FPL

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January 20, 2012

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

Re: Docket No. 110312-EQ - Petition for Approval of Rewewable Energy Tariff and Standard Offer Contract by Florida Power & Light Company

Dear Ms. Cole:

Please find enclosed for filing an original and five (5) copies of Florida Power & Light Company's responses to Staff's Data Requests Nos. 1-8 in the above-mentioned docket.

Thank you for your assistance. Please contact me should you or your staff have any questions regarding this filing.

Sincerely,

William P. Cox
Senior Attorney
Florida Bar No. 0093531

WPC/bag
Enclosures
cc: Pauline E. Robinson, Esq. (w/enc.)

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Q.

Please provide updated schedules 3.1, 3.2, 7.1, 7.2, and 9 of FPL's 2011 Ten Year Site Plan to reflect current planning assumptions. Please assume continuation of existing DSM plans and the implementation of FPL's Economic Rider Rate Schedule and New Existing Facility Economic Development Rider Rate Schedule as well as the Company's current plans for scheduled maintenance.

A.

FPL's current complete set of planning assumptions are those reflected in FPL's need determination filing for the Port Everglades modernization and the standard offer contract filing. Therefore, FPL will respond to this data request by using the format of the Ten-Year Site Plan schedules mentioned in the data request and planning assumptions that are consistent with those used in FPL's recent need determination filing for the Port Everglades modernization. These assumptions include a continuation of FPL's existing DSM plans, the implementation of the two rider rate schedules mentioned in the data request, and FPL's current schedule for planned generation maintenance.

FPL's response to this data request is presented in Tables SOC-3.1, SOC-3.2, SOC-7.1, SOC-7.2, and SOC-9. Please refer to these tables.

TABLES
SOC-3.1, SOC-3.2, SOC-7.1, SOC-7.2, and SOC-9

Table SOC 3.1
History and Forecast of Summer Peak Demand (MW)
(Historical)

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
2001	18,754	169	18,585	0	842	697	489	481	17,423
2002	19,219	261	18,958	0	879	754	489	517	17,851
2003	19,668	253	19,415	0	892	798	577	554	18,200
2004	20,545	258	20,287	0	894	846	588	577	19,063
2005	22,361	264	22,097	0	902	895	600	611	20,858
2006	21,819	256	21,563	0	928	948	635	640	20,256
2007	21,962	261	21,701	0	952	982	716	683	20,295
2008	21,060	181	20,879	0	966	1042	760	706	19,334
2009	22,351	249	22,102	0	981	1097	811	732	20,558
2010	22,256	419	21,837	0	992	1147	840	749	20,424

Historical Values (2001 - 2010):

Col. (2) - Col. (4) are actual values for historical Summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand

Col. (5) - Col. (9) represent actual DSM capabilities starting from January 1988 and are annual (12-month) values except for 2010 values which are August values. Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business On Call (BOC), CILC, and Commercial /Industrial Demand Reduction (CDR). Historical Residential Load Management MWs reflect the effect of new Measurement and Vertification kw/participant factors.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" as if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col.(2) - Col.(6) - Col.(8).

Table SOC 3.1
History and Forecast of Summer Peak Demand (MW)
(Projected)

(1) August of Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Res. Load Management	(7) Residential Conservation	(8) C/I Load Management	(9) C/I Conservation	(10) Net Firm Demand
2011	21,618	426	21,192	0	999	0	857	0	19,762
2012	21,623	432	21,191	0	1,011	69	875	32	19,637
2013	21,931	389	21,542	0	1,023	130	893	64	19,822
2014	23,243	1,187	22,056	0	1,035	196	945	97	20,971
2015	23,786	1,194	22,592	0	1,047	264	962	131	21,382
2016	24,315	1,201	23,114	0	1,059	333	980	165	21,779
2017	24,529	1,195	23,334	0	1,071	401	997	198	21,862
2018	24,674	1,202	23,472	0	1,083	469	1,015	232	21,875
2019	25,041	1,210	23,832	0	1,095	538	1,033	266	22,111
2020	25,499	1,217	24,282	0	1,107	606	1,050	299	22,437

Projected Values (2011 - 2020):

Col. (2) - Col. (4) represent FPL's forecasted peak w/o incremental conservation, cumulative load management, or incremental load management The values shown for 2011 for Cols. (2) - (4) are actual values.

Col. (5) - Col. (9) represent cumulative load management, and incremental conservation and load management. All values are projected August values. The projections for 2011 through 2020 are based on the recent DSM Plan decision by the FPSC. The conservation values for August 2011 are zero because the Sept. 2011 load forecast already accounted for incremental conservation signups for January through August of 2011. Res. Load Management and C/I Load Management include MW values of load management capability from Lee County that can be initiated at FPL's request

Col. (8) represents FPL's Business On Call, CDR, CILC, and Curtailable programs/rates.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

Table SOC 3.2
History and Forecast of Winter Peak Demand:Base Case
(Historical)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Firm Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
2001	18,199	150	18,049	0	749	459	448	183	17,002
2002	17,597	145	17,452	0	768	500	457	196	16,373
2003	20,190	246	19,944	0	802	546	453	206	18,935
2004	14,752	211	14,541	0	813	567	534	227	13,405
2005	18,108	225	17,883	0	816	583	542	233	16,751
2006	19,683	225	19,458	0	823	600	550	240	18,311
2007	16,815	223	16,592	0	846	620	577	249	15,392
2008	18,055	163	17,892	0	868	644	636	279	16,551
2009	20,081	207	19,874	0	881	666	676	285	18,524
2010	24,346	500	23,846	0	905	687	747	291	22,694

Historical Values (2001 - 2010):

Col. (2) - Col. (4) are actual values for historical Winter peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9), and may incorporate the effects of load control if load control was operated on these peak days. Therefore, Col. (2) represents the actual Net Firm Demand.

Col. (5) - Col. (9) for 2001 through 2010 represent actual DSM capabilities starting from January 1988 and are annual (12-month) values for December 31st of the prior year.

Note that the values for FPL's former Interruptible Rate are incorporated into Col. (8), which also includes Business On Call (BOC), CILC, and Commercial /Industrial Demand Reduction (CDR). Historical Residential Load Management MWs reflect the effect of new Measurement and Vertification kw/participant factors.

Col. (10) represents a HYPOTHETICAL "Net Firm Demand" as if the load control values had definitely been exercised on the peak. Col. (10) is derived by the formula: Col. (10) = Col.(2) - Col.(6) - Col.(8).

Table SOC 3.2
History and Forecast of Winter Peak Demand:Base Case
(Projected)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
January of Year	Total	Firm Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
2011	21,126	408	20,718	0	906	0	754	0	19,466
2012	20,889	411	20,478	0	916	18	766	10	19,180
2013	21,101	413	20,688	0	930	53	780	32	19,307
2014	21,959	1,038	20,921	0	943	91	834	55	20,035
2015	22,412	1,245	21,167	0	957	134	848	79	20,395
2016	22,675	1,252	21,423	0	971	176	861	103	20,564
2017	22,902	1,246	21,656	0	984	218	874	127	20,699
2018	23,151	1,254	21,897	0	998	261	887	151	20,854
2019	23,403	1,261	22,142	0	1,011	303	901	175	21,013
2020	23,667	1,269	22,398	0	1,025	345	914	200	21,183

Projected Values (2011 - 2020):

Col. (2) - Col.(4) represent FPL's forecasted peak w/o incremental conservation, cumulative load management, or incremental load management. The values shown for 2011 for Cols. (2) - (4) are actual values.

Col. (5) - Col. (9) represent cumulative load management, and incremental conservation and load management. All values are projected January values. The projections for 2011 through 2020 are based on the recent DSM Plan decision by the FPSC. The conservation values for January 2011 are zero because the Sept. 2011 load forecast already accounted for incremental conservation signups for January through August of 2011. Res. Load Management and C/I Load Management include MW values of load management capability from Lee County that can be initiated at FPL's request.

Col. (8) represents FPL's Business On Call, CDR, CILC, and Curtailable programs/rates.

Col. (10) represents a 'Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by using the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

Table SOC 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
August of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2011	22,474	1,461	0	595	24,530	21,618	1,856	19,762	4,767	24.1	0	4,767	24.1
2012	23,437	1,306	0	650	25,393	21,623	1,986	19,637	5,756	29.3	714	5,042	25.7
2013	24,164	1,306	0	650	26,120	21,931	2,109	19,822	6,298	31.8	826	5,472	27.6
2014	25,467	1,306	0	650	27,423	23,243	2,272	20,971	6,452	30.8	826	5,626	26.8
2015	25,507	1,306	0	740	27,553	23,786	2,404	21,382	6,170	28.9	0	6,170	28.9
2016	26,388	0	0	740	27,128	24,315	2,536	21,779	5,348	24.6	0	5,348	24.6
2017	26,388	0	0	740	27,128	24,529	2,667	21,862	5,266	24.1	0	5,266	24.1
2018	26,388	0	0	740	27,128	24,674	2,799	21,875	5,252	24.0	0	5,252	24.0
2019	26,388	0	0	740	27,128	25,041	2,930	22,111	5,017	22.7	0	5,017	22.7
2020	26,388	0	0	740	27,128	25,499	3,062	22,437	4,690	20.9	0	4,690	20.9

Col. (2) represents capacity additions and changes projected to be in-service by June 1st. These MWs are generally considered to be available to meet Summer peak loads which are forecasted to occur during August of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).
Col. (7) reflects the 2011 load forecast without incremental DSM or cumulative load management.
Col. (8) represents cumulative load management capability, plus incremental conservation, from 1/2011-on intended for use with the 2011 load forecast.
Col. (10) = Col. (6) - Col. (9)
Col. (11) = Col.(10) / Col.(9)
Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Summer peak period. This value is comprised of:
(i) 714 MW (at St. Lucie 2) of nuclear capacity that will be out-of-service during part of Summer in 2012 due to an extended planned outage as part of the capacity uprates project;
(ii) an additional 826 MW of fossil-fueled capacity that will be out-of-service in the Summer of 2013 (at Martin 1) and in the Summer of 2014 (at Martin 2) due to the installation of electrostatic precipitators.
Col. (13) = Col. (10) - Col. (12)
Col. (14) = Col.(13) / Col.(9)

Table SOC 7.2
Forecast of Capacity , Demand, and Scheduled Maintenance At Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
January of Year	Firm Installed Capability MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Winter Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2011	23,987	1,494	0	595	26,076	21,126	1,660	19,466	6,610	34.0	726	5,884	30.2
2012	24,386	1,494	0	595	26,475	20,889	1,709	19,180	7,295	38.0	2,392	4,903	25.6
2013	23,967	1,314	0	650	25,931	21,101	1,795	19,306	6,624	34.3	1,539	5,085	26.3
2014	25,528	1,314	0	650	27,492	21,959	1,925	20,035	7,457	37.2	832	6,625	33.1
2015	26,907	1,314	0	650	28,871	22,412	2,018	20,394	8,476	41.6	0	8,476	41.6
2016	26,951	383	0	740	28,074	22,675	2,111	20,564	7,509	36.5	0	7,509	36.5
2017	27,982	0	0	740	28,722	22,902	2,204	20,698	8,023	38.8	0	8,023	38.8
2018	27,982	0	0	740	28,722	23,151	2,298	20,854	7,868	37.7	0	7,868	37.7
2019	27,982	0	0	740	28,722	23,403	2,391	21,012	7,709	36.7	0	7,709	36.7
2020	27,982	0	0	740	28,722	23,667	2,484	21,182	7,539	35.6	0	7,539	35.6

Col. (2) represents capacity additions and changes projected to be in-service by January 1st. These MWs are generally considered to be available to meet winter peak loads which are forecasted to occur during January of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).
Col. (7) reflects the 2011 load forecast without incremental DSM or cumulative load management. 2011 load is an actual load value.
Col. (8) represents cumulative load management capability, plus incremental conservation, from 1/2011-on intended for use with the 2011 load forecast.
Col. (10) = Col. (6) - Col. (9)
Col. (11) = Col.(10) / Col.(9)
Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Winter peak period. This value is comprised of:
(i) 726 MW(at St. Lucie 2) of nuclear capacity that will be out-of-service in Winter of 2011 due to an extended planned outage as part of the capacity uprates project; (ii) an additional 1,570 MW (853 MW at St. Lucie 1 and 717 MW at Turkey Point 3) of nuclear capacity that will be out-of-service during part of the Winter of 2012 due to extended planned outages as part of the capacity uprates project; (iii) 717MW(at Turkey Point 4) that will be out-of-service in Winter of 2013 due to an extended planned outage as part of the capacity uprates project; (iv) an additional 822 MW that will be out-of-service in the Winter of 2012 (at Manatee 2) and in the Winter of 2013 (at Manatee 1) due to the installation of electrostatic precipitators; and (v) an additional 832 MW (at Martin 1) that will be out-of-service during the Winter of 2014 due to the installation of electrostatic precipitators.
Col. (13) = Col. (10) - Col. (12)
Col. (14) = Col.(13) / Col.(9)

Table SOC - 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Port Everglades Modernization

(2) **Capacity**
a. Summer 1,277 MW
b. Winter 1,429 MW

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

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

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

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

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

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

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

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

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

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

Planned Outage Factor (POF):	3.5%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	95.4%	
Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,330	Btu/kWh
Base Operation 75F,100%		

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

Book Life (Years):	30	years
Total Installed Cost (2016 $/kW):	948	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):	87	
Escalation ($/kW):		
Fixed O&M ($/kW-Yr): (2016 $)	30.00	
Variable O&M ($/MWH): (2016 $)	0.10	
K Factor:	1.51	

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

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

Table SOC - 9
Status Report and Specifications of Proposed Generating Facilities

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

(2) **Capacity**
a. Summer 1,262 MW
b. Winter 1,422 MW

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

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2019
b. Commercial In-service date: 2021

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

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

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

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

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

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

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

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

Planned Outage Factor (POF):	3.5%	
Forced Outage Factor (FOF):	1.1%	
Equivalent Availability Factor (EAF):	95.4%	
Resulting Capacity Factor (%):	Approx. 90%	(First Full Year Base Operation)
Average Net Operating Heat Rate (ANOHR):	6,369	Btu/kWh
Base Operation 75F,100%		

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

Book Life (Years):	30	years
Total Installed Cost (2021 $/kW):	1,076	
Direct Construction Cost ($/kW):		
AFUDC Amount ($/kW):	99	
Escalation ($/kW):		
Fixed O&M ($/kW-Yr): (2021 $)	35.08	
Variable O&M ($/MWH): (2021 $)	0.66	
K Factor:	1.51	

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

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

Q.

Please provide two updated and expanded schedules 7.1 and 7.2 of FPL's 2011 Ten-Year Site Plan to reflect projected reserve margins through 2025, with and without the 2021 unit. Please assume continuation of existing DSM plans and the implementation of FPL's Economic Rider Rate Schedule and New Existing Facility Economic Development Rider Rate Schedule as well as the Company's current plans for scheduled maintenance.

A.

FPL's current complete set of planning assumptions are those reflected in FPL's need determination filing for the Port Everglades modernization and the standard offer contract filing. Therefore, FPL will respond to this data request by using the format of the Ten-Year Site Plan schedules mentioned in the data request and planning assumptions that are consistent with those used in FPL's recent need determination filing for the Port Everglades modernization. These assumptions include a continuation of FPL's existing DSM plans, the implementation of the two rider rate schedules mentioned in the data request, and FPL's current schedule for planned generation maintenance.

FPL's response to this data request will also include an expanded view through the year 2025 of FPL's projected reserve margins.

FPL's response to this data request is presented in Tables SOC-7.1-A (expanded) and SOC-7.2-A (expanded). Please refer to these tables.

TABLES
SOC-7.1-A (expanded) and SOC-7.2-A (expanded)

Table SOC 7.1 (Expanded)
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Summer Peak With 2021 Unit

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
August of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance MW	% of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	% of Peak
2011	22,474	1,461	0	595	24,530	21,618	1,856	19,762	4,767	24.1	0	4,767	24.1
2012	23,437	1,306	0	650	25,393	21,623	1,986	19,637	5,756	29.3	714	5,042	25.7
2013	24,164	1,306	0	650	26,120	21,931	2,109	19,822	6,298	31.8	826	5,472	27.6
2014	25,467	1,306	0	650	27,423	23,243	2,272	20,971	6,452	30.8	826	5,626	26.8
2015	25,507	1,306	0	740	27,553	23,786	2,404	21,382	6,170	28.9	0	6,170	28.9
2016	26,388	0	0	740	27,128	24,315	2,536	21,779	5,348	24.6	0	5,348	24.6
2017	26,388	0	0	740	27,128	24,529	2,667	21,862	5,266	24.1	0	5,266	24.1
2018	26,388	0	0	740	27,128	24,674	2,799	21,875	5,252	24.0	0	5,252	24.0
2019	26,388	0	0	740	27,128	25,041	2,930	22,111	5,017	22.7	0	5,017	22.7
2020	26,388	0	0	740	27,128	25,499	3,062	22,437	4,690	20.9	0	4,690	20.9
2021	27,650	0	0	740	28,390	25,960	3,194	22,766	5,624	24.7	0	5,624	24.7
2022	28,750	0	0	740	29,490	26,492	3,326	23,167	6,323	27.3	0	6,323	27.3
2023	29,850	0	0	740	30,590	27,125	3,457	23,668	6,922	29.2	0	6,922	29.2
2024	29,850	0	0	740	30,590	27,680	3,589	24,091	6,499	27.0	0	6,499	27.0
2025	29,850	0	0	490	30,340	28,268	3,721	24,547	5,792	23.6	0	5,792	23.6

Col. (2) represents capacity additions and changes projected to be in-service by June 1st. These MWs are generally considered to be available to meet Summer peak loads which are forecasted to occur during August of the year indicated. Note: A 1,262 MW (Summer)/1422 MW (Winter combined cycle unit is assumed to be added in 2021. Turkey Point 6 & 7, 1,100 MW each, are projected to be added in June,2022 and June, 2023,respecti

Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).

Col. (7) reflects the 2011 load forecast without incremental DSM or cumulative load management.

Col. (8) represents cumulative load management capability, plus incremental conservation, from 1/2011-on intended for use with the 2011 load forecast.

Col. (10) = Col. (6) - Col. (9)

Col. (11) = Col.(10) / Col.(9)

Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Summer peak period. This value is comprised of:

(i) 714 MW (at St. Lucie 2) of nuclear capacity that will be out-of-service during part of Summer in 2012 due to an extended planned outage as part of the capacity uprates project;

(ii) an additional 826 MW of fossil-fueled capacity that will be out-of-service in the Summer of 2013 (at Martin 1) and in the Summer of 2014 (at Martin 2) due to the installation of electrostatic precipitators.

Col. (13) = Col. (10) - Col. (12)

Col. (14) = Col.(13) / Col.(9)

Table SOC 7.1 - A (Expanded)
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Summer Peak Without 2021 Unit

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
August of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Summer Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2011	22,474	1,461	0	595	24,530	21,618	1,856	19,762	4,767	24.1	0	4,767	24.1
2012	23,437	1,306	0	650	25,393	21,623	1,986	19,637	5,756	29.3	714	5,042	25.7
2013	24,164	1,306	0	650	26,120	21,931	2,109	19,822	6,298	31.8	826	5,472	27.6
2014	25,467	1,306	0	650	27,423	23,243	2,272	20,971	6,452	30.8	826	5,626	26.8
2015	25,507	1,306	0	740	27,553	23,786	2,404	21,382	6,170	28.9	0	6,170	28.9
2016	26,388	0	0	740	27,128	24,315	2,536	21,779	5,348	24.6	0	5,348	24.6
2017	26,388	0	0	740	27,128	24,529	2,667	21,862	5,266	24.1	0	5,266	24.1
2018	26,388	0	0	740	27,128	24,674	2,799	21,875	5,252	24.0	0	5,252	24.0
2019	26,388	0	0	740	27,128	25,041	2,930	22,111	5,017	22.7	0	5,017	22.7
2020	26,388	0	0	740	27,128	25,499	3,062	22,437	4,690	20.9	0	4,690	20.9
2021	26,388	0	0	740	27,128	25,960	3,194	22,766	4,362	19.2	0	4,362	19.2
2022	27,488	0	0	740	28,228	26,492	3,326	23,167	5,061	21.8	0	5,061	21.8
2023	28,588	0	0	740	29,328	27,125	3,457	23,668	5,660	23.9	0	5,660	23.9
2024	28,588	0	0	740	29,328	27,680	3,589	24,091	5,237	21.7	0	5,237	21.7
2025	28,588	0	0	490	29,078	28,268	3,721	24,547	4,530	18.5	0	4,530	18.5

Col. (2) represents capacity additions and changes projected to be in-service by June 1st. These MWs are generally considered to be available to meet Summer peak loads which are forecasted to occur during August of the year indicated. Turkey Point 6 & 7, 1,100 MW each, are projected to be added in June,2022 and June, 2023,respectively. No unit additions are shown for 2021 & 2025.
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).
Col. (7) reflects the 2011 load forecast without incremental DSM or cumulative load management.
Col. (8) represents cumulative load management capability, plus incremental conservation, from 1/2011-on intended for use with the 2011 load forecast.
Col. (10) = Col. (6) - Col. (9)
Col. (11) = Col.(10) / Col.(9)
Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Summer peak period. This value is comprised of:
(i) 714 MW (at St. Lucie 2) of nuclear capacity that will be out-of-service during part of Summer in 2012 due to an extended planned outage as part of the capacity uprates project;
(ii) an additional 826 MW of fossil-fueled capacity that will be out-of-service in the Summer of 2013 (at Martin 1) and in the Summer of 2014 (at Martin 2) due to the installation of electrostatic precipitators.
Col. (13) = Col. (10) - Col. (12)
Col. (14) = Col.(13) / Col.(9)

Table SOC 7.2 (Expanded)
Forecast of Capacity , Demand, and Scheduled Maintenance At Time of Winter Peak With 2021 Unit

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
January of Year	Firm Installed Capability MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Winter Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2011	23,987	1,494	0	595	26,076	21,126	1,660	19,466	6,610	34.0	726	5,884	30.2
2012	24,386	1,494	0	595	26,475	20,889	1,709	19,180	7,295	38.0	2,392	4,903	25.6
2013	23,967	1,314	0	650	25,931	21,101	1,795	19,306	6,624	34.3	1,539	5,085	26.3
2014	25,528	1,314	0	650	27,492	21,959	1,925	20,035	7,457	37.2	832	6,625	33.1
2015	26,907	1,314	0	650	28,871	22,412	2,018	20,394	8,476	41.6	0	8,476	41.6
2016	26,951	383	0	740	28,074	22,675	2,111	20,564	7,509	36.5	0	7,509	36.5
2017	27,982	0	0	740	28,722	22,902	2,204	20,698	8,023	38.8	0	8,023	38.8
2018	27,982	0	0	740	28,722	23,151	2,298	20,854	7,868	37.7	0	7,868	37.7
2019	27,982	0	0	740	28,722	23,403	2,391	21,012	7,709	36.7	0	7,709	36.7
2020	27,982	0	0	740	28,722	23,667	2,484	21,182	7,539	35.6	0	7,539	35.6
2021	27,982	0	0	740	28,722	23,952	2,578	21,374	7,347	34.4	0	7,347	34.4
2022	29,404	0	0	740	30,144	24,253	2,671	21,582	8,561	39.7	0	8,561	39.7
2023	30,504	0	0	740	31,244	24,606	2,765	21,842	9,402	43.0	0	9,402	43.0
2024	31,604	0	0	740	32,344	24,959	2,858	22,101	10,243	46.3	0	10,243	46.3
2025	31,604	0	0	490	32,094	25,302	2,952	22,350	9,744	43.6	0	9,744	43.6

Col. (2) represents capacity additions and changes projected to be in-service by January 1st. These MWs are generally considered to be available to meet Winter peak loads which are forecasted to occur during January of the year indicated. Note: A 1,262 MW (Summer)/1422 MW (Winter) combined cycle unit is assumed to be added in 2022. Turkey Point 6 & 7, 1,100 MW each, are projected to be added in June,2022 and June, 2023,respectively.

Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).

Col. (7) reflects the 2011 load forecast without incremental DSM or cumulative load management. 2011 load is an actual load value.

Col. (8) represents cumulative load management capability, plus incremental conservation, from 1/2011-on intended for use with the 2011 load forecast.

Col. (10) = Col. (6) - Col. (9)

Col. (11) = Col.(10) / Col.(9)

Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Winter peak period. This value is comprised of:

(i) 726 MW(at St. Lucie 2) of nuclear capacity that will be out-of-service in Winter of 2011 due to an extended planned outage as part of the capacity uprates project; (ii) an additional 1,570 MW (853 MW at St. Lucie 1 and 717 MW at Turkey Point 3) of nuclear capacity that will be out-of-service during part of the Winter of 2012 due to extended planned outages as part of the capacity uprates project; (iii) 717MW(at Turkey Point 4) that will be out-of-service in Winter of 2013 due to an extended planned outage as part of the capacity uprates project; (iv) an additional 822 MW that will be out-of-service in the Winter of 2012 (at Manatee 2) and in the Winter of 2013 (at Manatee 1) due to the installation of electrostatic precipitators; and (v) an additional 832 MW (at Martin 1) that will be out-of-service during the Winter of 2014 due to the installation of electrostatic precipitators.

Col. (13) = Col. (10) - Col. (12)

Col. (14) = Col.(13) / Col.(9)

Table SOC 7.2 - A (Expanded)
Forecast of Capacity , Demand, and Scheduled
Maintenance At Time of Winter Peak
Without 2021 Unit

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
January of Year	Firm Installed Capability MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Winter Peak Demand MW	Reserve Margin Before Maintenance MW	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin After Maintenance MW	Reserve Margin After Maintenance % of Peak
2011	23,987	1,494	0	595	26,076	21,126	1,660	19,466	6,610	34.0	726	5,884	30.2
2012	24,386	1,494	0	595	26,475	20,889	1,709	19,180	7,295	38.0	2,392	4,903	25.6
2013	23,967	1,314	0	650	25,931	21,101	1,795	19,306	6,624	34.3	1,539	5,085	26.3
2014	25,528	1,314	0	650	27,492	21,959	1,925	20,035	7,457	37.2	832	6,625	33.1
2015	26,907	1,314	0	650	28,871	22,412	2,018	20,394	8,476	41.6	0	8,476	41.6
2016	26,951	383	0	740	28,074	22,675	2,111	20,564	7,509	36.5	0	7,509	36.5
2017	27,982	0	0	740	28,722	22,902	2,204	20,698	8,023	38.8	0	8,023	38.8
2018	27,982	0	0	740	28,722	23,151	2,298	20,854	7,868	37.7	0	7,868	37.7
2019	27,982	0	0	740	28,722	23,403	2,391	21,012	7,709	36.7	0	7,709	36.7
2020	27,982	0	0	740	28,722	23,667	2,484	21,182	7,539	35.6	0	7,539	35.6
2021	27,982	0	0	740	28,722	23,952	2,578	21,374	7,347	34.4	0	7,347	34.4
2022	27,982	0	0	740	28,722	24,253	2,671	21,582	7,139	33.1	0	7,139	33.1
2023	29,082	0	0	740	29,822	24,606	2,765	21,842	7,980	36.5	0	7,980	36.5
2024	30,182	0	0	740	30,922	24,959	2,858	22,101	8,821	39.9	0	8,821	39.9
2025	30,182	0	0	490	30,672	25,302	2,952	22,350	8,322	37.2	0	8,322	37.2

Col. (2) represents capacity additions and changes projected to be in-service by January 1st. These MWs are generally considered to be available to meet winter peak loads which are forecasted to occur during January of the year indicated.Turkey Point 6 & 7, 1,100 MW each, are projected to be added in June,2022 and June, 2023,respectively. No unit additions are shown for 2021 & 2025.

Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).

Col. (7) reflects the 2011 load forecast without incremental DSM or cumulative load management. 2011 load is an actual load value.

Col. (8) represents cumulative load management capability, plus incremental conservation, from 1/2011-on intended for use with the 2011 load forecast.

Col. (10) = Col. (6) - Col. (9)

Col. (11) = Col.(10) / Col.(9)

Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Winter peak period. This value is comprised of:

(i) 726 MW(at St. Lucie 2) of nuclear capacity that will be out-of-service in Winter of 2011 due to an extended planned outage as part of the capacity uprates project; (ii) an additional 1,570 MW (853 MW at St. Lucie 1 and 717 MW at Turkey Point 3) of nuclear capacity that will be out-of-service during part of the Winter of 2012 due to extended planned outages as part of the capacity uprates project; (iii) 717MW(at Turkey Point 4) that will be out-of-service in Winter of 2013 due to an extended planned outage as part of the capacity uprates project; (iv) an additional 822 MW that will be out-of-service in the Winter of 2012 (at Manatee 2) and in the Winter of 2013 (at Manatee 1) due to the installation of electrostatic precipitators; and (v) an additional 832 MW (at Martin 1) that will be out-of-service during the Winter of 2014 due to the installation of electrostatic precipitators.

Col. (13) = Col. (10) - Col. (12)

Col. (14) = Col.(13) / Col.(9)

Q.
Please explain the rationale and sequence of events related to FPL changing its next avoidable unit from a Greenfield combined cycle unit with a 2016 in-service date, shown in FPL's Ten Year Site Plan filed April 2011, to a Greenfield combined cycle unit with a June 1, 2021, in-service date.

A.
On April 1, 2011, in Docket No. 110091-EQ, FPL's 2011 Renewable Energy Tariff and Standard Offer Contract docket, FPL filed a standard offer contract based upon a 2016 greenfield combined cycle unit, as included in our Ten-Year Site Plan filed on the same date. On July 18, 2011, in Docket No. 110228-EI, FPL filed a Petition to request exemption under Rule 25-22.082(18), F.A.C., from issuing a request for proposal ("RFP") for modernization of the Port Everglades Plant (now referred to as the Port Everglades Next Generation Clean Energy Center ("PEEC")). On September 12, 2011, in response to a Commission Staff data request in Docket No. 110091-EQ, FPL stated that the standard offer contract based on the 2011 Ten-Year Site Plan before the Commission was appropriate, complied with the rule, and should be approved. FPL also noted that, under the unique circumstances which prevailed, if the Commission was of the view that PEEC was the appropriate avoided unit for purposes of FPL's standard offer contract instead of the greenfield 3xl combined cycle plant proposed in FPL's 2011 Ten-Year Site Plan, FPL would not object. FPL further noted that upon filing of the determination of need for the PEEC modernization, which was expected to occur before year-end, FPL would be required pursuant to Rule 25-17.250(2)(a)(2), F.A.C. to close its then-existing standard offer contract and file a revised standard offer contract based on the next avoided unit in its Ten-Year Site Plan, a 2020 greenfield unit. On October 5, 2011, the Commission approved FPL's standard offer contract, as revised based upon PEEC as the avoided unit. This was formalized in Order No. PSC-11-0466-TRF-EQ on October 13, 2011.

On November 21, 2011, in Docket No. 110309-EI, FPL submitted a petition for a determination of need for PEEC, the 2016 avoided unit identified and approved in Docket No. 110091-EQ; therefore, as discussed in FPL's September 20, 2011 response to the Commission Staff data request, FPL must close the existing standard offer contract, since the unit is no longer "avoidable" under Rule 25-17.250(2)(a)2, F.A.C. Rule 25-17.250(2)(b), F.A.C. states that before a standard contract offering is closed, the utility must file a petition for approval of a new standard offer contract based on the next unit of the same generating technology, if any, in its Ten-Year Site Plan. FPL's current Ten-Year Site Plan projects the next unit would be a greenfield combined cycle facility in 2020.

Additionally, Rule 25-17.250(2)(a)3, F.A.C. indicates that a standard offer contract must remain open until the generating unit upon which the standard offer contract is based is no longer part of the utility's generation plan. According to FPL witness Juan Enjamio's direct testimony in the PEEC docket, the 2020 unit identified in FPL's current Ten-Year Site Plan is no longer part of FPL's generation plan. FPL's current generation plan projects that its next potentially avoidable fossil fueled generating unit within the meaning of Rule 25-17.250, F.A.C., would be a 1,262 MW combined cycle unit at a greenfield site with an expected in-service date of June 1, 2021. Accordingly, this 2021 combined cycle unit is the next avoidable unit and subject of the proposed standard offer contract for which FPL seeks approval.

Q.
Is the financial information in the petition for the next avoidable unit based on the same 3x1 combined cycle unit with "J" CT technology as proposed in the Port Everglades Energy Center need determination docket, Docket No.110309-EI?

A.
Yes

Q.
On what date does FPL anticipate beginning the RFP process and filing a need determination request for the Greenfield CC unit with the 2021 in-service date?

A.
FPL currently does not have specific dates projected for either beginning an RFP process or filing a need determination request for a 2021 unit. FPL will not make a final decision regarding a capacity addition in 2021 for a number of years.

Q.
Please provide details of the natural gas supply and other transportation needs for the 2021 unit.

A.
The future requirements for natural gas supply to FPL's system will be determined by many factors including system load growth, future deployment of demand side management ("DSM") and renewable resources, the overall generation resource plan and other factors, and not solely by the gas demand of any specific unit. As is customary, FPL's projections of these factors will likely undergo changes in the years leading up to a potential generating unit in 2021. Therefore, FPL has not developed a detailed gas supply plan for the 2021 avoided unit.

Q.

Please complete the tables below describing payments to a renewable provider based on the parameters included in FPL's revised standard offer contract. Please assume the renewable generator is a 50 MW facility providing firm capacity at the minimum capacity factor required for full capacity payments. Additionally, please assume as in service date of June 1, 2021 and a contract duration of 20 years. Please provide this information for the following scenarios:

- Normal Payments
- Levelized Payments
- Early Payments
- Early Levelized Payments

Committed Capacity (MW)	**50**
Capacity Factor (%)	
Payment Type:	

	Energy (MWh)	Capacity Rates($/kW-month)	Total Capacity Payments ($000)	Energy Rates ($/MWh)	Total Energy Payments ($000)	Total Payments to Renewable Provider ($000)
2012						
2013						
2014						
2015						
2016						
2017						
2018						
2019						
2020						
2021						
2022						
2023						
2024						
2025						
2026						
2027						
2028						
2029						
2030						
2031						
2032						

A.

Committed Capacity (MW)	50
Capacity Factor (%)	94
Payment Type:	Normal

	Energy (MWh)	Capacity Rates ($/kW-mo)	Total Capacity Payments ($000)	Energy Rates ($/MWh)	Total Energy Payments ($000)	Total Payments to Renewable Provider ($000)
2012	411,720	-	-	47.71	19,643	19,643
2013	411,720	-	-	43.31	17,832	17,832
2014	411,720	-	-	43.09	17,741	17,741
2015	411,720	-	-	46.16	19,005	19,005
2016	411,720	-	-	53.38	21,978	21,978
2017	411,720	-	-	57.64	23,732	23,732
2018	411,720	-	-	61.20	25,197	25,197
2019	411,720	-	-	64.50	26,556	26,556
2020	411,720	-	-	71.03	29,244	29,244
2021	411,720	9.77	5,862	55.68	22,925	28,786
2022	411,720	10.06	6,036	59.74	24,594	30,630
2023	411,720	10.36	6,215	63.94	26,324	32,539
2024	411,720	10.67	6,399	68.34	28,135	34,534
2025	411,720	10.98	6,589	72.71	29,937	36,526
2026	411,720	11.31	6,784	74.30	30,591	37,376
2027	411,720	11.64	6,986	75.65	31,147	38,133
2028	411,720	11.99	7,193	77.02	31,713	38,906
2029	411,720	12.34	7,407	78.42	32,289	39,696
2030	411,720	12.71	7,626	79.85	32,876	40,502
2031	411,720	13.09	7,853	81.30	33,474	41,327
2032	411,720	13.48	8,086	82.78	34,082	42,168

Committed Capacity (MW)	50
Capacity Factor (%)	94
Payment Type:	Levelized

	Energy (MWh)	Capacity Rates ($/kW-mo)	Total Capacity Payments ($000)	Energy Rates ($/MWh)	Total Energy Payments ($000)	Total Payments to Renewable Provider ($000)
2012	411,720	-	-	47.71	19,643	19,643
2013	411,720	-	-	43.31	17,832	17,832
2014	411,720	-	-	43.09	17,741	17,741
2015	411,720	-	-	46.16	19,005	19,005
2016	411,720	-	-	53.38	21,978	21,978
2017	411,720	-	-	57.64	23,732	23,732
2018	411,720	-	-	61.20	25,197	25,197
2019	411,720	-	-	64.50	26,556	26,556
2020	411,720	-	-	71.03	29,244	29,244
2021	411,720	10.98	6,586	55.68	22,925	29,510
2022	411,720	11.03	6,618	59.74	24,594	31,213
2023	411,720	11.09	6,652	63.94	26,324	32,976
2024	411,720	11.14	6,687	68.34	28,135	34,822
2025	411,720	11.20	6,722	72.71	29,937	36,660
2026	411,720	11.27	6,759	74.30	30,591	37,350
2027	411,720	11.33	6,797	75.65	31,147	37,944
2028	411,720	11.39	6,836	77.02	31,713	38,548
2029	411,720	11.46	6,876	78.42	32,289	39,165
2030	411,720	11.53	6,917	79.85	32,876	39,793
2031	411,720	11.60	6,959	81.30	33,474	40,433
2032	411,720	11.67	7,002	82.78	34,082	41,085

Committed Capacity (MW)	50
Capacity Factor (%)	94
Payment Type:	Early

	Energy (MWh)	Capacity Rates ($/kW-mo)	Total Capacity Payments ($000)	Energy Rates ($/MWh)	Total Energy Payments ($000)	Total Payments to Renewable Provider ($000)
2012	411,720	-	-	47.71	19,643	19,643
2013	411,720	-	-	43.31	17,832	17,832
2014	411,720	-	-	43.09	17,741	17,741
2015	411,720	4.77	2,862	46.16	19,005	21,867
2016	411,720	4.91	2,947	53.38	21,978	24,924
2017	411,720	5.06	3,034	57.64	23,732	26,766
2018	411,720	5.21	3,124	61.20	25,197	28,321
2019	411,720	5.36	3,217	64.50	26,556	29,773
2020	411,720	5.52	3,312	71.03	29,244	32,557
2021	411,720	5.68	3,411	55.68	22,925	26,335
2022	411,720	5.85	3,512	59.74	24,594	28,106
2023	411,720	6.03	3,616	63.94	26,324	29,940
2024	411,720	6.21	3,723	68.34	28,135	31,859
2025	411,720	6.39	3,834	72.71	29,937	33,771
2026	411,720	6.58	3,948	74.30	30,591	34,539
2027	411,720	6.77	4,065	75.65	31,147	35,212
2028	411,720	6.98	4,185	77.02	31,713	35,898
2029	411,720	7.18	4,310	78.42	32,289	36,599
2030	411,720	7.40	4,438	79.85	32,876	37,314
2031	411,720	7.62	4,569	81.30	33,474	38,043
2032	411,720	7.84	4,705	82.78	34,082	38,787

Committed Capacity (MW)	50
Capacity Factor (%)	94
Payment Type:	Early Levelized

	Energy (MWh)	Capacity Rates ($/kW-mo)	Total Capacity Payments ($000)	Energy Rates ($/MWh)	Total Energy Payments ($000)	Total Payments to Renewable Provider ($000)
2012	411,720	-	-	47.71	19,643	19,643
2013	411,720	-	-	43.31	17,832	17,832
2014	411,720	-	-	43.09	17,741	17,741
2015	411,720	5.65	3,392	46.16	19,005	22,397
2016	411,720	5.68	3,408	53.38	21,978	25,385
2017	411,720	5.71	3,424	57.64	23,732	27,156
2018	411,720	5.74	3,441	61.20	25,197	28,639
2019	411,720	5.76	3,459	64.50	26,556	30,015
2020	411,720	5.79	3,477	71.03	29,244	32,721
2021	411,720	5.83	3,495	55.68	22,925	26,420
2022	411,720	5.86	3,514	59.74	24,594	28,109
2023	411,720	5.89	3,534	63.94	26,324	29,858
2024	411,720	5.92	3,554	68.34	28,135	31,689
2025	411,720	5.96	3,575	72.71	29,937	33,512
2026	411,720	5.99	3,596	74.30	30,591	34,187
2027	411,720	6.03	3,618	75.65	31,147	34,764
2028	411,720	6.07	3,640	77.02	31,713	35,353
2029	411,720	6.11	3,663	78.42	32,289	35,952
2030	411,720	6.15	3,687	79.85	32,876	36,563
2031	411,720	6.19	3,712	81.30	33,474	37,185
2032	411,720	6.23	3,737	82.78	34,082	37,819

Q.

If FPL does not receive a need determination for the Port Everglades Energy Center, how would this action affect FPL's forecasted date of its next avoided unit?

a. Would such unit remain the 2016 unit listed in FPL's 2011 Ten Year Site Plan, a 2020 unit, or some other unit?
b. Would FPL continue the existing Standard Offer Contract?

A.

a) If FPL does not receive an affirmative need determination for the Port Everglades Next Generation Clean Energy Center ("PEEC"), it is highly unlikely that sufficient time would remain for FPL to meet its 2016 resource need through construction of a greenfield combined cycle unit. Therefore, FPL would have to meet its 2016 resource need with another type of (and likely a more expensive) resource option that could be in-service by June 2016. The introduction of such a "substitute" resource option would, in turn, affect both the magnitude and timing of FPL's 2017-on resource needs. Because at present FPL does not know the specific requirements for such a "substitute" resource option (*e.g.*, MW and length of contract), it is not currently possible to develop a meaningful forecast of when a subsequent avoided unit might be needed.

b) No. As noted in FPL's response to Commission Staff's data request No. 3, FPL believes that Rule 25-17.250(2)(a)(2), F.A.C. requires it to close the Standard Offer Contract based on PEEC when the request for a need determination for PEEC is <u>filed</u>. Further, since FPL's existing Standard Offer Contract is based upon PEEC, should a need determination not be received for the PEEC unit, it would be inappropriate to have a Standard Offer Contract based on this unit, since Rule 25-17.250(2)(a)3, F.A.C. indicates that a Standard Offer Contract must remain open until the generating unit upon which the Standard Offer Contract is based is no longer part of the utility's generation plan, and FPL's failure to receive a need determination for PEEC would effectively remove PEEC from FPL's generation plan.