FPL

William P. Cox
Senior Attorney
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420
(561) 304-5662
(561) 691-7135 (Facsimile)

May 15, 2019

-VIA ELECTRONIC FILING-

Mr. Adam Teitzman
Commission Cle
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallassee, FL 32399-0850

Re: Florida Power & Light Company's 2019 Ten Year Power Plant Site Plan
Docket 20190000-OT (Undocketed filings for 2019)

Dear Mr. Teitzman:

Please find enclosed for electronic filing Florida Power & Light Company's response to Staff's First Supplemental Data Request (Nos. 2-82)

If there are any questions regarding this transmittal, please contact me at 561-304-5662.

Sincerely,

s/ William P. Cox

William P. Cox
Senior Attorney
Florida Bar No. 0093531

Enclosure

cc: Douglas Wright / Philip Ellis, Division of Engineering

QUESTION:
Please provide all data requested in the attached forms labeled “Appendix A.” If any of the requested data is already included in the Company’s 2019 TYSP, state so on the appropriate form.

RESPONSE:
Please see Appendix A contained in Attachment No. 1 to this response.

QUESTION:
[Investor-Owned Utilities Only] Please provide, on a system-wide basis, the hourly system load for the period January 1, 2018, through December 31, 2018, in Microsoft Excel format.

RESPONSE:
Please see Attachment No. 1 to this response.

QUESTION:
Please provide the monthly peak demand experienced in the period 2016-2018, including the actual peak demand experienced, the amount of demand response activated during the peak, and the estimated total peak if demand response had not been activated. Please also provide the day, hour, and system-average temperature at the time of each monthly peak.

Historic Peak Demand Timing & Temperature

Year	Month	Actual Peak Demand (MW)	Demand Response Activated (MW)	Estimated Peak Demand (MW)	Day	Hour	System-Average Temperature (Degrees F)
2018	1						
	2						
	3						
	4						
	5						
	6						
	7						
	8						
	9						
	10						
	11						
	12						
2017	1						
	2						
	3						
	4						
	5						
	6						
	7						
	8						
	9						
	10						
	11						
	12						
2016	1						
	2						
	3						
	4						
	5						
	6						
	7						
	8						
	9						
	10						
	11						
	12						
Notes							
(Include Notes Here)							

RESPONSE:
Please see Attachment No. 1 to this response.

Florida Power & Light Company
2019 Ten-Year Site Plan
Staff's Supplemental Data Request # 1
Question No. 4
Attachment No. 1

Historic Peak Demand Timing & Temperature

Year	Month	Actual Peak Demand (MW)	Demand Response Activated (MW)	Estimated Peak Demand (MW)	Day	Hour	System-Average Temperature (Degrees F)
2018	1	19,109	0	19,109	1/5/2018	7-8 AM	42
	2	17,492	0	17,492	2/21/2018	3-4 PM	81
	3	17,887	0	17,887	3/1/2018	3-4 PM	82
	4	19,348	0	19,348	4/9/2018	6-7 PM	83
	5	19,595	0	19,595	5/7/2018	4-5 PM	84
	6	22,254	0	22,254	6/22/2018	3-4 PM	88
	7	22,528	0	22,528	7/2/2018	4-5 PM	88
	8	23,217	0	23,217	8/9/2018	3-4 PM	90
	9	23,187	0	23,187	9/17/2018	4-5 PM	89
	10	21,781	0	21,781	10/15/2018	3-4 PM	87
	11	19,649	0	19,649	11/8/2018	2-3 PM	84
	12	18,088	0	18,088	12/3/2018	2-3 PM	85
2017	1	16,535	0	16,535	1/3/2017	2-3 PM	83
	2	17,172	0	17,172	2/28/2017	3-4 PM	80
	3	18,029	0	18,029	3/29/2017	4-5 PM	82
	4	20,474	0	20,474	4/27/2017	4-5 PM	86
	5	22,311	0	22,311	5/30/2017	3-4 PM	88
	6	22,176	0	22,176	6/22/2017	4-5 PM	88
	7	23,109	0	23,109	7/27/2017	3-4 PM	91
	8	23,373	0	23,373	8/9/2017	4-5 PM	90
	9	23,243	0	23,243	9/1/2017	3-4 PM	91
	10	21,276	0	21,276	10/9/2017	3-4 PM	88
	11	18,126	0	18,126	11/9/2017	2-3 PM	84
	12	17,091	0	17,091	12/8/2017	2-3 PM	84
2016	1	16,934	0	16,934	1/1/2016	2-3 PM	81
	2	17,031	0	17,031	2/11/2016	7-8 AM	47
	3	19,190	0	19,190	3/15/2016	5-6 PM	83
	4	20,061	0	20,061	4/29/2016	4-5 PM	83
	5	20,392	0	20,392	5/3/2016	3-4 PM	84
	6	22,528	0	22,528	6/14/2016	3-4 PM	91
	7	23,858	0	23,858	7/6/2016	4-5 PM	90
	8	23,645	0	23,645	8/22/2016	4-5 PM	91
	9	21,574	0	21,574	9/9/2016	4-5 PM	88
	10	20,809	0	20,809	10/4/2016	4-5 PM	85
	11	17,240	0	17,240	11/2/2016	3-4 PM	81
	12	17,815	0	17,815	12/19/2016	2-3 PM	84

Notes

(Include Notes Here)

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

RESPONSE:
System-wide temperatures are calculated using hourly temperatures from four locations 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.

QUESTION:
Please explain how the Company's load and demand forecasting used in its 2019 TYSP was developed. In your response please include the following information: methodology, assumptions, data sources, third-party consultant(s) involved, and any difference/improvement made compared with the load and demand forecasting used in the Company's 2018 Ten-Year Site Plan.

RESPONSE:
Net Energy for Load ("NEL")
FPL uses a daily econometric model to produce a NEL per customer forecast. The inputs to the model include Florida real per capita income weighted by the percent of the population that is employed, and a price term to reflect increases in the real price of electricity. The model also includes daily weather variables for cooling degree-hours based on 68° F, heating degree-days based on 62° F for the winter months, and quadratic terms for both cooling degree-hours and heating degree-days. The economic data used in the NEL model are obtained from IHS Markit.

A composite hourly temperature profile is derived using hourly temperatures obtained from WSI, from four locations across FPL's service territory. Miami, Ft. Myers, Daytona Beach, and West Palm Beach are the locations where temperatures are obtained. In developing the composite hourly profile, these regional temperatures are weighted by regional energy sales. The resulting composite temperature is used to derive projected cooling degree-hours and heating degree-days. In addition, the NEL per customer model includes a variable for energy efficiency codes and standards, a dummy variable for weekends/holidays, and variables to account for the impact of Hurricane Irma in 2017. Finally, there are autoregressive terms in the model.

The energy efficiency variable is included to capture the impacts from major energy efficiency codes and standards, including those associated with the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and savings resulting from the use of compact fluorescent bulbs and LEDs. The estimated impact from these codes and standards includes engineering estimates and any resulting behavioral changes. The engineering estimates of savings from energy efficiency codes and standards are developed by ITRON, a leading expert in this field. These estimates were updated in late 2018.

Changes from the 2018 Ten-Year Site Plan include moving from a monthly model to a daily model. A daily model is more responsive to the impact of day to day temperature swings on energy usage. Weather data were also changed from monthly to daily. Other changes include the removal of the leap year term, the monthly dummies, and the price decrease term and the inclusion of variables to account for the impact of Hurricane Irma, and an additional autoregressive term.

The NEL forecast is developed by first multiplying the daily NEL per customer forecast by the projected total number of customers and summed for the month. The total customer forecast used to derive NEL is based on a regression model and uses population projections from IHS

Markit. These inputs are quantified and qualified using statistical models in terms of their impact on the future demand for electricity. The forecast is then adjusted for the expected changes in load resulting from plug-in electric vehicles, changes in wholesale requirements contracts, private solar, and FPL's economic development riders. As a result of FPL's acquisition of the City of Vero Beach electric system (COVB transaction), an adjustment is made for the additional load resulting from this acquisition. Once the NEL forecast is determined, total billed sales are computed using a historical ratio of sales to NEL. The residential and commercial sales forecasts are then adjusted to match the total billed sales.

System Peak Forecasts

The rate of absolute growth in FPL system peak load has been a function of the size of the customer base, varying weather conditions, projected economic conditions, and energy efficiency codes and standards. FPL developed the peak forecast models to capture these behavioral relationships. In addition, FPL's peak forecast also reflects the expected changes in load from plug-in electric vehicles, changes in wholesale requirements contracts, private solar, FPL's economic development riders, and the COVB transaction.

The savings from energy efficiency codes and standards incorporated into the peak forecast include the impacts from the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the use of compact fluorescent light bulbs and LEDs. This reduction includes engineering estimates and any resulting behavioral changes.

1. **System Summer Peak**

   The summer peak forecast is developed using an econometric model. The variables included in the model are Florida real per capita income, cooling degree-hours two days prior to the peak day, the maximum temperature on the day of the peak, a variable for energy efficiency codes and standards, autoregressive terms, and a dummy variable for the year 2005. The only change from the 2018 Ten-Year Site Plan summer peak model was the inclusion of the autoregressive terms. Economic data are obtained from IHS Markit, weather data from WSI, and energy efficiency estimates from ITRON. The model is based on the summer peak contribution per customer, which is multiplied by total customers. This product is then adjusted to reflect the expected changes in load from plug-in electric vehicles, changes in wholesale requirements contracts, private solar, FPL's economic development riders, and the COVB transaction to derive FPL's system summer peak.

2. **System Winter Peak**

   Like the system summer peak model, this model also is an econometric model. The model consists of a weather-related variable; the minimum temperature on the peak day, and a trend variable. The model also includes an autoregressive term. Changes from the 2018 Ten-Year Site Plan winter peak model were the inclusion of a trend term and an autoregressive term and the removal of the two dummy variables; one for post 2011 and one for the year 2008, and the removal of the customer variable, and the heating degree hour variable for the prior day squared. The sources for these data are the same as the summer peak model. The forecast winter peak is then adjusted for the expected changes in load from plug-in electric vehicles, changes in wholesale requirements contracts, private solar, FPL's economic development riders, the COVB transaction, and the impact of energy efficiency codes and standards to derive FPL's system winter peak.

Customer Forecasts

The forecasts of customers by revenue class for residential, commercial, industrial, and street & highway are based on econometric models and exponential smoothing models. Customer forecasts for other public authority, railroads & railways, and resale are based on customer specific information. An econometric model is used to forecast total customers. The sum of the revenue class forecasts is reconciled to the total customer forecast by adjusting the residential and commercial revenue class forecasts.

Sales Forecasts

The forecasts of sales by revenue class for residential, commercial, and industrial are based on econometric models and exponential smoothing models. Street & highway sales and railroads & railways sales are based on a trended use per customer, which is then multiplied by the forecasted number of customers. Sales for Other Public Authority are forecast based on historical usage characteristics. Wholesale sales are forecasted based on information provided directly by the wholesale customers, as well as historical demand and load factor trends. The forecasts for all revenue classes are summed, and the residential and commercial classes are adjusted proportionately to match the total sales forecast obtained from the NEL model output.

For additional details, see Chapter II, Forecast of Electric Power Demand, of FPL's "Ten Year Power Plant Site Plan 2019-2028."

QUESTION:
Please identify all closed and opened FPSC dockets and all non-docketed FPSC matters which were/are based on the same load forecast used in the Company's 2019 TYSP.

RESPONSE:
The following open FPSC dockets are based on the same load forecast used in FPL's 2019 TYSP:

- 20190001-EI – Florida Power & Light Company's Petition for Approval of Solar Base Rate Adjustment To Be Effective 2020
- 20190061-EI – Petition for approval of FPL SolarTogether program and tariff, by Florida Power & Light Company
- 20190082-EQ – Petition for approval of renewable energy tariff and standard offer contract, by Florida Power & Light Company
- 20190015-EG – Florida Power & Light Company's Petition for Approval of Numeric Conservation Goals

There are no closed FPSC dockets or non-docketed FPSC matters that used the same load forecast.

QUESTION:
[Investor-Owned Utilities Only] Does your Company review the accuracy of its customer, load, and demand forecasts presented in its TYSP by comparing the actual data for a given year to the data forecasted one, two, three, four, five, or six years prior?

a. If the response is affirmative, please explain the method used in such review.
b. If the response is affirmative, please provide the results of such review for each forecast presented in the TYSPs filed, or to be filed, to the Commission from 2001 to 2019 with supporting workpapers in Microsoft Excel format.
c. If the response is negative, please explain why not.

RESPONSE:
a. Yes. The formula used to calculate the forecast accuracy of customer, load, and demand forecasts is shown below. The forecast variance is calculated as the weather normalized actual value divided by the forecast value minus 1. For customers, actuals are used as there are no weather normalized actuals for customers. Variances are calculated over a one to ten year forecast horizon.

$$Forecast\ Variance\ (\%) = \left\lfloor \left(\frac{Weather\ Normalized\ Actual}{Forecast} \right) - 1 \right\rfloor$$

A positive forecast variance represents an under-forecast, while a negative forecast variance represents an over-forecast.

b. Please see Attachment No. 1 to this response for the customer, load, and demand forecast accuracy.

c. Not applicable.

QUESTION:
Please explain any recent and forecasted trends in customer growth, by customer type (residential, commercial, industrial) and as a whole.

RESPONSE:
Total customer growth, at an annual rate, grew at about 1.2% in 2018. This has been driven by the steady growth in both the residential and commercial customer classes. This growth is consistent with the continued steady growth in the Florida economy and in population growth. Growth in small and medium size commercial customers is once again the focus of the ongoing positive growth in total commercial customers in 2018, following a decline in medium commercial customers in 2017. Large commercial customers continue to decline from 2017 through 2018 and has declined in six of the past seven years. In 2018, industrial class customers, as a whole, declined for the second year in a row, albeit at a slower rate than in 2017. Positive customer growth is forecast for all three customer classes throughout the forecast horizon with the exception of small declines in the industrial class in the 2027-28 time period.

QUESTION:
Please explain any recent and forecasted trends in electricity use per customer, by customer type (residential, commercial, industrial) and as a whole.

RESPONSE:
Residential: There has been a general downward trend in residential weather normalized use-per-customer. This began in 2004, prior to the recession, and accelerated during the recession. With the exception of a few anomalous years, including a precipitous drop in 2017, this general downward trend has continued through 2018. This has been the result of improvements in energy efficiency, and the introduction of new technologies such as LED lighting. After increases in 2014 and 2015, residential weather normalized use-per-customer resumed its decline in 2016 and 2017. The decline in 2017 was significant and can be attributed, in part, to Hurricane Irma. Residential weather normalized use-per-customer increased from 2017 to 2018 due to the large decline experienced in 2017. The 2018 use-per-customer is in line with the longer term downward historical trend and with the continued forecast decline in use-per-customer through the TYSP forecast horizon.

Commercial: The trend in commercial weather normalized use-per-customer follows a similar pattern as the residential class including the significant decline in 2017 and an increase in 2018. This general downward trend, however, started in 2006, a few years after the observed decline began in the residential class. As with the residential class, this trend is forecast to continue through the TYSP forecast horizon.

Industrial: The industrial weather normalized use-per-customer has exhibited less of a consistent downward trend than either the residential or commercial classes. During the housing boom prior to 2005, the number of temporary construction accounts (classified as small industrial customers) increased, resulting in a decline in use-per-customer as a large share of industrial customers were comprised of these small accounts. With the housing market decline, the number of temporary construction accounts dropped dramatically resulting in a large increase in industrial use-per-customer. Since 2012, with the recovery of the housing market, industrial use-per-customer has been falling. As construction continues to do well, as is expected, the industrial use-per-customer will continue to follow the downward trend for a few years before leveling off.

Total: As one may expect, the trend in total weather normalized use-per-customer follows a similar pattern as the residential and commercial classes. As with the residential and commercial classes, this trend is forecast to continue through the TYSP forecast horizon.

QUESTION:
Please explain any recent and forecasted trends in peak demand by the sources of peak demand appearing in Schedule 3.1 of the 2019 TYSP.

RESPONSE:
Summer Peak: The Summer peak has trended up over the last 10 years. This increase has been driven by the growth in customers and partially offset by the reduction in use per customer. The increase is also due to the addition of new wholesale contracts. The forecast for the summer peak over the next 10 years indicates positive growth as a result of increases in the number of retail customers.

Wholesale peak: The wholesale summer peak has largely increased over the last 10 years, particularly in 2014 with the addition of all of Lee County's delivery points. Over the next 10 years, the wholesale summer peak is expected to decline with the expiration of the current wholesale requirements contract to Seminole as well as the expiration of some smaller contracts.

Load Management: Residential has seen a reduction in load management over the last 10 years, particularly in 2014 and 2015. Commercial has seen a slight increase over the last 10 years. Load management is expected to increase modestly for residential and commercial over the next 10 years.

Conservation: Residential and commercial/industrial conservation at the time of the summer peak has steadily increased over the last 10 years and is forecast to continue its steady increase over the next 10 years.

QUESTION:
[Investor-Owned Utilities Only] If not included in the Company's 2019 TYSP to be filed by April 1, 2019, please provide load forecast sensitivities (high band, low band) to account for the uncertainty inherent in the base case forecasts in the following TYSP schedules, as well as the methodology used to prepare each forecast:

a. Schedule 2.1 - History and Forecast of Energy Consumption and Number of Customers by Customer Class
b. Schedule 2.2 - History and Forecast of Energy Consumption and Number of Customers by Customer Class
c. Schedule 2.3 - History and Forecast of Energy Consumption and Number of Customers by Customer Class
d. Schedule 3.1 - History and Forecast of Summer Peak Demand
e. Schedule 3.2 - History and Forecast of Winter Peak Demand
f. Schedule 3.3 - History and Forecast of Annual Net Energy for Load
g. Schedule 4 - Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month.

RESPONSE:
Load forecast sensitivities are only developed for Net Energy for Load and Summer Peak. These sensitivities relate to the following schedules/columns and are in Attachment No. 1 to this response:

Net Energy for Load:	Schedule 2.3 column (19), Schedule 3.3 column (2), and Schedule 4 columns (5) and (7), Annual Values
Summer Peak:	Schedule 3.1 column (2), Schedule 4 columns (4) and (6), AUG

Sensitivities are not developed for the other Schedules or for other columns of the Schedules listed above.

Sensitivities were developed as follows. Using TYSPs back to 1989, forecast errors one to ten years ahead are computed for both Net Energy for Load and Summer Peak for each TYSP. Based on these historical forecast error distributions, 75% confidence intervals of forecast errors are computed. These one to ten year P75 forecast errors are applied to the forecasts of Net Energy for Load and Summer Peak to derive the high and low forecast sensitivities.

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Based on 75th Percentile of Historical Forecasting Errors

	Net Energy for Load				Summer Peak		
	Forecast	**High Band**	**Low Band**		**Forecast**	**High Band**	**Low Band**
2019	121,100	123,677	118,523	2019	24,305	24,881	23,729
2020	122,284	125,779	118,790	2020	24,507	25,164	23,851
2021	122,370	127,250	117,489	2021	24,668	25,475	23,861
2022	122,331	128,414	116,248	2022	24,837	25,888	23,787
2023	122,680	129,914	115,447	2023	25,173	26,479	23,868
2024	123,864	132,190	115,538	2024	25,583	27,086	24,080
2025	124,440	133,233	115,647	2025	25,939	27,600	24,277
2026	125,430	134,875	115,985	2026	26,380	28,185	24,575
2027	126,520	136,753	116,287	2027	26,867	28,844	24,890
2028	127,941	138,289	117,593	2028	27,363	29,376	25,349

Notes: Net Energy for Load Forecast is from Schedule 3.3, Column (2) and does not include adjustments for DSM
Summer Peak Forecast is from Schedule 3.1, Column (2) and does not include incremental conservation, cummulative load management, or incremental load management

QUESTION:
Please discuss whether the Company included plug-in electric vehicle (PEV) loads in its demand and energy forecasts for the 2019 TYSP. If so, how were these impacts accounted for in the modeling and forecasting process?

RESPONSE:
Yes, the contribution of plug-in electric vehicles to FPL's peak demands and energy forecasts are included in the 2019 Ten-Year Site Plan. A description of the methodology used to develop the plug-in electric vehicle energy and demand forecasts can be found in FPL's response to Staff's Supplemental Data Request # 1, Question No. 14. The impact of plug-in electric vehicles is accounted for in the forecasting process as line item adjustments to FPL's NEL, summer, and winter coincident peak demands for the 2019 through 2029 time period. These contributions are incremental from the end of 2018.

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

RESPONSE:
FPL estimates penetration based on registration data purchased from the Florida Department of Motor Vehicles (DMV). FPL performs its estimation using a two-step process.

First, FPL reviews its PEV forecast for Florida annually, and updates as necessary, using the following methodology:

- FPL starts by forecasting the number of PEVs expected to be in use in the United States using a number of third party resources (*i.e.*, Bloomberg New Energy Finance, ExxonMobil, British Petroleum, and International Energy Agency) and discussions with knowledgeable professionals in the automotive industry.
- FPL then takes the number of registered PEVs in Florida and divides it by the number of vehicles in use nationally to derive Florida's current share of the U.S. market.
- This percentage share (~3.3%) is then multiplied by FPL's national forecast to get the Florida PEV forecast by year.

Second, FPL updates its PEV forecast for its service territory annually using the following methodology:

- FPL takes the number of registered PEVs in its service territory (DMV registrations) and divides it by the number of PEVs in use in Florida to derive FPL's current share of the Florida market.
- This percentage share (~63%) is then multiplied by the Florida PEV forecast (as described above) to get the annual FPL PEV service territory forecast.

The contribution to net energy for load from PEVs was derived from FPL's light duty vehicle (passenger car or "LDV") and truck and bus forecasts using an estimated kWh per vehicle. It was assumed that charging would take place 328 days per year for LDVs, 250 days per year for medium duty trucks, and 360 days per year for buses. FPL has been testing PEVs in both fleet and commuting applications since the early 1990s. For residential/commuting applications, experience indicates that on average LDVs can travel approximately 3.5 miles for every kWh of charge. A survey by the U.S. Department of Transportation conducted on the National Household Travel Trends in 2009 indicates that the daily average driving distance in the U.S. is approximately 36.1 miles (Reference: Santoso 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-11-022), Table 14. P28.). 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

LDV would be about 10.3 kWh per day (36.1 miles per day / 3.5 miles per kWh.) The kWh forecast was developed using this factor plus a similar forecast updated in 2016 for trucks and buses. Energy values are at the generator and have been adjusted for system losses.

For summer and winter peak demand, FPL estimated the most likely charging schedule for LDVs, trucks, and buses. The percent of each vehicle type charging during the summer and winter peak periods was then estimated in relation to the forecasted summer and winter peak demands. To create the summer and winter coincident peak demand impacts, the estimated number of vehicles (as previously described) was multiplied by the percentage of each vehicle type charging during FPL's peak hour and multiplied by the kW per vehicle type.

<u>QUESTION</u>:
Please include the following information within the Utility's service territory: an estimate of the number of PEVs, an estimate of the number of public PEV charging stations, an estimate of the number of public "quick-charge" PEV charging stations (i.e., charging stations requiring a service drop greater than 240 volts and/or using three-phase power), and the estimated demand and energy impacts of the PEVs by year. As part of this response, please provide an electronic version of the table below in Microsoft Excel format.

Electric Vehicle Charging Impacts

Year	Number of PEVs	Number of Public PEV Charging Stations	Number of Public "Quick-charge" PEV Charging Stations	Cumulative Impact of PEVs		
				Summer Demand (MW)	Winter Demand (MW)	Annual Energy (GWh)
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						
2028						
Notes						
(Include Notes Here)						

<u>RESPONSE</u>:
Please see Attachment No. 1 to this response. Please note that FPL does not track or forecast the number of public charging stations because FPL does not believe that this number is relevant to forecasting the amount of demand and energy related to plug-in electric vehicles (PEVs).

QUESTION:
Please describe any Company programs or tariffs currently offered to customers relating to PEVs, and describe whether any new or additional programs or tariffs relating to PEVs will be offered to customers within the 2019-2028 period.

a. Of these programs or tariffs, are any designed for or do they include educating customers on electricity as a transportation fuel?

b. Does the Company have any programs where customers can express their interest or expectations for electric vehicle infrastructure as provided for by the Utility, and if so, please describe in detail.

RESPONSE:
At this time, FPL does not currently offer, nor are there any specific plans to offer, programs or tariffs related to plug-in electric vehicles (PEVs) within the 2019-2028 period. However, FPL continues to evaluate the potential need for such programs or tariffs. FPL customers can find information about electric vehicles (EVs) on the FPL website. In addition, FPL conducts some limited education and outreach activities, providing information to customers that reach out with questions about EVs and participating in over twenty EV events in 2018 with an additional twenty-five events scheduled for 2019.

a. Not applicable.

b. In summer of 2018, FPL commenced the launch of an approximately $10 million EV charging pilot program. FPL believes that this will enable at least 1000 charging handles and be a significant enough investment to fully gather the intended set of learnings from the pilot. Installations will encompass different EV charging technologies, market segments, and location types through FPL's service territory including:
    - DC Fast Charging - High-powered charging along highway corridors that enable long distance travel;
    - Workplace – Employee or fleet charging at public and or private workplaces;
    - Destination - Amenity centers where drivers can spend anywhere from a couple of hours to a full overnight stay, including malls, entertainment venues, hotels, attractions, and airports;
    - Residential – In home charging at EV customers' homes

    The objective of the pilot program is to gather data in the following areas to ensure future electric vehicle opportunities enhance service and reduce costs:
    - Utilization - understand when, where, and how customers use various types of charging stations;
    - Adoption - evaluate how public charging infrastructure influences electric vehicle adoption, and collaborate with a variety of host sites to better understand their reasons for supporting electric vehicle charging stations;

- Rate Structures - understand different potential rate structures and models for charging;
- Grid Services - gain knowledge about potential application and impact of “Vehicle To Grid” technology;
- Power Quality - research potential quality issues at locations where multiple high powered chargers share a transformer with other customers and determine if regulation that addresses these issues is needed to set guidelines for future deployment of charging stations; and
- Customer Experience - determine how charger placement, availability, segment/type, and billing mechanism impact customer satisfaction.

FPL has issued an RFP for EV charging providers and is in the process of selecting a vendor. We are also currently in discussions with potential site hosts with initial deployments expected in the second quarter of 2019. FPL intends to seek approval and prudency during the Company’s next rate case. Revenue generated by charging sessions is expected to reduce pilot operation, maintenance, and energy costs.

QUESTION:
Please describe how the Company monitors the installation of PEV public charging stations in its service area?

RESPONSE:
FPL does not actively monitor the number of public charging station installations for plug-in electric vehicles (PEVs) in its service territory. Please see FPL's response to Staff's Supplemental Data Request # 1, Question No. 15. However, the number of charging stations, both DC Fast Charging and Level 2, in FPL's service territory are expected to increase in the near future due to, but not limited to, the following reasons:

- Mandatory PEV charging station investment by Electrify America as a result of the Volkswagen (VW) Settlement
- Manufacturer installations to support their new PEVs (*e.g.*, Tesla Model 3)
- Florida will be receiving approximately $166MM VW Mitigation Trust funding of which it can elect to spend up to 15% (approximately $24MM) on PEV charging stations.

QUESTION:
Please describe any instances since January 1, 2018, in which upgrades to the distribution system were made where PEVs were a contributing factor.

RESPONSE:
FPL does not track the home and/or business locations that are associated with ownership of electric vehicles. Therefore, FPL is not aware of any specific upgrades to its distribution system where electric vehicles were the contributing factor.

QUESTION:
Has the Company conducted or contracted any research to determine demographic and regional factors that influence the adoption of electric vehicles applicable to its service territory? If so, please describe in detail the methodology and findings.

RESPONSE:
No, FPL has not conducted or contracted any research to determine demographic and regional factors that influence the adoption of electric vehicles applicable to its service territory.

QUESTION:
What processes or technologies, if any, are in place that allow the Utility to be notified when a customer has established an electrical vehicle charging station in the home?

RESPONSE:
FPL does not currently manage any system or process to track individual EV charger installations at customers' home and/or business locations.

QUESTION:
[FEECA Utilities Only] For each source of demand response, use the table below to provide the customer participation information listed on an annual basis. Please also provide a summary of all sources of demand response using the chart below. As part of this response, please provide an electronic version of the table below in Microsoft Excel format.

[Demand Response Source or All Demand Response Sources]									
Year	**Beginning Year: Number of Customers**	**Available Capacity (MW)**		**New Customers Added**	**Added Capacity (MW)**		**Customers Lost**	**Lost Capacity (MW)**	
		Sum	Win		Sum	Win		Sum	Win
2009									
2010									
2011									
2012									
2013									
2014									
2015									
2016									
2017									
2018									
Notes									
(Include Notes Here)									

RESPONSE:
Please see Tables 21A through 21F in Attachment No. 1 to this response.

QUESTION:
[FEECA Utilities Only] For each source of demand response, use the table below to provide the usage information listed on an annual basis. Please also provide a summary of all demand response using the chart below. As part of this response, please provide an electronic version of the table below in Microsoft Excel format.

[Demand Response Source or All Demand Response Sources]										
Year	**Summer**					**Winter**				
	Number of Events	**Average Event Size**		**Maximum Event Size**		**Number of Events**	**Average Event Size**		**Maximum Event Size**	
		(MW)	Number of Customers	(MW)	Number of Customers		(MW)	Number of Customers	(MW)	Number of Customers
2009										
2010										
2011										
2012										
2013										
2014										
2015										
2016										
2017										
2018										
Notes										
(Include Notes Here)										

RESPONSE:
Please see Tables 22A through 22C in Attachment No. 1 to this response. Please note that Residential On Call and Business On Call are dispatched together, as are Commercial/Industrial Load Control, Commercial/Industrial Demand Reduction, and Curtailable Service. Therefore, each group is shown combined.

QUESTION:
[FEECA Utilities Only] For each source of demand response, use the table below to provide the seasonal peak activation information listed on an annual basis. Please also provide a summary of all demand response using the chart below. As part of this response, please provide an electronic version of the table below in Microsoft Excel format.

[Demand Response Source or All Demand Response Sources]							
Year	Average Number of Customers	Summer Peak			Winter Peak		
		Activated During Peak? (Y/N)	Number of Customers Activated	Capacity Activated (MW)	Activated During Peak? (Y/N)	Number of Customers Activated	Capacity Activated (MW)
2009							
2010							
2011							
2012							
2013							
2014							
2015							
2016							
2017							
2018							
Notes							
(Include Notes Here)							

RESPONSE:
Please see Tables 23A through 23C in Attachment No. 1 to this response. Please note that Residential On Call and Business On Call are dispatched together, as are Commercial/Industrial Load Control, Commercial/Industrial Demand Reduction, and Curtailable Service. Therefore, each group is shown combined.

QUESTION:
Please identify and describe each existing utility-owned renewable resource as of December 31, 2018, that delivered energy during the year. Please include the facility's name, unit type, fuel type, its installed capacity (AC-rating for photovoltaic (PV) systems), its net firm capacity or contribution during peak demand (if any), capacity factor for 2018 based off of the installed capacity, and its in-service date. For multiple small distributed renewable resources (<250 kW per installation), such as rooftop solar panels, please include a single combined entry for the resources that share the same unit & fuel type. As part of this response, please provide an electronic version of the table below in Microsoft Excel format.

Existing Utility-Owned Renewable Resources

Facility Name	**Unit Type**	**Fuel Type**	**Installed Capacity (MW)**		**Net Firm Capacity (MW)**		**Capacity Factor**	**In-Service Date**
			Sum	Win	Sum	Win	(%)	(MM/YYYY)
Notes								
(Include Notes Here)								

RESPONSE:
Please see Attachment No. 1 to this response.

QUESTION:
Please identify and describe each planned utility-owned renewable resource for the period 2019-2028. Please include each proposed facility's name, unit type, fuel type, its installed capacity (AC-rating for PV systems), its net firm capacity or anticipated contribution during peak demand (if any), anticipated typical capacity factor, and projected in-service date. For multiple small distributed renewable resources (<250 kW per installation), such as rooftop solar panels, please include a single combined entry for the resources that share the same unit & fuel type. As part of this response, please provide an electronic version of the table below in Microsoft Excel format.

Planned Utility-Owned Renewable Resources

Facility Name	Unit Type	Fuel Type	Installed Capacity (MW)		Net Firm Capacity (MW)		Capacity Factor	In-Service Date
			Sum	Win	Sum	Win	(%)	(MM/YYYY)
Notes								
(Include Notes Here)								

RESPONSE:
Please see Attachment No. 1 to this response.

QUESTION:
Please refer to the list of planned utility-owned renewable resources for the period 2019-2028 above. Discuss the current status of each project.

RESPONSE:
Interstate, Miami-Dade, Sunshine Gateway and Pioneer Trail (universal solar PV, 74.5 MW each) were placed in service on January 31, 2019.

Voluntary Solar Partnership (VSP) program ("SolarNow") was approved for a second extension by the FPSC in Order No. PSC-2018-0581-TRF-EI on December 17, 2018 and is now scheduled to end at the close of 2019. For calendar year 2019, there are 32 projects in or under construction totaling an additional 715 kW of generation to be added to the program with planned in service dates spread throughout 2019.

C&I Solar Partnership Program ("CISPP") has installed approximately 3 MW of solar facilities on circuits that experience specific loading conditions to better study feeder loading impacts. Up to an additional 2 MW may be built in 2019 to further expand the understanding of integrating large PV facilities into the system. In addition, to further lessons learned to-date, and to better understand how future solar on distribution circuits may integrate into FPL operations, FPL may consider expanding this pilot to integrate storage (or other firm sources) into the final 2 MW of solar capacity deployed through this partnership program. FPL is also now evaluating the integration of solar into urban areas to test its impact on the distribution system on feeders that are heavily loaded as well as investigate the capabilities of a microgrid.

FPL's Solar Energy Centers Okeechobee, Hibiscus, Echo River, and Southfork (74.5 MW each), began construction in the spring of 2019 with projected in-service dates by May 2020. These 298 MWs of solar sites will complete the remainder of the solar sites authorized by the Solar Base Rate Adjustment ("SoBRA") portion of the 2016 FPL rate case settlement agreement.

FPL expects that it can continue to implement additional universal solar projects cost effectively in 2020 and beyond. Based on this assumption, FPL is projecting that, beginning in the year 2020 through 2028, it will have installed approximately 8,053 MW of solar generation on its system (which will be in addition to its existing 75 MW of solar thermal). These solar additions were reflected in FPL's "30 by 30" announcement in January 2019 which described FPL's plans to add 30 million solar panels cost-effectively by the year 2030. The projected annual solar additions are approximately: an additional 450 MW in 2020, 450 MW in 2021, 900 MW in 2022, 900 MW in 2023, 750 MW in 2024, 1,050 MW in 2025, 900 MW in 2027, and 1,200 MW in 2028.

A significant amount of this additional solar, particularly in the early years beginning in 2020, is projected to be added under FPL's new SolarTogether (a shared solar program) assuming that the FPSC approves the program as filed by FPL on March 13, 2019. The FPSC's decision regarding FPL's request will help determine how much of this annual solar rollout will be supplied under the FPL SolarTogether program. In its petition for approval of the FPL SolarTogether Program and Tariff, FPL proposed that phase 1 of the program would consist of 20 74.5 MW solar power plants, totaling 1,490 MW.

QUESTION:
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?

RESPONSE:
No planned utility-owned renewable resources have been cancelled, delayed, or reduced in scope within the past year.

QUESTION:
Please identify and describe each purchased power agreement with a renewable generator that delivered energy during 2018. Provide the name of the seller, the name of the generation facility associated with the contract, the unit type of the facility, the fuel type, the facility's installed capacity (AC-rating for PV systems), the amount of contracted firm capacity (if any), and the start and end dates of the purchased power agreement.

Existing Renewable Purchased Power Agreements

Seller Name	**Facility Name**	**Unit Type**	**Fuel Type**	**Installed Capacity (MW)**		**Contracted Firm Capacity (MW)**		**In-Service Date**	**Contract Term (MM/YY)**	
				Sum	Win	Sum	Win	(MM/YY)	Start	End
Notes										
(Include Notes Here)										

RESPONSE:
Please see Attachment No. 1 to this response.

Florida Power & Light Company
2019 Ten-Year Site Plan
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Question No. 28
Attachment No. 1

Existing Renewable Purchased Power Agreements

Seller Name	Facility Name	Unit Type	Fuel Type	Installed Capacity (MW)		Contracted Firm Capacity (MW)		In-Service Date	Contract Term (MM/YY)	
				Sum	Win	Sum	Win	(MM/YY)	Start	End
Broward South	Broward South	Steam	MSW	3.5	3.5	3.5	3.5	Mar-92	Jan-93	26-Dec
Solid Waste Authority of Palm Beach County	Solid Waste Authority of Palm Beach County	Steam	MSW	55	55	40	40	Apr-89	12-Jan	Apr-34
Solid Waste Authority of Palm Beach County	Expansion Unit	Steam	MSW	90	90	70	70	Apr-15	Jan-16	Apr-34
Notes										
SWA Expansion Unit started delivering as-available energy in April 2015										

<u>QUESTION</u>:
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 2019-2028. Provide the name of the seller, the name of the generation facility associated with the contract, the unit type of the facility, the fuel type, the facility's installed capacity (AC-rating for PV systems), the amount of contracted firm capacity (if any), and the start and end dates of the purchased power agreement.

Renewable Purchased Power Agreements

<table>
<tr><th rowspan="2">Seller Name</th><th rowspan="2">Facility Name</th><th rowspan="2">Unit Type</th><th rowspan="2">Fuel Type</th><th colspan="2">Installed Capacity (MW)</th><th colspan="2">Contracted Firm Capacity (MW)</th><th>In-Service Date</th><th colspan="2">Contract Term (MM/YY)</th></tr>
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<tr><td colspan="11">Notes</td></tr>
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<u>RESPONSE</u>:
At present, FPL has no purchased power agreements with renewable generators that are anticipated to begin delivering renewable energy from 2019 through 2028.

QUESTION:
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 2019-2028. Discuss the current status of each project.

RESPONSE:
Not applicable. Please see FPL's response to Staff's Supplemental Data Request # 1, Question No. 29.

QUESTION:
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?

RESPONSE:
No renewable purchased power agreements were cancelled, expired, delayed or modified within the past year.

QUESTION:
Please provide the actual and projected annual output for all renewable resources on the Company's system, including utility-owned resources (firm, non-firm, and co-firing), purchases (firm, non-firm, and co-firing), and customer-owned generation, for the period 2019 through 2028.

RESPONSE:
Please see Attachment No. 1 to this response.

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Renewable Generation by Source

Renewable Source	Annual Renewable Generation (GWh)										
	Actual	Projected									
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Utility - Firm*	0	0	0	0	0	0	0	0	0	0	0
Utility - Non-Firm*	1,887	2,678	4,247	5,583	7,656	9,720	11,459	13,828	13,788	15,829	18,609
Utility - Co-Firing	0	0	0	0	0	0	0	0	0	0	0
Purchase – Firm	892	998	998	998	998	998	998	998	998	998	998
Purchase - Non-Firm	217	195	195	195	195	195	195	195	195	195	195
Purchase – Co-Firing	0	0	0	0	0	0	0	0	0	0	0
Business PV for Schools	1	0	0	0	0	0	0	0	0	0	0
Customer-Owned	176	231	314	414	527	656	716	782	854	933	1,018
Total	**3,173**	**4,102**	**5,754**	**7,190**	**9,376**	**11,569**	**13,369**	**15,802**	**15,835**	**17,955**	**20,820**
Notes											
* All energy for FPL-owned renewables is being considered non-firm for the purposes of this table. However, FPL accounts for a percentage of the nameplate rating of PV facilities as firm capacity in reliability analyses.											

QUESTION:

Please complete the table below, providing a list of all of the Company's plant sites that are potential candidates for utility-scale (>2 MW) solar installations. As part of this response, please provide the plant site's name, approximate land area available for solar installations, potential installed capacity rating of a PV installation, and a description of any major obstacles that could affect utility-scale solar installations at any of these sites, such as land devoted to other uses or other requirements.

Candidate Sites - Solar

Plant Name	Land Available (Acres)	Installed Capacity (MW)	Potential Issues

RESPONSE:

Candidate Sites - Solar

Plant Name	Land Available (Acres)	Installed Capacity (MW)	Potential Issues
DeSoto	1,920	150	Transmission capacity, 3rd party impact potential, wetland impacts
Okeechobee	2,190	150	Wetland impacts
Nassau	750	75	Wetland Impacts
Del Monte South	722	75	Wetland Impacts
Sabal Palm	660	75	T-line ROW, vegetation buffer
Union Springs	506	75	Wetland impacts, gopher tortoises

The value shown in the "Installed Capacity (MW)" column represents the potential incremental installed nameplate PV capacity possible at the site.

The ~150 MW of available capacity at DeSoto are identified as preferred sites (Cattle Ranch and Rodeo) in Chapter IV.F.1 of the 2019 Ten-Year Site Plan. Eventual construction of these sites would reduce the available capacity at DeSoto to 0 MWs.

QUESTION:
Please complete the table below, providing a list of all of the Company's plant sites that are potential candidates for utility-scale wind installations. As part of this response, please provide the plant site's name, approximate land area available, potential installed capacity rating of a wind farm installation, and a description of any major obstacles that could affect utility-scale wind installations at any of these sites, such as land devoted to other uses or other requirements.

Candidate Sites - Wind

Plant Name	Land Available (Acres)	Installed Capacity (MW)	Potential Issues

RESPONSE:
Utility-scale wind installations in FPL's service territory are not a cost-effective resource. Consequently, FPL has no potential candidate sites.

QUESTION:
Please describe any actions the Company engages in to encourage production of renewable energy within its service territory.

RESPONSE:
FPL's long history of evaluating and supporting the production of renewable energy is discussed comprehensively in Section III.F of FPL's 2019-2028 Ten-Year Site Plan. A summary of FPL's recent actions to encourage use of renewable energy is provided in the paragraphs that follow.

Overview:

FPL began implementation of two DG PV pilot programs in 2015. The first DG PV program is a voluntary, community-based, solar partnership pilot to install new solar powered generating facilities. The program is at least partially funded by contributions from customers who volunteer to participate in the pilot and does not rely on subsidies from nonparticipating customers. The second program will implement approximately 5 MW of DG PV. The objective of this second program is to collect grid integration data for DG PV and develop operational best practices for addressing potential problems that may be identified. In addition, on March 13, 2019, FPL filed for FPSC approval of FPL's new SolarTogether program. If approved, FPL will add a significant amount of new PV facilities under that new program.

A brief description of these programs follows:

a) Voluntary, Community-Based Solar Partnership Pilot Program ("SolarNow"):
The Voluntary Solar Pilot Program, named FPL SolarNow, provides FPL customers with an additional and flexible opportunity to support development of solar power in Florida. The FPSC approved FPL's request for this three-year pilot program in Order No. PSC-14-0468-TRF-EI on August 29, 2014. The pilot program's tariff became effective in January 2015. The pilot was recently approved for a second extension of an additional year by the FPSC in Order No. PSC-2018-0581-TRF-EI on December 17, 2018 and is now scheduled to end at the close of 2019. This pilot program provides all customers the opportunity to support the use of solar energy at a community scale and is designed to be especially attractive for customers who do not wish, or are not able, to place solar equipment on their roof. Customers can participate in the program through voluntary contributions of $9/month. As of March 31, 2019 SolarNow enrollment has grown to 49,348 participants. This program has installed 39 projects located in 39 different locations within the FPL service territory. These projects represent approximately 1,359 kW-DC of PV generation.

b) **C&I Solar Partnership Pilot Program:**
This pilot program is conducted in partnership with interested commercial and industrial (C&I) customers over an approximate 5-year period. Limited investments will be made in PV facilities located at customer sites on selected distribution circuits within FPL's service territory.

c) SolarTogether-An FPL Shared Solar Program (FPL SolarTogether):

On March 13, 2019, FPL filed a community shared solar program for FPSC approval, Docket No. 20190061-EI. The program is named SolarTogether-An FPL Shared Solar Program (FPL SolarTogether). FPL has developed FPL SolarTogether as a cost-effective opportunity for customers to directly support the expansion of solar power without the need to install solar on their rooftop. Through FPL SolarTogether, customers will have the option to subscribe to kilowatts (“kW”) of solar capacity from dedicated cost-effective 74.5 MW solar power plants built for this program. Participating customers’ monthly bills will include the cost of their subscribed capacity and credits that reflect the system savings generated by their subscribed capacity.

QUESTION:
[Investor-Owned Utilities Only] Please discuss whether the Company has been approached by renewable energy generators during 2018 regarding constructing new renewable energy resources. If so, please provide the number and a description of the type of renewable generation represented.

RESPONSE:
FPL was approached multiple times in 2018 by potential renewable developers with a wide range of potential projects in various stages of discussion or development, but representing over 600 MW of nameplate capacity. While most of these projects were solar photovoltaic, developers have also proposed landfill gas generation and small waste to energy facilities.

QUESTION:
Does the Company consider solar PV to contribute to one or both seasonal peaks for reliability purposes? If so, please provide the percentage contribution and explain how the Company developed the value.

RESPONSE:
Yes. FPL considers universal (utility-scale) solar PV to contribute firm capacity towards FPL's Summer peak, which typically occurs at/near the 4 to 5 p.m. hour in the Summer, but it does not make any significant contribution of firm capacity towards FPL's Winter peak, which typically occurs at/near the 7 to 8 a.m. hour.

The percentage of a universal solar PV facility's nameplate rating that is assumed to be firm capacity can vary from one PV facility to the next due to various factors including, but not limited to, the following: the facility's geographic location, orientation of the PV panels, whether the PV panels are fixed tilt or tracking, the DC/AC ratio of solar equipment, the PV equipment used at the facility, and the amount of total solar installed on the system. For example, the average Summer firm capacity value for the four 2020 SoBRA PV facilities is approximately 61%. Among these four facilities, the Summer firm capacity values range from approximately 54% for the two fixed tilt facilities to approximately 69% for the two tracking facilities. In regard to the SolarTogether filing, the average Summer firm capacity value for the 20 solar PV facilities is approximately 50% with Summer firm capacity values ranging from approximately 43% to 53%.

FPL develops the projected Summer firm capacity value for a new universal solar PV facility (*i.e.*, the percentage of nameplate rating expected to contribute at FPL's Summer peak hour) based on calculations that account for forecasts of the hourly solar insolation at the site and the resulting hourly output of the universal solar PV facility. These projections may vary in the latter years of the 10-year reporting period due to solar additions in prior years shifting the peak load hour.

QUESTION:
Please identify whether a declining trend in costs of energy storage technologies has been observed by the Company.

RESPONSE:
Yes, FPL has observed declines in the cost of energy storage technologies for several years. Even though the rate of year-over-year cost reductions has declined significantly, FPL expects costs to continue to decline over the next several years.

QUESTION:
Briefly discuss any progress in the development and commercialization of non-lithium battery storage technology the Company has observed in recent years.

RESPONSE:
FPL actively monitors battery storage technology developments and evaluates emerging non-lithium prospects as they are identified. To date, FPL had not identified a commercially viable alternative to lithium batteries.

QUESTION:
Briefly discuss any considerations reviewed in determining the optimal positioning of energy storage technology in the Company's system. (e.g. Closer to/further from sources of load, generation, or transmission/distribution capabilities.)

RESPONSE:
The only sited storage facility presented in FPL's 2019 Ten-Year Site Plan is an approximate 409 MW battery storage facility that is projected to go into service in late 2021 or early 2022 in Manatee County near the existing Manatee Plant site. This battery and its location were selected based on FPL's plans to retire the existing Manatee Units 1 & 2 in that same time frame. Since the transmission infrastructure is already in place to accommodate the retired generation, the addition of approximately 409 MW of very quick start battery storage near the location of the Manatee Plant will utilize the existing capacity of the system. In addition, the battery will be located close to FPL's existing 74.5 MW solar facility at the Manatee Plant site. This helps enable the battery storage to be charged by solar resources. FPL's plan is to charge the new battery storage facility solely by solar for at least the first 5 years of the life of the battery storage, thus enabling the battery storage facility to qualify for the renewable investment tax credit (ITC). This helps lower the cost of the battery for the benefit of FPL's customers.

FPL's 2019 Ten-Year Site Plan also shows an additional 60 MW of battery storage being added in the same time period. A site(s) for this additional battery storage has not been selected. The ability of the battery storage to be charged by existing or new solar facilities will be one of the factors considered as the site(s) is selected.

In addition, FPL is evaluating battery storage in both Small Scale and Large Scale (50 MW) pilot projects in order to analyze a variety of potential battery applications. Please see pages 104 through 106 of FPL's 2019 Ten-Year Site Plan for a description of these pilot projects.

QUESTION:
Please provide whether ratepayers have expressed interest in energy storage technologies. If so, how have their interests been addressed?

RESPONSE:
To-date, FPL has received limited inquiries about energy storage technologies. To the extent requested by customers, FPL has provided technical and interconnection support. FPL is aware of sixty-four residential accounts and one commercial account that have installed battery storage systems to-date. This data is self-reported by FPL customers as part of the net-metering application; no compulsory mechanism exists for FPL to track the installation of behind the meter energy storage systems.

QUESTION:
Please complete the table below, identifying all energy storage technologies that are currently either part of the Company's system portfolio or are part of a pilot program sponsored by the Company. As part of this response, please identify the project to which the energy storage technology is associated with, whether this project is a pilot program or not, the in-service date or pilot start date associated with the energy storage technology, and the maximum capacity output and maximum energy stored of/by the energy storage technology under normal operating conditions.

Project Name	Pilot Program (Y/N)	In-Service/ Pilot Start Date	Max Capacity Output (MW)	Max Energy Stored (MHh)
Notes				
(Include Notes Here)				

RESPONSE:
Please see Attachment No. 1 to this response.

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Project Name	Pilot Program (Y/N)	In-Service/ Pilot Start Date	Max Capacity Output (MW)	Max Energy Stored (MHh)
Community Energy Storage (3 locations)	Y	May-16 to Jan-17	0.1	0.2
Southwest	Y	Oct-16	1.5	4
Florida Bay	Y	Dec-16	1.5	1.5
Mobile UPS	Y	Feb-17	0.8	<.1
Citrus	Y	Mar-18	4	16
Babcock Ranch	Y	Mar-18	10	40
Notes				

QUESTION:
Please identify and describe the objectives and methodologies of all energy storage pilot programs currently running or in development with an anticipated launch date within the next 10 years. If the Company is not currently participating in or developing energy storage pilot programs, has it considered doing so? If not, please explain.

a. Please discuss any pilot program results, addressing all anticipated benefits, risks, and operational limitations when such energy storage technology is applied on a utility scale (> 2 MW) to provide for either firm or non-firm capacity and energy.
b. Please provide a brief assessment of how these benefits, risks, and operational limitations may change over the next 10 years.
c. Please identify and describe any plans to periodically update the Commission on the status of your energy storage pilot programs.

RESPONSE:
a. - b. As described in Section III.F of FPL's 2019 TYSP, FPL has deployed energy storage pilot projects under two distinct pilot programs to date: 1) Small Scale Storage Pilot Projects; and 2) Large Scale (50 MW) Storage Pilot Project. The objectives of the two pilot projects are to identify the most promising applications for batteries on FPL's system and to gain experience with battery installation and operation.

Small Scale Storage Projects

In 2016 and early 2017, FPL implemented approximately 4 MW of battery storage systems, spread across six sites, with the general objective of demonstrating the operational capabilities of batteries and learning how to integrate them into FPL's system. FPL has operated the Small Scale Storage Pilot Projects for more than 2 years and has extracted significant valuable information. Some of the learnings derived to date from these pilots include the following:

- Southwest Storage – The Southwest Storage energy storage pilot is a 1.5 MW battery in Miami-Dade County primarily for peak shaving and frequency response. Many of the lessons learned relate to how to integrate batteries into FPL's system: definition of technical design requirements for a utility-operated battery system, including interconnection requirements; definition of communication approach and how to integrate the battery project with FPL's software systems; establishment of protocols for how to operate and maintain battery systems (change management); and formation of safety standards for batteries' safe operation and maintenance. The Southwest Storage pilot demonstrated how distribution connected batteries can provide grid services and how used electric vehicle (EV) batteries could be repackaged and repurposed for use in electric utility storage systems. FPL continues to believe that the viability of 2nd life battery use for utility systems would require additional coordination with EV manufacturers in order to reduce their integration costs and make them easier to manage from a communications and control standpoint.

- Florida Bay – The Florida Bay energy storage pilot is a 1.5 MW battery in Monroe County for backup power and voltage support. It has effectively demonstrated use of battery for backup in communities that rely on radial feeders while highlighting the technical challenges inherent in islanding loads from the system. It has proved batteries can be complementary to traditional distribution solutions for improving reliability in certain segments of the grid. Insights were gained on the sizing of battery systems for this use, and a best practice was identified of performing electrical islanding and power quality studies pre-battery installation in order to address potential perceived customer issues once a battery is installed. This pilot also provided learnings on performing grid service functions in the distribution grid, as injecting power into a feeder far away from its substation can create overvoltage issues if not appropriately managed.
- Community Energy Storage (CES) – CES consists of 0.1 MW batteries at 3 locations to study distributed storage reliability applications. Residential customer loads were backed up using CES battery systems that can serve anywhere from 1 to several residential customers when their feeders trip offline. These CES systems were effective at reducing momentaries for the test customers as well providing them with backup power during longer outages. The units are reliable and effective but very expensive. As battery costs continue to decline, FPL will continue to monitor whether the solution is cost effective in the future.
- Mobile UPS – Mobile IPS is a relocatable 0.75 MW uninterruptible power supply (UPS) battery for mitigation of momentary disruptions that could negatively impact sensitive customer loads and impact business continuity. The battery, transportable via flatbed truck, successfully mitigated power fluctuations at two customer facilities: a Tennis Center at Crandon Park in Key Biscayne with sensitive stadium light, which hosted the nationally televised Miami Open, and an industrial customer's facility with sensitive manufacturing loads.

Large Scale (50 MW) Storage Pilot Project

The Large Scale Storage Pilot Project, which was approved under the 2016 Base Rate Case Settlement Agreement, will deploy up to 50 MW of battery projects through 2020. The objectives of this larger pilot project is to expand the number of storage applications and configurations that FPL will be able to test, and make the scale of deployment more meaningful, given the large size of FPL's system.

The first two storage projects under this pilot involve pairing battery storage with existing universal PV facilities, and these projects went into service in the 1st Quarter of 2018.

- Citrus – The Citrus pilot is a 4 MW DC-coupled battery sited at FPL's Citrus Solar Energy Center, which captures clipped (curtailed) solar energy from the solar panels during high solar insolation hours, then releases this energy in other hours.
- Babcock Ranch – The Babcock Ranch pilot is a 10 MW AC-coupled battery at FPL's Babcock Ranch Solar Energy Center. This project is designed to shift PV output from non-peak times to peak times and also to provide "smoothing" of solar output and regulation services.

These two projects are designed to enhance the operations of existing solar facilities as outlined in the Settlement Agreement. FPL is continuing to gather data and lessons from these two projects and expects them to result in more optimized design configurations for solar-paired battery projects as well as improved operational parameters for economic dispatch.

Three additional pilot projects are under development:

- Wynwood – The Wynwood pilot is a 10 MW battery in Wynwood, a dense urban area close to downtown Miami. Scheduled to go in-service in the second half of 2019, the project is designed to examine the use of batteries to support the distribution system with a focus on addressing grid, system, and customer challenges.
- Microgrid – This pilot is a 3 MW battery alongside an existing solar PV system that will create a microgrid. The microgrid will be used for local resiliency and to provide additional grid services, including mitigation of disruptions potentially caused by solar in the distribution system.
- V2G - This pilot is approximately 1 MW of Electric-Vehicle-to-Grid ("V2G") batteries using electric school buses that will be able to discharge electricity to the grid when needed. This project will explore the potential for utilizing electric vehicles as grid resources on FPL's system for the first time ever.

c. In regard to the remaining 26 MW of allowed storage capacity, FPL is continuing to evaluate which types of battery storage configurations and applications are projected to be the most meaningful. Future Site Plans will provide additional information as new storage applications under the 50 MW Storage Pilot Project are selected.

FPL will continue to annually provide information regarding the status of its storage pilot programs, and FPL's future plans for utilizing storage technologies, in its Site Plan filings and through its responses to Staff's Supplemental Data Requests.

QUESTION:
If the Company utilizes non-firm generation sources in its system portfolio, please detail whether it currently utilizes or has considered utilizing energy storage technologies to provide firm capacity. If not, please explain.

RESPONSE:
FPL is attributing firm capacity value to the 469 MW of battery storage facilities coming in service in late 2021 or early 2022 that are presented in FPL's 2019 Ten-Year Site Plan. These battery storage additions are assumed to provide 100% of their nameplate rating as firm capacity and are accounted for as such in FPL's reserve margin and Loss of Load Probability (LOLP) analyses.

QUESTION:
Please identify and describe any programs you offer that allow your customers to contribute towards the funding of specific renewable projects, such as community solar programs.

a. Please describe any such programs in development with an anticipated launch date within the next 10 years.

RESPONSE:
FPL has three customer-focused solar programs: (i) Voluntary Solar Pilot Program, named FPL SolarNow, launched in 2015; (ii) C&I Solar Partnership Pilot Program, also launched in 2015, and (iii) SolarTogether-An FPL Shared Solar Program, which FPL filed for FPSC approval on March 13, 2019. Please see Section III.F, pages 102 through 104, of FPL's 2019 Ten-Year Site Plan for a detailed description of the programs.

QUESTION:
Please identify and discuss the Company’s role in the research and development of utility power technologies. As part of this response, please describe any plans to implement the results of research and development into the Company’s system portfolio and discuss how any anticipated benefits will affect your customers.

RESPONSE:
FPL understands the term “utility power technologies” to broadly mean the hardware, software, and communication technologies that either directly form part of generation and transmission systems or are used to operate them.

FPL stays abreast of developments in those technologies in a variety of ways, including:

- Monitoring industry publications and journals, as well as news in the sector;
- Participating in industry trade groups and conferences;
- Communicating regularly with vendors on new offerings or system needs; and
- Where appropriate, testing out equipment on a limited basis to determine its capabilities and risks.

Pilot projects represent one of the ways to test out equipment under real operating conditions, while only committing limited resources to a particular technology path. As described in Section III.F of FPL’s 2018 TYSP, several generation-related pilot programs have been implemented over the years to learn about various technologies and potential program structures, including the Living Lab, the Voluntary Solar Pilot Program, the Commercial & Industrial Solar Partnership Program, the Small Scale Storage Pilot Projects, and the Large Scale (50 MW) Storage Pilot. Once a technology reaches the point of being commercially viable and potentially economic for FPL’s customers, FPL will consider it in its resource planning activities.

QUESTION:
[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 2009-2018. If the Company uses multiple areas for as-available energy rates, please provide a system-average rate as well. Also, provide the projected annual average as-available energy rate in the Company's service territory for the period 2019-2028.

As-Available Energy Rates

Year		As-Available Energy ($/MWh)	On-Peak Average ($/MWh)	Off-Peak Average ($/MWh)
Actual	2009			
	2010			
	2011			
	2012			
	2013			
	2014			
	2015			
	2016			
	2017			
	2018			
Projected	2019			
	2020			
	2021			
	2022			
	2023			
	2024			
	2025			
	2026			
	2027			
	2028			
Notes				
(Include Notes Here)				

RESPONSE:
Please see Attachment No. 1 to this response.

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As-Available Energy Rates

Year		As-Available Energy	On-Peak Average	Off-Peak Average	Zonal As-Available Pricing														
					NENORTH			NESOUTH			SOEAST			SOUTH			WEST		
					As-Available Energy	On-Peak Average	Off-Peak Average	As-Available Energy	On-Peak Average	Off-Peak Average	As-Available Energy	On-Peak Average	Off-Peak Average	As-Available Energy	On-Peak Average	Off-Peak Average	As-Available Energy	On-Peak Average	Off-Peak Average
		($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
Actual	2009	35.07	49.60	29.94	34.04	47.99	29.12	35.31	49.76	30.21	35.52	50.34	30.29	36.27	51.89	30.75	34.22	48.04	29.35
	2010	41.89	60.28	35.59	40.80	58.82	34.63	42.67	61.35	36.27	42.14	60.55	35.84	42.59	61.35	36.16	41.26	59.31	35.07
	2011	31.09	39.84	28.02	30.36	38.67	27.44	31.77	40.82	28.59	31.24	40.00	28.16	31.53	40.66	28.32	30.57	39.03	27.60
	2012	22.46	28.42	20.34	22.06	27.67	20.07	22.87	29.06	20.66	22.54	28.56	20.40	22.77	29.07	20.53	22.06	27.76	20.04
	2013	22.92	25.29	22.00	22.54	24.72	21.70	23.19	25.64	22.24	22.92	25.28	22.00	23.35	25.96	22.34	22.62	24.87	21.74
	2014	27.19	30.64	25.99	26.75	30.00	25.60	27.55	31.09	26.31	27.24	30.69	26.03	27.52	31.23	26.25	26.91	30.21	25.75
	2015	17.47	20.06	16.54	17.21	19.64	16.33	17.65	20.32	16.69	17.52	20.10	16.60	17.69	20.50	16.69	17.26	19.75	16.37
	2016	16.70	19.70	15.65	15.57	18.20	14.64	17.18	20.33	16.08	16.97	20.03	15.90	17.00	20.18	15.88	16.79	19.78	15.75
	2017	18.93	21.32	18.07	18.23	20.12	17.56	19.27	21.83	18.37	19.08	21.55	18.21	19.17	21.78	18.17	18.90	21.32	18.05
	2018	21.85	25.73	20.50	21.56	25.31	20.25	22.10	26.11	20.71	21.85	25.71	20.50	21.98	25.95	20.60	21.76	25.57	20.42
Projected	2019	28.36	30.07	27.13															
	2020	20.17	20.20	20.15															
	2021	19.37	19.95	18.94															
	2022	18.92	19.21	18.71															
	2023	19.48	20.19	18.98															
	2024	21.61	22.16	21.21															
	2025	24.65	24.75	24.59															
	2026	25.98	26.52	25.59															
	2027	26.83	26.90	26.77															
	2028	27.16	27.59	26.85															

Notes

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

QUESTION:

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, 2018. 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.

Planned Unit Additions

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

RESPONSE:

Planned Unit Additions

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Combined Cycle Unit Additions				
Okeechobee Clean Energy Center	**1778**	**January, 2016**	**June, 2016**	**March, 2019**
Dania Beach Clean Energy Center	**1163**	**March, 2018**	**December, 2018**	**June, 2022**
Unsited Combined Cycle	**1886**	**TBD**	**TBD**	**June, 2026**
Notes				

QUESTION:
For each of the planned generating units contained in the Company's 2019 TYSP, 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.

RESPONSE:
New generation units presented in FPL's 2019 Ten-Year Site Plan that are not yet under construction are the 2022 Lauderdale Modernization (Dania Beach Clean Energy Center), approximately 469 MW of battery storage in 2022, the un-sited CC unit in 2026, and the 2020 through 2028 PV additions. The timelines for these generation additions are presented in Attachment No. 1 to this response. FPL currently has no future specific date or milestone that would constitute a "drop dead" date related to a decision to proceed with construction of these projects.

QUESTION:
Please provide an estimate of the revenue requirements of the Company based upon the 2019 TYSP's planned generating units.

RESPONSE:
At the time the resource plan presented in FPL's 2019 Ten-Year Site Plan was finalized, the cumulative present value of revenue requirements ("CPVRR") for the resource plan was projected to be $56,176. This value is in 2018$ for the years 2018 through 2067, assuming a discount rate of 7.73%, and updated forecasts for load, fuel costs, and environmental compliance costs.

QUESTION:
For each of the planned generating units contained in the Company's 2019 TYSP, please identify the next best alternative that was rejected for each unit. Provide information similar to Schedule 9 regarding each of the next best alternative unit(s). As part of this response, please also provide the additional revenue requirement that would have been associated with the next best alternative compared to the planned unit.

RESPONSE:
FPL interprets the question to refer to planned generating units/capacity additions that have not yet received FPSC approval for construction and/or cost recovery. Of the planned generating units/capacity additions presented in FPL's 2019 Site Plan, only the 2022 Dania Beach CC has received such approval.

The remaining planned generating units/capacity additions presented in the 2019 Site Plan are PV facilities, battery storage, and an un-sited CC unit. FPL's 2019 Ten-Year Site Plan includes Schedule 9 forms for each of these resource options.

FPL's resource planning work that led to the selection of this resource plan primarily examined different quantities of, and/or timing for, these same resources. Therefore, there is no single next best alternative to each of the planned units shown in the plan. Consequently, there is not a single additional revenue requirement value for the next best alternative. Schedule 9 information for these resource options is already provided in the Site Plan.

QUESTION:
For each existing and planned unit on the Company's system, provide the following data based upon historic data from 2018 and projected capacity factor values for the period 2019-2028. Please complete the tables below and provide an electronic copy in Microsoft Excel format.

Projected Unit Information – Capacity Factor (%)

Plant	Unit #	Unit Type	Fuel Type	Actual	Projected									
				2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Notes														
(Include Notes Here)														

RESPONSE:
Please see Attachment No. 1 to this response.

QUESTION:
For each existing unit on the Company's system, please provide the planned retirement date. If the Company does not have a planned retirement date for a unit, please provide an estimated lifespan for units of that type and a non-binding estimate of the retirement date for the unit.

RESPONSE:
In regard to new non-nuclear units presented in the 2019 Ten-Year Site Plan, the estimated economic life is generally assumed to be 30 years for PV facilities and 40 years for new CC facilities. These assumptions were used in the economic analyses that were performed that led to the 2019 Ten-Year Site Plan filing. For new nuclear units, FPL assumes a minimum operating life of 40 years and a more realistic 60-year operating life.

For FPL's existing nuclear units, the current dates for the end of the operating licenses for each unit are: July 19, 2032 for Turkey Point 3; April 10, 2033 for Turkey Point 4; March 1, 2036 for St. Lucie 1; and April 6, 2043 for St. Lucie 2. Therefore, a non-binding estimate of the retirement date for these existing nuclear units would normally be these end-of-operating-license dates. However, on January 30, 2018, FPL applied to the Nuclear Regulatory Commission (NRC) for Subsequent License Renewal (SLR) for Turkey Point Units 3 & 4. The SLR requests approval to extend the operating licenses by 20 years to 2052 and 2053, respectively.

For existing non-nuclear generating units, the FPSC approved FPL's 2016 proposal to increase the economic life of its CC and CT units from 30 years to 40 years. However, FPL does not have specific firm retirement dates for all of its units. FPL does have an estimated retirement date for Manatee 1 and 2 of late 2021 or early 2022.

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

Repowering Candidate Units - Steam

Plant Name	Fuel Type	Summer Capacity (MW)	In-Service Date	Potential Conversion	Potential Issues
Notes					
(Include Notes Here)					

RESPONSE:

Repowering Candidate Units - Steam

Plant Name	Fuel Type	Summer Capacity (MW)	In-Service Date	Potential Conversion	Potential Issues
Indiantown Co-gen	Coal	330	Dec-95	combined cycle	see notes below
Manatee Unit 1	Gas / Oil	785	Oct-76	combined cycle	see notes below
Manatee Unit 2	Gas / Oil	785	Dec-77	combined cycle	see notes below
Notes					
see below					

All existing conventional steam generating units are capable of being converted to combined cycle operation. The only remaining units on FPL's system which are potential candidates for repowering or conversion are:

- Indiantown Co-gen
- Manatee Units 1 and 2

However, the 2019 Ten-Year Site Plan forecasts Indiantown Co-gen to be retired in 2020 and Manatee Units 1 and 2 to be retired in 2022; therefore, they are no longer being considered for repowering or conversion.

QUESTION:
Please identify each of the Company's existing (as of December 31, 2018) and planned (between 2019-2028) power purchase contracts, including firm capacity imports reflected in Schedule 7 of the Company's 2019 TYSP. Provide the seller, the term of the contract, amount of seasonal capacity purchased, the primary fuel (if applicable, such as with a unit purchase), whether it is included in the Utility's firm peak capacity, and a description of the source of the purchase (such as the name of the unit in a unit purchase).

Existing Purchased Power Agreements

Seller	Contract Term		Contract Capacity (MW)		Capacity Factor	Primary Fuel	Firm Capacity	Description
	Begins	Ends	Summer	Winter	%	(if any)		
Notes								
(Include Notes Here)								

Planned Purchased Power Agreements

Seller	Contract Term		Contract Capacity (MW)		Capacity Factor	Primary Fuel	Firm Capacity	Description
	Begins	Ends	Summer	Winter	%	(if any)		
Notes								
(Include Notes Here)								

RESPONSE:
Please see Attachment No. 1 to this response.

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Existing Purchased Power Agreements as of December 31, 2018

Seller	Contract Term		Contract Capacity (MW)		Capacity Factor	Primary Fuel	Firm Capacity	Description
	Begins	Ends	Summer	Winter	(%)	(if any)		
Wheelabrator Technoligies	1/1/1993	12/31/2026	3.5	3.5	100	**MSW**	**Yes**	**Broward South**
Indiantown Cogen, L.P.[1]	12/22/1995	1/31/2024	330	330	0	**Coal**	**Yes**	
Solid Waste Authority of Palm Beach	1/1/2012	3/31/2034	40	40	94	**MSW**	**Yes**	
Solid Waste Authority of Palm Beach	1/1/2016	3/31/2034	70	70	94	**MSW**	**Yes**	
OUC	10/1/2018	12/31/2020	100	70	0	**Gas**	**Yes**	
Notes								
1. ICLP became a subsidiary of FPL on Jan 5, 2017, the PPA will be terminated when debt is retired in 2020								

Planned Purchased Power Agreements

Seller	Contract Term		Contract Capacity (MW)		Capacity Factor	Primary Fuel	Firm Capacity	Description
	Begins	Ends	Summer	Winter	(%)	(if any)		
N/A								
Notes								
While discussions are on-going with several vendors, no additional contracts are currently planned.								

QUESTION:
Please identify each of the Company's existing (as of December 31, 2018) and planned (between 2019-2028) power sales, including firm capacity exports reflected in Schedule 7 of the Company's 2019 TYSP. Provide the purchaser, the term of the contract, amount of seasonal capacity sold, the primary fuel (if applicable, such as with a unit purchase), whether it is included in the Utility's firm peak demand, and a description of the sale (such as the name of the unit in a unit purchase).

Existing Power Sales

Purchaser	Contract Term		Contract Capacity (MW)		Capacity Factor	Primary Fuel (if any)	Firm Demand	Description
	Begins	Ends	Summer	Winter	%			
Notes								
(Include Notes Here)								

Planned Power Sales

Purchaser	Contract Term		Contract Capacity (MW)		Capacity Factor	Primary Fuel (if any)	Firm Demand	Description
	Begins	Ends	Summer	Winter	%			
Notes								
(Include Notes Here)								

RESPONSE:
Please see Attachment No. 1 to this response.

Existing Power Sales

Purchaser	Contract Term		Contract Capacity (MW) ****		Primary Fuel (if any)	Firm Demand	Description
	Begins	Ends	Summer	Winter			
Florida Keys Long Term Agreement *	May 1, 2011	December 31, 2031	148 - 174	110 - 136	System Average	Yes	Full Requirements
City of Wauchula	January 1, 2017	December 31, 2021	14	10	System Average	Yes	Full Requirements
City of Winter Park	January 1, 2014	December 31, 2019	60	60	System Average	Yes	Partial Requirements
Lee County Full Requirements Agreement **	January 1, 2014	December 31, 2033	991 - 1,164	716 - 720	System Average	Yes	Full Requirements
Seminole Electric Cooperative	June 1, 2014	May 31, 2021	200	200	Natural Gas	Yes	Partial Requirements
City of New Smyrna Beach	February 1, 2014	December 31, 2021	75	75	System Average	Yes	Partial Requirements
City of New Smyrna Beach (#2)	July 1, 2017	December 31, 2021	20	20	Natural Gas	Yes	Partial Requirements
City of Homestead	August 1, 2015	December 31, 2024	27	27	Natural Gas	Yes	Partial Requirements
City of Quincy	January 1, 2016	December 31, 2023	19	19	System Average	Yes	Partial Requirements
Moore Haven	July 1, 2016	December 31, 2025	4	4	System Average	Yes	Partial Requirements
Florida Public Utilities Company ***	January 1, 2018	December 31, 2024	49	59	Natural Gas	Yes	Partial Requirements

Notes

* The contract includes an option to extend the agreement through December 31, 2051.
** The contract includes an option to extend the agreement through December 31, 2053.
*** The contract includes an option to extend the agreement through December 31, 2028.
**** Contract Capacity based on contracts from 2019 through 2028

Planned Power Sales

Purchaser	Contract Term		Contract Capacity (MW)		Primary Fuel (if any)	Firm Demand	Description
	Begins	Ends	Summer	Winter			
N/A							

Notes

(Include Notes Here)

QUESTION:
Please list and discuss any long-term power sale or purchase agreements within the past year that were cancelled, expired, or modified.

RESPONSE:
None of FPL’s long-term power sale or purchase agreements was cancelled, expired, or modified within the past year.

QUESTION:
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, when completing the table below.

Transmission Projects Requiring TLSA Approval

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

RESPONSE:
Please see Attachment No. 1 to this response.

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Transmission Projects Requiring TLSA Approval

Transmission Line	Line Length (Miles)	Nominal Voltage (kV)	Date Need Approved	Date TLSA Certified	In-Service Date
Levee-Midway (Note 1)	**150**	**500**	**5/28/1988**	**4/20/1990**	**Jun - 2019**

Notes:

1 - Construction of 114 miles is complete and in-service. An additional phase of the Levee-Midway project called the Corbett-Sugar-Quarry (CSQ) line project includes adding a 500 kV line from FPL's Corbett Substation to a new 500 kV section of FPL's existing Sugar Substation and adding an approximately 68 mile 500 kV line from Sugar to FPL's Quarry Substation in Miami-Dade County. The Quarry 500/230 kV Substation is adjacent and connected to FPL's Levee Substation. The CSQ line project is scheduled to be completed by June 2019.

QUESTION:
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 2018 period. As part of your narrative, please discuss the potential for existing environmental regulations to impact unit dispatch, curtailments, or retirements during the 2019-2028 period.

RESPONSE:
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 2018 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 Cross State Air Pollution Rule ("CSAPR") through the use of emission allowances and the operation of the Selective Catalytic Reduction ("SCR") and Flue Gas Desulphurization ("FGD") on controlled units; 3) compliance with the Mercury and Air Toxics Standards ('MATS") rule and 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 Cape Canaveral plant and Fort Myers plant when needed to provide warm water for manatees in compliance with an agency-approved manatee protection plan.

During the 2019 through 2028 period, FPL is aware of two final and several evolving regulations which could potentially affect generating unit dispatch or retirement including: 1) the EPA rulemaking for replacing the Clean Power Plan with Affordable Clean Energy rule 2) EPA's proposed rule repealing the 2015 definition of Waters Of The United States (WOTUS), 3) EPA's review of the Coal Ash Rule, and 4) the EPA promulgation of the Steam Effluent Limitation Guidelines rule. Some of these rules have been challenged and are currently in litigation. The 111(d) rule has been stayed pending the outcome of the litigation.

On April 29, 2014, the U.S. Supreme Court reversed the DC Circuit Court of Appeals decision on CSAPR and remanded the rule back to the lower court. In accordance with the December 23, 2008 Court decision, CAIR remained in effect until a replacement rule was finalized by the EPA. On November 21, 2014, EPA issued a ministerial rule that aligns the dates in the CSAPR rule text with the revised court-ordered schedule, including 2015 Phase 1 implementation and 2017 Phase 2 implementation. In a separate ministerial action, EPA issued a NODA, as required by CSAPR, which aligns the final CSAPR default allowance allocation years with the revised court-ordered schedule implementing revisions to CSAPR and tolling the compliance deadlines by three years. The annual allowance programs for CSAPR Phase 1 implementation began January 1, 2015, with Phase 2 beginning January 1, 2017. Under the CSAPR, Florida electric generating units are subject to only the ozone season program. To comply with the previous and current Transport Rules, FPL implemented several projects as the most cost effective compliance 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). FPL's construction of the West County Energy Center, Cape Canaveral Energy Center, Riviera Beach Energy Center, Port Everglades Energy Center, and the Okeechobee Clean Energy Center have reduced FPL system emissions to avoid the need for future purchase of emission allowances necessary to comply with the requirements of CSAPR. On November 16, 2015, EPA proposed The CSAPR – Update Rule to implement reductions that it deemed necessary to address the 2008 Ozone standard. In its evaluation of Florida's impacts on downwind ozone nonattainment and maintenance areas, EPA determined that Florida electric generating units no longer have a significant impact to air quality in those areas and has removed Florida from the CSAPR program in 2017. FPL's ownership share of Plant Scherer Unit 4 in the State of Georgia however will remain affected under CSAPR for the annual and ozone season programs.

The other final air regulation for which FPL has 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"). On April 15, 2014, the DC Circuit Court of Appeals upheld the final MATS rule denying petitioners challenges that EPA improperly promulgated the rule. 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 20l1 to prepare for compliance within the required time period using existing planned outages and additional system capacity additions from the modernization projects. Installation of ESPs on the Manatee Units 1 and 2 and Martin Units 1 and 2, along with all associated acceptance tests, were completed by February 2015. FPL's installation of controls at Plant Scherer for compliance with the Georgia Multi-Pollutant rule provided the necessary emission reductions that are needed for MATS compliance. The well-controlled coal-fired Indiantown Cogeneration ("ICL") facility that FPL purchased in 2017 has also demonstrated the ability to meet all applicable MATS emission specifications. In addition to Continuous Mercury Emission Monitoring systems that have been installed for compliance with MATS at Scherer, all three units will also require quarterly particulate matter emission tests instead of the previous annual requirement. As of April 19, 2018, the ICL, and Plant Scherer coal-fired generating units are subject to the rule's emissions standards and are currently demonstrating compliance. In January 2018, JEA and FPL retired the SJRPP coal-fired facility and in December 2018 FPL retired Martin Units 1 and 2. Dismantlement and demolition of the facilities is underway and they are no longer subject to any of the MATS, CSAPR, or GHG regulations. Additionally, FPL has announced its intent to retire Manatee Units 1&2 by 2022.

FPL is currently tracking the upcoming Affordable Clean Energy rule for any impacts. On August 21, 2018, the Affordable Clean Energy (ACE) rule was proposed to replace the 2015 Clean Power Plan. The ACE rule applies only to coal fired electric generating units and does not including gas fired combustion units. The rule requires states to establish their own standards to address greenhouse gas emissions based on on-site, heat rate efficiency improvements based on the best system of emission reduction (BSER). The rule is expected to be finalized in 2019 and states will have 3 years to develop plans.

The final 316(b) rule for Cooling Water Intake Structures at Existing Facilities (316(b) Rule) was published August 15, 2014, and became effective October 14, 2014. The final 316(b) Rule requires each affected facility to develop comprehensive studies and compliance plans to determine the appropriate compliance measures to achieve the Best Technology Available ("BTA") to minimize adverse environmental impacts and meet entrainment and impingement mortality reduction requirements. The timeline to complete these studies and plans, along with ultimate agency review and approvals, is being completed during the facility's next 5-year permit cycle following the Rule's effective date. Thus all studies for FPL plants will be completed and submitted by early 2021. Until these studies and compliance options are finalized and 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.

The final 316(b) Rule states that a variety of technological and operational measures, including cooling towers, may qualify as BTA to reduce the adverse environmental impacts of cooling water intake structures. Although the addition of cooling towers could be considered as BTA at some facilities, they may not be feasible at many locations due to impacts to endangered species (such as manatees), spatial limitations, and disproportionate costs versus benefits; therefore cooling towers were not declared BTA by EPA for all facilities. FPL operates ten (10) power plants in Florida to which the 316(b) Rule is applicable. Six (6) plants utilize once-through cooling water systems; while four (4) utilize closed-cycle recirculating systems (*i.e.*, cooling towers or cooling ponds). For the six plants utilizing once through cooling water systems, the 316(b) Rule will require comprehensive studies to determine the appropriate BTA to meet the 316(b) Rule requirements. If any of the six units is required to meet the BTA requirements by installing cooling towers, the cost would be very high; up to hundreds of millions of dollars per site. However, based on FPL's review of the 316(b) Rule and preliminary data that has been collected, and although it is much too early to make a final determination, we anticipate that most FPL facilities will not be required to retrofit their cooling systems with cooling towers and will be able to meet the determinations of BTA by installing alternative controls. These alternative controls could include fine mesh intake cooling water screens to minimize entrainment and modified traveling screens with fish return systems to meet the impingement mortality reduction standard.

For the plants utilizing closed-cycle cooling, FPL does not anticipate that additional technologies or operational changes to minimize impingement mortality or entrainment will be required. Some studies are required for these facilities, but they are relatively inexpensive and any capital improvements required at these facilities would be minimal.

FPL is also a co-owner of Scherer Unit 4. Scherer Unit 4 uses cooling towers to reduce the impacts of impingement mortality and entrainment mortality as required under the 316(b) Rule. Here, just as with the FPL plants that utilize closed-cycle cooling, we anticipate the impacts to be relatively small.

EPA published the final Coal Combustion Residuals ("CCR") rule on April 17, 2015. This rule regulates the disposal of combustion byproducts. The WIIN Act passed in 2016 provided for approval of State CCR regulatory programs. USEPA then issued revised regulations in 2018 which extended the deadline to initiate closure of certain CCR units to October 31, 2020. FPL's coal units at SJRPP and Scherer are affected by this rule and now have disposal and closure requirement(s) for bottom ash, fly ash and gypsum while FPL's Indiantown Cogeneration coal-fired unit is not affected by the rule. FPL and the co-owners of its coal-fired generating units affected by this rule are conducting the required engineering evaluations, inspections, and monitoring and have developed closure plans as required. FPL does not anticipate any adverse impacts to operation of its generating units to comply with the CCR rule at this time.

The EPA and the U.S. Army Corps of Engineers ("USACE") published the final Clean Water Rule on June 29, 2015, which redefines jurisdictional "Waters of the U.S." (WOTUS). The final rule created new definitions which will constitute classifications of jurisdictional waters that previously did not exist, which may result in longer permitting timelines and increased mitigation costs for future FPL development projects dependent on the project area and site specific siting. The EPA and USACE final rule will significantly expand the number of jurisdictional wetlands throughout the U.S. The new rule could result in the designations of ditches, dry tributary features, and isolated depressions as jurisdictional waters. The final rule went into effect August 28, 2015, and the rule is currently being challenged within multiple District Courts. In Florida, the determinations of jurisdictional waters are being conducted under the pre-rule regime of federal-state collaboration that has previously been in place pending further order of the court or a revision of the rule is completed by the agencies. On February 14, 2019, the EPA and the USACE published the proposed replacement WOTUS rule. The new rule's proposed definitions are much more reasonable and functional compared to the

Obama Administration's 2015 rule. The final rule should be published by the end of 2019 and will most likely be challenged.

The final Steam Electric Effluent Limitation Guidelines (ELG) rule was promulgated and became effective on January 4, 2016. It was adopted by the Florida Department of Environmental Protection on March 30, 2017.

Title 40 Code of Federal Regulations Part 423, which was promulgated under the authority of the Federal Clean Water Act, limits the discharge of pollutants into navigable waters and into publicly owned treatment works by existing and new sources of steam electric power plants. The previous version of the ELG was published in the Federal Register on November 19, 1982. On September 15, 2009, the EPA announced that they would undertake rulemaking to revise the ELG rule because, "current regulations, which were issued in 1982, have not kept pace with changes that have occurred in the electric power industry over the last three decades."

The final ELG rule, while it is applicable to all facilities that utilize steam for electrical generation (*i.e.*, have a steam turbine) regardless of fuel type, mainly focuses on wastewater generated by coal-fired power plants. The ELG Rule sets limits on the amount of toxic metals and other harmful pollutants that steam electric power plants are allowed to discharge in several of their more significant sources of wastewater.

The new ELG rule is applicable to thirteen FPL owned or partially owned steam generation facilities. It is not applicable to any of the combustion turbine-only powered facilities. There will be virtually no impact on the steam generation facilities which are fueled by natural gas/light oil or nuclear. Manatee Plant Units 1 and 2 can burn heavy (#6) oil so these facilities may be required, if they are still operating and burning #6 oil following the next NPDES permit renewal in 2021, to make some minor operational changes to achieve compliance with the ELG rule. This change might be required since water effluent is generated when fly ash is sluiced to treatment ponds when the units are burning heavy oil. Martin Plant Units 1 and 2 were retired in late 2018, and thus they will be removed from applicability of the ELG rule.

The most significant impacts of the ELG Rule will be realized by coal burning facilities, including Plant Scherer Unit 4. There will be no impact at ICL as the ELG Rule does not apply since ICL doesn't discharge effluent to waters of the state. The final ELG rule required compliance to occur during the 2018-2023 timeframe. However, on September 18, 2017, a final rule was published that delayed compliance dates for treatment and handling of effluent from flue gas desulfurization scrubbers and bottom ash sluicing until November 1, 2020. The Rule requires the permitting authority to consider the time it takes to expeditiously plan, design, procure, and install required equipment and other operational changes that will be required. Currently, Scherer Unit 4 is in the process of studying the rule and determining the best avenue for compliance. It is anticipated the costs for compliance will include capital and O&M costs and will be significant.

The several environmental regulations which FPL anticipates becoming final in the 2019 through 2028 period include: 1) Greenhouse Gas Performance Standards for Existing Sources as part of the Affordable Clean Energy rule; 2) Regional Haze Reasonable Further Progress requirements for visibility improvement; 3) SIP revisions for Startup/Shutdown/Malfunction ("SSM") excess emissions; and 4) 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 publicly 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. However, the impact of the Greenhouse Gas Performance Standards for Existing Sources on the operation and dispatch of FPL's fossil fuel fired electric generating units is uncertain until a final rule is published.

QUESTION:
Please complete the table below, providing actual and projected amounts of regulated air pollutants and carbon dioxide emitted, on an annual and per megawatt-hour basis, by the Company's generation fleet. Please also provide an electronic copy of the completed table in Microsoft Excel format.

Emissions of Registered Air Pollutants & CO2

Year		SOX		NOX		Mercury		Particulates		CO2	
		lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons
Actual	2009										
	2010										
	2011										
	2012										
	2013										
	2014										
	2015										
	2016										
	2017										
	2018										
Projected	2019										
	2020										
	2021										
	2022										
	2023										
	2024										
	2025										
	2026										
	2027										
	2028										
Notes											
(Include Notes Here)											

RESPONSE:
Please see Attachment No. 1 to this response.

QUESTION:
For the U.S. Environmental Protection Agency's (EPA's) Mercury and Air Toxics Standards (MATS) Rule:

a. Will your Company be materially affected by the rule?
b. What compliance strategy does the Company anticipate employing for the rule?
c. If the strategy has not been completed, what is the Company's timeline for completing the compliance strategy?
d. Will there be any regulatory approvals needed for implementing this compliance strategy? How will this affect the timeline?
e. Does the Company anticipate asking for cost recovery for any expenses related to this rule? Please complete the following chart regarding MATS-related costs:

Year	Estimated Cost of Mercury and Air Toxics Standards (MATS) Rule Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
Notes				
(Include Notes Here)				

If the answer to any of the above questions is not available, please explain why.

RESPONSE:
a. 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 demonstrated compliance with the rule requirements beginning April 2015 for its affected coal and oil fired electric steam generating units.

b. FPL had evaluated its compliance options for its oil units and decided the best compliance strategy for the rule was installation of Electro-Static Precipitators ("ESPs") on its Martin and Manatee 800 MW units, a limit on oil operation at its remaining Turkey Point fossil steam unit to current levels of operation, and the retirement of the Turkey Point Unit 2 and Sanford Unit 3 boilers in 2013 to meet the 2015 deadline. In December 2018, FPL retired Martin Units 1&2 removing all requirements to comply with the MATS rule at that Facility. FPL has also retired and decommissioned all other uncontrolled oil fired fossil steam generating units in its fleet including Turkey Point Unit 1. The St. Johns River Power Park

("SJRPP") coal units identified that the optimal strategy for compliance with MATS was the use of low mercury coals, use of halogenated fuel additives, and changes to scrubber reagents to improve mercury removal efficiency. On January 4, 2018 FPL and JEA retired SJRPP Units 1 & 2 removing all requirements to comply with the MATS rule at that facility. FPL's coal fired unit at Plant Scherer was required to install controls to comply with the Georgia Multi-Pollutant rule, and has demonstrated compliance with that rule's equipment operation emission standards. Plant Scherer was granted a one-year extension until April 15, 2016, to comply with the monitoring provisions of the final MATS rule and has demonstrated compliance with all emission specifications and reporting requirements. In 2016, FPL announced it had acquired the fluidized bed coal fired generating units at Cedar Bay and the pulverized coal generating unit at Indiantown Cogeneration which are all subject to the MATS rule and have demonstrated compliance with the rule requirements prior to purchase. Subsequent to the announcement, FPL announced the retirement of the Cedar Bay units in 2016 which eliminated MATS requirements for those units. FPL has also announced its intent to retire the Indiantown Cogeneration facility in 2019 and Manatee Units 1&2 by 2022.

c. FPL's MATS strategy currently in use is meeting the rule's requirements at all applicable facilities.

d. No.

e. Yes, FPL is currently recovering costs for compliance with the rule through projects previously approved by the commission: Project 33 MATS and Project 45 800 MW ESP. On April 2, 2019, FPL provided its 2019 Supplemental CAIR/MATS/CAVR annual update filing for the Environmental Cost Recovery Clause. Total project capital costs through 2018 were $325.9 million.

Year	Estimated Cost of Mercury and Air Toxics Standards (MATS) Rule Impacts (2018 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019	0.04	2.70	*	2.74
2020	*	*	*	*
2021	*	*	*	*
2022	*	*	*	*
2023	*	*	*	*
2024	*	*	*	*
2025	*	*	*	*
2026	*	*	*	*
2027	*	*	*	*
2028	*	*	*	*
Notes				
*FPL forecasts its costs for MATS compliance annually for its ECRC projection filing in August. Projections for annual capital and O&M expenses have not been projected beyond 2019 at this time but are anticipated to be similar.				

QUESTION:
For the U.S. EPA's Cross-State Air Pollution Rule (CSAPR):

a. Will your Company be materially affected by the rule?
b. What compliance strategy does the Company anticipate employing for the rule?
c. If the strategy has not been completed, what is the Company's timeline for completing the compliance strategy?
d. Will there be any regulatory approvals needed for implementing this compliance strategy? How will this affect the timeline?
e. Does the Company anticipate asking for cost recovery for any expenses related to this rule? Please complete the following chart regarding CSAPR-related costs:

Year	Estimated Cross-State Air Pollution Rule (CSAPR) Rule Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
Notes				
(Include Notes Here)				

If the answer to any of the above questions is not available, please explain why.

RESPONSE:
a. CSAPR Phase 1 implementation began January 1, 2015, and Phase 2 began January 1, 2017. FPL's fossil generating units in Florida and Georgia were subject to the CSAPR requirements as promulgated. On September 7, 2016, the EPA finalized an update to the Cross-State Air Pollution Rule ("CSAPR") for the 2008 ozone National Ambient Air Quality Standards ("NAAQS") by issuing the final CSAPR Update. Starting in May 2017, this rule removes compliance requirements for Florida electric generating from the CSAPR but requires continued compliance for FPL's Scherer Unit 4 generating unit.

b. To comply with current and previous Transport Rules, FPL implemented several projects as the most cost effective compliance 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); and 3) Installation of SCR on St. John's River Power Park ("SJRPP") Units 1 & 2. Additionally, FPL's construction of the West County Energy Center, Cape Canaveral Energy Center, Riviera Beach Energy Center, Port Everglades Energy Center, and the Okeechobee Clean Energy Center have reduced FPL system emissions to avoid the need for purchase of emission allowances necessary to comply with the requirements of CSAPR. Ongoing operating and maintenance activities associated with the equipment installed for compliance with CSAPR must continue for the FPL units where components cannot be removed from service. Costs for the CSAPR equipment installed at Plant Scherer Unit 4 will continue as a result of the rule's applicability to Georgia and that state's multi-pollutant rule. Additionally, FPL's retirement of SJRPP Units 1 & 2, Martin Units 1 & 2, and Lauderdale Units 4 & 5 removed those units from any applicability with the current and future transport rules.

c. FPL has completed implementation of the compliance strategy for the final CSAPR requirements.

d. No.

e. Yes, FPL is currently recovering costs for compliance with the rule through projects previously approved by the commission: Project 31 CAIR. On April 2, 2018, FPL provided its 2018 Supplemental CAIR/MATS/CAVR annual update filing for the Environmental Cost Recovery Clause ("ECRC").

Year	**Estimated Cross-State Air Pollution Rule (CSAPR) Rule Impacts (2018 $ millions)**			
	Capital Costs	**O&M Costs**	**Fuel Costs**	**Total Costs**
2019	1.07	3.83	*	4.9
2020	*	*	*	*
2021	*	*	*	*
2022	*	*	*	*
2023	*	*	*	*
2024	*	*	*	*
2025	*	*	*	*
2026	*	*	*	*
2027	*	*	*	*
2028	*	*	*	*
Notes				
*FPL forecasts its costs for CSAPR compliance annually for its ECRC projection filing in August. Projections for annual capital and O&M expenses have not been projected beyond 2019 at this time but are anticipated to be similar.				

QUESTION:
For the U.S. EPA's Cooling Water Intake Structures (CWIS) Rule:

a. Will your Company be materially affected by the rule?
b. What compliance strategy does the Company anticipate employing for the rule?
c. If the strategy has not been completed, what is the Company's timeline for completing the compliance strategy?
d. Will there be any regulatory approvals needed for implementing this compliance strategy? How will this affect the timeline?
e. Does the Company anticipate asking for cost recovery for any expenses related to this rule? Please complete the following chart regarding CWIS-related costs:

Year	Estimated Cost of Cooling Water Intake Structures Rule (CWIS) Rule Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
Notes				
(Include Notes Here)				

If the answer to any of the above questions is not available, please explain why.

RESPONSE:
a. Yes.

b. The final 316(b) rule for Cooling Water Intake Structures at Existing Facilities (316(b) Rule) was published August 15, 2014, and became effective October 14, 2014. The final 316(b) Rule requires each affected facility to develop comprehensive studies and compliance plans to determine the appropriate compliance measures to achieve the Best Technology Available ("BTA") to minimize adverse environmental impacts and meet entrainment and impingement mortality reduction requirements. The timeline to complete these studies and plans, along with ultimate agency review and approvals, may take five to seven years beyond the effective date of the rule. Until these studies and compliance options are finalized and 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.

The final 316(b) Rule states that a variety of technological and operational measures, including cooling towers, may be BTA to reduce the adverse environmental impacts of cooling water intake structures. Although the addition of cooling towers could be considered as BTA at some facilities, they may not be feasible at many locations due to impacts to endangered species (such as manatees), spatial limitations, and disproportionate costs versus benefits; therefore cooling towers were not declared BTA by EPA for all facilities. FPL operates ten (10) power plants in Florida to which the 316(b) Rule is applicable. Six utilize once-through (open) cooling water ("OTCW") systems, while four utilize closed-cycle recirculating systems (*i.e.*, cooling towers or cooling ponds). For the six plants utilizing OTCW systems, the 316(b) Rule will require comprehensive studies to determine the BTA to meet the 316(b) Rule requirements. If any of the six units is required to meet the BTA requirements by installing cooling towers, the cost would be very high; up to hundreds of millions of dollars per site. However, based on FPL's review of the 316(b) Rule and preliminary data that has been collected, and although it is much too early to make a final determination, we anticipate that none of FPL's facilities will be required to retrofit their OTCW systems with cooling towers and will be able to meet the determinations of BTA by installing alternative controls. These alternative controls could include modified traveling screens with fish return systems (three facilities already are equipped with this technology), fine mesh screens, or velocity caps with excluder devices that would meet impingement mortality reduction criteria. For the four plants utilizing closed-cycle cooling systems, some studies are required, but they are relatively inexpensive and any capital improvements required at these facilities would be minimal.

FPL is also a co-owner of Scherer Unit 4. Scherer Unit 4 uses cooling towers to reduce the impacts of impingement mortality and entrainment mortality as required under the 316(b) Rule. As with the FPL facilities utilizing closed-cycle cooling, some studies are required, but they are relatively inexpensive and any capital improvements required for Scherer Unit 4 would be minimal.

c. Required studies to determine the appropriate BTA to be applied to each facility will be completed in the 2016-2022 timeframe. Actual capital improvements, and optimization of the new technologies will most likely occur in the 2020-2026 timeframe.

d. Yes. The Florida Department of Environmental Protection, with oversight by the Environmental Protection Agency, the National Marine Fisheries Service, the US Fish and Wildlife Service, and the Florida Fish and Wildlife Conservation Commission will all have input into the final determination of BTA for each impacted facility. Negotiations, should there be a disagreement among the agencies, could prolong the process of installing new technologies by several years.

e. Yes. FPL has an FPSC-approved Environmental Cost Recovery Project to recover appropriate expenses associated with 316(b) Rule compliance.

Year	**Estimated Cost of Cooling Water Intake Structures Rule (CWIS) Rule Impacts (2019 $ millions)**			
	Capital Costs	**O&M Costs**	**Fuel Costs**	**Total Costs**
2019	0	1.62		1.62
2020	0	1.48		1.48
2021	0	1.66		1.66
2022	13	2.16		15.16
2023	23	2.40		25.40
2024	46	3.20		49.20
2025	12	2.80		14.80
2026	0	2.80		2.80
2027	0	2.80		2.80
2028	0	2.80		2.80
Notes				
Estimates assume modified traveling screens with fish return systems will be installed at PFM and PFL, and include potential costs for installation of fine mesh screens at CCEC, PFL, PFM, & PEEC for entrainment BTA. These estimates assume that future studies will indicate that cooling towers will not be required for FPL's affected facilities.				

QUESTION:
For the U.S. EPA's Coal Combustion Residuals Rule (CCR), both for classification of coal ash as a "Non-Hazardous Waste" and as a "Special Waste."

a. Will your Company be materially affected by the rule?
b. What compliance strategy does the Company anticipate employing for the rule?
c. If the strategy has not been completed, what is the Company's timeline for completing the compliance strategy?
d. Will there be any regulatory approvals needed for implementing this compliance strategy? How will this affect the timeline?
e. Does the Company anticipate asking for cost recovery for any expenses related to this rule?

Please complete the following chart regarding CCR-related costs:

If the answer to any of the above questions is not available, please explain why.

Year	Estimated Coal Combustion Residuals Rule (CCR) Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
Notes				
(Include Notes Here)				

RESPONSE:
a. EPA published the final Coal Combustion Residuals ("CCR") rule on April 17, 2015. This rule regulates the disposal of combustion byproducts. The WIIN Act passed in 2016 provided for approval of State CCR regulatory programs. USEPA then issued revised regulations in 2018 which extended the deadline to initiate closure of certain CCR units to October 31, 2020. Both St. John's River Power Park ("SJRPP") and Scherer are affected by this rule and now have disposal requirement(s) for bottom ash, fly ash, and gypsum. The Indiantown Cogeneration and Cedar Bay facilities are not affected by the rule as all CCR is transported offsite either to a licensed landfill for disposal or sent for beneficial use. FPL and the co-owners of its coal-fired generating units affected by this rule are conducting the engineering evaluations and inspections and developing operation and closure plans required by the CCR rule.

b. The Scherer surface impoundment (ash pond) will be closed, and a new ash landfill will be constructed for dry CCR management. Preparation for the closure of the ash pond has been initiated as the system is converted to dry ash management. Land acquisition and construction of the new dry ash landfill have been initiated.

SJRPP CCR is managed in the onsite landfill or applied to a beneficial use. The current landfill will begin closure beginning in late 2019 with the decommissioning of the facility. The landfill closure plan required by the CCR rule was filed by October, 2016.

c. The engineering details for closure of Scherer ash pond are being refined and preparation for closure (conversion to dry ash handling, treatment system for non-CCR waste streams, etc.) have begun and closure will take several years to complete. The SJRPP landfill will close as part of the decommissioning of the site. FPL does not anticipate any adverse impacts to operation of its generating units to comply with the CCR rule at this time.

d. Construction of the new CCR landfill at Plant Scherer to meet the CCR requirements will require a solid waste permit from the Georgia Environmental Protection Department and is not expected to impact the timeline.

e. FPL does anticipate seeking cost recovery for the additional costs attributed to the CCR rule requiring early closure of the Scherer ash pond and construction of a new landfill that is compliant with the new design standard. FPL also anticipates seeking cost recovery for the costs of additional closure and monitoring elements for the SJRPP ash landfill.

Year	Estimated Coal Combustion Residuals Rule (CCR) Impacts (2018 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019	[redacted]	*	N/A	[redacted]
2020	[redacted]	*	N/A	[redacted]
2021	[redacted]	*	N/A	[redacted]
2022	[redacted]	*	N/A	[redacted]
2023	[redacted]	*	N/A	[redacted]
2024	[redacted]	*	N/A	[redacted]
2025	[redacted]	*	N/A	[redacted]
2026	[redacted]	*	N/A	[redacted]
2027	[redacted]	*	N/A	[redacted]
2028	[redacted]	*	N/A	[redacted]

Notes

*Costs projections are not available for the period.

Capital costs include closure of existing Scherer ash pond and constructions of a new landfill for CCR management.

QUESTION:
For the U.S. EPA's Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units Rule:

a. Will your Company be materially affected by the rule?
b. What compliance strategy does the Company anticipate employing for the rule?
c. If the strategy has not been completed, what is the Company's timeline for completing the compliance strategy?
d. Will there be any regulatory approvals needed for implementing this compliance strategy? How will this affect the timeline?
e. Does the Company anticipate asking for cost recovery for any expenses related to this rule? Please complete the following chart regarding costs:

Year	Estimated Cost of Standards of Performance for Greenhouse Gas Emissions Rule for New Sources Impacts (2019 $ millions)			
	Capital Costs	O&M Costs	Fuel Costs	Total Costs
2019				
2020				
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
Notes				
(Include Notes Here)				

If the answer to any of the above questions is not available, please explain why.

RESPONSE:
a. In October 2015, the EPA's final rule for New Source Performance Standards ("NSPS") governing carbon dioxide ("CO_2") emissions from new fossil fuel-fired electric generating units became effective. This rule should have no impact on FPL facilities since (i) FPL's new combined-cycle gas facilities routinely have GHG emission rates below the NSPS limits, (ii) FPL's new simple-cycle gas-fired peakers will meet the NSPS limits for non-baseload generating units by using designated clean fuels, (iii) FPL's solar generating facilities do not emit GHGs and are unaffected by the rule, and (iv) FPL has no current plans to build new coal-fired facilities. Additionally, on March 28, 2017, EPA filed with the U.S. Court of Appeals for the D.C. Circuit a motion to hold the challenges to the NSPS case in abeyance while EPA undertakes review of the rule and forthcoming rulemaking as required by the President's Executive Order for review of the rule.

On August 21, 2018, the Affordable Clean Energy ("ACE") rule was proposed to replace the 2015 Clean Power Plan. The ACE rule applies only to coal fired electric generating units and does not including gas fired combustion units. The rule requires states to establish their own standards to address greenhouse gas emissions by use of on-site, heat rate efficiency improvements based on the best system of emission reduction (“BSER”). The rule is expected to be finalized in 2019, and states will have three years to develop plans.

b. - e. N/A

	Estimated Cost of Standards of Performance for Greenhouse Gas Emissions Rule for New Sources Impacts (2018 $ millions)			
Year	**Capital Costs**	**O&M Costs**	**Fuel Costs**	**Total Costs**
2018	0	0	0	0
2019	*	*	*	*
2020	*	*	*	*
2021	*	*	*	*
2022	*	*	*	*
2023	*	*	*	*
2024	*	*	*	*
2025	*	*	*	*
2026	*	*	*	*
2027	*	*	*	*
Notes				
• Costs are not available for this period.				

QUESTION:
Please identify, for each unit affected by one or more of EPA's 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 indicate the unit's name, type, fuel type, and net summer generating capacity. Please complete the table below and provide an electronic copy in Microsoft Excel format.

Estimated Impacts of EPA's Rules on Generating Units

Unit	Unit Type	Fuel Type	Net Sum Capacity (MW)	Type of EPA Rule Impacts					Anticipated Impacts
				MATS	CSAPR/ CAIR	CWIS	CCR		
							Non-Hazardous Waste	Special Waste	
Notes									
(Include Notes Here)									

RESPONSE:
Please see Attachment No. 1 to this response.

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

Estimated Unit Cost of EPA's Rules

<table>
<tr><th rowspan="3">Unit</th><th rowspan="3">Unit Type</th><th rowspan="3">Fuel Type</th><th rowspan="3">Net Sum Capacity (MW)</th><th colspan="7">Estimated Cost of EPA Rules Impacts (2019 $ millions)</th></tr>
<tr><th rowspan="2">MATS</th><th rowspan="2">CSAPR/ CAIR</th><th rowspan="2">CWIS</th><th colspan="2">CCR</th><th rowspan="2">Anticipated Impacts</th><th rowspan="2">Total Cost</th></tr>
<tr><th>Non-Hazardous Waste</th><th>Special Waste</th></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
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<tr><td colspan="10">Notes</td><td></td></tr>
<tr><td colspan="10">(Include Notes Here)</td><td></td></tr>
</table>

RESPONSE:
Please see confidential Attachment No. 1 to this response.

Florida Power & Light Company
2019 Ten-Year Site Plan
Staff's Supplemental Data Request # 1
Question No. 67
Attachment No. 1-Redacted
Tab 1 of 1

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 (2019 $ millions)					
				MATS	CSAPR/CAIR	CWIS	CCR Non-Hazardous Waste	CCR Special Waste	Total Cost
Cape Canaveral 3	CC	NG, ULSD	1210	N/A	0	25.13	N/A	N/A	9.14
Fort Myers Gas Turbines 1 & 9	GT	DFO	108	N/A	0	N/A	N/A	N/A	0
Fort Myers 2	CC	NG	1524	N/A	0	31.59	N/A	N/A	14.56
Fort Myers 3 A-D	GT	NG, ULSD	786	N/A	0	N/A	N/A	N/A	0
Dania Beach 7						31.74			
Lauderdale 4 ****	CC	NG, DFO	442	N/A	0	N/A	N/A	N/A	6.08
Lauderdale 5****	CC	NG, DFO	442	N/A	0	N/A	N/A	N/A	6.08
Lauderdale Gas Turbines 3 & 5	GT	NG, DFO	69	N/A	0	N/A	N/A	N/A	0
Lauderdale 6 A-F	GT	NG, ULSD	1055	N/A	0	N/A	N/A	N/A	0
Port Everglades 5	CC	NG, ULSD	1055	N/A	0	25.45	N/A	N/A	8.12
Riviera 5	CC	NG, ULSD	1219	N/A	0	3.40	N/A	N/A	7.95
Sanford 4	CC	NG	950	N/A	0	0.00	N/A	N/A	0.01
Sanford 5	CC	NG, ULSD	950	N/A	0	0.00	N/A	N/A	0.01
Turkey Point 3	PWR	NUC	811	N/A	N/A	N/A	N/A	N/A	0
Turkey Point 4	PWR	NUC	821	N/A	N/A	N/A	N/A	N/A	0
Turkey Point 5	CC	NG, ULSD	1187	N/A	0	N/A	N/A	N/A	0
Manatee 1	ST	NG, RFO	809	ESP Installation Completed 2013	800 MW Cycling Project Completec	0.000	N/A	N/A	0.003
Manatee 2	ST	NG, RFO	809	ESP Installation Completed 2012	800 MW Cycling Project Completec	0.000	N/A	N/A	0.003
Manatee 3	CC	NG	943	N/A	0	0.000	N/A	N/A	0.003
Martin 1****	ST	NG, RFO	823	ESP Installation Completed 2014; Unit Retired 2018	800 MW Cycling Project Completed; Unit Retired 2018	N/A	N/A	N/A	0
Martin 2 ****	ST	NG, RFO	803	ESP Installation Completed 2015; Unit Retired 2018	800 MW Cycling Project Completed; Unit Retired 2018	N/A	N/A	N/A	0
Martin 3	CC	NG	487	N/A	0	0.000	N/A	N/A	0.003
Martin 4	CC	NG	478	N/A	0	0.000	N/A	N/A	0.003
Martin 8	CC	NG, ULSD	1129	N/A	0	0.000	N/A	N/A	0.003
Martin SOLAR	ST	SUN	75***	N/A	N/A	0.000	N/A	N/A	0.003
St. Lucie 1	PWR	NUC	981	N/A	N/A	0.20	N/A	N/A	6.27
St. Lucie 2	PWR	NUC	840**	N/A	N/A	0.20	N/A	N/A	6.27
West County Energy Center 1	CC	NG, ULSD	1219	N/A	0	N/A	N/A	N/A	0
West County Energy Center 2	CC	NG, ULSD	1219	N/A	0	N/A	N/A	N/A	0
West County Energy Center 3	CC	NG, ULSD	1219	N/A	0	N/A	N/A	N/A	0
Okeechobee Clean Energy Center 1	CC	NG, ULSD	1600	N/A	N/A	N/A	N/A	N/A	0
SJRPP 1****	ST	BIT	127**	N/A	N/A	N/A	Estimate Not Available from operator	N/A	Estimate Not Available from operator
SJRPP 2****	ST	BIT	127**	N/A	N/A	N/A	Estimate Not Available from operator	N/A	Estimate Not Available from operator
Scherer 4	ST	SUB	634**	Hg Control Installed 2010, FGD Installation 2012	SCR & FGD Installed 2012	[redacted]			
Indiantown Cogeneration	ST	BIT	330	0	N/A	N/A	N/A	N/A	N/A
Space Coast Solar Energy	PV	SUN	10	N/A	N/A	N/A	N/A	N/A	None
Desoto Solar Energy	PV	SUN	25	N/A	N/A	N/A	N/A	N/A	None
Manatee Solar Energy	PV	SUN	74.5	N/A	N/A	N/A	N/A	N/A	None
Babcock Ranch Solar Energy	PV	SUN	74.5	N/A	N/A	N/A	N/A	N/A	None
Citrus Solar Energy	PV	SUN	74.5	N/A	N/A	N/A	N/A	N/A	None
Barefoot Bay Solar Energy	PV	SUN	74.5	N/A	N/A	N/A	N/A	N/A	None
Coral Farms Solar Energy	PV	SUN	74.5	N/A	N/A	N/A	N/A	N/A	None
Hammock Solar Energy	PV	SUN	74.5	N/A	N/A	N/A	N/A	N/A	None
Horizon Solar Energy	PV	SUN	74.5	N/A	N/A	N/A	N/A	N/A	None
Indian River Solar Energy	PV	SUN	74.5	N/A	N/A	N/A	N/A	N/A	None
Loggerhead Solar Energy	PV	SUN	74.5	N/A	N/A	N/A	N/A	N/A	None
Wildflower Solar Energy	PV	SUN	74.5	N/A	N/A	N/A	N/A	N/A	None
Blue Cypress Solar Energy	PV	SUN	74.5	N/A	N/A	N/A	N/A	N/A	N/A
Sunshine Gateway Solar Energy	PV	SUN	74.5	N/A	N/A	N/A	N/A	N/A	N/A

Notes

Unit Type: ST = Steam Turbine, GT = Gas Turbine, CC = Combined Cycle, PV = Photovoltaic

Fuel Type: NG = Natural Gas, DFO = Distillate Fuel Oil, RFO = Residual Fuel Oil, ULSD = Ultra-Low Sulfur Distillate, BIT = Bituminous Coal, SUB = Sub-Bituminous Coal, SUN = Solar (PV & thermal), NUC = Nuclear

Notes: * Total includes anticipated total project capital expenses for installation
** FPL Ownership Share only
*** Unit capability also included in Martin Unit 8 Net Summer Capability
**** SJRPP Units 1 & 2 were retired January 2018, and Martin Units 1 & 2 and Lauderdale Units 4 & 5 were retired Dec. 2018.

QUESTION:
Please identify, for each unit impacted by one or more of EPA's 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. Include important dates relating to each rule. Please complete the table below and provide an electronic copy in Microsoft Excel format.

Estimated Timing of Unit Impacts of EPA's Rules

<table>
<tr><th rowspan="3">Unit</th><th rowspan="3">Unit Type</th><th rowspan="3">Fuel Type</th><th rowspan="3">Net Sum Capacity (MW)</th><th colspan="5">Estimated Timing of EPA Rule Impacts (Month/Year - Duration)</th></tr>
<tr><th rowspan="2">MATS</th><th rowspan="2">CSAPR/ CAIR</th><th rowspan="2">CWIS</th><th colspan="2">CCR</th></tr>
<tr><th>Non-Hazardous Waste</th><th>Special Waste</th></tr>
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<tr><td colspan="9">Notes</td></tr>
<tr><td colspan="9">(Include Notes Here)</td></tr>
</table>

RESPONSE:
Please see Attachment No. 1 to this response.

QUESTION:
Explain any expected reliability impacts resulting from each of the EPA rules listed below. As part of your explanation, please discuss the impacts 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 due to each of these EPA rules.

a. Mercury and Air Toxics Standards (MATS) Rule.
b. Cross-State Air Pollution Rule (CSAPR).
c. Cooling Water Intake Structures (CWIS) Rule.
d. Coal Combustion Residuals (CCR) Rule.
e. Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units.

RESPONSE:
FPL does not anticipate any system reliability impacts associated with the compliance requirements of the MATS Rule, CSAPR Rule, CWIS Rule, CCR Rule, or EPA's Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 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.

a. For compliance with the MATS rule, FPL installed ESPs on the Martin and Manatee oil-fired steam 800 MW units, Sorbant Injection and baghouse on Scherer Unit 4, use of compliance coal in St. John's River Power Park ("SJRPP") Units 1 & 2, and existing controls for the coal fired Indiantown Cogeneration facility purchased by FPL in 2016 will comply with the emission standards established by the rule. FPL retired the Cedar Bay coal fired generating unit in 2016 and has completed demolition of the unit. Additionally, SJRPP Units 1&2 and Martin Units 1&2 were retired in 2018, effectively removing them from the MATS compliance requirements at this time. In its 2019 Ten-Year Site Plan filing, FPL provided notice of its intent to retire Manatee Units 1&2 in late 2021 and early 2022. FPL has not identified any potential impacts to the reliability or capability of its units, or transmission system, as a result of the MATS compliance plan.

b. FPL's CSAPR compliance plan has not, and will not, impact generating unit or system reliability or capability. With EPA's promulgation of the CSAPR update rule, FPL's Florida based generating units are no longer subject to the rule requirements. FPL's ownership share of Scherer Unit 4 will remain subject to the rule but has sufficient allowances to comply with the rule requirements. However, should future actual conditions vary significantly from projection assumptions, unit reliability impacts could occur though no transmission system impacts are projected to occur as a result.

c. FPL has evaluated the requirements for this rule and has developed anticipated costs associated with the various compliance requirements. Impacts for the CWIS Rule, which became final on October 14, 2014, will vary based on the level of modifications required by conclusions based on subsequent studies and negotiations with Florida Department of Environmental Protection ("FDEP") permit writers. Should, as is currently expected, modified Ristroph-type traveling screens and fish return systems, along with the possibility of fine mesh screens, be required for most facilities (those without cooling ponds or cooling towers), the impacts should be minimal where installations would be accommodated during scheduled maintenance outages. FPL has identified no system reliability impacts that would be anticipated to occur as a result of the expected rule requirements for CWIS.

d. For the CCR rule, FPL has evaluated anticipated compliance requirements based on EPA and industry comments for the April 17, 2015 final rule. The rule did continue the regulation of CCRs as non-hazardous waste. However, the CCR rule established new locations restrictions, disposal unit design standards, and numerous compliance plans, inspections, and certifications phased in over three years applicable to FPL's co-owned coal units. As a result of the new location and groundwater standards, FPL and co-owners initiated preparations in 2018 for closure of the Scherer Plant unlined Surface Impoundment (ash pond) and construction of a new landfill meeting the new design standards. FPL and its co-owners will initiate closure of the SJRPP landfill following removal of all CCR from impacted components during demolition, which is anticipated to begin summer 2019. The Indiantown Cogeneration facility, with a planned retirement date by the end of the 1st Quarter of 2020, manages CCR offsite and is therefore not subject to the rule. Actions for compliance with these changes in the regulatory standards for management 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.

e. FPL's Port Everglades Energy Center ("PEEC") received an air construction permit from DEP for the PSD pollutants and EPA for GHGs. EPA established a BACT limit for the PEEC facility at 830 lb C02 equivalent/MWh (net) while EPA's GHG limit performance standard for new gas fired units is 1000 lb/MWh (gross). Following the United States Supreme Court's decision on EPA's Tailoring rule, FPL submitted a request to rescind the GHG permit as not legally required since the Unit 5 netted emissions did not require a PSD permit. Subsequently, FPL submitted and received final Air Construction Permits for the construction of the Okeechobee Energy Center and Dania Beach Energy Center combined cycle units, which contain GHG limits of 850 lb CO2 equivalent/MWh (net) that FPL will be able to comply with during normal operation of the units in addition to the EPA 1000 lb/MWh federal limit. Accordingly, FPL does not anticipate any unit reliability impacts or system transmission impacts associated with the GHG rule. In addition, FPL also does not anticipate any additional capital or O&M expenditures will be needed to comply with the GHG performance standard for future units.

QUESTION:
If applicable, identify any currently approved costs for environmental compliance investments made by your Company, including but not limited to renewable energy or energy efficiency measures, which would mitigate the need for future investments to comply with recently finalized or proposed EPA regulations. Briefly describe the nature of these investments and identify which rule(s) they are intended to address.

RESPONSE:
Some examples of currently approved environmental compliance investments which help to mitigate future investments include, but are not limited to:

- Compliance plans implemented for CAIR and approved for recovery are sufficient to meet CSAPR rule requirements. FPL believes its previous CAIR and CAMR/MATS projects, and present CSAPR compliance plan, will meet the current SO_2, NO_2, fine particle, and ozone National Ambient Air Quality Standards ("NAAQS") requirements.
- Installation of Sorbent Injection / Baghouse, SCR, and Scrubber on Scherer Unit 4 for compliance with the Georgia Multi-Pollutant Rule 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 PV solar projects at DeSoto, Kennedy Space Center, Babcock Ranch, Citrus, Barefoot Bay, Coral Farms, Hammock, Horizon, Indian River, Loggerhead, Wildflower, Blue Cypress, and Sunshine Gateway and solar thermal project at the Martin Plant help lower FPL's fleet-wide GHG emissions further reducing exposure to future GHG rules. FPL has announced a robust plan to install 30 million solar panels by 2030. These projects will further reduce FPL's fleet-wide GHG emissions. In addition, FPL's current and planned expansion of the implementation of battery storage projects allows the storage of renewable generation to displace higher emitting peaking generation during system peak demand periods.
- Modified traveling screens with fish return systems have been installed as part of the modernizations of Cape Canaveral Energy Center, Riviera Beach Energy Center, and Port Everglades Energy Center to avoid retrofit costs that would be required to comply with the CWIS Rule in the future.
- Studies required by the CWIS Rule.

Many of FPL's approved costs for environmental compliance investments made by FPL can be found in FPL's filings made in the FPSC's annual Environmental Cost Recovery Clause docket.

QUESTION:
What steps has your Company taken, is currently taking, or is planning to take to address curbing carbon dioxide emissions for existing sources? How has your Company addressed the ruling by the U.S. Supreme Court that carbon dioxide is a pollutant under the Clean Air Act? How does your Company plan on addressing carbon dioxide emissions from existing sources during the 10-year site planning period?

RESPONSE:
Since 2001, FPL's investments in clean, fuel-efficient natural gas fired power plants have saved customers $10 billion in fuel costs and helped reduce the company's use of foreign oil by 99 percent. Because of these modernization efforts, FPL was able to avoid burning more than 39 million barrels of oil in 2018, using less than a million barrels of oil for generation. These investments have also enabled FPL to significantly reduce power plant emissions rates by 35% over this time period and have prevented nearly 13 million tons of CO2 emissions in 2018 alone. Installation of PV solar projects at DeSoto, Kennedy Space Center, Babcock Ranch, Citrus, Barefoot Bay, Coral Farms, Hammock, Horizon, Indian River, Loggerhead, Blue Cypress, Manatee, Sunshine Gateway, and Wildflower and the solar thermal project at the Martin Plant help lower FPL's fleet-wide CO_2 emissions further reducing exposure to future CO_2 rules. The 2019 Ten-Year Site Plan indicates FPL will be adding more solar by the end of 2028. The planned solar projects consist of a total of more than 8,053 MW of PV and 75 MW of solar thermal. This planned solar implementation schedule is consistent with FPL's January 2019 announcement of its "30 by 30" plan in which FPL stated an objective to install more than 30 million solar panels on FPL's system by the year 2030.

Since 2005, FPL has reduced CO_2 emissions rates by 31.3%, and in 2018, FPL's CO_2 emissions rate was approximately 31% lower than the U.S. utility sector.

In total, FPL will generate more than 97 percent of its energy from clean sources, with U.S.-produced natural gas continuing to constitute the largest component, followed by zero-emissions nuclear energy. By 2020, solar is projected to overtake coal as the third largest fuel source of electricity.

As noted in FPL's most recent Ten-Year Site Plan, FPL is working to further modernize its system by retiring Units 4 and 5 at its Lauderdale Plant in Dania Beach, Fla., which was repowered from fossil steam generators to combined cycle units more than two decades ago, and building a new, natural gas-fueled clean energy center in its place. The FPL Dania Beach Clean Energy Center, with approximately 1,200 megawatts of 24 -7 capacity, will begin serving FPL customers by mid-2022 and save FPL customers hundreds of millions of dollars over its operational life. The increased efficiency of the Dania Beach Plant will result in a CO2 rate that is 25% lower than to the existing Ft. Lauderdale Power Plant.

Over the last two years, FPL bought out existing contracts with two independent coal-fired power plants with the goal of shutting both plants down. These transactions will result in millions of dollars of savings for customers over the period of the original contract as well as the elimination of CO_2 emissions from those facilities. The first of these, the Cedar Bay Cogeneration Plant in Jacksonville, ceased operations at the end of 2016. The retirement of the Cedar Bay Plant reduces approximately 1 million tons of coal-fired CO_2 emissions annually. The second, the Indiantown Cogeneration Facility in Martin County, is on track to close by the end of the 1st Quarter of 2020. Shutdown of the Indiantown plant will result in an additional reduction of an average 800,000 tons of CO_2 annually.

In 2018, FPL’s co-owned St. Johns River Power Park was retired, as well as FPL’s Martin Plant Units 1 and 2 and the previously mentioned Lauderdale Plant Units 4 and 5. FPL’s construction and commercial operation of the highly efficient Okeechobee Clean Energy Center replaces that less efficient and higher emitting generation, further reducing system wide CO_2 emissions. Additionally, FPL announced in its Ten-Year Site Plan the planned retirement of Manatee Plant Units 1 and 2, which will be made possible with additional solar and a new battery facility at the plant. The retirement of these plants eliminates more than 9 million tons of carbon dioxide emissions annually.

In 2007, the U.S. Supreme Court determined, in Massachusetts vs. EPA, 549 U.S. 497 (2007), that CO_2 was a pollutant regulated under the Clean Air Act *if* EPA determined, through an Endangerment Finding, that CO_2 emissions were a threat to human health and the environment. Following EPA’s positive Endangerment Finding, it has been apparent that the agency would eventually regulate CO_2 emissions. FPL has accounted for projected CO_2 compliance costs in its resource planning since 2007 by including a projected carbon dioxide compliance cost forecast in its planning scenarios. The projected $/ton compliance costs by year are applied to carbon emissions from all FPL-owned generation, including both existing and planned generation units, to evaluate potential future impacts to FPL’s customers should a future carbon cost be imposed. CO_2 emissions reductions have been a component of the decision making process for the repowering of FPL’s older oil-fired generating units to install more efficient natural gas combined cycle units and in its decision to build additional universal solar generation throughout the state.

Under the Trump Administration, FPL has seen a significant rollback of CO_2 regulations risk resulting from EPA’s vacatur of the Clean Power Plan Rule. However, the Administration did not attempt to reverse the EPA Endangerment Finding that requires the agency to regulate CO_2 emissions. As a result, on August 21, 2018, the Affordable Clean Energy (ACE) rule was proposed to replace the 2015 Clean Power Plan. The ACE rule applies only to coal fired electric generating units and does not include gas fired combustion units. The rule requires states to establish their own standards to address greenhouse gas emissions based on on-site, heat rate efficiency improvements. This rule is expected to be finalized in 2019 and states will have three years to develop their State Implementation Plans that would then need to be approved by EPA. FPL anticipates numerous challenges to this rule that will delay its implementation.

As stated above, FPL is retiring higher emitting, less efficient coal-fired and oil-fired conventional steam generation and less efficient natural gas fired generation, while meeting its future generation needs with more efficient combined cycle natural gas fired plants and zero emitting universal solar generation. These ongoing improvements to FPL's generation fleet will result in cost savings to FPL's customers and significant reductions in CO_2 emissions during the next ten years.

QUESTION:
Please provide, on a system-wide basis, the actual annual fuel usage (in GWh) and average fuel price (in nominal $/MMBTU) for each fuel type utilized by the Company in the period 2009-2018. 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 2019-2028. As part of this response, please complete the table below and provide the completed table in Microsoft Excel format.

Average Fuel Price Comparison

Year		Uranium		Coal		Natural Gas		Residual Oil		Distillate Oil	
		GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU
Actual	2009										
	2010										
	2011										
	2012										
	2013										
	2014										
	2015										
	2016										
	2017										
	2018										
Projected	2019										
	2020										
	2021										
	2022										
	2023										
	2024										
	2025										
	2026										
	2027										
	2028										
Notes											
(Include Notes Here)											

RESPONSE:
Please see Attachment No. 1 to this response.

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

RESPONSE:
Fossil Fuel:

FPL’s medium fossil fuel price forecast methodology utilizes projections from The PIRA Energy Group (PIRA), rates of escalation from the U.S. 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 short-term forecast (current year, current year plus 1 and current year plus 2), creates a blend of forward curves and PIRA curves for the medium term (current year plus 3 and current year plus 4), and finally 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 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.

QUESTION:
Please identify and discuss expected industry trends and factors for each fuel type (coal, natural gas, nuclear fuel, oil, etc.) that may affect the Company during the period 2019-2028.

a. Coal
b. Natural Gas
c. Nuclear (if applicable)
d. Fuel Oil
e. Other (please specify each, if any)

RESPONSE:
a. Coal

FPL's fuel usage goal is to minimize the use of coal in the generation portfolio during the period 2019 through 2028. In 2019 at the start of the period, FPL only owns two coal fired units: Indiantown and 76.36% of Scherer No. 4. Indiantown burns bituminous coal supplied by mines in the Central Appalachia (CAPP) producing region of the US. As discussed in FPL's 2019 Ten-Year Site Plan, FPL intends to terminate this Power Purchase Agreement by the end of the 1st Quarter 2020. There are several industry issues that challenge and will continue to challenge CAPP coal including, but not limited to, supplier consolidation, diminished supply as metallurgical coal production takes precedence over steam coal production, and an aging workforce. FPL will most likely not be affected by any known or unknown CAPP coal issue as Indiantown is idle and not projected to run until being retired early in the period. Scherer No. 4 burns sub-bituminous coal supplied by surface mines in the Powder River Basin (PRB) producing region of the US. There will likely be upward pressure on PRB coal prices attributable to declining geologic conditions that are projected to result in higher mining costs. Considering the declining burn forecast trend for Scherer No. 4, the effect on FPL should be minimal.

b. Natural Gas

The EIA AEO2019 states that natural gas production is expected to grow 7% per year from 2018 to 2020, which is greater than the 4% per year average growth rate from 2005 to 2015. However, after 2020, it slows to less than 1% per year for the remainder of the projection period. Additionally, growing demand in domestic and export markets leads to increasing natural gas spot prices over the projection period at Henry Hub despite continued technological advances that support increased production. Natural gas used for electric power generation generally increases over the projection period but at a slower rate than in the industrial sector. This growth is supported by the scheduled expiration of renewable tax credits in the mid-2020s.

c. Nuclear (if applicable)

Please see FPL's response to Staff's Supplemental Data Request # 1, Question No. 82.

d. Fuel Oil

According to the EIA AEO2019, U.S. crude oil production will grow in the 2018-2021 period at 10% per year as upstream producers increase output because of the combined effects of rising prices and production cost reductions. In the AEO2019 forecast, domestic consumption of petroleum products stays steady through 2035 mainly due to vehicular fuel efficiency gains. Domestic liquids consumption and petroleum product exports are two of the main drivers for refinery utilization both historically and through the projection period.

e. Other (please specify each, if any)

Not applicable

QUESTION:
Please identify and discuss steps that the Company has taken to ensure natural gas supply availability and transportation over the 2019-2028 planning period.

RESPONSE:
FPL continues to evaluate strategies that will increase the reliability and supply diversity of its natural gas transportation portfolio to ensure adequate gas availability for future generation growth. In May of 2020, the quantity on the Sabal Trail Transmission, LLC (Sabal) and Florida Southeast Connection, LLC (FSC) pipelines will increase to 600,000 MMBtu/day. FPL also has negotiated options to secure additional quantities in the future if it is determined that negotiated option pricing on Sabal and FSC is the most cost effective solution when compared to expansions of the existing pipelines. The current gas transportation portfolio provides FPL access to a diverse range of natural 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 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.

QUESTION:
Please identify and discuss any existing or planned natural gas pipeline expansion project(s), including new pipelines and those occurring or planned to occur outside of Florida that would affect the Company for the period 2019-2028.

RESPONSE:
In 2018, Transcontinental Gas Pipe Line Company, LLC (Transco) placed the Atlantic Sunrise Project in service. This project, along with several other announced projects, will allow their existing pipeline facilities to deliver gas from the prolific Marcellus and Utica shale regions of Pennsylvania and Ohio to the Southeast. In addition, there are several projects that have been announced to bring gas to the Southeast from the Scoop/Stack and Haynesville production areas. FPL continues to explore opportunities to access these growing supply sources but currently has no definitive plans regarding these or other new pipelines.

QUESTION:
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 2019-2028.

RESPONSE:
The U.S. Energy Information Administration ("EIA") AEO2019 projects that pipeline exports to Mexico and LNG exports will continue to increase until 2021. After 2021, U.S. exports of LNG are projected grow at a more modest rate as U.S. sourced LNG becomes less competitive in global markets. As the circumstances unfold, FPL will continue its efforts in procuring the amount of gas needed at the most cost effective prices to continue serving its customers.

<u>QUESTION</u>:
Please identify and discuss the Company’s plans for the use of firm natural gas storage for the period 2019-2028.

<u>RESPONSE</u>:
FPL is under contract for 4.0 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, the Transcontinental Pipeline (“Transco”) 4A Lateral, and the Gulf South Pipeline Company, LP (“Gulf South”). Effective April 1, 2018, FPL entered into a one-year natural gas storage contract with Southern Pines Storage (SG Resources Mississippi, LLC) for 1 Bcf of firm storage. Southern Pines is interconnected with FGT, Transco, and Southeast Supply Header Pipeline. Both of these storage contracts have been extended through March 31, 2020. 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 greatly 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 typically maintains higher levels of 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. FPL continues to evaluate its future natural gas storage needs due to FPL's increasing dependency on natural gas.

QUESTION:
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 2019-2028. 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.

RESPONSE:
FPL's coal fired generating plants, Indiantown and Scherer Unit No. 4, are served exclusively by rail. Accordingly, waterborne transportation issues are not applicable to FPL's interests.

With respect to rail transportation issues during the period of 2019 through 2028, short term challenges of relatively low consequence, such as embargos for annual track maintenance or crew shortages, will likely persist. The railroads appear to be long on locomotive power. FPL owns or has under long term lease sufficient coal cars to haul the projected coal requirements.

When FPL acquired Indiantown in 2017, a long term rail transportation contract was assumed as part of the transaction, as well as a long term rail car lease agreement. The fact that Indiantown is served by a single railroad effectively eliminates competition among rail transportation modes. As discussed in FPL's 2019 Ten-Year Site Plan, FPL intends to terminate this power purchase agreement by the end of the 1st Quarter 2020.

Scherer No. 4 is also served by a single railroad. However, the rail movement of the coal from the Powder River Basin is a two line haul that enables competition from mine origin to an interchange point. The Plant Scherer co-owners including FPL utilized that circumstance to seek least cost transportation through bidding and negotiation that resulted in the current long term rail contract.

QUESTION:
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 2019-2028.

RESPONSE:
No changes are currently projected at the coal generating units, Indiantown or Scherer No. 4, for the period 2019-2028. However, as discussed in FPL's 2019 Ten-Year Site Plan, FPL intends to terminate the Indiantown Power Purchase Agreement by the end of the 1st Quarter of 2020.

QUESTION:
[DEF & FPL Only] Please identify and discuss the Company's plans for the storage and disposal of spent nuclear fuel for the period 2019-2028. 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.

RESPONSE:
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 31, 2009, NextEra Energy Inc. ("NextEra") reached a settlement with the U.S. Department of Energy ("DOE") that reimbursed certain costs incurred by NextEra, for on-site storage of SNF due to DOE's failures to dispose of SNF. The settlement allowed NextEra 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 NextEra, payable by the Government on an annual basis.

On March 3, 2010, the DOE 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 of the United States directed the Secretary of Energy to establish a Blue Ribbon Commission ("BRC") 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.

In 2012, the BRC issued its report and recommendations which includes a consent-based approach to site future nuclear waste management facilities; creation of a new organization, independent of the DOE, dedicated solely to assuring the safe storage and ultimate disposal of spent nuclear fuel and high-level radioactive waste; providing access to the U.S. government's nuclear waste fund for the purpose of nuclear waste storage and disposal; and initiating prompt efforts to develop geologic disposal facilities, consolidated interim storage facilities and transportation to those facilities.

In January 2013, the DOE issued a strategy document for implementing the BRC recommendations, outlining among other things, long-term plans for a new management organization to handle spent fuel storage and disposal activities, development of new interim storage facilities and several possible funding reforms, including accessing the nuclear waste fund for funding these activities. A DOE team began crafting strategies for reaching out to communities that might accept and store nuclear waste.
In February 2018, the President's administration requested $120MM to restart licensing activities for the Yucca Mountain nuclear waste repository and initiate a robust interim storage program. However, the approved budget allocated no money to the project.

In May 2018, the House passed, by a 340-72 vote, the Nuclear Waste Policy Amendments Act of 2018, a bill that addresses a major condition for licensing the Yucca Mountain repository by withdrawing the repository site from use under public land laws and placing it solely under DOE control. The bill also authorizes the DOE to store spent fuel at interim NRC-licensed storage facilities, which would be owned by a non-federal entity. It also increases Yucca Mountain's capacity limit from 70,000 to 110,000 metric tons. The Senate received the bill on May 14, and it was read twice referred to the Committee on Environment and Public Works, but no action has been taken since.

The House in the past year also passed another bill, Energy and Water Development Appropriations, 2019, which sought to provide FY2019 funding for nuclear energy programs and would give the DOE $100 million more than the $120 million requested for Yucca Mountain, but the Senate approved no Yucca Mountain funding. Instead, the Senate passed a bill that includes authorization for a pilot program in FY2019 to develop an interim nuclear waste storage facility at a voluntary site. However the FY2019 appropriations measure, which was enacted in September 2018, included neither the House-passed funding for Yucca Mountain nor the Senate interim storage authorization.

QUESTION:
Please identify and discuss expected uranium production industry trends and factors that will affect the Company during the period 2019-2028.

RESPONSE:
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 during the summer of 2013 to the levels that existed prior to the late 2010 uranium price increase. That 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. The market drifted down again in 2016 reaching a historic 12-year low in November. In early 2018, the market experienced a slight increase due to announcements of production cuts by two major mining companies, but the supply continues to exceed current demand. So far in 2019, the market again is seeing a slight decrease due to the continued over supply. FPL expects uranium prices to remain stable 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 74%, but the market is expected to stabilize. The timing of the return of the nuclear reactors in Japan and the quantity 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), prices are expected to remain rather stable, and additional production would be added as needed to meet new reactor requirements.