BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 130007-EI
FLORIDA POWER & LIGHT COMPANY

JUNE 28, 2013

ENVIRONMENTAL COST RECOVERY

TESTIMONY & EXHIBITS OF:

JUAN E. ENJAMIO

IN SUPPORT OF PETITION FOR APPROVAL OF NO_2 COMPLIANCE PROJECT

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF JUAN E. ENJAMIO

DOCKET NO. 130007-EI

JUNE 28, 2013

Q. Please state your name and business address.

A. My name is Juan E. Enjamio. My business address is 9250 West Flagler Street, Miami, Florida 33174.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company ("FPL") as Supervisor of Integrated Analysis in the Resource Assessment & Planning Department.

Q. Please describe your educational background and professional experience.

A. I graduated from the University of Florida in 1979 with a Bachelor of Science degree in Electrical Engineering. I joined FPL in 1980 as a Distribution Engineer. Since my initial assignment in FPL, I have held positions as a Transmission System Planner, Power System Control Center Engineer, Bulk Power Markets Engineer, Supervisor of Transmission Planning, and Supervisor of Supply and Demand Analysis. In 2004, I became Supervisor of Integrated Analysis – Resource Planning.

Q. Please describe your duties and responsibilities in your current position.

A. In my current position as Supervisor of Integrated Analysis, I am responsible for supervision and coordination of economic analyses of alternatives to meet FPL's resource needs and maintain system reliability.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits, which are attached to my direct testimony:

JEE-1 List of Transmission Improvements Required for Retire Plan

JEE-2 Resource Plans

JEE-3 Reserve Margins

JEE-4 Results of Economic Analysis

JEE-5 Average System Bill Impacts

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to address four major areas. First, I discuss the need for implementing NO_2 compliance reductions at FPL's existing gas turbine ("GT") sites and I describe the different options under consideration. Second, I explain the economic analysis methodology used in evaluating the different options. Third, I present the results of this economic analysis. Finally, I present my recommendation based on the results of the analysis.

Q. Please summarize your testimony.

A. There are a total of 48 FPL GTs affected by a new Environmental Protection Agency ("EPA") standard for 1-hour nitrogen dioxide ("NO_2") emissions. These GTs are located at the Lauderdale ("PFL"), Port Everglades ("PPE"), and Fort Myers ("PFM") plants and were placed in-service in the early 1970s.

To meet the new NO_2 standard at these locations, FPL considered three different options. The first option is to retrofit the GTs and add emission controls, such as Selective Catalytic Reduction ("SCR"), to meet the new emission standard. The second option is to retire the GTs and advance the in-service date of FPL's next generating unit as needed to meet the 20% reserve margin generation reliability criterion. The third option is to change the existing GT combustion technology at two of the three plants in favor of new highly-efficient combustion turbine technology ("CT") and retire the existing GTs at the third plant.

These NO_2 emission compliance options were further refined into three specific plans. FPL determined that there are technical limitations that would make retrofitting the GTs at two of the three plants infeasible, as described in the testimony of FPL's witness Domenech. Therefore, the first plan is a combination of different options: retrofitting the GTs at PFM, retiring the GTs at PPE, and changing out the GT combustion technology in favor of the modern CT technology at PFL; this plan is referred to as the "Hybrid Plan." The second plan is to implement the retirement option at the three plants; this plan is referred to as the "Retire Plan." The third plan is to change the existing GT combustion technologies at the PFL and PFM sites in favor of CTs, and retire the GTs at PPE; this plan is referred to as the "Combustion Technology Change Plan." The economics of these three plans were compared to determine the most cost-effective option for FPL's customers to meet the new revised 1-hour NO_2 standard.

The result of the economic analysis shows that the Combustion Technology Change Plan will provide savings to FPL's customers of about $56 million in cumulative present value of revenue requirements in 2013 dollars ("CPVRR") when compared to the Hybrid Plan, and about $870 million in CPVRR when compared to the Retire Plan.

I. DECISION TO ANALYZE NEW NO_2 COMPLIANCE OPTIONS AT EXISTING GAS TURBINE SITES

Q. Please describe the GTs that are affected by the new 1-hour NO_2 standard.

A. As stated earlier, the affected GTs are located at three power plant sites: PPE, PFL, and PFM.

Twelve GTs at PPE. These turbines were placed in-service in August 1971, and have a capacity of 420 MW (summer rating) out of a total site capacity of 1,697 MW after the construction of the Port Everglades Next Generation Clean Energy Center with a capacity of 1,277 MW is completed in 2016. The heat rate of these GTs is approximately 16,000 to 17,000 Btu/kWh.

Twenty-four GTs at PFL. These turbines were placed in-service in August 1970, and have a capacity of 840 MW (summer rating) out of a total site capacity of 1,724 MW. Other units at the site are the Lauderdale 4 and 5 combined cycle units, each with a capacity of 442 MW. The heat rate of these GTs is approximately 16,000 to 17,000 Btu/kWh.

Twelve GTs at PFM. These turbines were placed in-service in May 1974, and have a capacity of 648 MW (summer rating) out of a total site capacity of 2,396 MW. Other units at the site are the Fort Myers 2 combined cycle unit, with a capacity of 1,432 MW, and the Fort Myers 3A and 3B combustion turbines, each with a capacity of 158 MW. The heat rate of these GTs is approximately 13,200 Btu/kwh.

All together, the 48 GTs at these three sites total 1,908 MW of capacity and represent about 86% of FPL's total peaking capacity.

Q. Why does FPL need to reduce the emissions associated with the existing GTs?

A. As explained in the testimony of FPL witness LaBauve, the EPA revised its National Ambient Air Quality Standard ("NAAQS") for NO_2, and the Florida Department of Environmental Protection ("DEP") adopted this new 1-hour standard in 2013 for implementation in Florida. Emission testing and modeling performed on the GTs at FPL's PPE, PFL, and PFM plants has verified that emissions from these units can significantly exceed the 1-hour NO_2 standard at the property boundary. Under the DEP's rules to implement the NAAQS, FPL is required to take steps to avoid these exceedances. FPL has identified the three options that I described earlier in my testimony to achieve the necessary NO_2 emission reductions.

Q. What options did FPL consider to achieve the required emission reductions?

A. FPL considered three basic options to achieve the required emission reductions. These options were:

1 – Retrofit Option – Retrofit the GTs and add emission controls such as SCR to meet the new emission standards.

2 – Retirement Option - Retire the GTs and advance the in-service date of FPL's next generating unit, which is a new combined cycle unit, as needed to meet the 20% reserve margin generation reliability criteria.

3 – Combustion Technology Change Option - Retire the GTs and replace with new technology combustion turbines that provide quick-start peaking capacity.

Q. Please describe the Retrofit Option in more detail.

A. The Retrofit Option consisted of adding SCRs to each GT as well as making changes to the GTs themselves to accommodate the SCRs. FPL conducted extensive technical feasibility analyses of this option at each of the three plants. These analyses indicated that this option was technically viable at PFM and could be implemented by the summer of 2016. However, it was concluded that this option would not be technically feasible at the PPE and PFL plants. The technical feasibility analyses and its conclusions are described in the testimony of FPL witness Domenech.

Q. Please describe the Retirement Option in more detail.

A. The Retirement Option consisted of retiring all 48 GTs affected by the new 1-hour NO_2 standard without immediate replacement. To meet the 20% reserve margin criterion, short-term purchase agreements were assumed in the years 2017 and 2018. In 2019, a new combined cycle unit was added. This new combined cycle capacity would be a result of accelerating the construction of the next planned gas-fired combined cycle unit from 2025 to 2019.

For this option to be viable, FPL's transmission system would have to be enhanced to provide voltage support in the Fort Myers area. The transmission system delivering power into South Florida (Miami-Dade and Broward Counties) would also have to be strengthened. The Retirement Option would also require modifications to FPL's current system operating practices, resulting in additional fuel costs. Both the cost of the transmission facilities needed and the increased fuel costs due to revised operating reserve practices were factored in the economic analysis of this option.

Q. Can you explain why the transmission system has to be strengthened if the existing GTs are retired from service?

A. Miami-Dade and Broward Counties are the most populated counties with the highest concentration of customer load in FPL's service territory. The two counties together represent approximately 43% of FPL's total load. By 2016, these two counties will have approximately 10,100 MW of load, and this load is projected to continue to grow by about 170 MW per year. After the Port Everglades Clean Energy Center is placed in-service and the Turkey Point 1 unit is removed from generation service and converted into a synchronous condenser, both by the summer of 2016, FPL's total generation in the area will be about 6,200 MW. The balance of the load not served by generation in the area will be served from power imported from outside the area through transmission lines. The capability of the transmission system to import power into Miami-Dade and Broward Counties is limited to about 6,400 MW.

The existing GTs in Broward County are seldom dispatched, due to their high heat rates; however, the location of this reserve generation is critical to back up the remainder of the generation in Miami-Dade and Broward County area. If the GT generation in Broward County is retired and not replaced in the same area, there is a loss of 1,260 MW in local generation. The import capability of the transmission system will need to be increased from approximately 6,400 MW to approximately 7,400 MW due to the need to maintain adequate voltages and equipment loading within thermal limits for several transmission contingencies after the loss of a large unit in the area, such as one Turkey Point Nuclear Unit, the Turkey Point 5 combined cycle unit, or the Port Everglades combined cycle unit. Therefore, to meet all transmission reliability requirements, the removal of the PPE and PFL GT generation will require extensive transmission system upgrades to increase the import capability of the transmission system, at a total cost of $196 million.

Similarly, the GTs at PFM play an important role in area transmission voltage support. The operation of these units is required to maintain voltage support for transmission contingencies after the loss of the Fort Myers combined cycle unit. If these GTs are retired from service and not replaced on site, the transmission system must be enhanced through the construction of a static VAR compensator at Fort Myers for a cost of $76 million. A static VAR compensator is a device that uses capacitor banks with sophisticated controls to provide dynamic voltage support. The list of transmission facilities required if the existing GTs are retired without being replaced at the same sites is shown in Exhibit JEE-1.

Q. What are the operational considerations that would result in higher fuel costs if the GTs are retired from service and not replaced?

A. FPL is a participant in the Florida Reserve Sharing Group ("FRSG") whose purpose is to share the burden of having to carry additional available generation in order to be prepared for the sudden loss of a generating facility. As a result, FPL is required to provide approximately 380 MW of contingency generation reserves, an amount that is based on the size of the largest unit in the state. For the loss of one of the FRSG participant's generating units, FPL is required to have available, and if necessary, provide this amount of reserve capacity to the system within 15 minutes after the loss of the unit. For the loss of an FPL generating unit, FPL is also required to replace the full capacity of the unit within 30 minutes after its loss. These contingency generation reserves can be carried more economically by utilizing available off-line generating units that have quick-start capability such as the 48 GTs at PPE, PFL, and PFM.

If these FPL GTs are retired from service and other units with quick-start capability are not installed, such as CTs, some of these reserves would have to be carried as "spinning" reserves in units already dispatched. This would result in a larger number of units required to be on-line, and once committed, dispatched below their economically optimal levels to have available the required operating reserves. This would result in higher fuel costs. These higher fuel costs were accounted for in the economic analysis of the Retire Option, which retires the GTs without installing the CTs.

Q. Please describe the Combustion Technology Change Option.

A. The Combustion Technology Change Option consists of changing the GT combustion technology at the PFL and PFM plants in favor of highly efficient CT technology, and the retirement of the GTs at PPE. As a result FPL's existing 1,908 MW of GT capacity would be reduced to 1,608 MW of quick-start capacity using up-to-date combustion technologies. The change out of the combustion technologies at PFL and PPE can occur by 2016 but no earlier. Each of the new CTs would have a summer capacity rating of 201 MW and have a heat rate of 10,057 Btu/kWh. After the change out of the combustion technologies, the existing GT capacity at PFM with a capacity of 648 MW would be reduced to 603 MW, and the existing GT capacity at PFL would be increased from the current 840 MW to 1,005 MW. The existing GT capacity at PPE (420 MW) would be retired. With the change out of the combustion technologies at PFM and at PFL, transmission system enhancements costs are eliminated. Current practices for providing system operating reserves could also be maintained, thereby eliminating any fuel penalties from carrying higher spinning reserves.

Q. Did FPL consider soliciting proposals from third parties to build and provide peaking capacity in lieu of FPL's proposed change to the combustion technology at its plant sites?

A. No. FPL does not believe that such a solicitation realistically could result in the identification of alternatives that offer the economic and strategic benefits associated with maintaining peaking capacity at the PFL and PFM sites. The primary benefits of FPL maintaining peaking capacity at these locations are that (1) they would require only minimal transmission enhancements, (2) they have existing gas delivery and back-up fuel infrastructure, and (3) the land is available and already dedicated to generation of electricity. Any other proposed alternative sites and associated power plant facilities proposed by a third party would likely incur significant costs in each of these areas, making any alternative site a more costly alternative to these proposed sites.

Q. Would FPL be adding generation capacity as a result of implementing the Combustion Technology Change Option?

A. No. In fact, FPL's generation at the three sites affected was reduced by 300 MW. This is the minimum capacity reduction that could be effected while maintaining system reliability without incurring expensive transmission modifications. The need to implement this option is solely driven by environmental issues, the need to meet EPA's revised NAAQS standard for NO_2 and the resulting new 1-hour standard adopted by the DEP.

II. ECONOMIC ANALYSIS METHODOLOGY

Q. Did you perform an economic analysis of the three options described above?

A. Yes. After completing the technical feasibility analyses and transmission studies earlier described, FPL refined the three options by developing and analyzing three specific plans. These are:

Hybrid Plan- This plan is a combination of the Retrofit and Combustion Technology Change Options. Because retrofitting was deemed to be technically infeasible at PFL and PPE, the GT combustion technology at these sites is changed to new CT technology, with five new CTs at the Lauderdale site by 2016. The existing PFM GTs are retrofitted with the addition of the SCR, also by 2016. After the implementation of this plan, the peaking capacity of the new CTs totals 1,005 MW, a reduction of 255 MW when compared to the total capacity of GTs being retired at the PPE and PFL sites.

Retire Plan- This plan is the implementation of the Retirement Option. It would entail retiring the 48 GTs at the three sites and implementing transmission enhancements at Fort Myers and in South Florida by 2016. As a result of the retirement, FPL's next unit, a 3x1 combined cycle in 2025, is accelerated to 2019.

Combustion Technology Change Plan- This plan is the implementation of the Combustion Technology Change Option. It would entail replacing the GT combustion technology at PFL with new CT technologies with a total capacity of 1,005 MW, replacing the GT combustion technology at PFM with a total capacity of 603 MW, and the retirement of the GTs at PPE, all by 2016. The total capacity of the modified peaking units is 1,608 MW, a reduction of 300 MW from the total capacity of GTs being retired at the three sites.

The generation resource plans and resulting reserve margins for these three NO_2 reduction plans are shown in Exhibits JEE-2 and JEE-3. Once these three plans, which are all technically feasible, were defined, FPL performed an economic analysis to determine which of the three would result in the lowest CPVRR.

Q. How did FPL perform its economic analysis of the alternate plans?

A. FPL conducted an economic analysis of the three plans by determining which of the three would result in the lowest CPVRR. The plan with lowest CPVRR is also the plan with the lowest bill impact to FPL's customers.

The determination of CPVRR for each plan consists of two parts: (1) determining system variable costs for the plan, and (2) determining system fixed costs for the plan.

First, FPL used the P-MAREA production-costing model from P-Plus Corporation to determine system variable costs. System variable costs are the fuel costs, emission costs, and variable O&M costs of a given plan. The PMAREA model has been used by FPL and accepted by the Commission in numerous fuel cost recovery proceedings and need proceedings. The PMAREA model simulates the operation of FPL's system on an hourly basis. The model captures variable costs (such as fuel, variable O&M costs, and environmental compliance costs) in its production costing calculations, projects the magnitude of annual air emissions associated with FPL's resource plans, incorporates the effects of system transmission transfer limits on the dispatch of the generating units, and recognizes constraints on FPL's access to the natural gas pipelines that serve FPL's system, incorporating lateral constraints to the various plants in FPL's system.

Second, FPL computed the fixed costs of each plan. Fixed costs consist of the carrying charges of the facilities constructed (such as environmental equipment, new combustion technology installations, enhancements to existing GTs, and transmission facilities), fixed O&M costs, and necessary on-going capital expenditures. The addition of the revenue requirements of both components, variable and fixed costs, results in the total CPVRR for each plan.

Q. What assumptions did FPL use in its economic analysis of the alternate plans?

A. All assumptions used in the economic analysis are consistent with those used in FPL's Ten Year Power Plant Site Plan 2013-2022 ("Site Plan") filed on April 2013. These assumptions included the addition of new units previously approved by the Commission. These are the Cape Canaveral Next Generation Clean Energy Center (in-service 2013), the Riviera Beach Next Generation Clean Energy Center (in-service 2014), and the Port Everglades Next Generation Clean Energy Center (in-service 2016). The analysis also included the Turkey Point nuclear units 6 and 7 (in-service 2022 and 2023, respectively). After 2024, the resource plan assumes that gas-fired combined cycle units will be used to meet reserve margin requirements.

<u>Load Forecast:</u>

The load forecast used was updated in February 2013 and is the same load forecast as was used in the Site Plan.

<u>Fuel Forecast:</u>

The fuel forecast was developed in February 2013 using FPL's Long Term Fuel Price Forecasting Methodology and is the same fuel forecast as was used in the Site Plan.

III. RESULTS OF ECONOMIC ANALYSIS

Q. What were the results of the economic analysis?

A. The Combustion Technology Change Plan resulted in the lowest CPVRR of the three cases. Its CPVRR was $56 million lower than the Hybrid Plan, and $870 million lower than the Retire Plan. The results of the economic analysis are shown in Exhibit JEE-4.

Q. What would be the impact of these three plans on the average system bill for FPL's customers?

A. The average system impact for FPL's customers, computed on a 1,200 KWh per month basis is shown in Exhibit JEE-5. As seen in this exhibit, the Combustion Technology Change Plan bill impact is $0.02 lower than the Hybrid Plan and $0.58 lower than the Retire Plan, assuming a bill that was levelized over the study period.

IV. RECOMMENDATION

Q. What is your recommendation for the best plan to address the environmental requirement?

A. The Combustion Technology Change Plan results in the lowest CPVRR, *i.e.*, the lowest cost impact to FPL's customers. The change out to CT combustion technology in this plan is significantly more efficient and would have lower emissions than the existing GT technology even after modification. Since these new CTs have a quick-start capability, this plan avoids changes in operational reserves practices. Due to the location of the new CTs, the Combustion Technology Change Plan also avoids costly transmission system enhancements. Based on all the benefits discussed above, I conclude that the Combustion Technology Change Plan is the best available alternative for FPL's customers in regard to FPL's need to meet the new 1-hour NO_2 standard.

Q. Does this conclude your testimony?

A. Yes, it does.

List of Transmission Improvements Required for Retire Plan

Dade-Broward Area Improvements	**Million**
New Sheridan Substation	$36
Various 138 kV- 230 kV transmission line upgrades*	$37
New Andytown South Substation	$73
Sheridan- Andytown new line construction	$21
Sheridan- Andytown line re-building	$28
Total	**$196**

Ft Myers Area Improvements	**Million**
Orange River Sub	$2
New Orange River Static Var Compensator	$70
Orange River 230 kV Transmission Lines	$3
Total- Orange River SVC	**$76**

* ***Transmission line upgrades:***

Upgrade Motorola-Springtree 230kV line section to 1,446Amps (576MVA)
Upgrade Motorola-Jacaranda 230kV line section to 1,260Amps (502MVA)
Upgrade Hollybrook-Sheridan 230kV line section to 1,549Amps (617MVA)
Upgrade Crossbow-NEW Sheridan 230kV line section to 1,840Amps (736MVA)
Upgrade Perry-NEW Sheridan 138kV line section to 1,456Amps (348MVA)
Upgrade Andytown-Crossbow 230kV line section to 1,680Amps (669MVA)
Upgrade Sheridan-NEW Sheridan 230kV line section to 1,627Amps (648MVA)
Upgrade Perry-Snake Creek 138kV line section to 1,230Amps (294MVA)

Resource Plans Utilized in the Analyses

	Hybrid Plan	Retire Plan	Combustion Technology Change Option
2016	PEEC Add 5 CTs at PFL Modify GTs at PFM Retire GTs at PFL & PPE	PEEC Retire GTs at PFL, PPE & PFM	PEEC Add 5 CTs at PFL Add 3 CTs at PFM Retire GTs at PFL, PPE & PFM
2017			
2018			
2019		3X1 CC	
2020		3X1 CC	
2021			
2022	Turkey Point 6	Turkey Point 6	Turkey Point 6
2023	Turkey Point 7	Turkey Point 7	Turkey Point 7
2024			
2025	3X1 CC		3X1 CC

Note: 3xl CC is a combined cycle unit using three advanced combustion turbines in combined cycle mode, using one heat recovery steam generator.

Projection of FPL's Resource Needs through 2024
Hybrid Plan

	(1)	(2)	(3)	(4) = (1) + (2) - (3)	(5)	(6)	(7) = (5) - (6)	(8) = (4) - (7)	(9) = (8) / (7)
August of the Year	Projected FPL Unit Summer Capability (MW)	Projected Firm Capacity Summer Purchases (MW)	Projected Scheduled Summer Maintenance (MW)	Projected Total Summer Capacity (MW)	Projected Summer Peak Load (MW)	Projected Summer DSM Capability (MW)	Projected Summer Firm Peak Load (MW)	Projected Summer Reserves (MW)	Projected Summer Reserve Margin (%)
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2016	26,607	1,122	0	27,729	23,733	2,404	21,329	6,400	30.0%
2017	26,167	1,086	0	27,253	24,122	2,529	21,593	5,659	26.2%
2018	26,167	705	0	26,872	24,493	2,655	21,839	5,033	23.0%
2019	26,167	705	0	26,872	24,901	2,780	22,121	4,750	21.5%
2020	26,167	740	0	26,907	25,302	2,880	22,422	4,484	20.0%
2021	26,167	930	0	27,097	25,560	2,980	22,580	4,517	20.0%
2022	27,267	885	0	28,152	26,105	3,080	23,025	5,127	22.3%
2023	28,367	885	0	29,252	26,782	3,180	23,602	5,650	23.9%
2024	28,367	885	0	29,252	27,475	3,281	24,194	5,057	20.9%

Projection of FPL's Resource Needs through 2024
Retire Plan

	(1)	(2)	(3)	(4) = (1) + (2) - (3)	(5)	(6)	(7) = (5) - (6)	(8) = (4) - (7)	(9) = (8) / (7)
August of the Year	Projected FPL Unit Summer Capability (MW)	Projected Firm Capacity Summer Purchases (MW)	Projected Scheduled Summer Maintenance (MW)	Projected Total Summer Capacity (MW)	Projected Summer Peak Load (MW)	Projected Summer DSM Capability (MW)	Projected Summer Firm Peak Load (MW)	Projected Summer Reserves (MW)	Projected Summer Reserve Margin (%)
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2016	26,881	1,122	0	28,003	23,733	2,404	21,329	6,674	31.3%
2017	24,533	1,386	0	25,919	24,122	2,529	21,593	4,325	20.0%
2018	24,533	1,675	0	26,208	24,493	2,655	21,839	4,369	20.0%
2019	25,802	745	0	26,547	24,901	2,780	22,121	4,425	20.0%
2020	27,071	705	0	27,776	25,302	2,880	22,422	5,353	23.9%
2021	27,071	885	0	27,956	25,560	2,980	22,580	5,376	23.8%
2022	28,171	885	0	29,056	26,105	3,080	23,025	6,031	26.2%
2023	29,271	885	0	30,156	26,782	3,180	23,602	6,554	27.8%
2024	29,271	885	0	30,156	27,475	3,281	24,194	5,961	24.6%

Projection of FPL's Resource Needs through 2024
Combustion Technology Change Plan

	(1)	(2)	(3)	(4) = (1) + (2) - (3)	(5)	(6)	(7) = (5) - (6)	(8) = (4) - (7)	(9) = (8) / (7)
August of the Year	Projected FPL Unit Summer Capability (MW)	Projected Firm Capacity Summer Purchases (MW)	Projected Scheduled Summer Maintenance (MW)	Projected Total Summer Capacity (MW)	Projected Summer Peak Load (MW)	Projected Summer DSM Capability (MW)	Projected Summer Firm Peak Load (MW)	Projected Summer Reserves (MW)	Projected Summer Reserve Margin (%)
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2016	26,581	1,122	0	27,703	23,733	2,404	21,329	6,374	29.9%
2017	26,141	1,086	0	27,227	24,122	2,529	21,593	5,633	26.1%
2018	26,141	705	0	26,846	24,493	2,655	21,839	5,007	22.9%
2019	26,141	705	0	26,846	24,901	2,780	22,121	4,724	21.4%
2020	26,141	766	0	26,907	25,302	2,880	22,422	4,484	20.0%
2021	26,141	955	0	27,096	25,560	2,980	22,580	4,516	20.0%
2022	27,241	885	0	28,126	26,105	3,080	23,025	5,101	22.2%
2023	28,341	885	0	29,226	26,782	3,180	23,602	5,624	23.8%
2024	28,341	885	0	29,226	27,475	3,281	24,194	5,031	20.8%

Results of the Economic Analysis
Relative to Replace Plan
(millions, CPVRR, 2013$, 2013-2047)

Resource Plan	System Costs			Difference from Lowest Cost Plan
	Fixed Costs*	Variable Costs**	Total Costs	
Combustion Technology Change	$16,015	$94,665	$110,680	--
Retire	$17,318	$94,232	$111,550	$870
Hybrid	$16,067	$94,669	$110,736	$56

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

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

Projection of Approximate Bill Impacts: Combustion Technology Change Plan vs. Hybrid Plan

Year	(1) Replace Plan Annual Total Revenue Requirements ($millions, Nominal $)	(2) Hybrid Plan Annual Total Revenue Requirements ($millions, Nominal $)	(3) =(1)-(2) Differential in Annual Total Revenue Requirements ($millions, Nominal $)	(4) Projected Total Sales (GWh at the meter)	(5) =((3)x100)/(4) Differential in System Average Electric Rates (cents/kwh)	(6) =(5)x10 Differential in Customer Bill of 1,000 kwh ($)	(7) =(5)x12 Differential in Customer Bill of 1,200 kwh ($)
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2013	2,630	2,630	0	106,262	$0.00	$0.00	$0.00
2014	3,085	3,083	3	111,474	$0.00	$0.02	$0.03
2015	3,335	3,321	14	113,995	$0.01	$0.12	$0.15
2016	3,777	3,762	14	115,835	$0.01	$0.12	$0.15
2017	4,256	4,242	14	116,734	$0.01	$0.12	$0.15
2018	4,914	4,904	10	117,850	$0.01	$0.08	$0.10
2019	5,289	5,282	8	118,850	$0.01	$0.07	$0.08
2020	5,868	5,848	19	120,208	$0.02	$0.16	$0.19
2021	6,225	6,211	14	120,725	$0.01	$0.12	$0.14
2022	6,235	6,224	11	121,846	$0.01	$0.09	$0.11
2023	6,624	6,615	9	123,795	$0.01	$0.07	$0.08
2024	6,916	6,907	9	126,196	$0.01	$0.07	$0.08
2025	7,454	7,448	6	127,977	$0.00	$0.04	$0.05
2026	8,047	8,044	2	130,049	$0.00	$0.02	$0.02
2027	8,656	8,659	-3	131,983	$0.00	-$0.02	-$0.03
2028	9,216	9,217	-1	134,261	$0.00	-$0.01	-$0.01
2029	9,816	9,820	-5	135,816	$0.00	-$0.03	-$0.04
2030	10,468	10,480	-12	137,560	-$0.01	-$0.09	-$0.11
2031	11,123	11,138	-15	139,242	-$0.01	-$0.11	-$0.13
2032	12,178	12,195	-17	141,370	-$0.01	-$0.12	-$0.14
2033	13,784	13,806	-23	142,957	-$0.02	-$0.16	-$0.19
2034	14,742	14,771	-29	144,556	-$0.02	-$0.20	-$0.24
2035	15,608	15,709	-100	146,178	-$0.07	-$0.69	-$0.82
2036	17,399	17,460	-61	147,821	-$0.04	-$0.41	-$0.50
2037	18,478	18,531	-53	149,492	-$0.04	-$0.36	-$0.43
2038	19,601	19,652	-51	151,186	-$0.03	-$0.34	-$0.41
2039	20,842	20,916	-74	152,906	-$0.05	-$0.48	-$0.58
2040	21,936	22,003	-67	154,650	-$0.04	-$0.43	-$0.52
2041	23,366	23,420	-54	156,423	-$0.03	-$0.34	-$0.41
2042	24,894	24,945	-51	158,224	-$0.03	-$0.32	-$0.39
2043	27,035	27,096	-60	160,054	-$0.04	-$0.38	-$0.45
2044	28,951	29,006	-55	161,913	-$0.03	-$0.34	-$0.41
2045	30,747	30,801	-54	163,802	-$0.03	-$0.33	-$0.40
2046	32,309	32,370	-61	165,722	-$0.04	-$0.37	-$0.44
2047	34,095	34,166	-72	167,674	-$0.04	-$0.43	-$0.51
					levelized bill impact	-$0.02	-$0.02

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

Projection of Approximate Bill Impacts: Combustion Technology Change Plan vs. Retire Plan

Year	(1) Replace Plan Annual Total Revenue Requirements ($millions, Nominal $)	(2) Retire Plan Annual Total Revenue Requirements ($millions, Nominal $)	(3) =(1)-(2) Differential in Annual Total Revenue Requirements ($millions, Nominal $)	(4) Projected Total Sales (GWh at the meter)	(5) =((3)x100)/(4) Differential in System Average Electric Rates (cents/kwh)	(6) =(5)x10 Differential in Customer Bill of 1,000 kwh ($)	(7) =(5)x12 Differential in Customer Bill of 1,200 kwh ($)
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2013	2,630	2,630	0	106,262	$0.00	$0.00	$0.00
2014	3,085	3,078	7	111,474	$0.01	$0.06	$0.08
2015	3,335	3,298	37	113,995	$0.03	$0.33	$0.39
2016	3,777	3,691	85	115,835	$0.07	$0.74	$0.88
2017	4,256	4,168	88	116,734	$0.08	$0.75	$0.90
2018	4,914	4,844	70	117,850	$0.06	$0.59	$0.71
2019	5,289	5,295	-6	118,850	$0.00	-$0.05	-$0.06
2020	5,868	6,014	-146	120,208	-$0.12	-$1.22	-$1.46
2021	6,225	6,432	-207	120,725	-$0.17	-$1.71	-$2.06
2022	6,235	6,462	-227	121,846	-$0.19	-$1.86	-$2.23
2023	6,624	6,867	-243	123,795	-$0.20	-$1.96	-$2.35
2024	6,916	7,128	-213	126,196	-$0.17	-$1.68	-$2.02
2025	7,454	7,554	-100	127,977	-$0.08	-$0.79	-$0.94
2026	8,047	8,105	-58	130,049	-$0.04	-$0.45	-$0.54
2027	8,656	8,752	-95	131,983	-$0.07	-$0.72	-$0.87
2028	9,216	9,301	-85	134,261	-$0.06	-$0.63	-$0.76
2029	9,816	9,913	-97	135,816	-$0.07	-$0.72	-$0.86
2030	10,468	10,578	-110	137,560	-$0.08	-$0.80	-$0.96
2031	11,123	11,239	-116	139,242	-$0.08	-$0.83	-$1.00
2032	12,178	12,320	-142	141,370	-$0.10	-$1.00	-$1.21
2033	13,784	13,957	-173	142,957	-$0.12	-$1.21	-$1.45
2034	14,742	14,882	-140	144,556	-$0.10	-$0.97	-$1.17
2035	15,608	15,764	-156	146,178	-$0.11	-$1.07	-$1.28
2036	17,399	17,552	-153	147,821	-$0.10	-$1.03	-$1.24
2037	18,478	18,626	-148	149,492	-$0.10	-$0.99	-$1.19
2038	19,601	19,695	-94	151,186	-$0.06	-$0.62	-$0.74
2039	20,842	20,957	-115	152,906	-$0.08	-$0.75	-$0.90
2040	21,936	22,053	-117	154,650	-$0.08	-$0.76	-$0.91
2041	23,366	23,456	-90	156,423	-$0.06	-$0.57	-$0.69
2042	24,894	24,981	-87	158,224	-$0.06	-$0.55	-$0.66
2043	27,035	27,138	-103	160,054	-$0.06	-$0.64	-$0.77
2044	28,951	29,053	-102	161,913	-$0.06	-$0.63	-$0.75
2045	30,747	30,847	-100	163,802	-$0.06	-$0.61	-$0.73
2046	32,309	32,448	-139	165,722	-$0.08	-$0.84	-$1.00
2047	34,095	34,229	-134	167,674	-$0.08	-$0.80	-$0.96
					levelized bill impact	-$0.48	-$0.58

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