.2%	646		1 (698MW)	698	646	22.6%	6.2%
2x1 Filler CCs added	2027	---							---				
	2028	1	631						1	631			
	2029	2	1262						2	1262			
	2030	1	631						1	631			
	2031	1	631						1	631			
	2032	2	1262						2	1262			
	2033	3	1893						3	1893			
	2034	1	631						1	631			
	2035	1	631						1	631			
	2036	3	1893						3	1893			
	2037	1	631						1	631			
	2038	1	631						1	631			
	2039	2	1262						2	1262			
	2040	1	631						1	631			
	2041	1	631						1	631			
	2042	2	1262						2	1262			
	2043	2	1262						2	1262			
	2044	2	1262						2	1262			
	2045	1	631						1	631			
	2046	2	1262						2	1262			
	2047	1	631						1	631			
	Total MWs		24,998							24,998			

As shown on the Table 1, the reserve margin from generating resources only is as low as 3.2% in 2019 with most of the reserve margin being provided by DSM. Please refer to

companion document labeled "Response to Staff Request for PEEC Resource Plan Using 15% Reserve Margin Criterion" for a full description of FPL's concerns.

The economic analysis is based on the midcourse Fuel Price forecast and assumes that SJRPP suspension is delayed until 2017. The results for this comparison show that the 15% RMC case would result in an increase in CPVRR of $99 MM (as shown in the table that follows).

Table 2
Results of Economic Comparison of 15% RMC thru 2024 vs. 20% RMC

	Capital	O&M and Cap rep	Other	Total Fixed costs	Fuel and Vom	Emissions	Total variable costs	Total
20% RM -	$8,518	$2,477	$3,583	$14,578	$91,538	$28,448	$119,987	$134,564
15% RM thru 2024 -	$8,132	$2,296	$3,583	$14,011	$92,076	$28,577	$120,653	$134,664
Difference	(386)	(181)	0	(567)	537	129	666	99

Please note that the cumulative CO2 emission by 2030 of the "15% RMC thru 2024" resource plan is approximately 8 million tons greater than the 20% RMC resource plan.

DOCKET NO. 110309-EI
RESPONSE TO STAFF REQUEST FOR PEEC RESOURCE PLAN
USING 15% RESERVE MARGIN CRITERION

Pursuant to Staff's request at the February 3, 2012 informal meeting, attached is a PEEC resource plan in which capacity is added to satisfy a 15% reserve margin criterion (RMC) rather than the approved 20% RMC. Please note that PEEC is added in 2020 although the 15% RMC would not call for its addition until 2021. This was done to avoid the substantial transmission costs that FPL would have to incur if sufficient capacity is not added in Southeast Florida by 2020. Also attached is an updated PEEC resource plan applying the 20% RMC, to reflect the same assumptions used under the 15% RMC.

In responding to Staff's request, FPL respectfully wishes to preserve its concerns over the use of a 15% RMC, as summarized below:

- Reserves would be insufficient to offset the effects of commonly occurring differences between planning assumptions about load and the actual operating conditions under which FPL must operate:
  - Actual electricity demand may be higher than forecasted
  - Actual generation capacity availability may be lower than projected
- Reserves would be insufficient to offset the significant reduction in generating capability that occurs as a result of scheduled maintenance outages during off-peak months:
  - Nuclear re-fueling outages, combined with
  - Multiple combined cycle inspections (with strict schedules), and
  - Other unplanned unit outages
- The portion of projected reserves met with generating units (as opposed to load control (LC)) would drop significantly – as low as 3.2% in 2019. This could lead to a situation similar to what Progress Energy Florida's predecessor, Florida Power Corporation, experienced in the late 1990s, when much higher-than-forecasted Summer load forced frequent implementation of LC. As the Commission noted in Order No. PSC-03-0175-FOF-EI, excessive reliance on LC can significantly discourage customer participation over time.
- In the event that the use of a 15% RMC led to insufficient generating reserves or other problems and the Commission decided that utilities should switch back to a 20% RMC, there could be a significant cost impact on customers. To illustrate this point, FPL has attached a PEEC resource plan in which capacity additions are made based on a 15% RMC through 2024 but then are made on the basis of a 20% RMC from 2025 until the end of the analysis period. The CPVRR for this resource plan is substantially higher than for the PEEC resource plan that uses a 20% RMC consistently throughout the analysis period.
- Delaying the in-service date of PEEC to 2020 as indicated under a 15% RMC could result in very substantial cost increases for the project beyond the standard assumption of a 3% escalation rate. FPL's preliminary estimate is that a delay of even one year could add $50-100 million more than the 3% standard escalation.

Among the factors that could substantially increase the project costs are the following:

- FPL is presently able to contract for major components and commodities on favorable terms due to the slowdown on plant construction that has accompanied the economic recession. If the economy turns around in the next few years, FPL could be faced with much higher prices.
- These price increases could be substantially exacerbated if the current slate of stricter EPA air-emission regulations results in coal plant retirements and a surge in orders for new combined cycle facilities.
- PEEC (and perhaps the Ft. Lauderdale Plant as well) could be subjected to a significantly increased air permitting burden. This is because EPA's comprehensive and potentially burdensome prevention of significant deterioration (PSD) review for new sources is triggered when a modification to an existing facility is projected to result in increased air emissions compared to historical emission levels, as measured over the prior five years. Presently, FPL can rely on historic data for the existing Port Everglades power plant that reflect emissions resulting from a significant level of power operations, but in a couple of years that will no longer be the case.

There are also a number of precautions that should be noted when attempting to compare the CPVRR for resource plans using 15% and 20% RMCs. When all of the resource plans being compared are based on relatively similar timing for resource additions, FPL is able to use certain simplifying assumptions that may not be appropriate when comparing the very different timing for resource additions that would occur under those disparate reserve margin criteria. For example:

- FPL's assumed 3% escalation rate for all capital costs and a 2.5% escalation rate for all O&M expenses are reasonable when comparing plans with capacity additions in similar years, but may not be appropriate for comparing capacity additions at very different points in time.
- FPL's resource plans typically rely on filler units after the horizon of the current Ten Year Site Plan. The assumptions about costs and operating characteristic for these filler units are necessarily generic. When these filler units are projected to be added at generally the same points in time and with the same frequency in resource plans that are being compared, the results are not very sensitive to those assumptions. However, using different RMCs would lead to very different timing for the filler units, such that the economic comparison could be significantly affected by the assumptions.
- Any analysis between very different resource plans arising from the application of different RMCs would also be more sensitive to changes in fuel prices because of continuing differences in the number and timing of new efficient units. For example, if natural gas prices were to be only $1.45/MMBtu higher than under the most recent forecast, the cost of the 15% RMC plan would be the same as that of the 20% RMC plan.

Please note: All three of the attached PEEC resource plans reflect (1) SJRPP power purchases being available to meet Summer 2016 peak demand, and (2) in-service dates for Turkey Point Units 6 and 7 of 2022 and 2023, respectively, regardless of when the RMCs would indicate that the nuclear units should come into service.

EXHIBIT NO. 41

DOCKET NO: 110309

WITNESS:

PARTY: FLORIDA INDUSTRIAL POWER USERS GROUP

DESCRIPTION: COMPOSITE EXHIBIT OF FPL SUMMER PURCHASED POWER CONTRACTS FROM 2006 TO 2011

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 41
PARTY Florida Industrial Power Users Group
DESCRIPTION FPL PAA's from Summer 2006 - Summer 2011
DATE 02/20/12

Table I.B.1: FPL's Firm Purchased Power Summer MW

I. Purchases from QF's:

(Cogeneration/ Small Power Production Facilities)	Start Date	End Date	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1. Broward South	04/01/91	08/01/09	50.6	50.6	50.6	0	0	0	0	0	0	0
Broward South	01/01/93	12/31/26	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Broward South	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward South	01/01/97	12/31/26	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
2. Broward North	04/01/92	12/31/10	45.0	45.0	45.0	45.0	45.0	0	0	0	0	0
Broward North	01/01/93	12/31/26	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Broward North	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward North	01/01/97	12/31/26	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
3. Cedar Bay Generating Co.	01/25/94	12/31/24	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0
4. Indiantown Cogen., LP	12/22/95	12/01/25	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0
5. Palm Beach SWA	04/01/92	03/31/10	47.5	47.5	47.5	47.5	0	0	0	0	0	0
QF Purchases Sub Total =			738	738	738	687	640	595	595	595	595	595

II. Purchases from Utilities:

	Start Date	End Date	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1. UPS from Southern Co.	07/20/88	05/31/10	931	931	931	931	0	0	0	0	0	0
2. UPS Replacement	06/01/10	12/31/15	0	0	0	0	930	930	930	930	930	930
3. SJRPP	04/02/82	10/31/15	381	381	381	381	381	381	381	381	381	381
Utility Purchases Sub Total =			1312	1312	1312	1312	1311	1311	1311	1311	1311	1311

III. Other Purchases:

	Start Date	End Date	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1. Oleander/Constellation 1	06/01/02	05/31/05	0	0	0	0	0	0	0	0	0	0
2. Progress Energy Ventures/Desoto	06/01/02	05/31/05	0	0	0	0	0	0	0	0	0	0
3. Reliant/Pasco/Shady Hills	02/28/02	02/28/07	474	0	0	0	0	0	0	0	0	0
4. Reliant/Indian River	01/01/06	12/31/09	130	354	576	250	0	0	0	0	0	0
4a. Reliant/Indian River (Addl. Trans.)	05/01/06	12/31/09	345	222	0	326	0	0	0	0	0	0
5. Progress Energy Ventures/Desoto (Put option)	06/01/05	05/31/07	140	0	0	0	0	0	0	0	0	0
6. Oleander/Southern Co (Put option)	06/01/05	05/31/07	156	0	0	0	0	0	0	0	0	0
6a. Oleander (Extension)	06/01/07	05/31/12	0	158	158	158	158	158	0	0	0	0
7. Williams	03/01/06	12/31/09	56	106	106	106	0	0	0	0	0	0
8. Progress Energy Ventures	04/01/06	03/31/09	55	105	105	0	0	0	0	0	0	0
Other Purchases Sub Total =			1357	945	945	840	158	158	0	0	0	0

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Summer Purchases Total MW =	3407	2995	2995	2639	2109	2064	1906	1906	1906	1906

FPL TYSP 2006

(1)

Table I.B.1: FPL's Firm Purchased Power Summer MW

Summary of FPL's Firm Capacity Purchases: Summer MW (for August of Year Shown)

I. Purchases from QF's:

Cogeneration Small Power Production Facilities	Start Date	End Date	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1. Broward South	04/01/91	08/01/09	50.6	50.6	0	0	0	0	0	0	0	0
2. Broward South	01/01/93	12/31/26	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
3. Broward South	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
4. Broward South	01/01/97	12/31/26	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
5. Broward North	04/01/92	12/31/10	45.0	45.0	45.0	45.0	0	0	0	0	0	0
6. Broward North	01/01/93	12/31/26	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
7. Broward North	01/01/95	12/31/26	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
8.Broward North	01/01/97	12/31/26	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
9. Cedar Bay Generating Co.	01/25/94	12/31/24	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0
10. Indiantown Cogen., LP	12/22/95	12/01/25	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0
11. Palm Beach SWA	04/01/92	03/31/10	47.5	47.5	47.5	0	0	0	0	0	0	0
	QF Purchases Sub Total:		**738**	**738**	**687**	**640**	**595**	**595**	**595**	**595**	**595**	**595**

II. Purchases from Utilities:

	Start Date	End Date	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1. UPS from Southern Co.	07/20/88	05/31/10	931	931	931	0	0	0	0	0	0	0
2. UPS Replacement	06/01/10	12/31/15	0	0	0	930	930	930	930	930	930	930
3. SJRPP	04/02/82	10/31/15	381	381	381	381	381	381	381	381	381	0
	Utility Purchases Sub Total:		**1312**	**1312**	**1312**	**1311**	**1311**	**1311**	**1311**	**1311**	**1311**	**930**

III. Other Purchases:

	Start Date	End Date	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1. Reliant/Indian River	01/01/06	12/31/09	354	576	250	0	0	0	0	0	0	0
2. Indian River (Additional)	05/01/06	12/31/09	222	0	0	0	0	0	0	0	0	0
3. Progress Energy Ventures/Desoto (Put option)	06/01/05	05/31/07	0	0	0	0	0	0	0	0	0	0
4. Oleander/Southern Co (Put option)	06/01/05	05/31/07	0	0	0	0	0	0	0	0	0	0
5. Oleander (Extension)	06/01/07	05/31/12	156	156	156	156	156	0	0	0	0	0
6. Williams	03/01/06	12/31/09	106	106	106	0	0	0	0	0	0	0
7. Progress Energy Ventures	04/01/06	03/31/09	105	105	0	0	0	0	0	0	0	0
8. Other Short-Term Purchases	May-Sept of Year Shown		0	0	0	0	167	800	200	0	0	0
	Other Purchases Sub Total		**943**	**943**	**512**	**156**	**323**	**800**	**200**	**0**	**0**	**0**

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Summer Firm Capacity Purchases Total MW:	**2993**	**2993**	**2511**	**2107**	**2229**	**2706**	**2106**	**1906**	**1906**	**1525**

FPL TYSP 2007

(2)

Table I.B.1: FPL's Firm Purchased Power Summer MW

Summary of FPL's Firm Capacity Purchases: Summer MW (for August of Year Shown)

I. Purchases from QF's:

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1. Broward South	4/1/1991	8/1/2009 *	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6	50.6
2. Broward South	1/1/1993	12/31/2026	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
3. Broward South	1/1/1995	12/31/2026	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
4. Broward South	1/1/1997	12/31/2026	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
5. Broward North	4/1/1992	12/31/2010 *	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
6. Broward North	1/1/1993	12/31/2026	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
7. Broward North	1/1/1995	12/31/2026	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
8.Broward North	1/1/1997	12/31/2026	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
9. Cedar Bay Generating Co.	1/25/1994	12/31/2024	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0	250.0
10. Indiantown Cogen., LP	12/22/1995	12/1/2025	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0	330.0
11. Palm Beach SWA	4/1/1992	3/31/2010 *	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5	47.5
		QF Purchases Sub Total:	**738**	**738**	**738**	**738**	**738**	**738**	**738**	**738**	**738**	**738**

II. Purchases from Utilities:

	Contract Start Date	Contract End Date	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1. UPS from Southern Co.	7/20/1988	5/31/2010	931	931	0	0	0	0	0	0	0	0
2. UPS Replacement	6/1/2010	12/31/2015	0	0	930	930	930	930	930	930	0	0
3. SJRPP	4/2/1982	10/31/2015	381	381	381	381	381	381	381	381	0	0
		Utility Purchases Sub Total:	**1312**	**1312**	**1311**	**1311**	**1311**	**1311**	**1311**	**1311**	**0**	**0**

III. Other Purchases:

	Contract Start Date	Contract End Date	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1. Reliant/Indian River	1/1/2006	12/31/2009	576	250	0	0	0	0	0	0	0	0
2. Oleander (Extension)	6/1/2007	5/31/2012	156	156	156	156	0	0	0	0	0	0
3. Williams	3/1/2006	12/31/2009	106	106	0	0	0	0	0	0	0	0
4. Progress Energy Ventures	4/1/2006	3/31/2009	105	0	0	0	0	0	0	0	0	0
5. Additional Renewable Firm Capacity	6/1/2011	varies	0	0	0	32	126	126	126	126	126	126
		Other Purchases Sub Total	**943**	**512**	**156**	**188**	**126**	**126**	**126**	**126**	**126**	**126**

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Summer Firm Capacity Purchases Total MW:	**2993**	**2562**	**2205**	**2237**	**2175**	**2175**	**2175**	**2175**	**864**	**864**

* For planning purpose, the contracts for these renewable capacity purchases are assumed to be extended. New contractual arrangement have not yet been developed.

FPL ~~10-K~~ TYSP 2008

(3)

Table I.B.1: FPL's Firm Purchased Power Summer MW

Summary of FPL's Firm Capacity Purchases: Summer MW (for August of Year Shown)

I. Purchases from QF's:

Cogeneration/Small Power Production Facilities	Contract Start Date	Contract End Date	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Broward South	04/01/91	08/01/09	0	0	0	0	0	0	0	0	0	0
Broward South	01/01/93	12/31/26	1	1	1	1	1	1	1	1	1	1
Broward South	01/01/95	12/31/26	2	2	2	2	2	2	2	2	2	2
Broward South	01/01/97	12/31/26	1	1	1	1	1	1	1	1	1	1
Broward North	04/01/92	12/31/10	45	45	0	0	0	0	0	0	0	0
Broward North	01/01/93	12/31/26	7	7	7	7	7	7	7	7	7	7
Broward North	01/01/95	12/31/26	2	2	2	2	2	2	2	2	2	2
Broward North	01/01/97	12/31/26	3	3	3	3	3	3	3	3	3	3
Cedar Bay Generating Co.	01/25/94	12/31/24	250	250	250	250	250	250	250	250	250	250
Indiantown Cogen., LP	12/22/95	12/01/25	330	330	330	330	330	330	330	330	330	330
Palm Beach SWA	04/01/92	03/31/10	50	0	0	0	0	0	0	0	0	0
Palm Beach SWA-extension	04/01/12	04/01/32	0	0	0	55	55	55	55	55	55	55
		QF Purchases Sub Total:	**690**	**640**	**595**	**650**	**650**	**650**	**650**	**650**	**650**	**650**

II. Purchases from Utilities:	Contract Start Date	Contract End Date	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UPS from Southern Co.	07/20/88	05/31/10	931	0	0	0	0	0	0	0	0	0
UPS Replacement	06/01/10	12/31/15	0	930	930	930	930	930	930	0	0	0
SJRPP	04/02/82	04/01/16	381	381	381	381	381	381	381	0	0	0
		Utility Purchases Sub Total:	**1,312**	**1,311**	**1,311**	**1,311**	**1,311**	**1,311**	**1,311**	**0**	**0**	**0**

Total of QF and Utility Purchases =	**2,002**	**1,951**	**1,906**	**1,961**	**1,961**	**1,961**	**1,961**	**650**	**650**	**650**

III. Other Purchases:	Contract Start Date	Contract End Date	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Reliant/Indian River	01/01/06	12/31/09	250	0	0	0	0	0	0	0	0	0
Oleander (Extension)	06/01/07	05/31/12	156	156	156	0	0	0	0	0	0	0
Williams	03/01/06	12/31/09	106	0	0	0	0	0	0	0	0	0
Progress Energy Ventures	04/01/06	03/31/09	0	0	0	0	0	0	0	0	0	0
New Renewable Firm Capacity	Assumed	Assumed	0	0	0	0	0	50	50	50	50	50
		Other Purchases Sub Total:	**512**	**156**	**156**	**0**	**0**	**50**	**50**	**50**	**50**	**50**

Total "Non-QF" Purchase Sub-Total =	**1,824**	**1,467**	**1,467**	**1,311**	**1,311**	**1,361**	**1,361**	**50**	**50**	**50**

	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Summer Firm Capacity Purchases Total MW:	**2,514**	**2,107**	**2,062**	**1,961**	**1,961**	**2,011**	**2,011**	**700**	**700**	**700**

FPL TYSP 2009

Table I.B.1: FPL's Firm Purchased Power Summer MW

Summary of FPL's Firm Capacity Purchases: Summer MW (for August of Year Shown)

I. Purchases from QF's:

Cogeneration/Small Power Production Facilities	Contract Start Date	Contract End Date	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Broward South	01/01/93	12/31/26	1	1	1	1	1	1	1	1	1	1
Broward South	01/01/95	12/31/26	2	2	2	2	2	2	2	2	2	2
Broward South	01/01/97	12/31/26	1	1	1	1	1	1	1	1	1	1
Broward North	04/01/92	12/31/10	45	0	0	0	0	0	0	0	0	0
Broward North	01/01/93	12/31/26	7	7	7	7	7	7	7	7	7	7
Broward North	01/01/95	12/31/26	2	2	2	2	2	2	2	2	2	2
Broward North	01/01/97	12/31/26	3	3	3	3	3	3	3	3	3	3
Cedar Bay Generating Co	01/25/94	12/31/24	250	250	250	250	250	250	250	250	250	250
Indiantown Cogen., LP	12/22/95	12/01/25	330	330	330	330	330	330	330	330	330	330
Palm Beach SWA	04/01/92	03/31/10	0	0	0	0	0	0	0	0	0	0
Palm Beach SWA-extension	04/01/12	04/01/32	0	0	55	55	55	55	55	55	55	55
QF Purchases Sub Total:			**640**	**595**	**650**	**650**	**650**	**650**	**650**	**650**	**650**	**650**

II. Purchases from Utilities:

	Contract Start Date	Contract End Date	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
UPS Replacement	06/01/10	12/31/15	930	930	930	930	930	930	0	0	0	0
SJRPP	04/02/82	4/1/2016 *	375	375	375	375	375	375	0	0	0	0
Utility Purchases Sub Total:			**1,305**	**1,305**	**1,305**	**1,305**	**1,305**	**1,305**	**0**	**0**	**0**	**0**

Total of QF and Utility Purchases =			**1,945**	**1,900**	**1,955**	**1,955**	**1,955**	**1,955**	**650**	**650**	**650**	**650**

III. Other Purchases:

	Contract Start Date	Contract End Date	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Oleander (Extension)	06/01/07	05/31/12	155	155	0	0	0	0	0	0	0	0
Other Purchases Sub Total:			**155**	**155**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Total "Non-QF" Purchase Sub-Total =			**1,460**	**1,460**	**1,305**	**1,305**	**1,305**	**1,305**	**0**	**0**	**0**	**0**

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Summer Firm Capacity Purchases Total MW:	**2,100**	**2,055**	**1,955**	**1,955**	**1,955**	**1,955**	**650**	**650**	**650**	**650**

* 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.

FPL ~~TYSP~~ TYSP 2010

Other Purchases:

FPL has another firm capacity purchase contract with a non-QF, non-utility supplier. This purchase contract runs through May 2012. Table I.B.1 and I.B.2 present the Summer and Winter MW, respectively, resulting from this contract.

Table I.B.1: FPL's Firm Purchased Power Summer MW

Summary of FPL's Firm Capacity Purchases: Summer MW (for August of Year Shown)

I. Purchases from QF's:

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Broward South	1/1/1993	12/31/2026	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Broward South	1/1/1995	12/31/2026	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward South	1/1/1997	12/31/2026	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Broward North	1/1/1993	12/31/2026	7	7	7	7	7	7	7	7	7	7
Broward North	1/1/1995	12/31/2026	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Broward North	1/1/1997	12/31/2026	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Cedar Bay Generating Co.	1/25/1994	12/31/2024	250	250	250	250	250	250	250	250	250	250
Indiantown Cogen., LP	12/22/1995	12/1/2025	330	330	330	330	330	330	330	330	330	330
Palm Beach SWA - extension	4/1/2012	4/1/2032	0	55	55	55	55	55	55	55	55	55
Palm Beach SWA - additional	4/1/2015	4/1/2032	0	0	0	0	90	90	90	90	90	90
		QF Purchases Sub Total:	595	650	650	650	740	740	740	740	740	740

II. Purchases from Utilities:	Contract Start Date	Contract End Date	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
UPS Replacement	6/1/2010	12/31/2015	931	931	931	931	931	0	0	0	0	0
SJRPP	4/2/1982	4/1/2016 *	375	375	375	375	375	0	0	0	0	0
		Utility Purchases Sub Total:	1,306	1,306	1,306	1,306	1,306	0	0	0	0	0

		Total of QF and Utility Purchases =	1,901	1,956	1,956	1,956	2,046	740	740	740	740	740

III. Other Purchases:	Contract Start Date	Contract End Date	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Oleander (Extension)	6/1/2007	5/31/2012	155	0	0	0	0	0	0	0	0	0
		Other Purchases Sub Total:	155	0	0	0	0	0	0	0	0	0

		Total "Non-QF" Purchase Sub-Total =	1,461	1,306	1,306	1,306	1,306	0	0	0	0	0

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Summer Firm Capacity Purchases Total MW:	2,056	1,956	1,956	1,956	2,046	740	740	740	740	740

* Contract End Date shown does not represent the actual contract end 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.

FPL TYSP 2011

(6)

EXHIBIT NO. 42

DOCKET NO: 110309

WITNESS:

PARTY: FLORIDA INDUSTRIAL POWER USERS GROUP

DESCRIPTION: TRANSCRIPT OF NEXTERA CALL WITH INVESTORS 3RD QUARTER 2011 (NOV. 4, 2011)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110309-EI EXHIBIT 42
PARTY Florida Industrial Power Users Group
DESCRIPTION Transcript of NextEra Investors Call - 11/04/11
DATE 02/20/12

NextEra Energy's CEO Discusses Q3 2011 Results - Earnings Call Transcript

Executives

Armando J. Olivera - Chief Executive Officer of Florida Power & Light Company and President of Florida Power & Light Company

Armando Pimentel - Chief Executive Officer and President

Lewis Hay - Chairman, Chief Executive Officer, Chairman of Executive Committee, Chairman of FPL Energy LLC and Chairman of Florida Power & Light Company

Rebecca Kujawa -

Analysts

Michael J. Lapides - Goldman Sachs Group Inc., Research Division

Dan Eggers - Crédit Suisse AG, Research Division

Jonathan P. Arnold - Deutsche Bank AG, Research Division

Paul Patterson - Glenrock Associates LLC

NextEra Energy (NEE) Q3 2011 Earnings Call November 4, 2011 9:00 AM ET

Operator

Good day, everyone, and welcome to this NextEra 2011 Third Quarter Earnings Conference Call. Today's call is being recorded. At this time for opening remarks, I would like to turn the call over to Rebecca Kujawa, Director of Investor Relations. Please go ahead, ma'am.

Rebecca Kujawa

Thank you, Bill. Good morning, everyone, and welcome to our Third Quarter 2011 Earnings Conference Call. Lew Hay, NextEra Energy's Chairman and Chief Executive Officer, will provide an overview of NextEra Energy's performance and recent accomplishments. Lew will be followed by Armando Pimentel, our former Chief Financial Officer and current President and Chief Executive Officer of NextEra Energy Resources LLC, which we will refer to with its subsidiaries as Energy Resources in this presentation. Armando will discuss the specifics of our financial results. Also joining us this morning are Moray Dewhurst, Vice Chairman and Chief Financial Officer of NextEra Energy; Jim Robo, President and Chief Operating Officer of NextEra Energy; and Armando Olivera, President and Chief Executive Officer of Florida Power & Light.

Following our prepared remarks, our senior management team will be available to take your questions. We will be making statements during this call that are forward-looking. These statements are based on our current expectations and assumptions that are subject to risks and uncertainties. Actual results could differ materially from our forward-looking statements.

If any of our key assumptions are incorrect or because of other factors discussed in today's earnings news release and the comments made during this conference call in the Risk Factors section of the accompanying presentation or in our latest reports and filings with the Securities and Exchange Commission, each of which can be found in the Investor Relations section of our website, www.nexteraenergy.com. We do not undertake any duty to update any forward-looking statements.

Please also note that today's presentation includes references to adjusted earnings, which is a non-GAAP financial measure. You should refer to the information contained in the slides accompanying this presentation for definitional information and reconciliations of the non-GAAP measure to the closest GAAP financial measure.

With that, I will turn the call over to Lew Hay. Lew?

Lewis Hay

Okay. Thank you, Rebecca, and good morning, everyone. I'm pleased to report that FPL had strong performance in the third quarter and while Energy Resources had a challenging quarter financially, the team executed well on creating tangible growth opportunities for the future. During the quarter, we continued to build a large backlog of future investment opportunities at both of our main businesses. Despite the decline in year-over-year financial results at Energy Resources, we continue to expect adjusted earnings per share for 2011 to be at the low end of our range of $4.35 to $4.65.

At Florida Power & Light Company, earnings per share were up approximately 12% over the prior year comparable quarter due to increased investment in the business. The Florida economy continues to show mixed signs with improvement in some indicators and little change in others. Florida's unemployment rate was 10.6% as of September 2011. This is 1.1 percentage points below last year's comparable month, and represents one of the largest year-over-year decreases in state unemployment rates in the United States. Florida's housing affordability has improved significantly, particularly in FPL's core markets. The Case-Shiller index, which tracks the prices of residential real estate has fallen 50% from its 2006 peak for the Miami-Dade, Broward, and Palm Beach County markets in South Florida. This makes Florida much more attractive to baby boomers as they enter retirement, and the state's existing home sales trend continue to show positive momentum.

Over the quarter, FPL averaged 24,000 more customers than we had in the year-ago comparable quarter, and our inactive meters have declined 4.4% since the year-ago period. Florida also continues to have a low tax burden, and we are encouraged by the efforts of Governor Scott's administration to make the state even more attractive to businesses.

At FPL, we continue to make good progress on our large investment program. Our nuclear uprate work at St. Lucie and Turkey Point continues. Last week, the Florida Public Service Commission approved FPL's nuclear cost recovery of $196 million through the capacity clause. This amount relates primarily to the cost of nuclear uprates, which by themselves are estimated to provide fuel savings to customers of $4.6 billion to $4.8 million over the lives of the plants. The commission determined that FPL's 2009 and 2010 uprate costs were prudently incurred, and FPL's actual and projected 2011 and 2012 costs are reasonable. Cost recovery for 2009 and 2010 was one of several issues that had been left unresolved by the prior commission. All of the prior unresolved issues have now been resolved. This week, the commission approved the remainder of the clauses for 2012 including fuel conservation and environmental clauses. This approval was reached through stipulation with all parties.

During the third quarter, the commission accepted FPL's request for a bid rule exemption regarding the proposed modernization of the Port Everglades facility. And we plan to file a petition for a determination of need for the facility later this month. If the new plant were to come online in 2016 as currently proposed, the Port Everglade's modernization would cost roughly $1.2 billion and is expected to provide net customer benefits of more than $400 million over the life of the plant.

In aggregate, FPL's completed and planned investments from 2001 to 2016 are expected to save customers an estimated $1.3 billion in projected fuel costs in 2016 relative to a 2001 baseline. These investments are delivering significant benefits to our customers through operating efficiencies, cleaner generation and reduced fuel costs. As a result, FPL customers are receiving cleaner, more reliable energy for a typical bill that is the lowest in Florida and more than 20% below the national average. Looking forward, we expect that these investments will allow us to keep our typical residential customer bill among the lowest in the state.

On the Energy Resources side of the business, we made great strides in growing our backlog of contracted renewable energy projects by entering into contracts for approximately 1,100 megawatts of new renewable energy capacity since our second quarter earnings call. In fact, since the beginning of the year, we have signed approximately 2,100

megawatts of contracts per new wind and solar projects. Now the numbers I just gave you are slightly higher than what are shown on the slides as last night, we entered into a new 100-megawatt wind contract, which is not included in the numbers you're seeing on the slides. This year is the most successful contracting the year in Energy Resources' history.

On the solar development front, we were pleased to announce that we have purchased a 50% ownership interest in the 550-megawatt Desert Sunlight photovoltaic solar project. We believe the addition of Desert Sunlight, which is expected to be one of the world's largest solar PV facilities considerably strengthens our backlog of solar projects. We expect this project will begin operation in 2013 and be at full capacity in 2015. Long-term power purchase agreements or PPAs for the project have already been approved by the California Public Utilities Commission.

I also want to take this opportunity to announce that we are pursuing the necessary approvals and permits to develop the McCoy solar facility, a 250-megawatt solar PV project located in the Mojave Desert near the Genesis and Desert Sunlight projects. This project, which is expected to reach full commercial operations by 2016 has a long-term contract with Southern California Edison, currently pending approval by the California Public Utilities Commission. This project further enhances the visibility of our longer-term backlog, and we look forward to providing you additional updates on McCoy in the future. McCoy and Desert Sunlight join our solar portfolio alongside our Genesis and Spain solar thermal projects and several other smaller PV projects, increasing our backlog of already contracted solar opportunities to 940 megawatts expected to come into service sometime between 2011 and 2016. We expect these projects will begin contributing meaningfully to cash flow and earnings in 2013.

On the wind development front, we had another active quarter and now have long-term PPAs for over 1,400 megawatts of new wind projects to be commissioned in 2011 and 2012, including the contract we signed last night. By 2012, Energy Resources expects to have approximately 10,000 megawatts of operating wind projects that provide on their own attractive upside opportunities. Looking beyond 2012, our current backlog of already contracted wind projects for 2013 and 2014 is 593 megawatts, which includes 469 megawatts of Canadian projects that we talked about last quarter, as well as an additional Canadian project of 124 megawatts that we had previously included in our 2012 backlog but now expect to come online in 2013.

As you know, last month we announced new management roles for Armando Pimentel and Moray Dewhurst. Since Armando was Chief Financial Officer during the third quarter, he will be presenting the company's quarterly financial results today. With that, I will turn the call over to Armando before returning for some closing comments. Armando?

Armando Pimentel

Thank you, Lew, and good morning, everyone. In the third quarter of 2011, NextEra Energy's GAAP net income was $407 million or $0.97 per share. NextEra Energy's 2011 third quarter adjusted earnings and adjusted EPS were $551 million and $1.31 per share, respectively. The difference between the GAAP and adjusted results is the exclusion of the mark in our non-qualifying hedge category, the exclusion of net other than temporary impairments on certain investments or OTTI, and exclusion of the impact of the pending sale of Energy Resources' ownership interest in a portfolio for natural gas-fired generation assets. The pending sale of these assets resulted in a onetime after-tax charge of approximately $0.23 per share, of which approximately $0.22 was at Energy Resources and $0.01 was at corporate and other due to the consolidated tax impact. These results are still subject to various closing adjustments.

Late last month, we announced the sale of our ownership interest in RIEC, a 550-megawatt gas-fired generation asset. The transaction is expected to result in a onetime after-tax charge of less than $0.01 per share subject to final closing adjustments, which the company expects to exclude from fourth quarter and fiscal 2011 adjusted earnings.

For the third quarter of 2011, Florida Power & Light reported net income of $347 million or $0.83 per share. FPL's contribution to earnings per share increased $0.09 relative to the prior year's comparable quarter driven almost entirely by the substantial investments we have made in the business, including the nuclear uprates in our Martin solar facility. As a reminder, for the term of the 2010 base rate agreement, FPL's earnings will largely be a function of its rate base and return on equity cap. We continue to expect that FPL will realize a retail regulatory ROE at or near 11% during each of 2011 and 2012 subject to the normal caveats we provide, including weather and operating conditions. For the terms of the base rate agreement, we expect that FPL will be able to amortize surplus depreciation to offset most of the variability in its normal operations, including modest differences from normal weather. Keep in mind that because the return on equity is calculated each month on a trailing 12-month basis, you should expect to see continued variability in FPL's quarterly earnings. But on an annual basis, we expect that retail regulatory return to be approximately 11% in 2011 and 2012.

During the quarter, we reversed $47 million of surplus depreciation to maintain a regulatory ROE of 11% in accordance with the settlement agreement. Year-to-date, we have recognized approximately $84 million of surplus depreciation

amortization. For the full year 2011, assuming normal weather and operating conditions, we now expect to amortize between $160 million and $180 million, down from our previous range of $180 million to $200 million provided on our second quarter earnings call. This revision is largely a result of modestly favorable weather experienced in the third quarter. At this point, we expect to utilize between $510 million and $530 million of surplus depreciation in 2012, leaving us at the end of 2012 with between $180 million and $220 million remaining of the original $895 million established in the last rate case. Although, of course, the exact amount will depend upon a variety of other factors affecting 2012 results including the actual 2012 weather.

Some of FPL's key customer metrics continue to show mixed results. The table in the upper left shows the change in retail kilowatt-hour sales in the quarter versus last year's comparable period. Overall, on a comparable basis, retail kilowatt-hour sales decreased by 2.4% with the average number of customers increasing 0.5%. Although the usage due to weather is down slightly from last year, cooling degree days were 6.9% higher than normal. Non-weather related or underlying usage and all other declined by 1.1%. We continue to analyze customer usage statistics to assess how much of the decline can be attributed to the economic environment, and how much is the result of mandated efficiency standards. At this point, we believe each is contributing roughly equally to the decline. There is, however, more work for us to do in this important area. As depicted in the graph in the upper right corner, during the third quarter of 2011, we had approximately 24,000 more customers than we did in the comparable period of 2010. This is the seventh quarter in a row where we have had customer increases compared to the prior year comparable period. The graph on the bottom left of the page shows inactive and low usage customers, which we believe are indicative of the level of empty homes in our service territory. While the percentage of low usage customers is flat to last year, inactive accounts declined approximately 4.4% since the end of last year's third quarter. We also want to highlight a recent update from the Office of Economic and Demographic Research regarding its population growth outlook for Florida. The chart at the bottom right corner provides annual projected population growth in Florida through 2021. The chart shows population growth rates increasing from 0.6% in 2012 to a peak of 1.5% in 2016 before tapering off slightly. We believe this is a positive indication of long-term potential customer growth.

Turning to Florida's economic environment. A number of the indicators we follow have improved since the depth of the recession, but progress has been less consistent than we would prefer to see. Both the retail sales index and the tourism taxable sales are up over the comparable period in 2010. The trailing 12-month average of existing home sales continues to trend positively, suggesting the market is moving through the inventory of available homes. We continue to believe Florida offers a unique proposition in terms of housing affordability, great weather, low taxes and a pro-business economy. All of which should continue to lead to ongoing customer growth for FPL in the future.

Let me now turn to Energy Resources, which reported third quarter 2011 GAAP earnings of $67 million or $0.16 per share. Adjusted earnings for the third quarter, which exclude the effect of non-qualifying hedges, net OTTI and the previously announced loss in the 4 natural gas-fired generation assets held for sale, were $204 million or $0.49 per share.

Energy Resources' third quarter adjusted EPS decreased $0.15 from last year's comparable quarter. New wind and solar investment contributions decreased $0.06 relative to last year as a result of lower CITC elections and lower state tax credits. Our estimate for full-year 2011 CITC elections is unchanged at roughly 275 megawatts compared with approximately 600 megawatts for 2010 projects. We continue to expect the full-year impact of lower CITC elections in 2011 relative to 2010 to be approximately $0.07. In aggregate, the existing asset portfolio contribution was roughly flat relative to the prior year comparable quarter.

Wind resource in the quarter was 88% relative to normal compared to 99% relative to normal in the prior year comparable quarter. The weaker wind resource was the primary driver of the negative $0.04 contribution from existing wind assets relative to the prior year comparable quarter. Year-to-date, the wind resource has been at 98% of normal. The Texas gas-fired generation assets contributed $0.02 primarily as a result of extreme hot weather in the [indiscernible] region.

In the nuclear asset portfolio, Seabrook's contribution was lower by $0.03 as a result of lower price hedges while Point Beach contributed $0.05 more as a result of decommissioning fund gains, favorable generation and the lack of an outage in this quarter.

Our shale gas well-drilling program contributed an additional $0.05 compared to the prior year comparable quarter. Customer supply in proprietary trading were down $0.13. This includes lower earnings at Gexa, a retail business, of approximately $0.05 attributable to the extreme hot weather in Texas during the month of August, and lower contributions from our proprietary trading business of roughly $0.07.

As you know, there are 3 main parts to our Texas portfolio: two large-combined cycle plants, approximately 1,700

megawatts of hedged wind assets and a position in the competitive retail market through our Gexa subsidiary. Normally, we expect warm weather to be good for the gas assets, challenging for Gexa and uncertain for the wind assets. If the wind blows hard it is good, as we have excess capacity to sell. If the wind is weak, it is bad as we have to buy power to cover our hedges. Through most of the quarter, which experienced much warmer than usual weather, our experience was consistent with prior years. However, in August, when the Houston area experienced 22 days of record heat, the negative impact on Gexa increased more rapidly than the favorable impact on the gas plants, which were largely hedged and at the same time, the wind resource was light during the super peak period. As a result, the negatives out-weighed the positives and at the portfolio level, we were down $0.05.

After undertaking a thorough review, it is clear that we could have reacted more quickly to certain signs we were seeing in the marketplace and reduced this impact. We have made changes as a result, and we believe we are now better positioned to avoid a recurrence of this issue. Ironically, however, the same events that caused us pain in the current quarter helped in other ways as forward curves moved up sharply and we were able to hedge out additional volumes for future years at higher prices than we could have done before the heatwave.

From a development standpoint, we had a terrific quarter in terms of adding to our backlog of already contracted solar and wind opportunities, as Lew mentioned, just a couple of minutes ago. Starting with solar, since the second quarter, we have added 2 new projects: Desert Sunlight and McCoy. With the addition of these 2 projects, we now expect to be toward the high-end of the plans we laid out for investors at our May 2010 investor conference to invest between $3 billion and $4 billion in solar opportunities during the 2010 to 2014 timeframe. Including all of the planned solar projects that are already under long-term contract, Energy Resources plans to invest between $2.1 billion and $2.3 billion in 2011 and 2012, and between $1.3 billion and $1.5 billion in 2013 and 2014. We now plan to add roughly 660 megawatts of solar to the portfolio between 2011 and 2014, and plan for an additional roughly 280 megawatts to be brought into service between 2015 and 2016.

Turning to our wind business. Energy Resources' backlog of tangible investment opportunities includes plans to spend between $2.1 billion and $2.3 billion in 2011 and 2012, and $1.3 billion and $1.5 billion in 2013 and 2014. Included in these expectations are the 1,310 megawatts of signed PPAs for projects we plan to put in service in either 2011 or 2012. Our 2013 to 2014 backlog includes 593 megawatts Canadian wind projects. These numbers do not include the CapEx associated with the 100-megawatt contract we signed last night, which we expect to complete in 2012.

Since this is our first opportunity to talk to you regarding our 2 new large solar projects, we want to provide a short overview of each project. At the end of September, we acquired 50% ownership in the 550-megawatt Desert Sunlight solar PV project. Construction began in September and interconnection is expected by the end of 2013. Full commercial operation is expected in 2015. We plan to elect CITCs for Desert Sunlight as the megawatts go into service at an estimated pace of 150 megawatts in 2013, 90 megawatts in 2014 and 35 megawatts in 2015. The project has 2 long-term PPAs on the full output of the facility, both of which have already been approved by the California Public Utilities Commission. Total invested capital for the project is estimated at $2.2 billion, 50% of which represents our subsidiaries' capital obligations, and we will account for the project under the equity method of accounting.

Also adding to our solar development backlog, our newest development project, McCoy, is expected to consist of 250 megawatts of solar PV technology. We plan to develop the project so that it reaches full commercial operations in 2016. Total capital costs are expected to be approximately $1 billion. In September, we signed a PPA with the Southern California Edison for the full output of the project, contingent on the approval of the California Public Utilities Commission. This contract will be submitted for the commission's approval by the end of the year, and we expect approval in 2012. The McCoy site has further expansion capabilities, which could at least double our current plans.

Let's now spend some time to discussing our earnings expectations for the rest of 2011, as well as the next several years. Turning first to the outlook for the balance of the year, we continue to expect to come in at the low end of our original guidance range of $4.35 to $4.65. This is disappointing. We see with the benefit of hindsight that to reach the upper end of our range would have required contributions from our customer supply and proprietary trading operations that were not likely given how actual market conditions unfolded. And we have not increased and we do not intend to increase our risk exposure from those operations in an effort to make up any shortfall relative to our expectations. Having said that, it is also true that we believe that we could have and should have been at the midpoint of our original range had we executed better. Mistakes in execution are not acceptable to us and we are committed to improving. We have already taken several actions in response to the events of this year.

As far as the earnings outlook beyond 2011, we want to give you a bit more detail regarding some factors that are expected to drive results in 2012 and 2013. First, as we have indicated before, we expect that the major driver of our earnings growth over the next several years will be the investments that we continue to make at FPL. We expect these investments to reward our customers with operating efficiencies, cleaner generation and reduced fuel costs, all while keeping our bills among the lowest in Florida.

At Energy Resources, we expect the adjusted earnings drivers over the next couple of years to primarily fall into 2 different buckets. First, there are significant headwind associated with above-market hedges rolling off, as well as the expiration of PTCs and some increased costs. The second bucket contains the significant earnings contributions attributable to bringing our contract backlog of new solar and wind energy investments to completion. Although both of Energy Resources' drivers will affect our adjusted earnings expectations in the next couple of years, we expect the headwinds to be a bit stronger in 2012 while the contributions from new investments are expected to be much stronger in 2013 and beyond.

Looking at 2012 specifically, as a result of our rate agreement, FPL's earnings will be primarily based on the amount of rate base investment it makes. We expect average total rate base in 2012 to be between $24.7 billion and $24.9 billion or approximately 14% higher than in 2011. The growth in total rate base is driven primarily by generation projects that have received prior PSC approval. The variability in FPL's earnings, assuming normal conditions, is expected to fall within a relatively tight range because we have the opportunity under the rate agreement to vary the amount of surplus depreciation amortization we use to achieve an approximate 11% retail regulatory ROE.

At Energy Resources, significant headwinds primarily associated with above-market hedge roll-offs of roughly $60 million after-tax are expected to affect adjusted earnings from 2011 to 2012. Our expectations for 2012 also include PTC roll-offs and lower state tax benefits, which combined a roughly $75 million after-tax reduction to earnings compared to 2011.

In terms of offsetting positive drivers, fewer days of nuclear outages are expected to contribute approximately $60 million after-tax and new asset additions are expected to contribute roughly $70 million after-tax including higher CITC elections, which are expected to contribute approximately $20 million after-tax, all relative to 2011. We currently estimate that we will elect CITCs at approximately 450 megawatts of wind projects compared to our estimate of 275 megawatts in 2011. There are obviously other puts and takes, but these are the primary drivers we see in 2012. After accounting for all of these effects, we expect adjusted earnings per share for 2012 will be in the range of $4.35 to $4.65.

Turning to 2013, we expect FPL to have customer rates in place that will provide an appropriate cash return on the significant capital investments we continue to make. These investments in 2013 are expected to include the completion of our Cape Canaveral combined cycle project, completion of FPL's nuclear uprates at Turkey Point and St. Lucie, and the continuing construction of the Riviera Beach next-generation clean energy center.

Our customers should greatly benefit from the fuel efficiency and environmental improvements associated with these investments over their useful lives. We expect total average rate base in 2013 to be between $26.4 billion and $26.8 billion or approximately 7% higher than in 2012. In addition, the approximately 320-mile rate-regulated transmission line that our Lone Star Transmission subsidiary is building, is expected to be completed in 2013. Our expectations are that when completed, Lone Star will have approximately $800 million of utility rate base in Texas.

On this slide, we are providing you with a walk of Energy Resources' expected adjusted earnings from 2011 to 2013. The renewable energy investments we plan to commission in 2011, 2012 and 2013 provide significant earnings contributions at Energy Resources through 2013. As you can see from this chart, we expect that the growth in our solar business will contribute between $90 million and $115 million in earnings relative to 2011, with virtually all of these increased earnings coming in 2013. Driving this expected growth are the contributions from our Spain solar projects, the first half of our Genesis solar project and a portion of our Desert Sunlight project.

We expect our new wind additions, primarily the contributions from the 2011 and 2012 project additions, to contribute between $60 million and $75 million during this period. Recall that there will be no CITC earnings for new wind projects in 2013, and that we expect to have roughly $35 million of CITC earnings in 2011 so the $60 million to $75 million range you see here is net of that CITC amount. We also expect price escalators built into a number of our long-term PPAs on our existing assets to contribute approximately $55 million during this period. The tangible growth at Energy Resources that we see through 2013 resulting from these new long-term contract and investments will be partially offset by the expiration of production tax credits, higher costs and unfavorable market pricing from our merchant assets.

While we do not have the exposure to merchant prices that many of our peers have, as a result of our largely contracted portfolio, we do have some exposure that shows up here from higher price hedges that will be rolling off during this time period. In fact, from 2011 to 2013, the reduction in Energy Resources' gross margin associated with above-market hedge roll-offs is expected to be approximately $85 million. As I just pointed out a second ago, roughly $60 million of this $85 million occurs from 2011 to 2012, so there's much less headwind associated with above-market hedges rolling off in 2013. Overall, we are currently 92% hedged in 2013 in terms of equivalent gross margin for our existing assets. For your reference, we have included in the appendix to this presentation the 2012 and 2013 hedging slides.

On the 2012 slide, you will notice the reduction in our expectations for the proprietary trading business. As part of an effort to align the cost structure of our gas trading operations with our reduced expectations for the business going forward, in the first quarter 2012 we will be relocating the gas trading and scheduling operations from Houston back to our corporate headquarters in Florida. In addition to reducing costs, bringing these operations back to Florida will allow us to better integrate the teams and improve leverage across the overall business.

On the 2013 slide, note that the new investment line includes both the contributions from the 2012 additions and the 2013 additions that we already have under contract. Please also note that with the pending sale of the 5 natural gas plants, we have tried to simplify and clarify the hedging charts to align better with the primary drivers of commodity price exposure in the different parts of the portfolio. By executing on our tangible backlog of investment opportunities, we expect to be able to grow earnings at Energy Resources even in the face of the headwinds I have just described. The combination of FPL, Lone Star Transmission and Energy Resources' investments offset by the headwinds I've described for the period are expected to result in significant adjusted earnings growth in 2013 over 2012.

Turning to 2014. In addition to a full year of contributions from the 2013 Energy Resources investments I just discussed, 2014 is also expected to add the second half of our Genesis solar project, 90 megawatts of Desert Sunlight and contributions from our Canadian wind projects that we plan to put in service between 2013 and 2014. Also, the headwinds from the roll-off of above-market hedges are not present in 2014. In fact, we currently expect gross margin on our merchant assets to be up in 2014 compared to 2013. Our 2014 merchant assets gross margin is roughly 70% hedged. In addition to the contributions from Energy Resources, rate base growth at FPL is expected to be approximately 3% from 2013 to 2014. All of the investments we are making at FPL and Energy Resources are expected to meaningfully increase cash flow from operations beginning in 2013. We expect that in 2013, cash flow from operations will cover capital expenditures. And in 2014, we currently expect cash flow from operations to exceed capital expenditures and expected dividends, assuming we do not add any additional projects to our current backlog.

In 2014, we expect consolidated cash flow from operations to be approximately $5.5 billion, which would be an increase of over 35% from our consolidated expectations in 2011. Based on our current cash flow expectations and absent further new investment opportunities, we would therefore expect to be in a position to return some capital to shareholders in 2013 and 2014. We continue to believe that maintaining our strong balance sheet and capital structure is an important differentiator for us, and has added to our competitiveness at critical times over the past decade. As such, we plan to maintain this balance sheet strength and our credit metrics as we go forward. Of course, we will always look for additional opportunities to deploy capital into new investments that we would expect to produce additional value for our shareholders while maintaining our capital structure.

On a net basis from now through 2014, we expect that outstanding shares may decline slightly relative to 2011. Today, we have given you additional information to help you better understand the adjusted earnings drivers for our business over the next couple of years. In addition to the specific guidance ranges for 2011 and 2012, we have provided additional color on the expected adjusted earnings drivers for 2013 and 2014.

In summary, we continue to believe that our adjusted earnings per share will grow at an average of 5% to 7% per year through 2014 relative to a 2011 base of $4.35 to $4.65, which equates to a range of $5.05 to $5.65 in 2014 subject to all the usual caveats we provide, including normal weather and operating conditions.

Before turning the call back to Lew, I wanted to take a quick moment to thank all of you, the analysts and investors, with whom I have worked over the last few years while I was the CFO of NextEra Energy. I look forward to continuing to interact with you in my new role at Energy Resources.

With that, let me now turn the call back over to Lew for some closing remarks.

Lewis Hay

Thanks, Armando. To close, let me just say that while we're not satisfied with the financial results this year at Energy Resources, we remain very positive about our outlook for the future. During my tenure as CEO, we have never before enjoyed a position in which so much of our future is represented by projects in our current backlog with high visibility and a clear path to completion. Altogether, our backlogs total almost $20 billion of capital investments across FPL, Energy Resources and Lone Star. Our growth for the next few years will be driven primarily by growth at Florida Power & Light, where our investments are fundamentally substituting capital for fuel and thereby making our delivery system more efficient. We already have what we believe is the best customer value proposition in Florida, combining the lowest bills in the state with top-quartile reliability, award-winning customer service and the risk mitigation that comes for our clean emissions profile and we're working hard to improve this. Our investments will mean real benefits for our customers in the form of lower bill -- lower fuel bills, which means total bills will need to rise very little even in nominal

terms and will likely continue to decline in real terms. As a result, we believe we should be able to earn a fair rate of return on the capital we are investing the business. This will lead to strong growth and contributions to earnings per share.

While the outlook for FPL is for fairly consistent growth, at Energy Resources, we first need to fight through the effects of some headwinds, most notably the impact of the decline in power and gas prices that has occurred over the last few years and which will somewhat mask the positive impact of the strong growth in new business through the end of next year. Nevertheless, Energy Resources has a bright and highly visible future path to growth through 2014 in the form of continued investment in new wind and solar projects. And at the same time, the mix of Energy Resources' businesses will continue to shift toward long-term contracted projects, thus improving the overall risk profile. Combining all of these, we continue to believe we can grow earnings per share at 5% to 7% per year through 2014 relative to a 2011 base of $4.35 to $4.65, which equates to a range of $5.05 to $5.65. We can -- we believe we can do so even after conservatively assuming no U.S. wind additions in 2013 or 2014. Yet we firmly believe we will find additional growth opportunities in the years ahead beyond those we have currently identified, and we will be working very hard to do so.

Notwithstanding the short-term uncertainties related to renewable energy policy, we believe that U.S. Renewable Energy policies will continue to be supportive of future investments over the long haul. We understand that we have much work to do to execute effectively against our extensive backlog of projects, and that is our immediate focus. But we will continue to seek ways to deploy new capital at attractive returns to build long-term value for our shareholders.

With that, I'm going to turn the call over to the conference moderator for questions. Thank you.

Question-and-Answer Session

Operator

[Operator Instructions] And we'll take our first question from Daniel Eggers, Crédit Suisse.

Dan Eggers - Crédit Suisse AG, Research Division

Lew, maybe you kind of hit on at the end but could you talk a little more about where you guys see renewable tax policy headed and then as it relates to the backlog, how much of the solar and wind you guys have in place that's dependent upon an extension of U.S. tax policy beyond the 2012 expiration as currently laid out in law?

Lewis Hay

Okay, Dan. First of all, I'll answer the second part of your question. None of the forecast that we gave you is dependent on any future extensions or changes in tax policy. So I think that was in pretty darn good shape. As far as what we see happening right now, we don't have -- we don't even have a murky crystal ball or a clear crystal ball on this. You all read the papers and between the U.S. deficit situation and some of the partisan politics, it's hard to say where things are going to go in the short term. Although I will note, a bill has just been introduced in Congress to extend wind PTCs to 2016, which is the same period of time where the solar PTCs expire. But historically, renewables have received strong bi-partisan support and I think it will -- renewables are going to be an important part of our energy mix going forward. And the other thing that I will add is, as I think you all have seen now, over the years, the cost for renewables, wind and solar, especially, continues to come down. And so they are becoming more and more competitive. So it's proof that these incentives have worked in terms of making renewables much more cost effective. So it's hard to predict what's going to happen very short term. I'm pleased that we're in a position that we can give guidance out through 2014 that doesn't rely on any changes to U.S. energy policy. But again, as I said at the end of my prepared remarks, I see over the long haul that we will have continued support for renewables and renewables are going to be a viable business.

Dan Eggers - Crédit Suisse AG, Research Division

When I look at the -- what you guys laid out today that you're going to implement buybacks in '13 and '14 kind of to fill in some of the excess cash presumably because the reinvestment pipeline is slowing a bit at that point in time, should we think of that as a placeholder given the current environment, or is it just the opportunities that as you guys look out is getting a little less compelling for some of the resources or reinvestment than what you've seen in past years?

Lewis Hay

Well, let me -- first of all, we're providing you total clarity on what we've seen in terms of contracted projects, projects

that we have contracted as of November 2011. It's the biggest backlog we've ever had in our history, and it's also a backlog that goes for more years than we've really ever had in history. So I wouldn't read anything more into it other than it's a very big, very positive backlog. And so the comments on our capital position and therefore share count, are really a function of those known contracted projects that we've just told you about. As I think Armando said and I said, we're going to continue to look for other opportunities and if you look at our track record of finding other opportunities, I think it's a pretty darn good bet that we will have other opportunities. But for a financial forecast, you have to make some kind of assumption at this point. We never like to assume things that we don't know about, and so I think that provides sort of a baseline kind of forecast. For sure, we're not going to go and invest in things that are dilutive or highly dilutive. So if we find new investments, they've got to have a better economic proposition than what you're seeing in the numbers we've just laid out. So I can assure you, my request to the team and the things that they're going to be incentivized on are to execute well on the projects that we've talked about, but also to keep the nose to the grindstone, if you will, in coming up with attractive investment opportunities.

Dan Eggers - Crédit Suisse AG, Research Division

Okay, and one last quick question. Does the free cash flow positive position assume any sort of tax equity to monetize some of the PTC balance, or is that natural cash from operations to get to the free cash position?

Armando Pimentel

It's very small tax equity in our financial forecast going forward, but it's not to say there's not none. We have used the end tax equity -- and this by the way is your last question because we've got to get to others. We've used tax equity over the last 24 months really on not only new projects, but existing projects to do a couple of things. The cash is nice, but the real primary piece has been to reduce the amount of production tax credits that would otherwise have been capitalized on our balance sheet. And we've done a great job of that and I believe in one of our future earnings calls, we're gonna kind of lay out exactly what we've done so investors can see how good we've done on that front.

Operator

And we'll take our next question from Michael Lapides with Goldman Sachs.

Michael J. Lapides - Goldman Sachs Group Inc., Research Division

Real quick. And I apologize because when you ran through it in your prepared remarks, it's a little bit hard to catch up with. Could you run through all of the solar projects you're doing over the next 3 to 4 years, 3 to 5 years and the timeline for megawatts coming into service, please?

Armando J. Olivera

Sure. The first project would be our Spain solar project. It's really 2 projects, each slightly less than 50 megawatts. The first part of that will come in, in the first half of 2013. And the second half will come in, in the latter parts of 2013. The second project that we mentioned is our Genesis solar project. It's a 250-megawatt thermal project out in California, 125 megawatts of that project will come in mid- to last-half of 2013 and the other 125 megawatts will come in around mid-2014. The third project is Desert Sunlight. That's an equity investment by us, 50%. That megawatt is currently -- those megawatts are currently scheduled to come in roughly 150 megawatts later in 2013, roughly 90 megawatts, I'd say, probably throughout 2014 and roughly 30 megawatts, I'd say, probably the first half of 2015. And then we've got McCoy, which we talked about today. McCoy is a 250-megawatt, also a PV Project like Desert Sunlight. That's actually -- there is some CapEx from McCoy in our forecast period, it's not significant and by our forecast period, I mean through 2014. But we don't expect any earnings associated with McCoy until 2015. Most of that -- most of those earnings though will probably be in 2016.

Michael J. Lapides - Goldman Sachs Group Inc., Research Division

Okay. And on the wind side, the CapEx you're showing for wind post-2012 largely driven by the Canadian development, I assume?

Armando Pimentel

It is all driven by our Canadian projects.

Michael J. Lapides - Goldman Sachs Group Inc., Research Division

Got it. Last item, if I just take the very low end of your 2011 guidance, so $4.35. Take the mid-point of your 2012 guidance, let's say, $4.50-ish. To get to the midpoint of your 2014, that's implying almost a 10% year-over-year growth in '13 and '14 from '12. Is that -- can I ask a question what in terms of pricing assumptions granted that you don't have that much exposure to the forward curves? But that's a pretty big uptick, and just trying to put my arms around it a little bit.

Armando Pimentel

Well, it's the things we laid out. I'm not going to remember the slide. The slide's probably in the upper teens but it's 2012 -- I'm sorry, 2013 drivers and the 2013 drivers really come in 3 pieces. First, you've got Florida Power & Light Company. which is making significant investments to rate base in 2011, 2012. And we'll have new rates in 2013 since our rate agreement ends at the end of 2012. That's the first big driver. The second big driver's $800 million of rate base in our Texas utility our transmission utility, Lone Star. And the next big driver which we laid out really on 19, and we laid it out from '11 to '13 but it's really the Energy Resources solar projects, which I talked about in my prepared comments. So you've got first half of Genesis, you've got Spain Solar, you've got Desert Sunlight and you've got a whole bunch of wind that you're putting in, primarily in '12 as opposed to '11. And those wind projects that are going in, in '12 will have a full year of operations in 2013. When you put all that together, that accounts for the big driver from '12 to '13. The other piece that we shouldn't forget I also mentioned in my prepared remarks, we've got a -- at Energy Resources, a significant amount of headwinds from the roll-off of above-market hedges from 2011 to 2012. So if you look at Slide 19, and you look at the merchant pricing down of $85 million from '11 to '13, $60 of that is actually from '11 to '12. And so you have much less headwinds in 2013. Now I'm going just make this comment because you also had Merchant in there. On the Merchant side of the business, our Merchant gross margin at this point is not fully locked up. But even in 2014, as I mentioned in my prepared remarks, we've got 70% of that margin in 2014 locked up. And in 2013, if you look at the new slide that's in the appendix, we've got 86% of that gross margin currently hedged. So we feel fairly comfortable that there will be a big up in adjusted earnings per share assuming we can execute on our plans. But if we execute on our plans, there should be a pretty big up in adjusted EPS from 2012 to 2013.

Michael J. Lapides - Goldman Sachs Group Inc., Research Division

Got it. One last item, a little bit of a modeling one. O&M trajectory at Energy Resources, it actually -- if I just look at the financials on the back of your tables, it actually was down a little bit year-over-year from third quarter last year to third quarter this year. Just curious a, the driver of that especially since you've added some new assets and b, kind of the trajectory going forward.

Armando Pimentel

Trajectory going forward, I don't think is going to be -- well, we've got a whole bunch of new projects that are going in, right. So all of those new projects going in are going to have their own O&M. And let me just -- I'm going to get to the rest of your question in a second. But if you go to Slide 19, for those of you that are out there trying to model all this, the green bars that you see there, those ups that you see on those projects, those green bars are already net of the O&M for those new projects. So the O&M increase that you see on that slide which I think is part of your question, Michael, is really for existing projects, not new projects. As far as our expectations just on a general basis going forward, I wouldn't expect it to be much more than inflation and maybe it's slightly even less than inflation on a go-forward basis.

Operator

And our next question comes from Paul Patterson, Glenrock Associates.

Paul Patterson - Glenrock Associates LLC

The CITC benefit in 2011, 2012 and 2013, I wasn't completely clear as to how we should be thinking about the level of CITC contribution to your growth rate.

Armando Pimentel

Let me give you a little shortcut. From 2010 to 2011, this is on adjusted earnings. From '10 to '11, you're down about $28 million, that's the $0.07 per share that I talked about in my prepared remarks. From 2011 to 2012, you're going to be roughly up $18 million and that's all most -- actually all associated with wind. And from 2012 to 2013, you will be up

roughly $12 million. That $12 million is a net number though, because you will not have any CITC for wind in 2013, so you'll be down on the wind side probably around $62 million, that's the gross number, and you'll be up on solar roughly $74 million.

Paul Patterson - Glenrock Associates LLC

Okay, great. And what's the total number of CITC in that year?

Armando Pimentel

CITC in 2013 is probably somewhere around 275 megawatts or so, all of solar.

Paul Patterson - Glenrock Associates LLC

And that's equals what kind of dollar amount?

Armando Pimentel

Roughly $70 million to $74 million, after tax.

Paul Patterson - Glenrock Associates LLC

Okay, great. Excellent. And then when we're looking at the slides on the hedging, the Merchant wind in New England seem to be moving in different directions year-over-year. The megawatt hours seem the same but in some cases, it seems like there's a big increase in what we're seeing.

Armando Pimentel

Yes, Paul, that's true. You should -- you and the rest of folks should understand. We try to hedge really on what I call corporate-wide basis at Energy Resources. And that means a times, we may move some hedges from some of our wind assets to some of our power assets and back and forth. And we're not really doing that to confuse you, although it might have confused folks. I think the better way to look at it would be actually to look at the total amounts that you see, especially when you're looking at Texas wind and Northeast. What's happened to those total numbers.

Operator

And we'll take our next question from Jonathan Arnold, Deutsche Bank.

Jonathan P. Arnold - Deutsche Bank AG, Research Division

Could I just follow-up on Paul's question, and thank you for that disclosure on the '13 CITC. How should we think about that number in '14, I mean with respect to your guidance and growth rate?

Armando Pimentel

The '14 CITC number, that's actually a number I don't have in front of me. Hold on just -- do you have another question actually, Paul? I'm sorry, do you have another question, Jonathan? I don't have that number in front of me.

Jonathan P. Arnold - Deutsche Bank AG, Research Division

Should we try that first? The other one was on the gas plants that you recently sold where you got the operating contracts back, I think, for some varying numbers of years. Could you quantify what the benefit of those ongoing operating contracts is likely to be to earnings and where we'd be looking for that? And is it something we'd notice as in when they roll down?

Armando Pimentel

Well, we'll go back to your first question, Jonathan, because we're not going to answer that question.

Jonathan P. Arnold - Deutsche Bank AG, Research Division

You're not going to answer either half of that question?

Armando Pimentel

Yes. That's -- I think that's a competitive question, and I don't think it's really appropriate for us to answer. But on your first question where you were wondering how many megawatts of CITC we would have in 2014, I'd say roughly between 200 and 215 megawatts and it's all solar at that point.

Jonathan P. Arnold - Deutsche Bank AG, Research Division

So it will be a little -- there'll be a slight headwind versus '13 but not significant?

Armando Pimentel

Not significant.

Jonathan P. Arnold - Deutsche Bank AG, Research Division

Okay. And on my other question, I mean is this a number we'll notice when those contracts end rather than asking for a specific? Is it a driver we should even think about?

Armando Pimentel

Jonathan, here's what I would say about it, which is, obviously, it's accretive right now to earnings but it's small. And we're not doing it for free, but that O&M service is a competitive business and so it's accretive, it's small and not going to be a giant driver one way or another.

Operator

At this time, I would like to close the conference out. We thank you for your participation.