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

FPL

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May 1, 2013

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VIA HAND DELIVERY

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

RE: Staff's First Data Request; Florida Power & Light Company's 2013 Ten Year Power Plant Site Plan

Dear Ms. Cole:

Please find enclosed one hard copy and one compact disc, per Staff's request, containing Florida Power & Light Company's responses to Staff's First Data Request, Question Nos. 2-42 and 44-65. FPL's response to Question No. 43 is confidential and is being filed separately along with a Notice of Intent to Request Confidential Classification.

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

Sincerely,

Lynne A. Adams
for
Jessica A. Cano

COM ____
AFD ____
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Enclosure
cc: Charles Murphy

DOCUMENT NUMBER-DATE
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FPSC-COMMISSION CLERK

Q.

Please provide all data requested in the attached forms labeled 'Appendix A,' **only** as an electronic copy in Microsoft Excel (.xls or .xlsx). Please do **not** provide a hardcopy of this response. If any of the requested data is already included in the Company's Ten-Year Site Plan, state so on the appropriate form.

A.

See Attachment No. 1.

Q.

[Investor-owned Utilities Only] Please provide, on a system-wide basis, the hourly system load for the period January 1, 2012, through December 31, 2012. Please provide this **<u>only</u>** as an electronic copy in Microsoft Excel (.xls or .xlsx). Please do **<u>not</u>** provide a hardcopy of this response.

A.

Please see Attachment No. 1.

Q.

Please discuss any recent trends in customer growth, by customer type (residential, commercial, industrial) and as a whole. Please explain the nature or reason for these trends, and identify what types of customers are most effected by these trends.

A.

Customer growth has been gradually recovering following the absolute decline in customers during the Great Recession. The average number of customers for the year 2012 increased over 2011 for the third consecutive year following the decline in customers experienced in 2009. Although relatively low by historical standards, the 2012 increase in customers was the strongest since 2007.

Customer growth in the residential sector in 2012 was up modestly from 2011 with much of the increase in that sector coming in the second half of the year. Commercial customer growth was steady during 2012 remaining in a fairly narrow range, similar to 2011, but at a slightly lower level. After experiencing five years of consecutive declines, there was a net increase in the number of industrial customers in 2012. Temporary and construction accounts represent a large share of FPL's industrial customers. The increase in the number of industrial customers is therefore indicative of the improvement in the housing market.

Q.

Please provide the timing and temperature associated with the company's historic monthly peak demand for the period 2010 through 2012. Please also provide the day of the month, hour of the day, and system-average temperature at the time of each monthly peak. Please complete the table below and provide an electronic copy (in Excel).

Historic Peak Demand Timing & Temperature

Year	Month	Peak Demand	Day of Month	Hour of Day	System-Average Temperature
		(MW)	-	-	(Degrees F)
2012	1				
	2				
	3				
	4				
	5				
	6				
	7				
	8				
	9				
	10				
	11				
	12				

A.
See Attachment No. 1

Historic Peak Demand Timing & Temperature

Year	Month	Peak Demand (MW)	Date	Hour	Temperature (F)
2010	1	24,346	1/11/2010	7-8 AM	35
	2	16,488	2/17/2010	7-8 AM	46
	3	17,748	3/5/2010	7-8 AM	46
	4	15,480	4/25/2010	4-5 PM	84
	5	19,217	5/7/2010	4-5 PM	86
	6	21,901	6/16/2010	3-4 PM	93
	7	21,633	7/28/2010	3-4 PM	92
	8	22,256	8/19/2010	3-4 PM	92
	9	20,738	9/13/2010	4-5 PM	89
	10	19,099	10/27/2010	4-5 PM	84
	11	17,127	10/29/2010	3-4 PM	86
	12	21,126	12/15/2010	7-8 AM	40
2011	1	18,552	12/29/2010	7-8 AM	44
	2	14,483	2/22/2011	7-8 PM	74
	3	16,088	3/27/2011	5-6 PM	85
	4	19,615	4/27/2011	4-5 PM	85
	5	19,747	5/11/2011	4-5 PM	87
	6	21,222	6/23/2011	3-4 PM	91
	7	21,377	7/25/2011	3-4 PM	92
	8	21,619	8/5/2011	4-5 PM	91
	9	20,035	9/11/2011	4-5 PM	90
	10	18,757	10/12/2011	4-5 PM	86
	11	16,831	11/16/2011	2-3 PM	83
	12	14,575	12/23/2011	6-7 PM	75
2012	1	17,934	1/4/2012	7-8 AM	40
	2	16,228	2/24/2012	3-4 PM	84
	3	16,310	3/22/2012	4-5 PM	80
	4	18,108	4/4/2012	5-6 PM	83
	5	19,981	5/30/2012	4-5 PM	88
	6	20,351	6/4/2012	4-5 PM	90
	7	21,343	7/26/2012	4-5 PM	90
	8	21,440	8/9/2012	4-5 PM	88
	9	19,711	9/1/2012	4-5 PM	88
	10	19,337	10/5/2012	3-4 PM	88
	11	14,282	11/12/2012	6-7 PM	75
	12	16,025	12/10/2012	6-7 PM	77

Q.

Please identify the weather station(s) used for calculation of the system-wide temperature for the utility's service territory. If more than one weather station is utilized, please describe how a system-wide average is calculated.

A.

System-wide temperatures are calculated using hourly temperatures across FPL's service territory. Miami, Ft. Myers, Daytona Beach, and West Palm Beach are the locations from which temperatures are obtained. In developing the system-wide hourly temperatures, these regional temperatures are weighted by regional retail energy sales.

Q.

Please provide the average cost of a residential customer bill, based upon a monthly usage of 1000 kilowatt-hours, for the period 2003 through 2012. Please complete the table below and provide an electronic copy (in Excel).

Typical Customer Bill Information

Year		Residential Bill ($/1000-kWh)
Actual	2003	
	2004	
	2005	
	2006	
	2007	
	2008	
	2009	
	2010	
	2011	
	2012	

A.

See Attachment No. 1.

	Year	Residential Bill* ($/1000 kWh-mo.)
Actual	2003	82.55
	2004	86.44
	2005	91.71
	2006	108.61
	2007	103.45
	2008	106.03
	2009	108.86
	2010	94.84
	2011	96.29
	2012	94.75

* Residential bill amount includes gross tax receipts, and excludes both Franchise Fees and Municipal Tax.

Q.

Please discuss whether the company included plug-in electric vehicle loads in its demand and energy forecasts for the 2013 Ten-Year Site Plan.

A.

Yes, the contribution of plug-in electric vehicles to FPL's peak demands and energy forecasts are included in the 2013 Ten-Year Site Plan. Please see FPL's response to Staff's First Data Request No. 10 for the GWH and MW contribution of plug-in vehicles to annual NEL and summer and winter coincident peak demands for the 2012 through 2022 time period. A description of the methodology used to develop these forecasts can be found in FPL's response to Staff's First Data Request No. 9.

Q.

Please discuss the methodology (or, if applicable, the source(s) of the data) used to estimate the number of vehicles operating in the company's service territory and the methodology used to estimate the cumulative impact on system demand and energy consumption.

A.

FPL's annual projection of in-territory plug-in electric vehicle (PEV) sales is the product of multiplying the following three variables:

1. **Projections of the U.S. market for PEVs**. Developed based on a review of multiple forecasts from industry experts and FPL's discussions with knowledgeable professionals in the automotive industry.
2. **Florida's share of the U.S. PEV market**. Number of hybrid electric vehicles (excluding PEVs) currently located in the state according to the Center for Automotive Research (CAR) is used as a proxy for PEVs.
3. **FPL's share of Florida PEV market.** Assumed to be 50 percent – based on the rough proportion of Florida's population in FPL's service territory.

When forecasting sales/registrations of vehicles, FPL used July 2012 estimates, the most current data available. Cumulative sales beyond 2012 are the sum of the current year's annual sales added to the total sales from the previous year. Vehicle life expectancy is assumed to be ten years.

The contribution to net energy for load from PEVs was derived from FPL's vehicle forecast using an estimated kWh per vehicle. It was assumed that charging would take place 365 days per year. FPL has been testing electric vehicles in both fleet and commuting applications since the early 1990s. In the case for residential/commuting applications, experience indicates that on average electric vehicles can travel three miles for every kWh of charge. A recent survey by the U.S Department of Transportation conducted on the National Household Travel Trends in 2009 (Reference: Santos, A., McGuckin, N., Nakamoto, H. Y., Gray, D., & Liss, S. U. S. Department of Transportation, Federal Highway Administration. (2011). *Summary of travel trends:2009 national household travel survey* (FHWA-PL-ll-022), Table 14. P 28.) revealed that the daily average driving distance in the U.S. is 36.1 miles. When this estimate is coupled with the FPL experience for electric vehicles in residential/commuting applications it suggests the average daily charging energy required per electric vehicle would be about 12 kWh per day (i.e., 36.1 miles per day divided by 3 miles per kWh = 12.01 kWh per day). The kWh forecast shown below was developed using this factor plus a similar forecast developed in 2010 for trucks. Energy values shown are at the generator having which have been adjusted for system losses.

For summer and winter peak demand, an estimate was made based on the most likely charging schedule for each electric vehicle application. The percent of vehicles charging during the summer and winter peak periods was then estimated in relation to the forecast for summer and winter peak demand. The estimated number of vehicles, as previously described, is multiplied by the percentage of vehicles charging during FPL's peak hour, multiplied by the kW per vehicle, and adjusted for losses to provided the summer and winter coincident peak demand at the generator in the forecast.

Sources used to arrive at these numbers include The Center for Automotive Research, JD Powers, Pike Research, the Department of Energy, the Electric Power Research Institute, and discussions with key industry stakeholders such as major auto manufacturers and electric utilities.

Q.

Please include the following information within the utility's service territory: an estimate of the number of electric vehicles, an estimate of the number of public EV charging stations, and the estimated demand and energy impacts of the electric vehicles by year.

A.

Electric Vehicle Charging Impacts

Year	Number of Electric Vehicles	Number of Public EV Charging Stations	Cumulative Impact of Electric Vehicles		
			Summer Demand (MW)	Winter Demand (MW)	Annual Energy (GWh)
2012	2,020	na	3	1	13
2013	5,006	na	8	3	31
2014	9,669	na	15	6	62
2015	16,413	na	26	10	110
2016	25,490	na	41	16	173
2017	39,461	na	63	25	261
2018	53,896	na	87	34	358
2019	72,139	na	116	45	480
2020	107,352	na	169	67	688
2021	159,439	na	245	101	984
2022	236,695	na	357	151	1,408

Estimates include cars and trucks

Please see table above regarding the number of PEVs and the associated estimated demand and energy impacts. FPL does not track or forecast the number of public EV charging stations because FPL does not believe that this number is relevant to forecasting the amount of demand and energy related to PEVs. The charging stations themselves do not use energy.

Q.

Please describe any company programs or tariffs currently offered to customers relating to plug-in electric vehicles, and describe whether any new or additional programs or tariffs relating to plug-in electric vehicles will be offered to customers within the ten-year period?

A.

FPL does not currently offer, nor are there any plans to offer, programs or tariffs specific to PEVs. However, the potential need for such programs or tariffs will continue to be monitored.

Q.

Please describe how the company monitors the installation of public charging stations in its service area? Please provide the number of "quick-charge" electric vehicle charging stations (i.e., charging stations requiring a service drop greater than 240 volts and/or using three-phase power) currently installed in the service area.

A.

As discussed in FPL's response to Staff's First Data Request No. 10, FPL does not actively monitor the installation of public charging stations in its service territory. Additionally, there is currently no reporting system in place that provides consistent, reliable information about such locations. FPL is not aware of any "quick charge" stations in its service territory.

Q.

Please describe any instances since January 1, 2012 in which upgrades to the distribution system were made where electric vehicles were a contributing factor?

A.

FPL is not aware of any such instances. Please also see FPL's response to Staff's First Data Request Nos. 10 and 12.

Q.

Please identify and describe each existing utility-owned renewable resource as of December 31, 2012. Please include the facility's name, unit type, fuel type, whether it is a firm or non-firm resource, its net installed capacity, annual generation for 2012, capacity factor for 2012, and commercial in-service date. For small, distributed renewable resources, such as rooftop solar panels, please combine all under a single resource entry.

Existing Utility-Owned Renewable Resources

Facility Name	Unit Type	Fuel Type	Capacity Type	Net Capacity (MW)		Annual Generation	Capacity Factor	Commercial In-Service Date
-	-	-	Firm/Non-Firm	Sum	Win	(MWh)	(%)	(MM/YYYY)

A.

See Attachment No. 1.

Q.

Please identify and describe each planned utility-owned renewable resource for the period 2013 through 2022. Please include each proposed facility's name, unit type, fuel type, whether it will be a firm or non-firm resource, its net installed capacity, anticipated average annual generation, anticipated average capacity factor, and projected commercial in-service date. For small, distributed renewable resources, such as rooftop solar panels, please combine all under a single resource entry.

Planned Utility-Owned Renewable Resources

Facility Name	Unit Type	Fuel Type	Capacity Type	Net Capacity (MW)		Annual Generation	Capacity Factor	Commercial In-Service Date
-	-	-	Firm/Non-Firm	Sum	Win	(MWh)	(%)	(MM/YYYY)

A.

At this time, FPL has not fully developed specific solar projects at specific power plant sites for utility owned renewable generators. Rather, FPL has identified potential sites for solar development and performed initial permitting and due diligence with respect to available solar and other renewable power technologies that may be pursued in the future.

Regarding distributed renewable resources, FPL has planned installations of company-owned PV projects to be located at customer facilities through the Business PV for Schools Pilot. Based on projections as of April 2013, some will be installed in 2013 and some in 2014. FPL will own the PV system for five years after which time the systems will be transferred to the customer. Please see the table below for specific information.

Planned Utility-Owned Renewable Resources

Facility Name	Unit Type	Fuel Type	Capacity Type	Net Capacity (MW AC)		Annual Generation	Capacity Factor	Commercial In-Service Date
-	-	-	Firm/Non-Firm	Sum	Win	(MWh)	%	(MM/YYYY)
PV for Schools	PV	Solar	Non-Firm	0.281	0.281	485	19.7%	2013 Various
PV for Schools	PV	Solar	Non-Firm	0.162	0.162	279	19.7%	2014 Various

Note: MW and MWh are based on AC rating

Q.

Please refer to the list of planned utility-owned renewable resources for the period 2013 through 2022 above. Discuss the current status of each project.

A.

Please see FPL's response to Staff's First Data Request No. 15.

Q.

Please list and discuss any planned utility-owned renewable resources within the past year that were cancelled, delayed, or reduced in scope. What was the primary reason for the changes? What, if any, were the secondary reasons?

A.

FPL has no such projects.

Q.

Please identify and describe each existing and planned co-fired renewable fuel source. Please include the name of the fuel production facility, the source of the renewable fuel, the type of fuel produced, what unit co-fires the fuel and its type, the amount of energy generated by the co-fired fuel, what percent of the co-firing unit's fuel is renewable, and the start and end dates of the agreement (if any).

Existing & Planned Renewable Co-Firing

Facility Name	In-Service Date	Source Type	Fuel Type	Co-Firing Unit	Unit Type	Energy Generated	% Fuel of Unit	Contract Term (MM/YYYY)	
-	(MM/YYYY)	-	-	-	-	(MWh)	(%)	Start	End

A.

FPL operates no existing co-fired renewable fuel generating facilities, although FPL's Martin Next Generation Solar Energy Center, which became commercial in December 2010, is the world's first "hybrid" solar energy facility – integrating a 75MW solar thermal facility with an existing natural gas combined cycle unit. FPL also has no new "co-fired renewable fuel sources" planned.

Q.

Please identify and describe each purchased power agreement with a renewable generator that delivered energy during 2012. Please include the name of the facility, fuel type, whether the contract is for firm capacity, the contracted capacity (if firm), the energy delivered in 2012, the capacity factor for 2012, and the start and end dates of the purchased power agreement.

Existing Renewable Purchased Power Agreements (2012)

Facility Name	Fuel Type	Capacity Type	Contracted Capacity (MW)		Energy Delivered	Capacity Factor	Contract Term (MM/YYYY)	
-	-	Firm/Non-Firm	Sum	Win	(MWh)	(%)	Start	End

A.

Please see Attachment No. 1.

Existing Renewable Purchased Power Agreements (2012)								
Facility Name	Fuel Type	Capacity Type	Contracted Capacity (MW)		Energy Delivered	Capacity Factor	Contract Term (MM/YYYY)	
-	-	Firm/Non-Firm	Sum	Win	(MWh)	(%)	Start	End
Broward North	MSW	Firm	11	11	96,106	89	1/1/1993	12/31/2026
Broward South	MSW	Firm	3.5	3.5	29,677	93	1/1/1993	12/31/2026
Solid Waste Authority of Palm Beach County	MSW	Firm	40	40	370,109	85	1/1/2012	4/1/2032

Q.

Please identify and describe each purchased power agreement with a renewable generator that is anticipated to begin delivering renewable energy to the Company during the period 2013 and 2022. Please include the name of the facility, fuel type, whether the contract is for firm capacity, the contracted capacity (if firm), the average annual energy to be delivered, the average capacity factor, and the start and end dates of the purchased power agreement.

Renewable Purchased Power Agreements (2013 - 2022)

Facility Name	Fuel Type	Capacity Type	Contracted Capacity (MW)		Energy Delivered	Capacity Factor	Contract Term (MM/YYYY)	
-	-	Firm/Non-Firm	Sum	Win	(MWh)	(%)	Start	End

A.

Please see Attachment No. 1.

Renewable Purchased Power Agreements (2013 - 2022)								
Facility Name	**Fuel Type**	**Capacity Type**	**Contracted Capacity (MW)**		**Energy Delivered**	**Capacity Factor**	**Contract Term (MM/YYYY)**	
-	-	Firm/Non-Firm	Sum	Win	(MWh)	(%)	Start	End
Solid Waste Authority of Palm Beach	MSW	Firm	70	70	613,200	85	6/1/2016	6/1/2034
U.S. EcoGen Clay	Biomass	Firm	60	60	473,040	90	12/14/2012	12/31/2049
U.S. EcoGen Okeechobee	Biomass	Firm	60	60	473,040	90	12/14/2012	12/31/2049
U.S. EcoGen Martin	Biomass	Firm	60	60	473,040	90	12/14/2012	12/31/2049

Q.

Please refer to the list of renewable purchased power agreements that are anticipated to begin delivering capacity and/or energy to the Company during the period 2013 through 2022. Discuss the current status of each project.

A.

The Solid Waste Authority of Palm Beach County project proceeds on or perhaps ahead of schedule. Turbine generator delivery is expected before the end of the year, and the advance capacity payment is anticipated to be due in January 2014. The project should meet its scheduled on-line date.

The three U.S. EcoGen projects were just approved by the Commission in April 2013.

Q.

Please list and discuss any renewable purchased power agreements within the past year that were cancelled, expired, delayed, or modified. What was the primary reason for the changes? What, if any, were the secondary reasons?

A.

No renewable purchased power agreements were cancelled, expired, delayed or modified in 2012.

Q.

Please identify and describe each existing and planned renewable generator, including both interconnected and self-service generators, within the Company's service territory. Please include the facility's name, unit type, fuel type, the installed capacity of the generator, the commercial in-service date of the unit, and whether the renewable generator is contracted by the Company or another utility. Please do not include customer-owned distributed renewable generation in this response.

Existing Renewable Generators in the Company's Service Territory

Facility Name	Unit Typ e	Fuel Typ e	Net Capacity (MW)		Commercial In-Service Date	Contrac t Status
-	-	-	Su m	Win	(MM/YYYY)	-

Planned Renewable Generators in the Company's Service Territory

Facility Name	Unit Typ e	Fuel Typ e	Net Capacity (MW)		Commercial In-Service Date	Contrac t Status
-	-	-	Su m	Win	(MM/YYYY)	-

A.

See Attachment No. 1

Q.

Please provide the annual output for the company's renewable resources, including utility-owned firm resources, utility-owned non-firm resources, firm renewable PPAs, non-firm renewable purchases (such as as-available energy purchases), or customer-owned generation, for the period 2012 through 2022. Please complete the table below and provide an electronic copy (in Excel).

Renewable Generation by Source

Annual Output (GWh)	Actual	Projected									
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Firm Utility											
Non-Firm Utility											
Firm PPA											
Non-Firm Purchase											
Customer-Owned											
Total											

A.

Please see Attachment No. 1.

Q.

[Investor-owned Utilities Only] Provide, on a system-wide basis, the historical annual average as-available energy rate in the Company's service territory for the period 2003 through 2012. If the Company uses multiple areas for as-available energy rates, please provide a system-average rate as well. Also, provide the forecasted annual average as-available energy rate in the Company's service territory for the period 2013 through 2022. Please complete the table below and provide an electronic copy (in Excel).

Average As-Available Energy Rates				
Year		As-Available Energy	On-Peak Average	Off-Peak Average
		($/MWh)	($/MWh)	($/MWh)
Actual	2003			
	2004			
	2005			
	2006			
	2007			
	2008			
	2009			
	2010			
	2011			
	2012			
Projected	2013			
	2014			
	2015			
	2016			
	2017			
	2018			
	2019			
	2020			
	2021			
	2022			

A.

See Attachment No. 1.

Q.

Please provide the cumulative present worth revenue requirement of the Company's Base Case for the 2013 Ten-Year Site Plan. If available, please provide the cumulative present worth revenue requirement of any sensitivities studied as well.

A.

The projected cumulative present value of revenue requirements (CPVRR) for the resource plan presented in FPL's 2013 Ten Year Site Plan is approximately $104,477 million in 2013$ for the years 2013-2044 assuming a 7.45% discount factor. (Consistent with Schedule 9, found on pages 107-112 of FPL's 2013 TYSP, this CPVRR value includes no capital costs for either the nuclear uprates or FPL's planned new nuclear unit Turkey Point Unit 6 that is projected to be added in 2022.)

Q.

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

A.

The load forecast that is presented in FPL's 2013 Ten-Year Site Plan was developed in February 2013. The only load forecast sensitivities analyzed during 2012/early 2013 were high load forecast sensitivities developed solely to analyze the quality of FPL's future reserves and the projected frequency at which load control might be implemented, and to analyze from an operation perspective the scheduling of planned maintenance for FPL's generating units. These analyses are on-going and the load forecast sensitivities have not been used to determine potential changes to the resource plan that was presented in the 2013 Site Plan.

Q.

Please complete the following table detailing unit specific information on capacity and fuel consumption for 2012. For each unit on the Company's system, provide the following data based upon historic data from 2012; the unit's capacity, annual generation, capacity factor, estimated annual availability factor, unit average heat rate, and average energy cost for the unit's production. For dual fuel units, please report each fuel separately. Please complete the table below and provide an electronic copy (in Excel).

Utility-Owned Generation

Plant	Unit #	Unit Type	Fuel Type	Net Capacity (MW)		2012 Annual Generation	Capacity Factor	Avail. Factor	In-Service Date	Heat Rate	Unit Fuel Cost
				Sum	Win	(MWh)	(%)	(%)		(BTU/kWh)	(¢/kWh)

A.

See Attachment No. 1.

Q.

Please complete the following table detailing planned unit additions, including information on capacity and in-service dates. Please include only planned conventional units with an in-service date past January 1, 2013, and including nuclear units, nuclear unit uprates, combustion turbines, and combined-cycle units. For each planned unit, provide the date of the Commission's Determination of Need and Power Plant Siting Act certification (if applicable), and the anticipated in-service date. Please complete the table below and provide an electronic copy (in Excel).

Planned Unit Additions for 2013 through 2022

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Nuclear Unit Additions / Uprates				
Combustion Turbine Unit Additions				
Combined Cycle Unit Additions				
Steam Turbine Unit Additions				

A.
See Attachment No. 1.

Planned Unit Additions for 2013 through 2022

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		Commercial In-Service Date
		Need Approved (Commission)	PPSA Certified	
Nuclear Unit Additions / Uprates				
Turkey Point Unit # 4 Uprates	115	September-08	October-08	2/28/2013
Turkey Point Unit #6	1,100	April-08	Pending	6/1/2022
Combustion Turbine Unit Additions/Upgrades				
Fort Myers 2 *	51	n/a	n/a	8/1/2015
Manatee 3 *	39	n/a	n/a	9/1/2014
Sanford 4 *	16	n/a	n/a	4/1/2013
Sanford 5 *	19	n/a	n/a	9/1/2013
Turkey Point 5 *	33	n/a	n/a	3/1/2014
Combined Cycle Unit Additions				
Cape Canaveral Next Generation Clean Energy Center	1,210	September-08	October-09	6/1/2013
Riviera Beach Next Generation Clean Energy Center	1,212	September-08	November-09	6/1/2014
Port Everglades Next Generation Clean Energy Center	1,277	April-12	March-13	6/1/2016
Vero Beach Combined Cycle	46	Existing Unit	Existing Unit	1/1/2014 **
Steam Turbine Unit Additions				

* Date shown for the CT upgrades represents last date of phased CT upgrades at the site.
** This date is the date that FPL takes ownership of the existing Vero Beach unit.

Q.

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

A.

Please see Attachment No. 1 for the timelines. Construction is already underway for the following planned generating units presented in FPL's 2013 Site Plan: Cape Canaveral (modernization), Riviera (modernization), and Port Everglades (modernization). In addition, the construction work associated with the nuclear uprate at Turkey Point Unit 4 is complete.

The only remaining planned generating unit presented in FPL's 2013 Site Plan is the new nuclear unit, Turkey Point Unit 6, which is projected to come in-service in 2022. FPL has received need determination approval for this new nuclear unit from the FPSC. The next step is to receive a Combined Operating License (COL) from the Nuclear Regulatory Commission (NRC). At the time this document is being prepared, the NRC has withdrawn its schedule for reviewing FPL's COL application for Turkey Point Unit 6 and no new schedule for this review has been issued. In order to respond to this request, FPL is utilizing the previous NRC COL review schedule in developing the general timeline attached while noting that this timeline is subject to change.

Q.

For each existing and planned unit on the Company's system, provide the following data based upon historic data from 2011 and forecasted capacity factor values for the period 2012 through 2021. Please complete the tables below and provide an electronic copy (in Excel).

Projected Unit Information – Capacity Factor (%)

Projected Unit Information – Capacity Factor (%)														
Plant	Unit #	Unit Type	Fuel Type	Actual	Projected									
				2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022

A.

Please see Attachment No. 1.

Q.

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

Repowering Candidate Units

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

A.

Please see the Attachment No. 1. All existing conventional steam generating units and the combustion turbine units at Fort Myers are capable of being converted to combined cycle operation. The list of such units on FPL's system, in alphabetical order, which are potential candidates for repowering or conversion are:

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

Included in the above list are eight units which FPL received FPSC approval to convert into new combined cycle units. These units are Cape Canaveral Units 1 and 2 (currently planned to be converted in 2013), Riviera Units 3 and 4 (currently planned to be converted in 2014), and Port Everglades Units 1, 2, 3, and 4 (currently planned to be converted in 2016). In practice, there are a number of considerations that are taken into account when analyzing whether to convert an existing conventional steam generating unit to a combined cycle unit. Some of these considerations can be thought of as feasibility issues (such as whether there is sufficient land at the existing site for this type of unit) while other issues are typically thought of as economic issues. Any of these considerations could potentially become a major obstacle to a plant conversion at a specific site.

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

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

Q.

Please complete the following table detailing the Company's planned changes to summer capacity. In addition to providing the net change for the current year's Ten-Year Site Plan, please also provide the net change based on last year's Ten-Year Site Plan. Please complete the table below and provide an electronic copy (in Excel).

System Capacity Changes by Fuel & Unit Type

Fuel Type	Unit Type	Summer Capacity Changes (MW)	
		2012 TYSP (2012-2021)	2013 TYSP (2013-2022)
Natural Gas	Combined Cycle		
	Combustion Turbine		
	Steam		
Coal	Steam		
	Integrated Coal Gasification		
Oil	Combustion Turbine & Diesel		
	Steam		
Nuclear	Steam		
Firm Purchases	Independent Power Producer (IPP)		
	Interchange		
	Non-Utility Generator (NUG)		
	Renewables		
NET CAPACITY ADDITIONS			

A.
Please see Attachment No. 1.

System Capacity Changes by Fuel & Unit Type

Fuel Type	Unit Type	2012 TYSP (2012-2021)	2013 TYSP (2013-2022)
Natural Gas 1/	Combined Cycle	3,901	3,857
	Combustion Turbine	---	---
	Steam	---	---
Coal 1/	Steam	(30)	---
	Integrated Coal Gasification	---	---
Oil 1/	Combustion Turbine & Diesel	---	---
	Steam	(399)	(1,552)
Nuclear 1/	Steam 3/	459	1,215
Firm Purchases 2/	Independent Power Producer (IPP)	(305)	(40)
	Interchange	(1,428)	(1,309)
	Non-Utility Generator (NUG)	---	---
	Renewables 4/	70	290
	Unspecified Purchase 5/	250	---
	NET CAPACITY ADDITIONS	**2,518**	**2,461**

Notes:

1/ The values shown for the 2012 TYSP and the 2013 TYSP for Natural Gas, Coal, Oil and Nuclear represent the total of those MWs shown in Schedule 8 of the respective site plans .

2/ The value shown for the 2012 TYSP and the 2013 TYSP for Firm Purchases represents the difference in the values shown in Table 1.B.1 of the respective site plans.

3/ The 2012 site plan nuclear value projects an increase of 459 MW (to a total of 490 MW) above the 31 MW achieved in 2011. The 2013 site plan value contains Turkey Point Nuclear Unit 6 and the uprate to Turkey Point 4.

4/ The 2012 Site Plan renewable value of 70 MW is based on the additional contract for 70 with Palm Beac SWA in 2016. Also includes EcoGen which starts in 2021.

5/ Unspecified Purchase is reflected in the 2012 Ten Year Site Plan in Col (2) Firm Installed Capacity.

Q.

[Investor-Owned Utilities Only] Please complete the table below describing the status of the company's generating units during each month's peak demand, for the year 2012. As part of this response, include the actual values at monthly peak for installed capacity, scheduled maintenance, forced outages, available capacity, and net firm peak demand. Please complete the table below and provide an electronic copy (in Excel).

Available Capacity at Time of Peak Demand

Capacity / Demand at Time of Monthly Peak (MW)						
Year	Month	Installed Capacity	Scheduled Maintenance	Forced Outages	Available Capacity	Peak Demand
2012	1					
	2					
	3					
	4					
	5					
	6					
	7					
	8					
	9					
	10					
	11					
	12					

A.

See Attachment No. 1.

Capacity (6) / Demand at Time of Peak (MW)						
Year	Month	Installed Capacity (1)	Scheduled Maintenance (2)	Forced Outages (3)	Available Capacity (4)	Peak Demand (5)
2012	1	25,640	1,989	120	23,531	17,934
	2	25,640	4,397	41	21,202	16,228
	3	25,640	6,405	-	19,235	16,310
	4	24,444	5,855	15	18,574	18,108
	5	24,414	2,680	161	21,573	19,981
	6	24,414	1,710	897	21,808	20,351
	7	24,411	1,041	48	23,322	21,343
	8	24,559	2,179	133	22,246	21,440
	9	24,559	3,113	75	21,371	19,711
	10	24,681	2,356	84	22,241	19,337
	11	25,907	5,767	165	19,975	14,282
	12	25,255	5,280	483	19,492	16,025

Notes:

(1) FPL-owned generating units' projected monthly long-term firm peak capability ratings (excluding solar) for summer months (April-October) and winter months (November-March). This "Installed Capacity" includes MW capability for the inactive reserve units.

(2) Scheduled Maintenance MW is based on the "Installed Capacity" in column 1 multiplied by the percent of time during the peak day that all FPL owned generating units were in a planned and maintenance outage (including units in inactive reserve). FPL maintains the practice of using available capacity year-round for scheduling maintenance of its fossil-fueled units as opportunities arise.

(3) Forced Outage MW is based on the "Installed Capacity" in column 1 multiplied by the percent of time during the peak day that all FPL owned generating units were in a forced outage (including units in inactive reserve).

(4) This "Available Capacity" has been calculated as MW = Installed Capacity MW - Scheduled Maintenance MW - Forced Outage MW. This Available Capacity was not adjusted for peak day ambient conditions.

(5) Peak Demand is based on the actual peak MW system demand reported over the peak hour.

(6) This information in columns 1-4 relate to FPL-owned generating units only.

Q.

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

Existing Purchased Power Agreements as of January 1, 2013

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

Planned Purchased Power Agreements for 2013 through 2022

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

A.

See Attachment No. 1.

Existing Purchased Power Agreements as of January 1, 2013

Seller	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel	Description
					Note 1	Note 2		
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	
Southern Co	6/1/2010	12/31/2015	584	584	1,919,857	38%	Natural Gas	Harris
Southern Co	6/1/2010	12/31/2015	185	185	648,558	40%	Natural Gas	Franklin
Southern Co	6/1/2010	12/31/2015	159	159	275,101	20%	Coal	Scherer 3
Wheelabrator Technologies	1/1/1993	12/31/2026	11	11	96,106	89%	MSW	Broward North
Wheelabrator Technologies	1/1/1993	12/31/2026	3.5	3.5	29,677	93%	MSW	Broward South
Cedar Bay Generating Co.	1/25/1994	12/31/2024	250	250	680,500	96%	Coal	---
Indiantown Cogen, LP	12/22/1995	12/1/2025	330	330	801,060	98%	Coal	---
Solid Waste Authority of Palm Beach	1/1/2012	4/1/2032	40	40	370,109	85%	MSW	---
SJRPP *	4/2/1982	4/1/2017	381	388	1,852,074	56%	Coal	---

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

Planned Purchased Power Agreements for 2013 through 2022

Seller	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	
Solid Waste Authority of Palm Beach	6/1/2016	6/1/2034	70	70	613,200.00	85%	MSW	---
U.S. EcoGen - Clay	1/1/2021	12/31/2049	60	60	473,040.00	90%	Biomass	
U.S. EcoGen -Okeechobee	1/1/2021	12/31/2049	60	60	473,040.00	90%	Biomass	
U.S. EcoGen - Martin	1/1/2021	12/31/2049	60	60	473,040.00	90%	Biomass	
OUC - Stanton 1	1/1/2014	12/31/2016	20.5	20.5	67,058.33	37%	Coal	
OUC - Stanton 2	1/1/2014	12/31/2016	16	16	53,646.67	37%	Coal	

Note 1 - Where historical data is available, values reflect purchases for year 2012 as reported in the FERC Form 1

Note 2 - Calculations are based on Summer Contract Capacity

Q.

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

Existing Power Sales as of January 1, 2013

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

Planned Power Sales for 2013 through 2022

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

A.
See Attachment No. 1.

Existing Power Sales as of January 1, 2013

Purchaser	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor *	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(If any)	
Florida Keys Long Term Agreement	February 7, 2011	December 31, 2051	143 - 152	110 - 116	757,912 - 807,002	60.6%	System Average	Fulll Requirements
Key West Long Term Agreement	June 1, 1993	May 31, 2013	45	45	88,673	22.5%	System Average	Partial Requirements
Lee County Partial Requirements	January 1, 2010	December 31, 2013	233	233	1,213,921	59.5%	System Average	Partial Requirements
City of Wauchula	October 1, 2011	December 31, 2016	13	13	63,489 - 64,093	56.3%	System Average	Fulll Requirements
City of Blountstown	May 1, 2012	April 30, 2017	8	8	39,437	56.3%	System Average	Fulll Requirements
Transmission Service Agreement	July 9, 1996	October 31, 2013	1	1	4,998	57.1%	System Average	Transmission Losses

Planned Power Sales for 2013 through 2022

Purchaser	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor *	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(If any)	
Lee County Full Requirements	January 1, 2014	December 31, 2053	819 - 950	810- 888	3,833,107 - 4,693,930	56.4%	System Average	Full Requirements
Cooperative	June 1, 2014	May 31, 2021	200	200	489,600 - 838,400	47.9%	Natural Gas	Heat Rate Call Option

* Capacity Factor calculations use the highest annual generation and peak annual contract capacity values forecast during the contract period.

Q.

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

A.

The MW impact of all of FPL's long-term firm capacity contracts is shown in Table I.B.1 and Table I.B.2 in Chapter 1 of FPL's 2013 Ten-Year Site Plan.

FPL projects that several contracts will begin to deliver capacity during the 2013-2022 time period. The first of these contracts is with the Solid Waste Authority (SWA) of Palm Beach County and it is scheduled to provide 70 MW of firm capacity with a start date of 1/1/2015 and an end-date of 4/01/2032. Two other contracts are essentially being transferred to FPL as part of the agreement under which FPL will begin providing electric service to Vero Beach starting on January 1, 2014. These two contracts are with Orlando Utilities Commission Stanton generating unit. The combined capacity of these two contracts is approximately 37 MW. These two contracts are projected to end on 12/31/2016. In addition, there are three separate contracts with U.S. EcoGen of 60 MW each that are projected to begin providing non-firm energy in 2019 and to begin providing firm capacity and energy starting in 1/01/2021. These contracts have an end-date of 12/31/2049.

The following long-term firm capacity contracts presented in Tables I.B.1 and I.B.2 of FPL's 2013 Ten-Year Site Plan have contract end dates that fall within the 2013-2022 time period addressed by this Site Plan:

- UPS Replacement contract with a summer capacity of 928 MW and a contract end date of 12/31/2015; and,
- SJRPP with a summer capacity of 381 MW and a "contract end date" (which is actually a projected energy delivery suspension date as explained below) of 11/1/2017.

The UPS Replacement contract for 928 MW began on 6/1/2010 and will remain in place through 12/31/2015. No extension of that contract is currently projected by FPL.

The amount of firm capacity that FPL receives under the SJRPP contract is subject to an energy "cap" regarding the cumulative total MWh that FPL may receive consistent with Internal Revenue Service regulations. Once this energy cap has been reached, FPL cannot receive additional energy under the contract. The sustained downturn in natural gas prices has made gas-fired generation more attractive relative to the energy cost for SJRPP energy and hence has reduced FPL's recent utilization of SJRPP. FPL currently projects that the energy cap will not be reached until November 2017 at the earliest. The date shown in the table as the "contract end date" conservatively reflects November 2017 as the earliest date when the suspension of capacity and energy could occur.

For purposes of its resource planning, FPL assumes that all of its existing long-term firm capacity purchases shown in Table I.B.1 and Table I.B.2 in Chapter 1 of its 2013 Site Plan will remain in place to the Contract End Date shown in these tables. Individual contracts may have options with which one or both parties may either terminate earlier than the listed contract end date or extend this date. In addition, these contracts may be subject to renegotiation with mutual consent of both parties. As dictated by changes in resource needs, economic conditions, regulatory changes, and/or performance under the contract, FPL may examine such options available under the contract.

Discussion of all of FPL's long term sales forecasts can be found in Chapter 2 of FPL's 2013 Ten-Year Site Plan.

Q.

Please list and discuss any long-term power sale or purchase agreements within the past year that were cancelled, expired, or modified. What was the primary reason for the changes? What, if any, were the secondary reasons?

A.

Power Sales

- Lee County Electric Cooperative Short Term and Long Term Agreement
  - Primary Reason: Annual modification, filed with and approved by FERC, to adjust the line item references in the cost based formulas of the Agreement to FPL's FERC Form 1, which change each year.
  - Secondary Reason: None.

- Florida Keys Electric Cooperative Long Term Agreement
  - Primary Reason: Annual modification, filed with and approved by FERC, to adjust the line item references in the cost based formulas of the Agreement to FPL's FERC Form 1, which change each year.
  - Secondary Reason: None.

Power Purchases

- DeSoto County Generating Company - (305 MW Peaking Product)
  - Primary Reason: Expired on December 31, 2012 and not renewed as FPL no longer had a need for this capacity to meet temporary system needs.
  - Secondary Reason: Renewing the Agreement for 2013 would not provide any projected fuel savings for FPL Customers.

- Oleander Power Project L.P. - (155 MW Peaking Product)
  - Primary Reason: Expired on September 30, 2012 and not renewed as FPL no longer had a need for this capacity to meet temporary system needs.
  - Secondary Reason: Renewing the Agreement for 2013 would not provide any projected fuel savings for FPL Customers.

Seminole Electric Cooperative, Inc. - (150 MW Peaking Product)

- o Primary Reason: Expired on September 30, 2012 and not renewed as FPL no longer had a need for this capacity to meet temporary system needs.
- o Secondary Reason: Renewing the Agreement for 2013 would not provide any projected fuel savings for FPL Customers.

TECO - (Up to 125 MW System Product)

- o Primary Reason: Expired on December 31, 2012 and not renewed as FPL no longer had a need for this capacity to meet temporary system needs.
- o Secondary Reason: Renewing the Agreement for 2013 would not provide any projected fuel savings for FPL Customers.

Q.

Provide a narrative explaining the impact of any existing environmental regulations relating to air emissions and water quality or waste issues on the Company's system during the 2012 period. As part of your discussion, please include the potential for existing environmental regulations to impact unit dispatch, curtailments or retirement during the 2013 through 2022 period.

A.

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

FPL has evaluated the impact of all existing regulations on the operation of its generating units and has developed compliance plans to limit, or avoid, impacts to generating unit operation. During the 2012 period, impacts from air and water environmental restrictions to generating units included the following environmental requirements: 1) use of "environmental" natural gas during startup of FPL's oil/gas steam units; 2) compliance with Clean Air Interstate Rule (CAIR) through the use of emission allowances and the operation of the Selective Catalytic Reduction (SCR) at SJRPP; 3) compliance with the Georgia Multi-Pollutant Rule requirements at Plant Scherer through operation of sorbent injection / bag-house control for mercury and operation of SCR and FGD (Scrubber); and 4) operation of temporary heaters at Riviera and Cape Canaveral plants when needed to provide warm water for manatees in compliance with manatee protection plan.

To comply with the CAIR, FPL implemented several projects as the most cost effective strategy, which included: 1) the 800 MW Cycling Project at the Martin 1&2 and Manatee 1&2 units to improve the ability of the units to be economically dispatched to meet system demand and allow the removal of "must run" status; 2) installation of SCR and Scrubber on Plant Scherer Unit 4 (also required by the Georgia Multi-pollutant rule); 3) installation of SCR on SJRPP Units 1 & 2; and 4) purchase of emission allowances as needed. During the 2013 through 2022 period FPL is aware of two final regulations, and several evolving regulations, which could potentially affect generating unit dispatch or retirement.

On July 6, 2010, the EPA published a proposed Clean Air Transport Rule (CATR) to replace the CAIR rule that had been remanded to EPA by the Court. EPA subsequently withdrew the proposed CATR and on July 6, 2011, EPA made public its Cross State Air Pollution Rule (CSAPR) as the replacement to CAIR to be implemented January 1, 2012. On December 30, 2011 the DC Circuit Court of Appeals issued a stay of the rule and set an abbreviated schedule for submittal of briefs. On April 13, 2012 oral argument was held to assess the merits of a continuing stay and remand of the rule to EPA. On August 21, 2012 the US Court of Appeals for the DC Circuit issued its opinion vacating the rule and remanding it to EPA. On October 15, 2012 EPA filed a petition for rehearing enbanc and on January 24, 2013 was denied rehearing. On March 29, 2013 the solicitor general filed a petition for review before the US Supreme Court. FPL anticipates that the Supreme Court is likely to reject EPA's petition for review of the Circuit Court's decision leaving EPA with the task of rewriting a transport rule that conforms to the DC Circuit Court's decision. In accordance with the December 23, 2008 Court decision, CAIR remains in effect until a replacement rule is finalized by the EPA. FPL's construction of the West County Plant, and the modernizations of the Cape Canaveral and Riviera Beach facilities have reduced, and will reduce, FPL system emissions to avoid the need for future purchase of emission allowances necessary to comply with the requirements of either CSAPR or CAIR as currently promulgated.

The other final air regulation for which FPL has new compliance obligations is the Mercury and Air Toxics Standards (MATS) rule. The rule finalizes the coal- and oil fired Maximum Achievable Control Technology (MACT) standards that the EPA had proposed to reduce emissions of Hazardous Air Pollutants (HAPs). FPL does not anticipate any adverse impacts to operation of its generating units to comply with the MATS rule at this time. FPL began its planned installation of ESPs on its 800 MW oil fired units at Manatee and Martin plants in 2011 to plan for compliance within the required time period using existing planned outages and additional system capacity additions from the modernization projects. Installation of ESP at Manatee Unit 2 has been completed and construction continues on the Unit 1 ESP. The Martin 800 MW units have received their air construction permits and have begun construction planning. For the SJRPP Coal-Fired Units, FPL and Co-Owner JEA initiated an engineering study to identify the most cost effective approaches to comply with the rule. A more detailed study of the three most cost effective strategies identified in the initial study is presently underway. FPL does not anticipate any additional changes to its remaining oil fired steam electric generating units as a result of existing planned unit retirements and the use of the rules limited oil use provisions until planned unit retirements.

The several environmental regulations which FPL anticipates becoming final in the 2013 through 2022 period include: 1) 316(b) Cooling Water Intake Rule; 2) Coal Combustion Residuals Rule; 3) Steam Electric Effluent Guidelines; 4) Greenhouse Gas Performance Standards for Existing Sources; 5) Regional Haze Reasonable Further Progress requirements for visibility improvement; 6) EPA Waters of the U.S. Guidance Document; 7) SIP revisions for Startup/Shutdown/Malfunction (SSM) excess emissions and 8) new and future revisions to the National Ambient Air Quality Standard (NAAQS) for the criteria pollutants. While FPL does not yet know what requirements would be included in each final rule, it has made a preliminary determination using publically available information that the anticipated compliance requirements for FPL would not impact any of the company's generating unit capability or reliability to meet projected system demand.

Q.

Please provide the amount of regulated air pollutants and carbon dioxide emitted, on an annual and per megawatt-hour basis, for the Company's generation fleet during the period 2003 through 2022. Please complete the table below and provide an electronic copy (in Excel).

Emissions of Registered Air Pollutants & CO2

Year		SOX		NOX		Mercury		Particulates		CO2e	
		lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons
Actual	2003										
	2004										
	2005										
	2006										
	2007										
	2008										
	2009										
	2010										
	2011										
	2012										
Projected	2013										
	2014										
	2015										
	2016										
	2017										
	2018										
	2019										
	2020										
	2021										
	2022										

A.

See Attachment No. 1.

Emissions of Registered Air Pollutants & CO2											
Year		SOX		NOX		Mercury		Particulates		CO2e	
		lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons
Actual	2003	2.871	126,640	1.243	54,828	*	*	*	*	988	43,606,284
	2004	2.770	120,018	1.150	49,850	*	*	*	*	1009	43,630,249
	2005	2.570	118,289	1.150	52,883	*	*	*	*	976	44,930,742
	2006	1.370	66,443	0.850	41,417	*	*	*	*	878	42,683,702
	2007	1.400	68,441	0.810	39,735	*	*	*	*	896	43,826,364
	2008	1.010	47,976	0.679	32,375	*	*	*	*	851	40,444,387
	2009	0.847	40,790	0.574	27,618	*	*	*	*	845	40,706,301
	2010	0.688	34,419	0.448	22,409	*	*	*	*	818	40,912,209
	2011	0.395	20,149	0.325	16,554	*	*	*	*	799	40,711,094
	2012	0.195	10,024	0.329	16,930	*	*	*	*	820	42,188,541
Projected	2013	0.048	2,597	0.129	6,940	*	*	*	*	682	36,558,000
	2014	0.045	2,547	0.116	6,482	*	*	*	*	683	38,278,000
	2015	0.059	3,347	0.123	6,989	*	*	*	*	691	39,325,000
	2016	0.068	3,972	0.110	6,423	*	*	*	*	681	39,946,000
	2017	0.048	2,876	0.109	6,493	*	*	*	*	689	41,167,000
	2018	0.064	3,885	0.110	6,698	*	*	*	*	694	42,084,000
	2019	0.064	3,852	0.107	6,453	*	*	*	*	694	41,870,000
	2020	0.072	4,358	0.111	6,766	*	*	*	*	702	42,764,000
	2021	0.077	4,711	0.113	6,908	*	*	*	*	707	43,237,000
	2022	0.069	4,278	0.103	6,375	*	*	*	*	669	41,383,000

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

- FPL projects future emissions based on the projected unit dispatch, net generation, and fuel types and quantities anticipated.
- CO2 emissions are based on EPA emission factors associated with each fuel type burned and the quantity of fuel burned.
- NOx projected emissions are based on unit emission curves and factors that have been derived from actual historical operation for each unit and anticipated level of emissions when NOx emission controls are in use.
- SO2 emissions are based on the fuel specifications, and associated fuel sulfur concentrations, which FPL anticipates using during the projected period and use of SO2 emission controls where applicable.
- Projected SO2 and NOx emissions are anticipated to be much lower during the site plan period due to: 1) Installation of pollution controls on active steam units and 2) more combined cycle units with low emission rates coming online.

Q.

Please indicate if your company will be materially affected by the new or proposed rules listed below. If the company will be affected by the rules, identify any compliance strategies the company intends to employ for each rule. If a compliance strategy has not been completed, explain the timeline for completion of the compliance strategy, including any regulatory approvals, for each rule.

a. Mercury and Air Toxics Standards (MATS) Rule

b. Cross-State Air Pollution Rule (CSAPR) or Clean Air Interstate Rule (CAIR) Rule

c. Cooling Water Intake Structures Rule (CWIS)

d. Coal Combustion Residuals Rule (CCR), both for classification of coal ash as a "Non-Hazardous Waste" and as a "Special Waste"

e. Florida's State Implementation Plan for Regional Haze

f. Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units

A.

a) MATS

The Mercury and Air Toxics Standards (MATS) rule finalizes the Maximum Achievable Control Technology (MACT) standards that EPA had proposed for the reduction of emissions of Hazardous Air Pollutants (HAPs) from coal and oil fired electric steam generating units. FPL must demonstrate compliance with the rule requirements by April of 2015 for its affected coal and oil fired electric steam generating units. FPL evaluated its compliance options for its oil units and decided the best compliance strategy for the rule would be the installation of ESPs on its Martin and Manatee 800 MW units, a limit on oil operation at its Turkey Point fossil steam units to current levels of operation, and the retirement of the Sanford fossil steam unit by the 2015 deadline. FPL has received air construction permits from the State of Florida that are required for installation of the ESPs. Construction of the ESP for Manatee Unit 2 has been completed and construction of the Unit 1 ESP is currently underway. Construction of the ESPs for the Martin units are scheduled for completion in 2014 and 2015. FPL's coal fired unit at plant Scherer was required to install controls to comply with the Georgia Multi-Pollutant rule which will also meet the compliance requirements of MATS. The evaluation of compliance strategies for the St. Johns River Power Park coal units was initiated in March of 2012 following the release of EPA's final MATS rule and has identified the top three least cost alternatives for which a more detailed engineering and cost study was initiated in March 2013. Results are anticipated late summer 2013.

b) CSAPR/CAIR

The EPA Cross-State Air Pollution Rule (CSAPR) was finalized in 2011 to replace the vacated CAIR. FPL's compliance plan for the CSAPR cap-and-trade program included controls installed at Plant Scherer for GMPR, the controls installed at SJRPP and the Martin and Manatee 800 MW Cycling Project for CAIR compliance, and the addition of the West County generating units to meet demand growth. FPL, along with industry groups including the Florida Coordinating Group, petitioned EPA to reconsider various aspects of its final rule. In December 2011, the D.C. Circuit Court of Appeals issued a stay for the implementation of CSAPR and ordered that CAIR be implemented while the Court considered the merits of a continuing stay and remand of CSAPR. On January 24, 2013, the Court of Appeals rejected EPA's petition for rehearing en banc. On March 29, 2013, EPA petitioned the US Supreme Court for review of the D.C. Circuit Court's opinion. While the regulatory certainty of CSAPR is unknown at this time, FPL's compliance plan to meet the rule requirements was the plan that had been implemented for compliance with the CAIR and Georgia Multi-Pollutant rules. Currently, FPL believes its allocation of allowances and reduced emissions from installation of controls and modernization of its generating units will result in sufficient allowances to comply with CAIR. FPL will continue to evaluate its compliance strategy including emission allowance market prices and whether further cost-effective reductions from generating units would provide its customers with reductions in environmental compliance costs through revenue from the sale of excess emission allowances. Additionally, FPL will continue to participate in responses to EPA and the DEP during the review and possible rewrite of CSAPR and the Court ordered replacement of CAIR.

c) CWIS

The final requirements of the 316 (b) Rule are not yet certain as the final Rule is not expected to be issued until at least June 27, 2013. FPL anticipates that EPA will make numerous revisions to the draft rule based on additional data and comments that will be submitted to the rulemaking record. As proposed, the rule would require each affected facility to develop compliance plans and comprehensive studies to determine the appropriate compliance measures to achieve the Best Technology Available (BTA) and meet entrainment and impingement reduction requirements. As proposed by the rule, the timeline to complete these analyses, studies and ultimate agency review and approvals may take up to eight years beyond the effective date of the rule. Until these studies and compliance options are reviewed, it is not possible to determine what the exact compliance controls and costs will be for each power plant affected by the rule. Generally, the implementation of the 316 (b) rule must take into account the site specific characteristics of each generating facility, the water body types that supply the intake structure and the types of aquatic organisms in the vicinity.

EPA's analyses presented in the draft Rule indicate that cooling towers may be BTA to reduce the impacts of cooling water intake structures. Though the addition of cooling towers could be required at some facilities under the proposed rule, they are not feasible at many locations due to impacts to endangered species such as manatees, spatial limitations and disproportionate costs versus benefits and therefore were not declared BTA for all facilities. FPL operates 10 (not including Cutler Power Plant) power plants in Florida that may be affected by the proposed 316 (b) rule and may require comprehensive studies to determine the BTA to meet the 316 (b) rule. If affected units at each of the six (6) power plants (not including Sanford Unit 3) that currently don't employ closed-cycle cooling (i.e., cooling towers or cooling ponds) were required to install cooling towers at each of these facilities, it is anticipated that the capital cost could be as high as $1.5 billion, based on costs estimates from the Electric Power Research Institute. However, we anticipate that, based on the current draft rule, most FPL facilities will not require to retrofit their cooling systems with cooling towers and will be able to meet the determinations of BTA by installing alternative controls such as wedge wire screens, advanced travelling screens with fish returns or reductions of intake flow velocities that would meet impingement criteria. If each facility affected by the proposed 316 (b) rule were capable of reducing intake flow velocities to meet the 0.5 feet per second rule, the costs for FPL plants to comply would be approximately $170 million, as compared to the approximately $1.5 billion estimated for cooling towers at these facilities.

FPL is also a co-owner of the Scherer Unit 4 and SJRPP coal-fired units. Both Scherer Unit 4 and SJRPP already have cooling towers to reduce the impacts of entrainment as required under the proposed 316 (b) rule. However, each of these facilities may have to evaluate the installation of additional impingement controls under the requirements included in the currently proposed rule. FPL does not agree with this requirement for additional impingement controls if a facility already meets the definition of a closed cycle cooling system through the use of cooling towers. We will include this comment in the record when we file comments with EPA. Since the rule is not final and these facilities have not completed their comprehensive studies to evaluate the type of impingement control that may be necessary we cannot provide a reasonable cost estimate to comply.

d) CCR

FPL does not operate any coal-fired power plants and hence is not directly responsible for coal combustion residual storage or disposal. However, FPL is a co-owner of two coal-fired units that are operated by others: Scherer Unit 4, which is operated by Georgia power Company (GPC); and the St. Johns River Power Park (SJRPP), which is operated by JEA. By contractual arrangement, FPL requires that all management activities be conducted in full compliance with existing regulations and prudent industry practices. FPL expects the operating partner to manage coal by-product storage and disposal programs consistent with prudent industry practices and in full compliance with any federal, state and local regulations. It is anticipated that whenever practical coal by-products will be beneficially used rather than placed for long term storage. EPA published the proposed rule in June 2010 and has since received over 450,000 comments from the public. FPL's current strategy to manage the CCR process includes the participation with various industry groups in petitioning EPA to maintain the current designation of coal combustion residuals as non-hazardous waste under the Federal Resource Conservation and Recovery Act (RCRA) Subtitle D (as EPA "D Prime" proposal) regulation, and to work with legislators in support of maintaining designation as non-hazardous. FPL advocates the development of a non-hazardous waste standard implemented by the states with the continued use of existing ash impoundments through their remaining useful life. For new facilities FPL supports the use of dry ash handling and lined landfill disposal. Compliance strategies will be developed in cooperation with the co-owners and operators of FPL's co-owned coal fired generating units once a final rule has been promulgated.

e) REGIONAL HAZE

FPL submitted to the Florida DEP its compliance plan, which was approved subsequently, for compliance with the BART and Regional Haze requirements and is not materially affected by this rule. FPL's plan requires that the Manatee Fossil Steam Units 1 & 2, and Turkey Point Fossil Unit 1 limit residual oil fuel purchases to 0.7% sulfur. FPL anticipates the lower sulfur fuel will remain readily available and priced similarly to the 1% sulfur oil which it replaces.

f) GHG NSPS for NEW UNITS

FPL's proposed construction of new fossil fuel electric generating units continues to utilize highly efficient natural gas fired combined cycle units. FPL's Best Available Control Technology analysis for its new combined cycle modernization units at Port Everglades Energy Center (PEEC) proposed a GHG limit of 850 lb CO_2/MWh. EPA's proposed limit for new units was set at 1000 lb CO_2/MWh, considerably higher than the proposed limit for PEEC. FPL is still in the permitting process with EPA for the required GHG permit and anticipates having a complete permit within 18 months of beginning that process. Challenges to EPA issued permits could result in review by the federal Environmental Appeals Board which potentially adds 1 year to the permitting process.

Q.

Please identify, for each unit affected by one or more of EPA's new or proposed rules, what the impact is for each Rule, including; unit retirement, curtailment, installation of additional emissions controls, fuel switching, or other impacts identified by the Company. As part of this response, please also provide the unit's name, type, fuel type, and net summer generating capacity. Please complete the table below and provide an electronic copy (in Excel).

Unit Impacts of EPA's New and Proposed Rules									
Unit	Unit Type	Fuel Type	Net Summer Capacity	Type of New and Proposed EPA Rule Impacts					Anticipated Impacts
				MATS	CSAPR/CAIR	CWIS	CCR		
			(MW)				Non-Hazardous Waste	Special Waste	

A.

See Attachment No. 1.

Q.

Please identify, for each unit impacted by one or more of the EPA's new or proposed rules, what the estimated cost is for implementing each Rule over the course of the planning period. As part of this response, please provide the unit's name, type, fuel type, and net summer generating capacity. Please complete the table below and provide an electronic copy (in Excel).

Estimated Unit Cost of EPA's New and Proposed Rules

Unit	Unit Type	Fuel Type	Net Sum Capacity (MW)	Estimated Cost of New or Proposed EPA Rules Impacts (2013 $ millions)					
				MATS	CSAPR/CAIR	CWIS	CCR Non-Hazardous Waste	CCR Special Waste	Total Cost

A.

Please see confidential Attachment No. 1. Attachment No. 1 is confidential and will be provided to the clerk with FPL's Notice of Intent to Request Confidential Classification.

Q.

Please identify, for each unit impacted by one or more of EPA's new or proposed rules, when and for what duration units would be required to be offline due to retirements, curtailments, installation of additional controls, or additional maintenance related to emission controls. Also include important dates relating to each rule. Please complete the table below and provide an electronic copy (in Excel).

Estimated Timing of Unit Impacts of EPA's New and Proposed Rules

Unit	Unit Type	Fuel Type	Net Sum Capacity (MW)	Estimated Timing of New and Proposed EPA Rule Impacts (Month/Year - Duration)				
							CCR	
				MATS	CSAPR / CAIR	CWIS	Non-Hazardous Waste	Special Waste

A.

Please see Attachment No. 1. Schedule for rule implementation is as follows:

MATS Key Dates:	
EPA Secretary Jackson signs final rule:	December 21, 2011
Final rule is published in federal Register:	March 16, 2012
Final Rule is Effective (60 days after publication):	May 15, 2012
Compliance with emission standards:	May 15, 2015
(For units adding emission controls):	May 15, 2016
CSAPR/CAIR Key Dates:	
EPA Secretary Jackson signs final rule:	July 6, 2011
Final rule is published in federal Register:	August 8, 2011
Technical adjustments (incl. Florida):	October 6, 2011
DC Circuit Court of Appeals stay issued:	December 30, 2011
CAIR Reinstated (while is stay in effect):	January 1, 2012
Court denies EPA petition:	January 24, 2013
EPA Petitions Supreme Court:	March 29, 2013
CWIS Key Dates:	
EPA Secretary Jackson signs final rule:	June 27, 2013
Final rule is published in federal Register (estimated):	July 15, 2013
Final Rule is Effective (60 days after publication):	September 13, 2013
Various studies required:	2014 - 2018
Compliance with Impingement Mortality Standards (5- 8 years after rule is effective):	September 13, 2021
Compliance with Entrainment Standards:	No set date
CCR Key Dates:	
Proposed Rule published in Federal Register:	June 21, 2010
Consent Order for EPA to issue Rule:	April 5, 2012
Final Rule (estimated):	Late 2013 - Mid 2014

Q.

From a system-wide perspective, provide a preliminary estimate of the cost associated with each EPA Rule over the planning period, 2013 through 2022 expressed in 2013 dollars. As part of this response, please include the estimated additional capital cost expenditures, O&M costs, and impact on generation costs associated with each rule. Please complete the table below and provide an electronic copy (in Excel).

Estimated Cost of EPA's New and Proposed Rules				
	Impacts (2013 $ millions)			
EPA Rule	Capital Costs	O&M Costs	Fuel Costs	Total Costs
Mercury and Air Toxics Standards (MATS) Rule*				
Cross-State Air Pollution Rule (CSAPR)**				
Cooling Water Intake Structures Rule (CWIS)				
Coal Combustion Residuals Rule (CCR)				

A.

See Attachment No. 1.

Estimated Cost of EPA's New and Proposed Rules				
EPA Rule	Estimated Cost of New or Proposed EPA Rules Impacts (2013 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
Mercury and Air Toxics Standards (MATS) Rule*	$223	$6	(N/A)***	$226
Cross-State Air Pollution Rule (CSAPR)**	$0	$7	(N/A)***	$0
Cooling Water Intake Structures Rule (CWIS)	$95-$1339	$27-$176	(N/A)***	$122 - $1515
Coal Combustion Residuals Rule (CCR)	Waiting for Final Rule	Waiting for Final Rule	(N/A)***	Waiting for Final Rule

Note: * Includes O&M costs for complaince with CAMR & Georgia Multi-Pollutant Rule

** Includes O&M costs for complaince with CAIR & Georgia Multi-Pollutant Rule

*** FPL has not currently forecasted changes to unit operation or dispatch that would result in fuel changes

Q.

Explain any expected reliability impacts resulting from each of the EPA Rules listed below. As part of this discussion, include the impact of transmission constraints and units not modified by the rule, that may be required to maintain reliability if unit retirements, curtailments, additional emissions control upgrades, or longer outage times are impacts of the EPA Rules.

a. Mercury and Air Toxics Standards (MATS) Rule
b. Cross-State Air Pollution Rule (CSAPR) or CAIR Rule
c. Cooling Water Intake Structures Rule (CWIS)
d. Coal Combustion Residuals Rule (CCR)
e. Florida's State Implementation Plan for Regional Haze

A.

FPL does not anticipate any system reliability impacts associated with the compliance requirements of the MATS Rule, CSAPR Rule, CWIS Rule, CCR Rule, or Florida's State Implementation Plan for Regional Haze including generating unit reliability, transmission system constraints, and installation of controls on units not regulated by these rules, nor does FPL anticipate early retirement of units in response to these regulations. FPL evaluates the potential impacts to unit operation based on proposed and draft rule language that identifies compliance requirements for environmental regulations. For the final MATS and CSAPR rules FPL has not identified any impacts to unit or system reliability, or capability, from its planned compliance strategy. With the Court's stay of the CSAPR, the EPA was required to implement the CAIR requirements instead of CSAPR until the stay is lifted or a replacement rule is promulgated. FPL's CAIR compliance plan has not, and will not, impact generating unit or system reliability or capability. FPL's projected compliance plan is based on current fuel availability and price forecasts, planned generating unit availability, purchase power contracts, and projected system load. However, should future actual conditions vary significantly from projection assumptions, reliability impacts could occur.

For the CWIS and CCR rules FPL has evaluated anticipated compliance requirements based on EPA and industry comments, but cannot yet know the appropriate compliance strategy until the final rules are promulgated. FPL has evaluated the potential requirements and developed a range of costs associated with the various compliance requirements that we anticipate could be included in the final rules. Impacts for CWIS will vary based on the level of modifications required by the final rule and the results of subsequent studies and negotiations with FDEP permit writers. Should, as is currently expected, modified Ristroph type traveling screens and fish return systems, along with the possibility of variable speed drive circulating (cooling) water pumps be required, for most facilities (those without cooling ponds or cooling towers), the impacts should be minimal where installations could be accommodated during scheduled maintenance outages. Under the anticipated rule requirements for CWIS, FPL has not identified system reliability impacts which would be anticipated to occur. FPL's compliance plan for the proposed CCR regulations depends on the final form of the regulation and the outcome of any legal challenges, and cannot be determined at this time given the breadth of requirements being considered under the three approaches proposed by EPA. While FPL, and the co-owners of its coal fired generating units, maintain that the appropriate designation of CCRs continue as non-hazardous, additional regulation of coal combustion by-products could have a significant impact on management, beneficial use, and disposal of such by-products. Impacts for compliance with changes in the regulatory status of CCRs for FPL's co-owned coal units are not anticipated to create impacts to the reliability of any generating unit or FPL's system.

FPL's approved plan for compliance with BART and Florida's Regional Haze Reasonable Further Progress State Implementation Plan requires that FPL limit operation of the Manatee Fossil Steam Units 1 & 2 and Turkey Point Fossil Steam Unit 1 to 0.7% sulfur residual oil and to retain Turkey Point Fossil Unit 2 in the synchronous condensor mode for transmission support. FPL plan retains fuel diversity at these locations and does not anticipate any impacts to the availability of the 0.7% residual fuel oil.

Q.

If applicable, identify any currently approved costs for environmental compliance investments made by your company which would mitigate the need for future investments to comply with recently finalized or proposed EPA regulations.

A.

Three examples of currently approved environmental compliance investments which helped mitigate future investments include, but are not limited to:

- Compliance plans implemented for CAIR and approved for recovery were sufficient to meet CSAPR rule requirements. Unless EPA significantly modifies CAIR in its future replacement rule, FPL believes its CAIR projects will meet the fine particle and ozone NAAQS requirements.
- Installation of Sorbant Injection/ Baghouse, SCR, and Scrubber on Scherer Unit 4 for compliance with the Georgia Multi-Pollutant Rule which mitigated most of the potential costs for compliance with the Mercury and Air Toxics Standards (MATS) and with requirements associated with both the Clean Air Interstate Rule and the Cross State Air Pollution Rule.
- Installation of SCR on SJRPP for the Clean Air Interstate Rule which reduces air emissions of mercury compounds near those levels required by the MATS rule.

Q.

Please indicate if your company has filed any comments with EPA during EPA's rule development proceedings for the following:

a. Mercury and Air Toxics Standards (MATS) Rule

b. Cross-State Air Pollution Rule (CSAPR) or CAIR Rule

c. Cooling Water Intake Structures (CWIS) Rule

d. Coal Combustion Residuals (CCR) Rules

e. Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units

A.

Yes, FPL has submitted comments in the rule development of MATS, CSAPR/CAIR, CWIS, CCR, and GHG NSPS for Utility Units.

Q.

On August 21, 2012, the U.S. Circuit Court of Appeals decided to vacate the CSAPR Rule. Has the Court's order to vacate the CSAPR Rule and require EPA to continue administering the CAIR Rule impacted your compliance strategies? If so, how?

A.

FPL's strategy for compliance with the Cross-State Air Pollution Rule's (CSAPR) cap-and-trade program was primarily based on the implementation and use of those projects identified for compliance with the predecessor Clean Air Interstate Rule, and Scherer Unit 4 compliance with the Georgia Multi-pollutant Rule. FPL petitioned EPA to reconsider applicability of the rule to Florida and, in the alternative, to reconsider its model assumptions which led to a lower allocation of allowances to the State of Florida. With the stay of CSAPR the Court instructed EPA to reinstitute the compliance requirements under CAIR until either the stay is lifted or EPA promulgates a CSAPR replacement rule. As a result of FPL's CAIR projects, and the addition of the West County and modernization projects at Cape Canaveral and Riviera, there are sufficient allocated allowances for compliance with the either the CSAPR and CAIR allowance programs. The Court's decision to vacate the CSAPR does not impact FPL's compliance plan for either program. While the EPA has petitioned for a writ of certiorari before the Supreme Court, FPL anticipates that the court will reject the petition leaving EPA with the task of rewriting a new rule that will address the newest NAAQS standards as well. FPL's compliance plans for CAIR will be sufficient to meet a revised CSAPR rule. However, FPL does not yet know whether EPA would make significant changes to the CSAPR replacement rule beyond those that would be required to meet the air quality goals required by the rule that would adversely impact current compliance plans.

Q.

Please discuss the impacts, if any, the Stationary Reciprocating Internal Combustion Engines (RICE) Rule will have on your company.

A.

EPA's final RICE rule (also known as the National Emission Standards for Hazardous Air Pollutants, or "NESHAP") amended requirements for engines that are categorized as emergency and non-emergency. Presently, equipment that FPL owns and operates are for emergency use and are subject only to those requirements under the rule.

FPL stationary equipment that is subject to the requirements for emergency equipment include emergency fire pumps and generators located at FPL's fossil and nuclear generating stations, transmission and distribution service centers, regional dispatch centers and corporate offices. In general, impacts of the emergency engine requirements include new record-keeping requirements, notifications required to the state and regional EPA agencies, additional maintenance requirements, restrictions on non-emergency use for maintenance and testing, and potential costs related to permitting requirements of the Florida Department of Environmental Protection (FDEP). In addition to the direct costs for compliance with the maintenance requirements, FPL has identified additional costs for its nuclear facilities where additional backup temporary sources may be required on-site during certain maintenance activities as required by the Nuclear Regulatory Commission (NRC).

This rule also impacts certain backup generators used by many commercial/industrial customers that participate in FPL's load management programs. FPL's currently approved programs and associated tariffs permit load management in situations that do not meet the EPA's new definition of "emergency" events. FPL's commercial/industrial load management programs are currently projected to have about 750 MW of demand reduction capability by August 2013. It is FPL's understanding that a large percentage of the participating customers use backup generators as the means to reduce their load on FPL's system when called upon to do so (though FPL notes that having a backup generator is not a program participation requirement). Many of these participants with backup generators will be affected by the EPA's NESHAP rule. As a result of the EPA's rule, affected participants may request to terminate program participation, which would result in a decrease in the MWs available from the program. Additionally, FPL believes the increased costs imposed by the EPA's rule will reduce the expected recruitment of new participants in the company's Commercial/Industrial Demand Reduction (CDR) program. FPL is currently evaluating these potential impacts.

Q.

Please discuss your company's current coal residual disposal practices for each coal generating facility.

A.

Florida Power and Light Company (FPL) is a co-owner of units at two generating stations, Georgia Power - Plant Scherer and JEA - St Johns River Power Park (SJRPP). FPL does not operate either plant. While FPL has a membership vote in decisions regarding operation of these generating units, decisions regarding coal residual disposal practices are decided by the managing boards for those plants. By contractual arrangement FPL does require that all management activities be conducted in full compliance with existing regulations and prudent industry practices. For SJRPP, the solid fuel combustion byproducts that have not been transported off-site for sale have been placed in the on-site dry byproduct storage areas (BSAs). Bottom ash and pyrites are loaded by conveyor belts from the dewatering bins to a load-out area to either be transported off-site for beneficial use or transported, via rear dump truck, to the on-site BSA. Fly ash is transported to the on-site BSA or off-site for beneficial use. The solid waste handling system is also designed to load the material into rail cars for transport off-site for beneficial use. A major goal and objective of the SJRPP Coal Combustion Residual program is to develop markets for the solid waste by-products to reduce and/or curtail the placement into the on-site byproduct storage area. For the Scherer Unit 4, byproducts are both disposed and sold for beneficial reuse depending on market conditions and product quality. Plant Scherer Unit 4 disposes coal combustion residuals in one landfill and one ash pond, which each serves all four units at the plant. Coal combustion residuals that are not beneficially reused are sluiced wet to the ash pond for storage. Powdered Activated Carbon and Gypsum are stored in the on-site landfill.

Q.

Please briefly discuss your company's efforts to facilitate the recycling of coal waste into beneficial products. What percentage of your company's coal waste is used for beneficial purposes?

A.

As discussed in FPL's response to Staff's First Data Request No. 51, FPL co-owns but does not operate its coal fired generating units. Efforts to facilitate the recycling of coal waste are conducted by the operators of each facility as agent for the owners.

SJRPP has had an aggressive by-product marketing program in place since it began operations in the late 1980s. SJRPP has pursued the following markets for its by-products: use of synthetic gypsum in wallboard and agronomic applications, use of fly ash as cement plant feed or fuel, and use of fly and bottom ash in concrete batch plants and other aggregate markets. Since 2004, overall by-product utilization rates have approached 75%, but recent declines in construction activity in Florida and the Southeast have adversely impacted markets. Utilization rates for the last several years have declined to approximately 50%.

The operator of Plant Scherer, Georgia Power, has contracted with a leading ash marketer that sells Plant Scherer's fly ash for multiple beneficial uses such as concrete, mineral filler, and exterior trim. The Georgia Power ash marketer has an active research facility that continually develops new and better uses of fly ash to improve products and to benefit the environment through increased recycling. Additionally, Georgia Power continuously seeks additional opportunities to beneficially reuse Coal Combustion By-products.

Q.

Please provide, on a system-wide basis, the historic annual fuel usage (in GWh) and historic average fuel price (in nominal $/MMBTU) for each fuel type utilized by the company in the period 2003 through 2012. Also, provide the forecasted annual fuel usage (in GWh) and forecasted annual average fuel price (in nominal $/MMBTU) for each fuel type forecasted to be used by the Company in the period 2013 through 2022. Please complete the table below and provide an electronic copy (in Excel).

Average Fuel Price Comparison

Year		Uranium		Coal		Natural Gas		Residual Oil		Distillate Oil	
		GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU
Actual	2003										
	2004										
	2005										
	2006										
	2007										
	2008										
	2009										
	2010										
	2011										
	2012										
Projected	2013										
	2014										
	2015										
	2016										
	2017										
	2018										
	2019										
	2020										
	2021										
	2022										

A.

See Attachment No. 1.

Year		Uranium		Coal		Natural Gas		Residual Oil		Distillate Oil	
		GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU
Actual	2003	23,524	0.255	6,625	1.830	37,707	6.237	20,304	4.460	248	7.135
	2004	23,013	0.277	6,315	1.686	40,970	6.370	19,709	4.429	199	7.959
	2005	21,406	0.321	5,765	1.724	47,114	8.533	19,069	6.164	186	12.093
	2006	23,533	0.376	6,168	2.031	56,985	8.806	9,586	8.154	26	13.876
	2007	21,899	0.380	6,856	2.122	59,300	9.703	9,651	9.306	27	14.472
	2008	24,024	0.427	6,423	2.238	58,820	10.245	5,702	10.298	17	15.834
	2009	22,893	0.512	6,363	2.443	62,728	8.188	4,560	10.645	21	14.063
	2010	22,850	0.549	5,721	2.587	66,765	6.356	4,081	11.486	278	13.841
	2011	22,942	0.608	5,634	2.844	74,388	5.832	630	12.926	123	19.465
	2012	16,916	0.566	4,745	2.885	80,505	4.965	378	13.811	54	20.516
Projected	2013	27,184	0.726	4,884	2.704	74,686	3.706	246	16.942	4	24.175
	2014	27,812	0.747	5,211	2.714	78,694	4.232	198	16.310	23	23.447
	2015	27,986	0.756	5,931	2.792	79,346	4.428	309	15.804	44	22.434
	2016	28,609	0.775	5,400	2.872	82,585	4.679	368	15.101	139	23.485
	2017	28,295	0.795	6,069	2.803	84,751	5.031	162	15.016	46	23.502
	2018	27,967	0.816	6,088	2.978	86,762	5.853	228	16.191	8	25.130
	2019	28,568	0.837	6,609	3.744	85,118	6.395	174	16.542	2	25.646
	2020	28,193	0.856	6,890	3.887	86,353	6.936	213	16.847	5	26.534
	2021	27,977	0.879	7,073	3.974	86,933	7.333	230	17.527	8	27.943
	2022	33,482	0.897	7,066	4.060	82,739	7.646	157	18.352	2	29.408

Q.

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

A.

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

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

Q.

Please identify and discuss expected industry trends and factors for each fuel type (coal, natural gas, nuclear fuel, oil, etc.) that will affect the Company during the period 2013 through 2022.

A.

Coal prices are expected to slowly increase over the 2013 through 2022 period as worldwide demand growth, primarily in the Pacific Rim countries, places upward pressure on domestic and imported coal prices throughout the period. The supply of domestic coal and the availability of imports will be sufficient to meet a stable to very slow growth in domestic demand over the period.

The demand for natural gas in the United States as well as in the Florida market is expected to continue to grow through the 2013 through 2022 period, primarily in the power generation sector. The supply of natural gas to the United States as well as to the Florida markets is expected to grow and match the growth in demand as declines in production from the mature conventional gas regions of the Gulf Coast onshore, Gulf Coast offshore, and Permian Basin are replaced with rapid growth in unconventional gas mainly from the Mid-Continent and Central Appalachian regions. This will result in natural gas prices increasing moderately over the 2013 through 2022 period.

Similarly, fuel oil prices will increase moderately over the 2013 through 2022 period. The worldwide demand for fuel oil will grow over the forecast horizon primarily in the emerging market countries in the Pacific Rim and in the transportation and distillate end-use sector. Non-OPEC supply is projected to grow moderately over this period and OPEC production will grow to fill the supply shortfall.

The uranium price increased during the second half of 2010 due primarily to the news of a significant increase in the future uranium demand to feed an increase in the number of new reactors that the Chinese planned to build. The earthquake and tsunami that struck Japan in March 2011 reversed that trend when all of the Japanese reactors were shut down and several other countries initiated abandonment of their nuclear programs. The market has drifted down since then and returned last summer to the levels that existed prior to the late 2010 uranium price increase. This downward drift was aided by the decision by the Department of Energy to sell some of its excess uranium inventories to fund the decontamination and decommissioning activities of old uranium enrichment plants. At this time uranium demand is rather stable and supply exceeds current demand. FPL expects less volatility in uranium prices in the next few years, with price behavior to be more consistent with market fundamentals.

The events in Japan have also had a significant impact on the enrichment services market. To date that market has declined by about 20% and further small declines are possible before the market stabilizes again. The timing of the return of the nuclear reactors in Japan, if they return at all, will play an important role in the future enrichment price.

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

Q.

Please identify and discuss steps that the Company has taken to ensure natural gas supply availability and transportation over the 2013 through 2022 planning period.

A.

FPL continues to evaluate strategies that will increase the reliability and supply diversity of its gas transportation portfolio to ensure adequate gas availability for future generation growth. The current gas transportation portfolio provides FPL access to a diverse range of gas supply alternatives, which helps mitigate FPL's exposure to supply disruptions. FPL has secured natural gas transportation on a number of upstream pipelines with access to onshore natural gas supplies which has significantly reduced its dependence on Gulf of Mexico supplies, thereby decreasing the exposure to tropical events. In addition, FPL has contracted for natural gas storage to provide access to natural gas in the event of a loss of supply. To meet FPL's anticipated gas transportation needs during the planning period, FPL issued a Firm Gas Transportation Request for Proposals (RFP) on December 19, 2012. FPL is currently evaluating the proposals submitted in response to this RFP and expects to execute agreements with the winning bidders by July 15, 2013.

Q.

Please identify and discuss any existing or planned natural gas pipeline expansion project, including new pipelines and those outside of the State of Florida, that would affect the Company for the period 2013 through 2022.

A.

FPL is currently in the process of constructing a pipeline lateral from the Martin facility to the Riviera Beach Next Generation Clean Energy Center (RBEC) which will provide the primary gas delivery to RBEC. In addition, the winning proposals from FPL's Firm Gas Transportation Request for Proposals (RFP) will introduce new pipeline capacity into Florida with a scheduled in-service date of May 1, 2017. Outside of Florida, both Transcontinental Gas Pipe Line (Transco) and Gulf South Pipeline Company, LP (Gulf South) have announced expansions into Florida Gas Transmission (FGT) and Gulfstream Natural Gas (Gulfstream) systems, which would provide additional capacity to transport shale gas into Florida starting in the 2014-2015 timeframe. Several other pipelines are also exploring projects which will allow their existing pipeline facilities to deliver gas from the prolific Marcellus and Utica shale regions of Pennsylvania and Ohio to the Southeast. FPL continues to explore opportunities to access these growing supply sources.

Q.

Please identify and discuss expected liquefied natural gas (LNG) industry factors and trends that will impact the Company, including the potential impact on the price and availability of natural gas, for the period 2013 through 2022.

A.

Liquified Natural Gas (LNG) exports from the U.S. are not expected to begin until 2016, assuming the U.S. price of natural gas continues to be lower than European and Asian prices, which creates an economic incentive to export, due to the amount of time it takes to receive a Federal Government export license, and the cost and time associated with converting LNG import terminals to export terminals. If U.S. prices remain lower than European and Asian prices, exports are expected to grow from about 0.3 billion cubic feet per day (Bcf/day) in 2016 to about 7.0 Bcf/day by 2022. This level of LNG exports represents less than 8% of the total U.S. supply over the 2016 through 2022 period, and is likely to have minimal impact on FPL's projected natural gas supply and price to customers.

Q.

Please identify and discuss the Company's plans for the use of firm natural gas storage for the period 2013 through 2022.

A.

Bay Gas Storage:

FPL is under contract for 2.5 billion cubic feet (Bcf) of firm natural gas storage capacity in the Bay Gas storage facility located in Alabama. The Bay Gas storage facility is interconnected with the Florida Gas Transmission (FGT) pipeline and the Transcontinental Pipeline (Transco) 4A Lateral.

FPL has predominately utilized natural gas storage to help mitigate gas supply problems caused by severe weather and/or infrastructure problems. Over the past several years, FPL has acquired upstream transportation capacity on several pipelines to help mitigate the risk of offshore supply problems caused by severe weather in the Gulf of Mexico. While this transportation capacity has reduced FPL's offshore exposure, a portion of FPL's supply portfolio remains tied to offshore natural gas sources. Therefore, natural gas storage remains an important tool to help mitigate the risk of supply disruptions. For these reasons, FPL has typically maintained nearly full natural gas inventory during normal operations from June through November (hurricane season). From December through March, FPL typically maintains lower levels of natural gas inventory when compared to peak months.

As FPL's reliance on natural gas has increased, its ability to manage the daily "swings" that can occur on its system due to weather and unit availability changes has become more challenging, particularly from oversupply situations. Natural gas storage is a valuable tool to help manage the daily balancing of supply and demand. From a balancing perspective, injection and withdrawal rights associated with storage have become an increasingly important part of the evaluation of overall storage requirements.

Future Natural Gas Storage

The Bay Gas storage contract is a one year contract with extension options. FPL continues to evaluate its future natural gas storage needs and may add additional storage as FPL's dependency on natural gas increases in the coming years.

Q.

Please identify and discuss expected coal transportation industry trends and factors, for transportation by both rail and water, that will impact the Company during the period 2013 through 2022. Please include a discussion of actions taken by the Company to promote competition among coal transportation modes, as well as expected changes to terminals and port facilities that could affect
coal transportation.

A.

FPL does not anticipate being impacted to a significant extent by evolving rail industry trends and factors in the period 2013 through 2022.

Downturns in the US economy typically cause the railroads to furlough employees which can hamper their ability to respond to changes in customer needs.

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

Emerging technology could alter railroad operations and the underlying cost structure. A plan by the Plant Scherer co-owners, including FPL, to evaluate electronic brakes by placing a test train provided by the Norfolk Southern (NS) in service, remains on hold. If the Scherer test and other industry tests of electronic braking systems are ultimately successful, the Federal Rail Administration could mandate the technology and the retrofitting of existing railcar fleets.

The Burlington Northern Santa Fe (BNSF) railroad has sought to regulate coal dust released from open top rail cars in transit from Wyoming's Powder River Basin (PRB). Shippers have challenged the BNSF coal dust tariffs in proceedings before the STB. The final ruling could ultimately have transportation implications for the Plant Scherer co-owners, including FPL.

The need to update the Uniform Rail Cost System (URCS) utilized by the STB in rail rate cases continues to be discussed. The impact a revision to the current, long-running, methodology might have on future rates is unknown.

There are no water transportation implications for inland Plant Scherer.

Recurring issues for the St. John's River Power Park (SJRPP) include dredging and constraints imposed by the Jones Act. SJRPP is responsible for maintenance dredging at the St. Johns River Coal Terminal (SJRCT). Disposal of dredge material, while always a concern, has not been and is not currently an issue. However, circumstances could change during the period. Dredging of the main channel is the responsibility of the U.S. Army Corps of Engineers (ACOE). Should proper funding not be available to the ACOE on a timely basis, when and if conditions warrant future dredging, vessel access to SJRCT could be constrained, thereby impacting rates.

There are a limited number of Jones Act vessels and ocean-going barges. If demand for the shipment of domestic coal or petroleum coke between U.S. ports should exceed supply at any time between 2013 and 2022, alternative fuel supply chains would have to be considered and shipping costs could be impacted. The rapidly expanding demand for coal in China, India and other developing countries could indicate that factors impacting vessel/ocean barge transportation to SJRPP might change more frequently and rapidly between 2013 and 2022. Existing agreements would mitigate the impact to contract purchases, although, spot transactions would be immediately affected.

Q.

Please identify and discuss any expected changes in coal handling, blending, unloading, and storage for any planned changes and construction projects at coal generating units for the period 2013 through 2022.

A.

FPL does not expect any significant changes at SJRPP or Plant Scherer related to coal handling, blending, unloading or storage during the period 2013 through 2022.

Q.

Please identify and discuss the Company's plans for the storage and disposal of spent nuclear fuel for the period 2013 through 2022. As part of this discussion, please include the Company's expectation regarding short-term and long-term storage, dry cask storage, litigation involving spent nuclear fuel, and any relevant legislation.

A.

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

On March 3, 2010, the U.S. Department of Energy filed a motion with the Nuclear Regulatory Commission to withdraw the license application for a high-level nuclear waste repository at Yucca Mountain with prejudice. In light of the decision not to proceed with the Yucca Mountain nuclear waste repository, the President directed the Secretary of Energy to establish a Blue Ribbon Commission on America's Nuclear Future to conduct a comprehensive review of policies for managing the back end of the nuclear fuel cycle and to provide recommendations for developing a safe, long-term solution to managing SNF and nuclear waste. DOE's withdrawal was denied by the NRC's Atomic Safety and Licensing Board. On appeal, the Commission split evenly on the question of whether DOE was allowed to withdraw the application, but allowed the termination of the licensing proceeding due to budgetary constraints.

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

Q.

Please identify and discuss expected uranium production industry trends and factors that will affect the Company during the period 2013 through 2022.

A.

Please see FPL's response to Staff's First Data Request No. 55.

Q.

Please identify and discuss expected fuel oil transportation industry trends and factors that will affect the Company during the period 2013 through 2022.

A.

Heavy Fuel Oil

The industry consensus is that Panamax freight rates worldwide should remain flat during the balance of 2013. This has been a predicted reality since 2012 with spot and time charter rates remaining fairly stable. Time charter rates for first class Panamax ships have gone from a $18,000 per day high in the spring of 2012 to the current market rate of $17,000 per day. The new build order book offsets the phase out schedule to some extent, supporting the flat market outlook for 2013. However, the new build order book is expected to be weaker than predicted due to financial issues with the yards and ship owners. Market recovery is predicted to occur in late 2013/early 2014 when many older ships have been phased out due to stricter regulations. The projected escalation schedule for Panamax tankers during the 2013 to 2023 period is listed below:

Panamax/ Ocean Going Barge 12 month time charter:
2013: $17,000
2014: $18,000
2015: $19,500
2016: $20,500
2017: $21,000
2018: $23,000
2019: $24,000
2020: $25,000
2021: $26,000
2022: $27,000
2023: $28,000

The cost for U.S. flagged, ocean-going fuel oil barges, which deliver the majority of fuel oil to FPL, has increased significantly over the past year. Domestic crude oil production increases, and the corresponding demand for ocean-going fuel oil barges, have made availability very sporadic and unpredictable. The rate for a 150,000 barrel barge was $18,000 - $24,000 per day prior to 2012. While there are many barges contracted for existing charters at these levels for several years forward, new charter rates have risen dramatically over the past 6 months with some barges attaining $50,000 per day for 12-month contracts. The lack of available barge tonnage is expected to continue until pipeline and rail transport becomes more effective over the next few years. Barge rates are expected to remain at these elevated levels until 2015.

Distillate Fuel Oil
All of FPL's distillate fuel oil requirements are met with truck deliveries. The freight rates for truck deliveries have generally followed the U.S. inflation rate. During the period from 2013 through 2023, FPL expects this trend to continue.

Q.

Please provide a list of all proposed transmission lines in the planning period that require certification under the Transmission Line Siting Act. Please also include those that have been approved, but are not yet in-service. Please complete the table below and provide an electronic copy (in Excel).

Transmission Projects Requiring TLSA Approval

Transmission Line	Line Length	Nominal Voltage	Date Need Approved	Date TLSA Certified	In-Service Date
	(Miles)	(kV)			

A.

See Attachment No. 1.

Transmission Projects Requiring TLSA Approval

Transmission Line	Line Length	Nominal Voltage	Date Need Approved	Date TLSA Certified	In-Service Date
	(Miles)	(kV)			
Manatee - Bobwhite	30	230		November 6, 2008	December 1, 2014
St Johns - Pringle	25	230		April 21, 2006	December 1, 2016