State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: September 12, 2013

TO: Ann Cole, Commission Clerk, Office of Commission Clerk

FROM: Keino Young, Chief Trial Counsel, Office of the General Counsel KY

RE: Docket No. 130208-Ei - Petition for limited proceeding to approve revised and restated stipulation and settlement agreement by Duke Energy Florida, Inc. d/b/a Duke Energy.

Please add the attached documents associated with Duke Energy Florida, Inc.'s Response to Staff's First Data Request to the docket file of the above referenced docket.

KY/ace

Duke Energy Florida
Response to Staff's 1st Data Request - Docket #130208 - Q29 c.
Bill Comparisons for Demand Rate Class
CCR Billing on KWH vs. KW Basis

	General Service Demand - GSD-1						
	Billing Units	Billing Rate	Unit of Measure	2013 Rates CCR on kWh	2013 rates CCR on kW	Difference (4)	
Customer Charge	1	11.59	$ / month	11.59	11.59		
Base Rate Energy	22,601	2.045	cents/kWh	462.19	462.19		
Base Rate Demand	60	4.59	$/kW-Mo	275.40	275.40		
Fuel	22,601	3.703	cents/kWh	836.92	836.92		
CCR	22,601	1.184	cents/kWh	267.60			
CCR (1)	60	4.40	$/kW-Mo		264.00		
ECCR	60	0.90	$/kW-Mo	54.00	54.00		
ECRC	22,601	0.485	cents/kWh	109.61	109.61		
Subtotal Electric				2,017.30	2,013.71		
Gross Receipt Tax		2.5641%	of Sub Elect	51.73	51.63		
Total Bill				2,069.03	2,065.34	(3.70)	-0.2%

	Interruptible Service - IS-1						
	Billing Units	Billing Rate	Unit of Measure	2013 Rates CCR on kWh	2013 rates CCR on kW		
Customer Charge	1	278.95	$ / month	278.95	278.95		
Base Rate Energy	1,219,392	0.902	cents/kWh	10,998.92	10,998.92		
Base Rate Demand	3,200	6.24	$/kW-Mo	19,968.00	19,968.00		
Interruptible Credit	3,200	(4.99)	$/kW-Mo	(15,968.00)	(15,968.00)		
Fuel	1,219,392	3.703	cents/kWh	45,154.09	45,154.09		
CCR	1,219,392	0.961	cents/kWh	11,718.36			
CCR (2)	3,200	3.62	$/kW-Mo		11,584.00		
ECCR	3,200	0.80	$/kW-Mo	2,560.00	2,560.00		
ECRC	1,219,392	0.474	cents/kWh	5,779.92	5,779.92		
Subtotal Electric				80,490.23	80,355.88		
Gross Receipt Tax		2.5641%	of Sub Elect	2,063.85	2,060.41		
Total Bill				82,554.08	82,416.29	(137.80)	-0.2%

	Curtailable Service - CS-1						
	Billing Units	Billing Rate	Unit of Measure	2013 Rates CCR on kWh	2013 rates CCR on kW		
Customer Charge	1	75.96	$ / month	75.96	75.96		
Base Rate Energy	658,095	1.346	cents/kWh	8,857.96	8,857.96		
Base Rate Demand	1,500	7.37	$/kW-Mo	11,055.00	11,055.00		
Curtailable Credit	1,500	(3.74)	$/kW-Mo	(5,610.00)	(5,610.00)		
Fuel	658,095	3.703	cents/kWh	24,369.26	24,369.26		
CCR	658,095	0.893	cents/kWh	5,876.79			
CCR (3)	1,500	3.88	$/kW-Mo		5,820.00		
ECCR	1,500	0.86	$/kW-Mo	1,290.00	1,290.00		
ECRC	658,095	0.485	cents/kWh	3,191.76	3,191.76		
Subtotal Electric				49,106.73	49,049.94		
Gross Receipt Tax		2.5641%	of Sub Elect	1,259.15	1,257.69		
Total Bill				50,365.88	50,307.63	(58.25)	-0.1%

(1) Components: Capacity - 3.23, Levy - 0.84, CR3 Uprate - 0.33
(2) Components: Capacity - 2.66, Levy - 0.69, CR3 Uprate - 0.27
(3) Components: Capacity - 2.69, Levy - 0.91, CR3 Uprate - 0.28
(4) Differences are due to rounding in the derivation of rates

Duke Energy Florida
Response to Staff's 1st Data Request - Docket #130208 - Q41 a.
Impact of Revised and Restated Stipulation and Settlement Agreement (RRSSA) on
The Residential $/1000 KWH Bill

Charge Type Settlement ¶		RS - 1000 KWH Bill Impact 2013	2014	2015	2016	2017	2018	2019
Customer Charge		No changes	No changes	No changes	No changes	No changes	No changes	No changes
Base Rate Energy Charge Changes:								
¶ 11	Levy-DTA $20M Tsf from NCRC to Base	0.62	0.62	0.62	0.62	0.62	0.62	0.62
¶ 13	$150M included in 2012 Settlement	4.65	4.65	4.65	4.65	4.65	4.65	4.65
¶ 14	Transfer CAIR Assets to Base in 2014-$154M		4.60	4.60	4.60	4.60	4.60	4.60
¶ 16. a	Built CT's & Purchased Plants		unknown	unknown	unknown	unknown	unknown	unknown
¶ 5. e	CR3 Recovery - 2017 Base					5.59	5.59	5.59
¶ 16. b	Combined Cycle 2018						unknown	unknown
¶ 7. b	Nuclear Decommissioning Funding		unknown	unknown	unknown	unknown	unknown	unknown
Fuel Rate Changes:								
¶ 6. a	$129M Refund for 2013 & 2014	(3.44)	(3.42)					
¶ 6. a	$10M Refund RS & GS only 2014-2016		(0.49)	(0.48)	(0.47)			
¶ 6. b	$100M Refund $40 in 2015 & $60 in 2016			(1.04)	(1.53)			
¶ 7. d	Increase for Deferred Replacement Power-$326M		8.68					
¶ 7. c	NEIL Refund - $490M in 2014		(12.99)					
¶ 7. a	CR3 Recovery - 2014-2016 FAC		1.00	1.00	1.50			
ECRC Rate Changes:								
¶ 14	Transfer CAIR Assets to Base in 2014-$154M		(4.15)	(4.15)	(4.15)	(4.15)	(4.15)	(4.15)
NCRC Rate Changes:								
¶ 11	Levy-Incr in 2012 Settle from $2.67 to $3.45	0.78	0.78	0.78	0.78	0.78		
¶ 11	Levy-DTA $20M Tsf from NCRC to Base	(0.62)	(0.62)	(0.62)	(0.62)	(0.62)	(0.62)	(0.62)
ECCR Rate Changes:								
¶ 19	Impact of Increase IS/CS/SBG Credits	0.31	0.44	0.53	0.53	0.53	0.53	0.53
Gross Receipts Tax on Above Impacts		0.06	(0.02)	0.15	0.15	0.31	0.29	0.29
Total RRSSA Impact on RS 1000 KWH Bill		2.35	(0.92)	6.05	6.06	12.32	11.52	11.52

136 FERC ¶ 61,033
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Marc Spitzer, Philip D. Moeller,
John R. Norris, and Cheryl A. LaFleur.

Florida Power Corporation — Docket No. ER11-3584-000

ORDER ON RETAIL ADJUSTMENTS TO DEPRECIATION RESERVES

(Issued July 15, 2011)

1. On May 16, 2011, pursuant to section 205 of the Federal Power Act (FPA),[1] Florida Power Corporation (Florida Power) filed to reflect the impact of retail rate depreciation reserve[2] adjustments on Florida Power's Open Access Transmission Tariff (OATT) formula rates. In this order, we reject the adjustments and instead direct Florida Power to account for the retail rate adjustments as regulatory assets, as discussed below.

I. Background

2. On February 28, 2011, in Docket No. ER11-2584, the Commission issued an order accepting Florida Power's proposed depreciation rates included in Schedule 10 of Florida Power's OATT.[3] These depreciation rates were the same as those approved by the Florida Public Service Commission (Florida Commission) in 2010.[4] Protestors in Docket No. ER11-2584 argued that Florida Power should be required to supplement that filing to

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[1] 16 U.S.C. § 824d (2006).

[2] As used here, the term "depreciation reserve" refers to amounts recorded in Florida Power's Account 108, Accumulated Provision for Depreciation of Electric Utility Plant.

[3] *Florida Power Corp.*, 134 FERC ¶ 61,145, at P 3 (2011) (February 28 Order).

[4] *In re: Petition for Increase in Rates by Progress Energy Florida, Inc.*, Docket No. 090079-EI, at 45-46 (Fla. Pub. Serv. Comm'n Mar. 5, 2010 and June 18, 2010).

reflect the Florida Commission's approval of adjustments necessary to eliminate theoretical depreciation reserve imbalances (excess depreciation reserves).[5] They argued that those adjustments will have a wholesale rate effect beyond that included in Florida Power's filing. Florida Power argued, however, that the actual quantitative rate impact of those adjustments would not be available for Commission consideration until April 2011, after it filed its 2010 FERC Form No. 1.[6] The Commission agreed with the protestors that, consistent with Order No. 618,[7] additions or deductions to depreciation expense to reflect any theoretical reserve amortization would require an FPA section 205 filing because such amortization would affect the remaining life calculations typically used to determine subsequent depreciation rates.[8] The Commission emphasized that it was only approving the proposed depreciation rates and not any adjustments to eliminate the theoretical depreciation reserve surplus.[9] Florida Power committed to make a FPA section 205 filing to account for these adjustments after its FERC Form No. 1 data became available and before filing its 2010 Annual Update for its OATT formula rate.

II. <u>Florida Power's Filing</u>

3. In the instant filing, Florida Power submits the 2010 impact of the retail depreciation reserve adjustments on its OATT formula rate. Florida Power states that it reduced the cost of removal portion of its depreciation reserve for production and distribution accounts, pursuant to Florida Commission orders and a retail Stipulation and Settlement Agreement dated May 10, 2010 that was accepted by the Florida Commission.[10] This Settlement Agreement states in part:

> [Florida Power] will have the discretion to reduce depreciation expense (cost of removal) by up to $150 million in 2010, up to $250 million in 2011, and up to any remaining

[5] The theoretical depreciation reserve balance is "the calculated balance that would be in the reserve if the life and salvage estimates now considered appropriate had always been applied." *Id.*

[6] FERC February 28 Order, 134 ¶ 61,145 at P 12.

[7] *Depreciation Accounting*, Order No. 618, FERC Stats. & Regs. ¶ 31,104, at 31,695, n.25 (2000) (Order No. 618).

[8] FERC February 28 Order, 134 ¶ 61,145 at P 20.

[9] *Id.*

[10] Transmittal Letter, Attachment 1 at 3 (Settlement Agreement).

> balance in 2012 during the term of this Agreement until the earlier of (a) [Florida Power's] depreciation (cost of removal) reserve reaches zero, or (b) the term of this Agreement expires. In the event [Florida Power] reduces depreciation expense (cost of removal) by less than the caps set forth in this paragraph, [Florida Power] may carry forward (i.e. increase the cap by) any used depreciation (cost of removal) reserve amounts in subsequent years during the term of this Agreement.[11]

Because the Settlement Agreement grants Florida Power discretion to reduce depreciation expense up to a specified amount in 2010, 2011, and 2012, Florida Power asserts that it does not know whether and to what extent the adjustments to depreciation reserves will impact the OATT formula rate for service in 2011 and 2012.[12]

4. Florida Power states that it has recorded total 2010 depreciation reserve reductions of $65,840,613, consisting of a $33,296,538 reduction to the production plant depreciation reserve and a $32,544,075 reduction to its distribution plant depreciation reserve.[13] These depreciation reserve reductions result in reduced amounts of allocated deferred income taxes attributable to wholesale rate base and, consequently, result in a wholesale rate increase of $79,986 under the OATT formula rate for 2010.[14]

5. Florida Power further explains that it implemented the retail depreciation reduction for 2010 effective January 1, 2010. Accordingly, Florida Power requests waiver of the Commission's prior notice requirements to permit an effective date of January 1, 2010.[15] In support of this waiver, Florida Power explains that, on June 1, 2011, it will complete its Annual Update and true up of the OATT formula rate for 2010 transmission service, and that such true up will be completed using the 2010 FERC Form No. 1 data, which incorporates the depreciation adjustments described in this filing. Therefore, Florida Power is implementing the depreciation adjustments consistent with the OATT formula

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[11] *Id.*

[12] *Id.* at n.8.

[13] *Id.* at 3.

[14] *Id.* The depreciation reserve is an offset to plant in service. Therefore a decrease in reserve results in an increase in rate base.

[15] *Id.* at 4.

rate. Florida Power notes that the Commission has granted waiver of its notice requirements in several similar cases.[16]

III. Notice of Filing and Responsive Pleadings

6. Notice of Florida Power's filing was published in the *Federal Register*, 76 Fed. Reg. 30,330 (2011), with interventions or protests due on or before June 6, 2011. Timely motions to intervene were filed by Florida Municipal Power Agency and Seminole Electric Power Cooperative, Inc.

IV. Discussion

A. Procedural Matters

7. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2011), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

B. Substantive Matters

8. As explained below, the Commission finds that Florida Power's adjustment of its depreciation reserves is not in accordance with the Commission's accounting and reporting requirements. We also find that Florida Power must recognize the economic effects of the Florida Commission's rate actions as regulatory assets in Account 182.3, Other Regulatory Assets, rather than as adjustments to its depreciation reserve.

9. In Order No. 618 and in the February 28 Order, the Commission stated that the cost of property used in utility operations should be allocated in a "systematic and rational manner" to periods during which the property is used in utility operations, i.e., over the property's remaining estimated useful service life.[17] For this reason, changes in asset depreciation estimates, including cost of removal, should be made prospectively over the

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[16] *Id.* (*citing South Carolina Electric and Gas Co.,* 132 FERC ¶ 61,043 (2010); *Duke Energy Carolinas, LLC,* 130 FERC ¶ 61,079 (2010)).

[17] *See* FERC February 28 Order, 134 ¶ 61,145 at P 19; Order No. 618, FERC Stats. & Regs. ¶ 31,104 at 31,694-95. Additionally, the Commission's Uniform System of Accounts provides, in part, that, "[u]tilities must use percentage rates of depreciation that are based on a method of depreciation that allocates in a systematic and rational manner the *service value* of depreciable property to the service life of the property." General Instruction No. 2, Depreciation Accounting, 18 C.F.R. Part 101 (2011) (emphasis added). "Service value" refers to "the difference between original cost and net

(continued…)

asset's remaining life. Florida Power proposes to adjust its depreciation reserves by $65,840,613 in 2010 and intends to adjust its depreciation reserves by varying amounts in 2011 through 2013 rather than allocating the excess depreciation reserves over the remaining service lives of the related utility plant. While these adjustments may be acceptable for retail ratemaking purposes, they do not conform to our requirements for allocating the costs of utility plant over their service lives. Accordingly, we will direct Florida Power to reinstate all such adjustments to its depreciation reserves (Account 108). Florida Power must also re-file its 2010 FERC Form No. 1 to reflect the restatement of its depreciation reserves. Additionally, because Florida Power's OATT Formula Rate automatically incorporates the revised plant amounts, we will direct Florida Power to recalculate wholesale formula rate billings[18] to reflect the reinstatement of the depreciation reserves and refund with interest all amounts improperly collected from wholesale customers.

10. Additionally, we find that the adjustments approved by the Florida Commission should be recognized in Florida Power's accounts and FERC Form No. 1 financial statements as regulatory assets. The Commission's Uniform System of Accounts for public utilities provides for the use of regulatory assets and liabilities to account for, *inter alia*, rate actions of regulatory agencies that differ from the Commission's accounting requirements.[19] Specifically, Account 182.3, Other Regulatory Assets, provides for amounts of regulatory-created assets, not includible in other accounts, resulting from the ratemaking actions of regulatory agencies. Therefore, Florida Power must debit Account 182.3 and credit Account 407.4, Regulatory Credits, for the above discussed adjustments that are reflected in its retail rate orders.

<u>The Commission orders</u>:

(A) Florida Power's proposed adjustments to its depreciation reserves are hereby rejected, and Florida Power is hereby directed to reinstate amounts improperly removed from Account 108, as discussed in the body of this order.

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salvage value of electric plant." Definition No. 37, Service Value, 18 C.F.R. Part 101 (2011). The "net salvage value" is the "salvage value of property retired less the cost of removal." Definition No. 19, Net Salvage Value, 18 C.F.R. Part 101 (2011).

[18] Florida Power Corp., OATT, Schedule 10 (1.0.0), Section 1.

[19] *See* Definition No. 31, Regulatory Assets and Liabilities, 18 C.F.R. Part 101 (2011).

(B) Florida Power is hereby directed to record a regulatory asset to record the economic effects of the Florida Commission's retail rate order, as discussed in the body of this order.

(C) Florida Power is hereby directed to refund with interest all amounts improperly collected from wholesale customers, as discussed in the body of this order.

(D) Florida Power is hereby directed to file a refund report with the Commission within 30 days after making the refunds.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Summary Brief

Progress Energy Florida

Crystal River Unit 3 Repair Project

Updated Life-Cycle Net Present Worth (CPVRR) Assessment

Prepared by:

Duke Energy IRP & Analytics

January 25, 2013

Objective:

As a part of the evaluation of options surrounding the Crystal River Nuclear Unit (CR3) Progress Energy Florida (PEF) has prepared an updated life-cycle net present worth (also referred to as cumulative present value of revenue requirements, or CPVRR) assessment of CR3 based on PEF's current forecasts. The objective of the study was to provide a comparative CPVRR assessment of the alternatives for repairing CR3 or retiring the unit and utilizing alternate generation to meet PEF's capacity and energy needs.

The results of this updated assessment are presented herein based on the best information available at this time and consistent with the current updated projections.

Overview of the Updated Assessment:

In this study, PEF initially established potential return to service dates for the Crystal River nuclear unit (CR3) and then developed optimized resource portfolios to accompany the alternatives during the duration of the projected life of the facility. Additional needed resources were selected from natural gas fired simple cycle and combined cycle units along with identified potential near term power purchase opportunities to complete each scenario portfolio over the study period. An alternate scenario was also developed based exclusively on natural gas fired generation resources with the assumption that CR3 would not return to service.

The optimizations were performed using the Strategist™ model based on PEF's forecasts for Load and Energy requirements, fuel prices, emission allowance costs and the development costs for new unit additions. The study period costs were then compared for the two return to service portfolios (plans) to project the life cycle savings (or costs) between the repair plan(s) and the retirement plan on a cumulative present value of revenue requirements (CPVRR) basis.

In the initial modeling, reimbursement of repair costs or payment of insurance claim by Nuclear Electric Insurance Limited (NEIL) was treated neutrally, i.e. with the assumption that the payments from NEIL would be equal in either the repair or retire cases. A post modeling overlay was prepared demonstrating the impacts of a maximum reimbursement from NEIL in the repair case compared to an estimated claim payment in the retirement case.

The results presented are differential results, showing the difference in CPVRR between the total utility production cost for the selected repair case and the retirement case.

A Summary of Key Assumptions and Key Drivers:

The key drivers identified in the economic assessment were determined to be the forecasted costs of fuel, the potential impacts of carbon policy and the projected capital costs for the repair of CR3 and self build and purchased power natural gas generation alternatives. The economic assessment addressed the relative impacts of each of these drivers in the study results by comparing the cumulative present value of system revenue requirements (CPVRR) for each sensitivity applied to the repair plans versus the retirement plan. This approach provides a comparable comparison of life cycle cost between alternatives being considered.

Fuel Forecasts: This assessment was performed with the long term planning fuel forecasts which were updated in October 2012 supporting this year's normal planning cycle. PEF included low and high forecast sensitivities around the mid reference fuel case.

Emission Forecasts: This assessment was performed with the long term planning emissions forecasts which were updated in late 2012 in support of this year's normal planning cycle. The carbon policy scenarios used in the 2012 study have been retained for this year's study. This reflects the lack of ongoing action on carbon policy at federal and state levels, but recognizes the consensus understanding, supported by PEF, that some carbon policy will be enacted in the timeframe during the expected life of the repaired CR3 unit (the study period). In this year's studies, the analysis was run with no CO2 cost and with two CO2 emissions cost projections provided in nominal $/ton of equivalent CO2. The two scenarios were based on studies of the Waxman-Markey draft bill performed by the Environmental Protection Agency (EPA), and Charles River Associates (CRA). While there are evolving policy developments at the state and national levels, these forecasts are deemed to be a reasonable characterization of potential outcomes and, as such, have been used for this updated assessment.

Commercial In-Service and Cost Projection Update for the Repair Project: To perform this assessment, the CR3 repair technical review team was asked to provide updated project cash flow estimates for the repair construction based on the latest projected project schedules for the two repair options evaluated. Two recent options were considered, a 54 month repair at a cost of $1.9 billion and a 60 month repair at a cost of $2.44 billion. In each case, construction work on the repair was considered to start in June 2014 resulting in in-service dates of January 2019 and July 2019 respectively.

Cost Projections for Gas-Fired New Unit Additions: This assessment was performed with long term planning project cost estimates for new peaking and combined cycle generation resource options which were updated this year to support the regular planning cycle.

Load and Energy Forecast: This assessment was performed using the long term planning Load and Energy forecasts prepared in October 2012 for the anticipated use in preparing PEF's 2013 Ten Year Site Plan (TYSP'13).

Nuclear Joint Ownership: In this assessment, the current ownership percentage is assumed. PEF maintains a 91.8% ownership stake in the unit and both the costs and benefits are adjusted to reflect the current ownership of CR3.

Discount Rate: This assessment was performed using a discount rate adjusted to reflect the planning basis for weighted average cost of capital based on PEF's current allowed rate of return.

The current discount rate being used for long term planning is 6.47%. An alternative discount rate is used in the retirement scenario for CR3 investments to reflect the return on equity for the CR3 investment pursuant to the Commission-approved settlement in Order No. PSC-12-0104-FOF-EI in the company's weighted average cost of capital.

Summary Results Overview:

The three tables attached provide a summary of the results. The results tables represent the benefit (cost) of the life cycle cost comparisons of the CR3 repair projects versus the retirement case based on Cumulative Present Value of Revenue Requirements (CPVRR) for each of the sensitivities addressed.

Table 1 provides an overview of the results for the $1.9 billion, 54 month repair scenario.

Table 2 provides an overview of the results for the $2.44 billion, 60 month repair scenario.

Table 3 provides the results from Table 2 adjusted for an overlay of the differential between a maximum allowable NEIL recovery associated with the repair and the potential anticipated insurance claim amount associated with retirement.

Observations:

Key issues around the development of the model inputs and scenarios are discussed here.

Mid Reference Fuel Forecasts: The fossil fuel price forecasts (e.g. natural gas, coal and oil) used in this assessment are taken from data provided by Energy Ventures Analysis Inc. (EVA), the current contractor to Duke Energy for the 2012/2013 corporate fundamental forecasts. The forecast prices are provided in the attached appendix tables.

Fuel Forecast Sensitivities: The low and high fuel sensitivities presented in this assessment are based on PEF's standard methodology for confidence intervals. Lower forecasted fuel prices tend to decrease the life cycle costs projected for the gas fired replacement resource portfolio more than those projected for the CR3 return portfolio which results in a less favorable projection for the repair cases. The fuel forecast sensitivities are expected to be a significant driver in the differences between scenarios.

Full CPVRR modeling of the high and low gas price scenarios was not performed. Impacts of the high and low natural gas price forecasts were estimated and used to provide directional results indicating an anticipated outcome in these scenarios.

Emission Forecasts: The emission forecasts for SO_2, and NO_x used the most recent Duke Energy forecasts. The projections for the impacts of carbon policy were taken from projections developed for the 2011 and 2012 Levy Nuclear Feasibility studies. Forecasts based on projections developed by the US Environmental Protection Agency (EPA) and Charles River Associates (CRA) were selected for their consistency with forecasts used by Duke Energy Carolinas in its 2012 Integrated Resource Plan

(IRP). Thus, the forecasts of potential carbon cost impacts being studied are consistent with forecasts used in the Levy Nuclear Feasibility assessment and recent Duke Energy filings. As a result, the impacts in CPVRR differentials due to carbon policy, while still significant, have narrowed to a limited extent.

Commercial In-Service and Cost Projection Updates for the CR3 Repair Project: This assessment was performed with information for projected project costs and return to service dates for two scenarios, a $1.9 billion, 54 month repair excluding additional work on the containment dome and a $2.44 billion, 60 month repair including identified work on the dome. In each case construction work for the repair was presumed to start in June 2014. These projects resulted in return to service dates of January 2019 and July 2019 respectively.

Cost Projections for New Natural Gas Fired Unit Additions: PEF utilized standard generic cost projections for several alternate potential gas fired units. Strategist selected a portfolio of future units including 3x1 G advanced turbine combined cycle configurations, 2x1 G advanced turbine combined cycle configurations and F-class combustion turbines in simple cycle (peaking) service. Capital cost and operating projections for these units are presented in the appendix.

Load and Energy Forecast: This assessment was performed using the long term planning Load and Energy forecast that was developed in the fall of 2012 which is anticipated to be the forecast for the 2013 PEF TYSP.

Nuclear Joint Ownership: The results provided are net of PEF's current joint ownership position of 91.8% of CR3. All costs have been treated as though shared in accordance with the ownership percentage.

Discount Rate: The results provided reflect the use of a 6.47% discount rate which reflects the Company's average weighted cost of capital (WACC) for planning purposes. An alternative discount rate is used for CR3 investments in the retirement scenario to reflect the return on equity for the CR3 investment pursuant to the Commission-approved settlement in Order No. PSC-12-0104-FOF-EI in the company's weighted average cost of capital.

Summary:

PEF completed the updated CPVRR assessment and comparison of life cycle costs for two unit repair scenarios compared to the option of retiring the unit and replacing the generation. The results are shown in Tables 1, 2 and 3. Tables 1 and 2 show the results with the assumption that NEIL payments have no net impact on the outcome, i.e. that NEIL would reimburse the unit owners the same amount whether the unit was repaired or retired. Table 3 shows the results with an assumption of full repayment by NEIL. In this table, NEIL is assumed to pay the maximum amount covered under the policy, $2.25 billion for a repair, compared to a coverage amount of $500 million for the retirement.

2013-RRSSA-STAFFDR1-51-000005

This scenario is considered to be illustrative only given that neither of these dollar values has been agreed upon by PEF or NEIL.

TABLE 1

Summary of CPVRR Results for $1.9 billion Repair vs. Retirement

$1.9B Repair (54 mos./ Jan 2019 restart)

CO_2 / Gas Price	Low	Base Gas Forecast	High
High CO_2	-	(0.1B)	+
Mid CO_2	-	($0.6B)	+
No CO_2	-	($1.5B)	-

Notes:

- Positive values favor repair of the unit. Negative values favor retirement.
- Full modeling of Low and High Gas Price Forecast Sensitivities was not performed. Projected impacts of changes to fuel prices were used to infer positive or negative signs for each case.

TABLE 2

Summary of CPVRR Results for $2.44 billion Repair vs. Retirement

$2.44B Repair (60 mos./ July 2019 restart)

High CO_2	-	($0.8B)	+
Mid CO_2	-	($1.2B)	-
No CO_2	-	($2.1B)	-
CO_2 / Gas Price	Low	Base Gas Forecast	High

Notes:

- Positive values favor repair of the unit. Negative values favor retirement.
- Full modeling of Low and High Gas Price Forecast Sensitivities was not performed. Projected impacts of changes to fuel prices were used to infer positive or negative signs for each case.

TABLE 3

Summary of CPVRR Results for $2.44 billion Repair vs. Retirement

Potential Maximum NEIL Recovery Scenario

$2.4B Repair (60 mos./July 2019 restart)

High CO2	+	$1.0B	+
Mid CO2	0	$0.6B	+
No CO2	-	(0.3B)	+
CO_2 / Gas Price	Low	Base Gas Forecast	High

Notes:

- Positive values favor repair of the unit. Negative values favor retirement.
- Full modeling of Low and High Gas Price Forecast Sensitivities was not performed. Projected impacts of changes to fuel prices were used to infer positive or negative signs for each case.
- NEIL recovery of $2.25 billion assumed for repair cases vs. $500 million assumed for retirement cases.

APPENDIX

January 2013 CR3 Analysis
Planning and Modeling Assumptions Summary

Prepared 1/25/13 by Duke Energy IRP and Analytics Florida

January 2013 CR3 Analysis
Financial and Economic Assumptions

1 PEF Capitalization Ratios and Projected Cost of Capital

Component	Ratio	Cost
Debt	47%	3.05%
Preferred	0%	na
Equity	53%	10.50%

2 Projected Discount Rate: 6.466%

3 Projected AFUDC Rate: 6.466%

4 Tax Assumptions

a)	Composite Effective Income Tax Rate	37.120%
b)	Combined Cycle Book Life	25 Years
	Combined Cycle Tax Depreciation Life	20 Years
c)	Simple Cycle CT Book Life	25 Years
	Simple Cycle CT Tax Depreciation Life	15 Years
d)	Nuclear Generation Book Life	40 Years
	Nuclear Generation Tax Depreciation Life	15 Years
e)	Transmission Book Life	40 Years
	Transmission Tax Depreciation Life	15 Years

5 General Inflation Rate 2.25%

6 General Escalation Rate 2.25%

January 2013 CR3 Analysis

Financial and Economic Assumptions

Note: These assumptions were used only for recovery of CR3 investments under a retirement scenario

1 PEF Capitalization Ratios and Projected Cost of Capital

Component	Ratio	Cost
Debt	47%	3.05%
Preferred	0%	na
Equity	53%	7.35%

2 Projected Discount Rate: 4.797%

3 Projected AFUDC Rate: 4.797%

4 Tax Assumptions

a)	Composite Effective Income Tax Rate	37.120%
b)	Combined Cycle Book Life	25 Years
	Combined Cycle Tax Depreciation Life	20 Years
c)	Simple Cycle CT Book Life	25 Years
	Simple Cycle CT Tax Depreciation Life	15 Years
d)	Nuclear Generation Book Life	40 Years
	Nuclear Generation Tax Depreciation Life	15 Years
e)	Transmission Book Life	40 Years
	Transmission Tax Depreciation Life	15 Years

5 General Inflation Rate 2.25%

6 General Escalation Rate 2.25%

January 2013 CR3 Analysis

Strategist Input Assumptions - Emission Cost Estimates

	SO2 $/ton	NOX Ozone $/ton	EPA WM CO2 $/ton	CRA WM CO2 $/ton	DEC 2012 IRP Mid CO2 $/ton	DEC 2012 IRP High CO2 $/ton
2013	5.38	1,591	-	-		
2014	8.81	1,039	-	-	Not Used for Modeling. Reference only.	
2015	12.66	888	-	-		
2016	4.00	749	-	-		
2017	4.00	696	-	-		
2018	0.59	556	-	-		
2019	0.61	362	-	-		
2020	0.62	142	20	32	17	31
2021	0.64	-	22	35	18	34
2022	0.66	-	24	38	20	36
2023	0.67	-	26	40	21	39
2024	0.69	-	28	43	23	43
2025	0.71	-	30	46	25	46
2026	0.72		32	50	27	50
2027	0.74		34	54	30	54
2028	0.76	-	36	57	32	58
2029	0.78	-	38	61	35	63
2030	0.80	-	40	65	38	68
2031	0.82	-	44	70	41	74
2032	0.84	-	48	75	44	80
2033	0.86	-	52	80		
2034	0.88	-	55	85		
2035	0.90	-	59	90		
2036	0.92	-	63	97		

January 2013 CR3 Analysis

New Plant Modeling Information Summary

Capital Cost Estimates for Strategist Modeling

Gas Fired Generation Summary Information

	Generic 3x1G Combined Cycle 1st Unit	Generic 3x1G Combined Cycle 2nd Unit
Reference In-Service Year	**2016**	**2016**
Projected Nominal Plant Cost ($000 Before AFUDC)	1,037,428	847,863
Projected Nominal Trans Cost ($000 Before AFUDC)	413,025	206,512
Winter Capacity Rating (MW)	1,307	1,307
Summer Capacity Rating (MW)	1,189	1,189
Fixed O&M ($000/yr)- $2013, Esc Annually at 2.25%	5,810	2,190
Variable O&M ($/MWh) - $2013, Esc Annually at 2.25%	4.19	4.19
Pipeline Reservation Charges ($000/yr) - $2013, Constant	76,236.22	76,236.22
Planned Outage Rate	6.7%	6.7%
Average Heat Rate at Maximum (Btu/kWh)	6,775	6,775

January 2013 CR3 Analysis

New Plant Modeling Information Summary

Capital Cost Estimates for Strategist Modeling

Gas Fired Generation Summary Information	Generic 2x1G Combined Cycle	Generic 2x1G Combined Cycle
	1st Unit	2nd Unit
Reference In-Service Year	**2016**	**2016**
Projected Nominal Plant Cost ($000 Before AFUDC)	718,534	570,146
Projected Nominal Trans Cost ($000 Before AFUDC)	309,787	103,262
Winter Capacity Rating (MW)	866	866
Summer Capacity Rating (MW)	793	793
Fixed O&M ($000/yr)- $2013, Esc Annually at 2.25%	5,106	2,124
Variable O&M ($/MWh) - $2013, Esc Annually at 2.25%	4.22	4.22
Pipeline Reservation Charges ($000/yr) - $2013, Constant	50,740	50,740
Planned Outage Rate	6.7%	6.7%
Average Heat Rate at Maximum (Btu/kWh)	6,780	6,780

January 2013 CR3 Analysis

New Plant Modeling Information Summary

Capital Cost Estimates for Strategist Modeling

Gas Fired Generation Summary Information	Generic F Frame Simple Cycle
	2nd Unit
Reference In-Service Year	**2015**
Projected Nominal Plant Cost ($000 Before AFUDC)	83,404
Projected Nominal Trans Cost ($000 Before AFUDC)	25,774
Winter Capacity Rating (MW)	214
Summer Capacity Rating (MW)	187
Fixed O&M ($000/yr)- $2013, Esc Annually at 2.25%	560
Variable O&M ($/MWh) - $2013, Esc Annually at 2.25%	10 13
Pipeline Reservation Charges ($000/yr) - $2013, Constant	12,700
Planned Outage Rate	3 85%
Average Heat Rate at Maximum (Btu/kWh)	10,170

January 2013 CR3 Analysis

Strategist Fuel Forecasts - Mid Reference Fuel Table

	FUEL 1 COAL 1.8	FUEL 5 COAL 5	FUEL 4 CR3	FUEL 35 LNP U1	FUEL 36 LNP U2	FUEL 7 OIL 1.1	FUEL 8 OIL 1.7	FUEL 10 GAS FGTF	FUEL 18 GulfFirm	FUEL 27 Dist 0.3	FUEL 28 Dist 0.5	FUEL 29 Dist ULS
2013	2.62	1.83				14.47	14.38	4.02	4.02	21.95	21.54	22.27
2014	2.88	2.03				13.88	13.79	4.33	4.33	21.23	20.96	21.53
2015	3.03	2.16				13.50	13.41	4.49	4.49	20.84	20.58	21.13
2016	3.19	2.16				13.09	12.93	5.03	5.03	19.11	19.11	19.13
2017	3.35	2.21				12.64		5.35	5.35	19.39	19.38	19.40
2018	3.51	2.28				12.20		5.63	5.68	19.45	19.44	19.46
2019	3.66	2.34	0.76					6.03	6.03	19.50	19.49	19.50
2020	3.78	2.40	0.76					6.38	6.38	19.59	19.59	19.60
2021	3.90	2.47	0.85					6.74	6.74	20.09	20.09	20.09
2022	4.03	2.54	0.85					7.12	7.12	20.60	20.60	20.59
2023	4.16	2.61	0.93					7.51	7.51	21.12	21.12	21.11
2024	4.30	2.68	0.93	1.07				7.91	7.91	21.65	21.66	21.63
2025	4.44	2.76	0.98	1.07	1.06			8.33	8.33	22.19	22.20	22.16
2026	4.58	2.83	0.98	1.00	1.08			8.68	8.68	22.84	22.86	22.80
2027	4.73	2.91	1.04	1.00	1.08			9.04	9.04	23.50	23.52	23.46
2028	4.88	2.99	1.04	0.96	1.02			9.42	9.42	24.17	24.21	24.12
2029	5.03	3.06	1.10	0.96	0.98			9.80	9.80	24.86	24.90	24.80
2030	5.19	3.15	1.10	0.99	0.99			10.18	10.18	25.56	25.60	25.49
2031	5.35	3.22	1.13	1.04	1.01			10.58	10.58	26.17	26.12	26.25
2032	5.51	3.30	1.13	1.04	1.01			10.96	10.96	26.96	26.91	27.03
2033	5.68	3.39	1.17	1.08	1.05			11.33	11.33	27.76	27.71	27.82
2034	5.85	3.47	1.17	1.10	1.07			11.71	11.71	28.45	28.39	28.54
2035	6.01	3.55	1.22	1.10	1.07			12.09	12.09	29.14	29.07	29.25
2036	6.17	3.63	1.22	1.15	1.11			12.47	12.47	29.83	29.74	29.96

January 2013 CR3 Analysis
Energy Requirements
Forecasts
Net Energy for Load (GWh)

YEAR	Forecast Base
2013	40,786.4
2014	41,564.9
2015	42,549.4
2016	43,420.6
2017	43,823.9
2018	44,451.7
2019	45,037.3
2020	45,653.5
2021	46,179.0
2022	46,688.8
2023	47,199.6
2024	47,706.5
2025	48,114.5
2026	48,551.7
2027	49,100.5
2028	49,659.2
2029	50,228.4
2030	50,810.6
2031	51,407.8
2032	52,020.7
2033	52,632.6
2034	53,241.2
2035	53,844.4
2036	54,481.1

January 2013 CR3 Analysis
Energy Demand Forecasts

	Summer Peak Net Firm Demand (MW)	Winter Peak Net Firm Demand (MW)
YEAR	Forecast	Forecast
2013	8,965	8,987
2014	9,026	9,090
2015	9,185	9,710
2016	9,442	9,842
2017	9,504	9,910
2018	9,674	10,036
2019	9,846	10,188
2020	10,017	10,335
2021	10,086	10,485
2022	10,252	10,635
2023	10,417	10,785
2024	10,580	10,931
2025	10,742	11,076
2026	10,903	11,222
2027	11,062	11,366
2028	11,222	11,511
2029	11,379	11,652
2030	11,535	11,795
2031	11,690	11,936
2032	11,843	12,077
2033	11,996	12,216
2034	12,145	12,353
2035	12,297	12,488
2036	12,470	12,637