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Comprehensive Exhibit List for Entry into Hearing Record
Docket No. 150009-EI
August 18 - 19, 2015

Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
STAFF				
1		Exhibit List	Comprehensive Exhibit List	
FLORIDA POWER & LIGHT (FPL) (DIRECT)				
2	Steve Scroggs and Jennifer Grant-Keene	SDS-1	T- Schedules for Turkey Point 6 & 7 Site Selection and Pre-Construction Costs	
3	Steve Scroggs	SDS-2	Turkey Point 6 & 7 Licenses, Permits, and Approvals	
4	Steve Scroggs	SDS-3	Comparison of Prior and Current Turkey Point 6 & 7 Project Schedules	
5	Steve Scroggs	SDS-4	Turkey Point 6 & 7 Procedures and Work Instructions	
6	Steve Scroggs	SDS-5	Turkey Point 6 & 7 Project Reports	
7	Steve Scroggs	SDS-6	Turkey Point 6 & 7 Project Instructions and Forms	
8	Steve Scroggs	SDS-7	Turkey Point 6 & 7 Summary Tables of the 2014 Expenditures	
9	Steve Scroggs and Jennifer Grant-Keene	SDS-8	Turkey Point 6 & 7 Site Selection and Pre-construction Nuclear Filing Requirement Schedules	
10	Steve Scroggs	SDS-9	Turkey Point 6 & 7 Project Expenditure Summary Tables	
11	Steve Scroggs	SDS-10	Turkey Point 6 & 7 Project Benefits at a Glance	

12	Steve Scroggs	SDS-11	Turkey Point 6 & 7 Customer Savings from Nuclear Cost Recovery Law	
13	Steve Scroggs	SDS-12	Remaining Steps in Turkey Point 6 & 7 Licensing	
14	Nils Diaz	NJD-1	Summary Resume of Nils J. Diaz, PhD	
15	John J. Reed	JJR-1	Résumé of John J. Reed	
16	John J. Reed	JJR-2	Expert Testimony of John J. Reed	
17	John J. Reed	JJR-3	PTN 6 & 7 Organization Charts	
18	Jennifer Grant-Keene	JGK-1	Final True-Up of 2014 Revenue Requirements	
19	Jennifer Grant-Keene	JGK-2	2014 EPU T-Schedules	
20	Jennifer Grant-Keene	JGK-3	2016 Revenue Requirements	
21	Richard O. Brown	ROB-1	Summary of Results from FPL's 2015 Feasibility Analyses of the Turkey Point 6 & 7 Project (Plus Results from Additional Analyses)	
22	Richard O. Brown	ROB-2	Comparison of Key Assumptions Utilized in the 2014 and 2015 Feasibility Analyses of the Turkey Point 6 & 7 Project	
23	Richard O. Brown	ROB-3	Projection of FPL's Resource Needs Through 2030	
24	Richard O. Brown	ROB-4	The Two Resource Plans Utilized in FPL's 2015 Feasibility Analyses of the Turkey Point 6 & 7 Project	

25	Richard O. Brown	ROB-5	2015 Feasibility Analyses Results for the Turkey Point 6 & 7 Project: Case # 1 Analysis - 40-Year Operating Life; Total Costs, Total Cost Differentials, and Breakeven Costs for All Fuel and Environmental Compliance Cost Scenarios in 2015	
26	Richard O. Brown	ROB-6	2015 Feasibility Analyses Results for the Turkey Point 6 & 7 Project: Case# 2 Analysis- 60-Year Operating Life; Total Costs, Total Cost Differentials, and Breakeven Costs for All Fuel and Environmental Compliance Cost Scenarios in 2015	
OFFICE OF THE PUBLIC COUNSEL (OPC) RE: FPL				
27	William R. Jacobs, Jr. PhD	WRJ-1	Resume of William R. Jacobs, Jr.	
STAFF RE: FPL				
28	Iliana H. Piedra	IHP-1	Auditor's Report – Turkey Point Units 6 & 7	
29	David Rich	DR-1	Review of Project Management Internal Controls	
30	Steven D. Scroggs		FPL's Responses to Staff's First Set of Interrogatories (Nos. 1-3 and revised 4) *[Bates Nos. 00001 – 00007]*	
31	Steven D. Scroggs Jennifer Grant-Keene Richard O. Brown		FPL's Responses to Staff's Second Set of Interrogatories (Nos. 5-9, 11-18, and 20-46) (SEE STAFF EXHIBIT CD FOR EXCEL FILES re: Nos. 13 and 43) *[Bates Nos. 00008 – 00090]*	

32	Steven R. Sim		FPL's Responses to Staff's Third Set of Interrogatories (Nos. 47-49) *[Bates Nos. 00091 – 00095]*	
33	Steven R. Sim		FPL's Responses to Staff's Fourth Set of Interrogatories (No. 51) *[Bates Nos. 00096 – 00099]*	
34	Steven R. Sim		FPL's Responses to Staff's Fifth Set of Interrogatories (No. 52) *[Bates Nos. 00100 – 00104]*	
35			FPL's Responses to Staff's First Request for Production of Documents (Nos. 2 and 6) (SEE STAFF EXHIBIT CD FOR EXCEL FILES re: Nos. 6a and 6b) *[Bates Nos. 00105 – 00108]*	
36			FPL's Responses to Staff's Second Request for Production of Documents (Nos. 8 and 9) *[Bates Nos. 00109 – 00112]*	
37	Steven D. Scroggs		FPL's Responses to OPC's First Set of Interrogatories (Nos. 4 and 5) *[Bates Nos. 00113 – 00117]*	
38	Steven D. Scroggs John J. Reed		FPL's Responses to OPC's Third Set of Interrogatories (Nos. 15, 19, 21, 22, 33, 34, and 35) *[Bates Nos. 00118 – 00129]*	
38A	Steven D. Scroggs John J. Reed		FPL's Responses to OPC's Third Set of Interrogatories (No. 18) *[Bates Nos. 00130 – 00132]*	
39	Steven D. Scroggs		FPL's Responses to Miami's First Set of Interrogatories (No. 11) *[Bates Nos. 00133 – 00135]*	
40			FPL's Responses to Miami's Second Request for Production of Documents (No. 11) *[Bates Nos. 00136 – 00138]*	

41	Eugene T. Meehan		Miami's Responses to Staff's First Set of Interrogatories (Nos. 1 and 2) (SEE STAFF EXHIBIT CD FOR EXCEL FILES re: No. 1) *[Bates Nos. 00139 – 00142]*	
42			Miami's Responses to Staff's First Request for Production of Documents (Nos. 1 and 2) *[Bates Nos. 00143 – 00145]*	
43	Steven D. Scroggs		Late-filed exhibit #9 to the deposition of Steve Scroggs *[Bates Nos. 00146 – 00172]*	
CITY OF MIAMI (MIAMI) RE: FLORIDA POWER & LIGHT (FPL)				
44	Eugene T. Meehan	ETM-1	CV of Eugene T. Meehan	
45	Eugene T. Meehan	ETM-2	2015 feasibility analyses results for Turkey Point units 6 & 7: 40-year operating life	
46	Eugene T. Meehan	ETM-3	2015 feasibility analyses results for Turkey Point units 6 & 7: 60-year operating life	
DUKE ENERGY FLORIDA (DEF) (DIRECT)				
47	Thomas G. Foster	TGF-1	**CONFIDENTIAL** - reflects the actual costs associated with the LNP and consists of: 2014 True-Up Summary, 2014 Detail Schedule and Appendices A through E, which show DEF's retail revenue requirements for the LNP from January 2014 through December 2014	

48	Thomas G. Foster	TGF-2	**CONFIDENTIAL** - reflects the actual costs associated with the EPU project and consists of: 2014 True-Up Summary, 2014 Detail Schedule and Appendices A through E, which show DEF's retail revenue requirements for the EPU project from January 2014 through December 2014	
49	Thomas G. Foster	TGF-3	**CONFIDENTIAL** - reflects the actual and estimated costs associated with the LNP and consists of: 2016 Revenue Requirement Summary, 2015 Revenue Requirement Detail Schedule, 2016 Revenue Requirement Detail Schedule, 2015 LLE Deferred Balance Detail Schedule, 2016 LLE Deferred Balance Detail Schedule, 2016 Estimated Rate Impact Schedule, and Appendices A through E	
50	Thomas G. Foster	TGF-4	**CONFIDENTIAL** - reflects the actual costs associated with the EPU project and consists of: 2016 Revenue Requirement Summary, 2015 Revenue Requirement Detail Schedule, 2016 Revenue Requirement Detail Schedule, 2016 Estimated Rate Impact Schedule, and Appendices A through F	
51	Mark R. Teague	MT-1	The CR3 Administrative Procedure, AI-9010, Conduct of CR3 Investment Recovery	
52	Mark R. Teague	MT-2	The CR3 Investment Recovery Project, Project Execution Plan	

53	Mark R. Teague	MT-3	The Investment Recovery Guidance Document IRGD-001, Sales Track Guidance and Documentation Package Development	
54	Mark R. Teague	MT-4	**CONFIDENTIAL** – Chart of EPU-related assets disposed of through sales to third parties or affiliate transfers in 2014	
55	Mark R. Teague	MT-5	**CONFIDENTIAL** – Integrated Change Form for the retention of an auction company used to sell CR3 plant assets, including EPU-related assets	
56	Mark R. Teague	MT-6	DEF Abandon In-place Justification for (1) New Stator Core and Rewound Generator Rotor; (2) Feedwater Heat Exchangers CDHE-3A/3B; (3) Belly Drain Heat Exchangers CDHE-7A/7B; (4) Isolated Phase Bus Duct Coolers; and (5) Moisture Separator Reheaters	
57	Mark R. Teague	MT-7	CR3 Investment Recovery Project (IRP) Closeout and Long-Term SAFSTOR Asset Recovery Plan	
58	Christopher M. Fallon	CMF-1	**CONFIDENTIAL** – DEF's January 2014 letter to the Consortium terminating the EPC Agreement	
59	Christopher M. Fallon	CMF-2	**CONFIDENTIAL** – LNP LLE Disposition Plan	
60	Christopher M. Fallon	CMF-3	**CONFIDENTIAL** – Final resolution with Stone & Webster, Inc. ("S&W") for costs under the EPC Agreement	
61	Christopher M. Fallon	CMF-4	**CONFIDENTIAL** – Tioga LNP LLE final disposition settlement memorandum	

62	Christopher M. Fallon	CMF-5	**CONFIDENTIAL** – DEF letter to the Consortium accepting the Tioga LNP LLE final disposition settlement offer	
63	Christopher M. Fallon	CMF-6	**CONFIDENTIAL** – January 12, 2015 Status Update for LNP LLE Disposition Memorandum	
64	Christopher M. Fallon	CMF-7	**CONFIDENTIAL** – Chart of the Company's LNP LLE disposition actions and status	
65	Christopher M. Fallon	CMF-8	Chart of the expected LNP Combined Operating License Application ("COLA") schedule	
STAFF RE: DUKE ENERGY FLORIDA (DEF)				
66	Ronald A. Mavrides	RAM-1	Auditor's Report – Crystal River Unit 3 Uprate	
67	Ronald A. Mavrides	RAM-2	Auditor's Report – Levy Nuclear Plant Units 1 & 2	
68	William Coston	WC-1	Review of Project Management Internal Controls	
69	Mark Teague Thomas G. Foster		DEF's Responses to Staff's First Set of Interrogatories (Nos. 1-11) *[Bates Nos. 00173 – 00194]*	
70	Thomas G. Foster		DEF's Responses to Staff's Second Set of Interrogatories (No. 12) *[Bates Nos. 00195 – 00198]*	
71	Mark Teague Thomas G. Foster		DEF's Responses to Staff's First Set of Interrogatories (Nos. 1-3) *[Bates Nos. 00199 – 00206]*	

OTHER HEARING EXHIBITS				
Exhibit Number	Witness	Party	Description	Moved In/Due Date of Late Filed
72	Scroggs	OPC	Final Order	Not moved in
73	Scroggs	OPC	Concentric Energy Advisors update to AP1000 Project Cost December 2014	
74	Scroggs	OPC	FPL' s Response to OPC's 3rd set of IRROGS	
75	Scroggs	Miami	EPA Comments	
76	Reed	OPC	Supreme Court Order	
77	Reed	OPC	Final Order of PSC	Not moved in
78	Reed	FIPUG	Moody's Report on US Export LNG Project	
79	Grant-Keene	OPC	FPL's Response to OPC's IRROGS 31, 32, 34	.
80	Scroggs	OPC	Final Order approving Levy revised and restated stipulation and agreement	Judicial Notice taken
81	Scroggs	OPC	Commission Staff June 5th Audit Levy Pages 8, 9	.
82	Reed	OPC	Composite Exhibit of PTN 3,4 and contingency Turkey Point 3 and 4 EPU Costs	.
83	Reed	OPC	FPL Responses to OPC's IRROGS Nos. 23-30 FOAK Responses	.

84	Sim	FPL	Revised ROB-6	.
85	Sim	SACE	Environmental Compliance forecast high, low	.
86	Sim	SACE	Synapse Co2 compliance cost Projections pages 27, 31	.
87	Sim	SACE	Net Fuel Savings Crossover	.
88	Sim	SACE	US Census Palm Beach County Demographics	.
89	Sim	Miami	Excerpt of FPL responses to Staff's 4th set of IRROGS, No. 51, Attachment 1	.

Turkey Point 6 & 7 Site Selection and Pre-Construction Costs
Nuclear Filing Requirements (NFRs)
2014 T-Schedules (Actual)
January 2014 - December 2014

Site Selection & Pre-Construction

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 2
PARTY: FLORIDA POWER & LIGHT (FPL) (DIRECT)
DESCRIPTION: Steve Scroggs and Jennifer Grant-Keene SDS-1

Turkey Point 6 & 7 Site Selection & Pre-Construction
Nuclear Filing Requirements (NFRs)
2014 T-Schedules
January 2014 - December 2014

Site Selection Table of Contents

Page (s)	Schedule	Year	Description	Sponsor
4-5	T-1	2014	Retail Revenue Requirements Summary	J. Grant-Keene
6-8	T-2	2014	True-up of Site Selection Costs	J. Grant-Keene
9-11	T-3A	2014	Deferred Tax Carrying Costs	J. Grant-Keene

Pre-Construction Table of Contents

Page (s)	Schedule	Year	Description	Sponsor
13-14	T-1	2014	Retail Revenue Requirements Summary	J. Grant-Keene
15-17	T-2	2014	True-up of Pre-construction costs	J. Grant-Keene
18-20	T-3A	2014	Deferred Tax Carrying Costs	J. Grant-Keene
21	T-6	2014	Monthly Expenditures	J. Grant-Keene & S. Scroggs
22	T-6A	2014	Monthly Expenditure Descriptions	S. Scroggs
23	T-6B	2014	Variance Explanations	S. Scroggs
24	T-7A	2014	Contracts Exceeding $250,000 Executed	S. Scroggs
25	T-7B	2014	Contracts Exceeding $1,000,000 Executed (Detailed)	S. Scroggs

Site Selection
True-up

2014

Schedule T-1 (True-up)

Turkey Point Units 6&7
Carrying Costs on Prior Period Site Selection Cost Balance
True-up Filing: Retail Revenue Requirements Summary

[Section (6)(c)1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the calculation of the true-up of total retail revenue requirements based on actual expenditures for the prior year and the previously filed expenditures.

For the Year Ended 12/31/2014

Witness: Jennifer Grant-Keene

Line No.		(A) Actual January	(B) Actual February	(C) Actual March	(D) Actual April	(E) Actual May	(F) Actual June	(G) 6 Month Total
		Jurisdictional Dollars						
1	Site Selection Revenue Requirements (Schedule T-2, Line 7)	($942)	($939)	($940)	($940)	($941)	($941)	($5,643)
2	Construction Carrying Cost Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
3	Recoverable O&M Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
4	DTA/(DTL) Carrying Cost (Schedule T-3A, Line 8)	$13,276	$13,275	$13,275	$13,274	$13,273	$13,272	$79,646
5	Other Adjustments	$0	$0	$0	$0	$0	$0	$0
6	Total Period Revenue Requirements (Lines 1 though 5)	$12,334	$12,336	$12,335	$12,334	$12,332	$12,331	$74,003
7	Projected Carrying Cost on DTA/(DTL) for the Period (Order No. PSC 13-0493-FOF-EI)	$13,374	$13,374	$13,374	$13,374	$13,374	$13,374	$80,244
8	Difference (True-up to Projections) (Over)/Under Recovery for the Period (Line 6 - Line 7)	($1,040)	($1,038)	($1,039)	($1,040)	($1,042)	($1,043)	($6,241)
9	Actual/Estimated Revenue Requirements for the period (Order No. PSC 14-0617-FOF-EI)	$13,194	$13,197	$13,195	$13,194	$13,193	$13,191	$79,164
10	Final True-up Amount for the Period (Line 6 - Line 9)	($860)	($860)	($860)	($860)	($860)	($860)	($5,161)

* Totals may not add due to rounding

Schedule T-1 (True-up)

Turkey Point Units 6&7
Carrying Costs on Prior Period Site Selection Cost Balance
True-up Filing: Retail Revenue Requirements Summary

[Section (6)(c)1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the calculation of the true-up of total retail revenue requirements based on actual expenditures for the prior year and the previously filed expenditures.

For the Year Ended 12/31/2014

Witness: Jennifer Grant-Keene

Line No.		(H) Actual July	(I) Actual August	(J) Actual September	(K) Actual October	(L) Actual November	(M) Actual December	(N) 12 Month Total
		Jurisdictional Dollars						
1	Site Selection Revenue Requirements (Schedule T-2, Line 7)	($942)	($936)	($924)	($911)	($898)	($885)	($11,140)
2	Construction Carrying Cost Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
3	Recoverable O&M Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
4	DTA/(DTL) Carrying Cost (Schedule T-3A, Line 8)	$13,265	$13,264	$13,263	$13,262	$13,262	$13,261	$159,224
5	Other Adjustments	$0	$0	$0	$0	$0	$0	$0
6	Total Period Revenue Requirements (Lines 1 though 5)	$12,323	$12,328	$12,340	$12,351	$12,363	$12,375	$148,084
7	Projected Carrying Cost on DTA/(DTL) for the Period (Order No. PSC 13-0493-FOF-EI)	$11,674	$11,661	$11,648	$11,635	$11,621	$11,607	$150,091
8	Difference (True-up to Projections) (Over)/Under Recovery for the Period (Line 6 - Line 7)	$649	$667	$692	$717	$742	$768	($2,007)
9	Actual/Estimated Revenue Requirements for the period (Order No. PSC 14-0617-FOF-EI)	$13,183	$13,188	$13,199	$13,211	$13,223	$13,235	$158,402
10	Final True-up Amount for the Period (Line 6 - Line 9)	($860)	($860)	($860)	($859)	($859)	($859)	($10,318)

* Totals may not add due to rounding

Schedule T-2 (True-up)

Turkey Point Units 6&7
Carrying Costs on Prior Period Site Selection Cost Balance
True-up Filing: Site Selection

[Section (6)(c)1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the calculation of the true-up of Site Selection costs based on actual Site Selection costs for the prior year and the previously filed costs.

For the Year Ended 12/31/2014

Witness: Jennifer Grant-Keene

Line No.		(A) Beginning of Period	(B) Actual January	(C) Actual February	(D) Actual March	(E) Actual April	(F) Actual May	(G) Actual June	(H) 6 Month Total
						Jurisdictional Dollars			
1	a. Nuclear CWIP Additions		$0	$0	$0	$0	$0	$0	$0
	b. Prior Month's (Over)/Under Recovery Eligible for Return (Prior Month's Line 1b + Prior Month's Line 9)		$0	($942)	($1,881)	($2,821)	($3,761)	($4,702)	($5,643)
2	Unamortized CWIP Base Eligible for Return (d)	($10,398)	($9,531)	($8,665)	($7,798)	($6,932)	($6,065)	($5,199)	
3	Amortization of CWIP Base Eligible for Return (e)	($10,398)	($866)	($866)	($866)	($866)	($866)	($866)	($5,199)
4	Average Net Unamortized CWIP Base Eligible for Return		($9,964)	($9,569)	($9,643)	($9,716)	($9,790)	($9,864)	
5	Return on Average Net Unamortized CWIP Eligible for Return								
	a. Equity Component (Line 5b x .61425) (a)		($39)	($37)	($38)	($38)	($38)	($39)	($229)
	b. Equity Component grossed up for taxes (Line 4 x 0.006366265) (a) (b) (c)		($63)	($61)	($61)	($62)	($62)	($63)	($373)
	c. Debt Component (Line 4 x 0.001225871) (c)		($12)	($12)	($12)	($12)	($12)	($12)	($72)
6	Total Return Requirements for the Period (Line 5b + Line 5c)		($76)	($73)	($73)	($74)	($74)	($75)	($444)
7	Total Costs, Carrying Costs & Amortization for the Period (Line 1a + 3 + 6 + 10)		($942)	($939)	($940)	($940)	($941)	($941)	($5,643)
8	Projected Carrying Costs for the period (Order No. PSC-13-0493-FOF-EI) (g)		$0	$0	$0	$0	$0	$0	$0
9	(Over)/Under Recovery (True-up to Projections) (Line 7 - Line 8)		($942)	($939)	($940)	($940)	($941)	($941)	($5,643)
10	Adjustments		$0	$0	$0	$0	$0	$0	$0
11	(Over)/Under Recovery eligible for return (Line 9 + Line 10)		($942)	($939)	($940)	($940)	($941)	($941)	($5,643)
12	Actual/Estimated Revenue Requirements for the period (Order No. PSC-14-0617-FOF-EI)		($76)	($73)	($73)	($74)	($74)	($75)	($444)
13	Final True-up for the Period (Line 7 - Line 12)		($866)	($866)	($866)	($866)	($866)	($866)	($5,199)

* Totals may not add due to rounding

See notes on Page 3 of 3

Schedule T-2 (True-up)

Turkey Point Units 6&7
Carrying Costs on Prior Period Site Selection Cost Balance
True-up Filing: Site Selection

[Section (6)(c)1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the calculation of the true-up of Site Selection costs based on actual Site Selection costs for the prior year and the previously filed costs.

For the Year Ended 12/31/2014

Witness: Jennifer Grant-Keene

Line No.		(I) Actual July	(J) Actual August	(K) Actual September	(L) Actual October	(M) Actual November	(N) Actual December	(O) 12 Month Total
		Jurisdictional Dollars						
1	a. Nuclear CWIP Additions	$0	$0	$0	$0	$0	$0	$0
	b. Prior Month's (Over)/Under Recovery Eligible for Return (Prior Month's Line 1b + Prior Month's Line 9)	($5,643)	($4,886)	($4,109)	($3,307)	($2,478)	($1,623)	($742)
2	Unamortized CWIP Base Eligible for Return (f)	($4,332)	($3,466)	($2,599)	($1,733)	($866)	$0	
3	Amortization of CWIP Base Eligible for Return	($866)	($866)	($866)	($866)	($866)	($866)	($10,398)
4	Average Net Unamortized CWIP Base Eligible for Return	($9,938)	($9,164)	($7,530)	($5,874)	($4,192)	($2,484)	
5	Return on Average Net Unamortized CWIP Eligible for Return							
	a. Equity Component (Line 5b x .61425) (a)	($39)	($36)	($29)	($23)	($16)	($10)	($382)
	b. Equity Component grossed up for taxes (Line 4 x 0.006366265) (a) (b) (c)	($63)	($58)	($48)	($37)	($27)	($16)	($622)
	c. Debt Component (Line 4 x 0.001225871) (c)	($12)	($11)	($9)	($7)	($5)	($3)	($120)
6	Total Return Requirements for the Period (Line 5b + Line 5c)	($75)	($70)	($57)	($45)	($32)	($19)	($742)
7	Total Costs, Carrying Costs & Amortization for the Period (Line 1a + 3 + 6)	($942)	($936)	($924)	($911)	($898)	($885)	($11,140)
8	Projected Carrying Costs for the period (Order No. PSC-13-0493-FOF-EI) (g)	($1,700)	($1,713)	($1,726)	($1,740)	($1,753)	($1,767)	($10,398)
9	(Over)/Under Recovery (True-up to Projections) (Line 7 - Line 8)	$758	$777	$802	$828	$855	$881	($742)
10	Adjustments	$0	$0	$0	$0	$0	$0	$0
11	(Over)/Under Recovery eligible for return (Line 9 + Line 10)	$758	$777	$802	$828	$855	$881	($742)
12	Actual/Estimated Revenue Requirements for the period (Order No. PSC-14-0617-FOF-EI)	($75)	($70)	($57)	($45)	($32)	($19)	($742)
13	Final True-up for the Period (Line 7 - Line 12)	($866)	($866)	($866)	($866)	($866)	($866)	($10,398)

* Totals may not add due to rounding

See notes on Page 3 of 3

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Schedule T-2 (True-up)

Turkey Point Units 6&7
Carrying Costs on Prior Period Site Selection Cost Balance
True-up Filing: Site Selection

[Section (6)(c)1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the calculation of the true-up of Site Selection costs based on actual Site Selection costs for the prior year and the previously filed costs.

For the Year Ended 12/31/2014

Witness: Jennifer Grant-Keene

(a) For carrying charge purposes monthly equity component reflects a 10.5% return on equity.
(b) Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5%, for an effective rate of 38.575%.
(c) In order to gross up the equity component for taxes a monthly rate of 0.006366265 (Equity) and 0.001225871 (Debt), results in the annual pre-tax rate of 9.39%.
(d) Line 2 (Column A) - Unamortized CWIP Base Eligible for Return consists of the total over recovered balance beginning in 2014. This amount is reduced by the 2014 amounts refunded (Line 3) and a carrying charge calculated on the unrefunded balance.

	Docket No. 120009-EI 2013 Projections	Docket No. 140009-EI 2013 True-up		Docket No. 140009-EI 2012/2013 Over Recovery	
Line 2 Beginning Balances includes:					
2013 DTA/DTL Carrying Cost (P-3A, Line 8 / T-3A, Line 8)	$180,883	$170,485	**JGK-1 Col. B, Line 7, Dkt No. 140009-EI**	($10,398)	**JGK-1 Col. C Line 7, Dkt No. 140009-EI**
	$180,883	$170,485		($10,398)	

(e) Line 3 (Column A) - Amortization of CWIP Base Eligible for Return is the amount that was refunded over 12 months in 2014 as approved by the Commission in Order No. PSC 13-0493-FOF-EI. Docket No. 130009-EI.

	2012 Final True-Up/2013 A/E (Over)/Under Recovery	
Line 3 Beginning Balance includes:		
2013 Over Recovery of Carrying Costs on DTA/DTL (AE-3A, Line 10)	($10,398)	**($10,398) JGK-1, Column F, Line 7, Dkt No. 140009-EI**
	($10,398)	

(f) Line 2 (Column N) - Ending Balance consists of the 2013 final true-up amount which will be refunded over 12 months in 2015.

	Docket No. 130009-EI 2013 Actual/Estimated	Docket No. 140009-EI 2013 True-up	Docket No. 140009-EI 2013 Final True-up	
Line 2 Ending Balance includes:				
2013 Site Selection Costs + Carrying Costs (AE-2, Line 1 + 6 / T-2, Line 1 + 6)	$0	$0	$0	**$0 JGK-1, Column I, Line 7, Dkt No. 140009-EI**
2013 DTA/DTL Carrying Cost (AE-3A, Line 8 / T-3A, Line 8)	$170,485	$170,485	$0	
	$170,485	$170,485	$0	

(g) Total being recovered in 2014 as approved in Order No PSC-13-0493-FOF-EI in Docket No. 130009-EI:

	January-June	July	August	September	October	November	December	12 Month
2012 Final True-Up (2012 T-1, Line 10)	$0	$0	$0	$0	$0	$0	$0	$0
2013 (Over)/Under Recovery (AE-1, Line 8)	$0	($1,700)	($1,713)	($1,726)	($1,740)	($1,753)	($1,767)	($10,398)
2014 Projected Cost / Carrying Cost (P-2, Line 7)	$0	$0	$0	$0	$0	$0	$0	$0
2014 (Over)/Under Recovery P-2	$0	($1,700)	($1,713)	($1,726)	($1,740)	($1,753)	($1,767)	($10,398)

* Totals may not add due to rounding

Schedule T-3A (True-up)

Turkey Point Units 6&7
Carrying Costs on Prior Period Site Selection Cost Balance
True-Up Filing: Deferred Tax Carrying Costs

[Section (6)(c)1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the actual deferred tax carrying costs.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2014

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.			(A) Beginning of Period	(B) Actual January	(C) Actual February	(D) Actual March	(E) Actual April	(F) Actual May	(G) Actual June	(H) 6 Month Total
							Jurisdictional Dollars			
1	Construction Period Interest			$0	$0	$0	$0	$0	$0	$0
2	Recovered Costs Excluding AFUDC			$0	$0	$0	$0	$0	$0	$0
3	Other Adjustments			$0	$0	$0	$0	$0	$0	$0
4	Tax Basis Less Book Basis (Prior Month's Balance + Lines 1 + 2 + 3) (d)		$4,533,203	$4,533,203	$4,533,203	$4,533,203	$4,533,203	$4,533,203	$4,533,203	$4,533,203
5	Deferred Tax Asset DTA/(DTL) on Tax Basis in Excess of Book (Line 4 x Tax Rate) (b)	38.575%	$1,748,683	$1,748,683	$1,748,683	$1,748,683	$1,748,683	$1,748,683	$1,748,683	$1,748,683
6	a. Average Accumulated DTA/(DTL)			$1,748,683	$1,748,683	$1,748,683	$1,748,683	$1,748,683	$1,748,683	
	b. Prior months cumulative Return on DTA/(DTL)			$0	($98)	($196)	($296)	($396)	($496)	($1,482)
	c. Average DTA including prior period return subtotal			$1,748,683	$1,748,585	$1,748,487	$1,748,387	$1,748,287	$1,748,187	
7	Carrying Cost on DTA/(DTL)									
	a. Equity Component (Line 7b x .61425) (a)			$6,838	$6,838	$6,837	$6,837	$6,837	$6,836	$41,023
	b. Equity Component grossed up for taxes (Line 6c x 0.006366265) (a) (b) (c)			$11,133	$11,132	$11,131	$11,131	$11,130	$11,129	$66,786
	c. Debt Component (Line 6c x 0.001225871) (c)			$2,144	$2,144	$2,143	$2,143	$2,143	$2,143	$12,860
8	Total Return Requirements Carrying Costs on DTA/(DTL) for the Period (Line 7b + Line 7c)			$13,276	$13,275	$13,275	$13,274	$13,273	$13,272	$79,646
9	Projected Carrying Cost on DTA/(DTL) for the Period (Order No. PSC 13-0493-FOF-EI)			$13,374	$13,374	$13,374	$13,374	$13,374	$13,374	$80,244
10	Difference True-up (Over)/Under Recovery (Line 8 - Line 9)			($98)	($99)	($99)	($100)	($101)	($102)	($598)
11	Actual/Estimated Revenue Requirements for the period (Order No. PSC 14-0617-FOF-EI)			$13,270	$13,269	$13,269	$13,268	$13,267	$13,266	$79,609
12	Final True-up Amount for the Period (Line 8 - Line 11)			$6	$6	$6	$6	$6	$6	$38

* Totals may not add due to rounding

See notes on Page 3 of 3

Schedule T-3A (True-up)

Turkey Point Units 6&7
Carrying Costs on Prior Period Site Selection Cost Balance
True-Up Filing: Deferred Tax Carrying Costs

[Section (6)(c)1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the calculation of the actual deferred tax carrying costs.

For the Year Ended 12/31/2014

Witness: Jennifer Grant-Keene

Line No.		(I) Beginning of Period	(J) Actual July	(K) Actual August	(L) Actual September	(M) Actual October	(N) Actual November	(O) Actual December	(P) 12 Month Total
			Jurisdictional Dollars						
1	Construction Period Interest		$0	$0	$0	$0	$0	$0	$0
2	Recovered Costs Excluding AFUDC		$0	$0	$0	$0	$0	$0	$0
3	Other Adjustments		$0	$0	$0	$0	$0	$0	$0
4	Tax Basis Less Book Basis (Prior Month's Balance + Lines 1 + 2 + 3)	$4,533,203	$4,533,203	$4,533,203	$4,533,203	$4,533,203	$4,533,203	$4,533,203	$4,533,203
	38.575%								
5	Deferred Tax Asset DTA/(DTL) on Tax Basis in Excess of Book (Line 4 x Tax Rate) (b)	$1,748,683	$1,748,683	$1,748,683	$1,748,683	$1,748,683	$1,748,683	$1,748,683	$1,748,683
6	a. Average Accumulated DTA/(DTL)		$1,748,683	$1,748,683	$1,748,683	$1,748,683	$1,748,683	$1,748,683	
	b. Prior months cumulative Return on DTA/(DTL)		($1,482)	($1,591)	($1,701)	($1,811)	($1,923)	($2,035)	($2,149)
	c. Average DTA including prior period return subtotal		$1,747,201	$1,747,092	$1,746,982	$1,746,872	$1,746,760	$1,746,648	
7	Carrying Cost on DTA/(DTL)								
	a. Equity Component (Line 7b x .61425) (a)		$6,832	$6,832	$6,832	$6,831	$6,831	$6,830	$82,011
	b. Equity Component grossed up for taxes (Line 6c x 0.006366265) (a) (b) (c)		$11,123	$11,122	$11,122	$11,121	$11,120	$11,120	$133,514
	c. Debt Component (Line 6c x 0.001225871) (c)		$2,142	$2,142	$2,142	$2,141	$2,141	$2,141	$25,709
8	Total Return Requirements Carrying Costs on DTA/(DTL) for the Period (Line 7b + Line 7c)		$13,265	$13,264	$13,263	$13,262	$13,262	$13,261	$159,224
9	Projected Carrying Cost on DTA/(DTL) for the Period (Order No. PSC 13-0493-FOF-EI)		$13,374	$13,374	$13,374	$13,374	$13,374	$13,374	$160,488
10	Difference True-up (Over)/Under Recovery (Line 8 - Line 9)		($109)	($110)	($111)	($112)	($112)	($113)	($1,265)
11	Actual/Estimated Revenue Requirements for the period (Order No. PSC 14-0617-FOF-EI)		$13,258	$13,257	$13,256	$13,255	$13,255	$13,254	$159,144
12	Final True-up Amount for the Period (Line 8 - Line 11)		$7	$7	$7	$7	$7	$7	$79

* Totals may not add due to rounding

See notes on Page 3 of 3

Schedule T-3A (True-up)

Turkey Point Units 6&7
Carrying Costs on Prior Period Site Selection Cost Balance
True-Up Filing: Deferred Tax Carrying Costs

[Section (6)(c)1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the actual deferred tax carrying costs.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2014

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

(a) For carrying charge purposes monthly equity component reflects a 10.5% return on equity.
(b) Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5%, for an effective rate of 38.575%.
(c) In order to gross up the equity component for taxes a monthly rate of 0.006366265 (Equity) and 0.001225871 (Debt), results in the annual pre-tax rate of 9.39%.
(d) The Beginning Balance of T-3A, Line 4 has been revised to reflect the Jurisdictional Separation Factor effective in 2014.

	Docket No. 140009-EI 2013 Ending Balance as filed March 3, 2014 (e)	Tax Deductions at January 2014 Jurisdictional Factor (f)	T-3A Beginning Balance at January 2014 Jurisdictional Factor
Line 4, Column (A) Tax Basis Less Book Basis	$4,458,255	$74,948	$4,533,203

(e) Line 4 - Beginning Balance comes from 2013 T-3A, Line 4 (Column P).

(f) Calculation of 2014 beginning balance of Tax Deductions at the 2014 Jurisdictional Separation Factor.

	2006	2007	Total	Difference
Tax Deductions included in T-3A, Line 4 balance	($336,073)	($1,304,002)	($1,640,075)	
Annual Jurisdictional Factor	0.99648888	0.99648888		
Total Jurisdictionalized Tax Deductions	($334,893)	($1,299,423)	($1,634,317)	
Tax Deductions included in T-3A, Line 4 balance	($336,073)	($1,304,002)	($1,640,075)	
2014 Jurisdictional Factor	0.95079073	0.95079073		
Total revised Jurisdictionalized Tax Deductions	($319,535)	($1,239,833)	($1,559,368)	$74,948

* Totals may not add due to rounding

Pre-Construction True-up

2014

Schedule T-1 (True-up)

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs
True-up Filing: Retail Revenue Requirements Summary

[Section (6)(c)1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the calculation of the true-up of total retail revenue requirements based on actual expenditures for the prior year and previously filed expenditures.

For the Year Ended 12/31/2014

Witness: Jennifer Grant-Keene

Line No.		(A) Actual January	(B) Actual February	(C) Actual March	(D) Actual April	(E) Actual May	(F) Actual June	(G) 6 Month Total
		Jurisdictional Dollars						
1	Pre-Construction Revenue Requirements (Schedule T-2, Line 7)	($105,905)	$985,306	$1,729,724	$948,051	$1,227,335	$1,975,426	$6,759,938
2	Construction Carrying Cost Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
3	Recoverable O&M Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
4	DTA/(DTL) Carrying Cost (Schedule T-3A, Line 8)	$490,070	$494,079	$499,036	$503,900	$507,985	$513,544	$3,008,614
5	Other Adjustments	$0	$0	$0	$0	$0	$0	$0
6	Total Period Revenue Requirements (Lines 1 though 5)	$384,165	$1,479,385	$2,228,761	$1,451,951	$1,735,319	$2,488,971	$9,768,552
7	Projected Revenue Requirements for the Period (Order No. PSC 13-0493-FOF-EI) (a)	$1,694,170	$1,357,082	$1,941,863	$1,665,592	$1,790,761	$2,045,964	$10,495,431
8	Final True-up Amount of (Over)/Under Recovery for the Period (Line 6 - Line 7)	($1,310,005)	$122,303	$286,898	($213,640)	($55,441)	$443,006	($726,879)
9	Actual/Estimated Revenue Requirements for the period (Order No. PSC-14-0617-FOF-EI)	$384,701	$1,479,721	$1,787,428	$1,454,124	$1,139,310	$1,581,899	$7,827,183
10	Final True-up Amount for the Period (Line 6 - Line 9)	($536)	($336)	$441,332	($2,173)	$596,009	$907,072	$1,941,369

11 (a) Total recovered in 2014 as approved in Order No. PSC-13-0493-FOF-EI in Docket No. 130009-EI:

		January	February	March	April	May	June	6 Month Total
12	2012 Final True-Up (2012 T-1, Line 10)	($5,137)	($65)	($1,193,576)	$107,924	($2,045,915)	($293,584)	($3,430,352)
13	2013 (Over)/Under Recovery (AE-1, Line 8)	($1,320,718)	($1,916,213)	($952,611)	$58,354	$232,183	($1,187,448)	($5,086,454)
14	2014 Projected Cost / Carrying Cost (P-2, Line 7)	$1,159,902	$819,694	$1,401,006	$1,120,829	$1,242,343	$1,493,347	$7,237,120
15	2014 Projected DTA/DTL Carrying Cost (P-3A, Line 8)	$534,268	$537,388	$540,857	$544,763	$548,418	$552,617	$3,258,311
16	2014 Total (Over)/Under Recovery	$368,315	($559,196)	($204,324)	$1,831,870	($22,971)	$564,932	$1,978,625

* Totals may not add due to rounding

See notes on Page 2 of 2

Schedule T-1 (True-up)

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs
True-up Filing: Retail Revenue Requirements Summary

[Section (6)(c)1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the calculation of the true-up of total retail revenue requirements based on actual expenditures for the prior year and previously filed expenditures.

For the Year Ended 12/31/2014

Witness: Jennifer Grant-Keene

Line No.		(H) Actual July	(I) Actual August	(J) Actual September	(K) Actual October	(L) Actual November	(M) Actual December	(N) 12 Month Total
					Jurisdictional Dollars			
1	Pre-Construction Revenue Requirements (Schedule T-2, Line 7)	($326,506)	$487,158	$1,349,800	$1,134,085	$407,382	$379,120	$10,190,977
2	Construction Carrying Cost Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
3	Recoverable O&M Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
4	DTA/(DTL) Carrying Cost (Schedule T-3A, Line 8)	$516,796	$517,832	$521,317	$525,765	$528,824	$530,748	$6,149,897
5	Other Adjustments	$0	$0	$0	$0	$0	$0	$0
6	Total Period Revenue Requirements (Lines 1 though 5)	$190,290	$1,004,990	$1,871,117	$1,659,851	$936,206	$909,868	$16,340,874
7	Projected Carrying Cost for the Period (Order No. PSC 13-0493-FOF-EI) (a)	$1,616,732	$1,578,331	$2,069,068	$1,652,534	$1,484,940	$4,252,860	$23,149,896
8	Actual (Over)/Under Recovery for the Period (Line 6 - Line 7)	($1,426,441)	($573,341)	($197,951)	$7,317	($548,734)	($3,342,992)	($6,809,022)
9	Actual/Estimated Revenue Requirements for the period (Order No. PSC-14-0617-FOF-EI)	$1,184,166	$1,115,039	$1,433,566	$1,019,064	$908,765	$3,544,603	$17,032,386
10	Final True-up Amount for the Period (Line 6 - Line 9)	($993,876)	($110,049)	$437,551	$640,787	$27,441	($2,634,734)	($691,512)

		July	August	September	October	November	December	12 Month Total
11	(a) Total being recovered in 2014 as approved in Order No. PSC-13-0493-FOF-EI in Docket No. 130009-EI:							
12	2012 Final True-Up (2012 T-1, Line 10)	$139,743	($77,716)	($909,817)	($738,602)	($1,343,584)	$757,529	($5,602,800)
13	2013 (Over)/Under Recovery (AE-1, Line 8)	$706,970	$1,494,077	$236,455	($140,818)	$242,404	$1,072,318	($1,475,048)
14	2014 Projected Cost / Carrying Cost (P-2, Line 7)	$1,060,202	$1,018,614	$1,505,510	$1,085,049	$914,429	$3,675,451	$16,496,375
15	2014 Projected DTA/DTL Carrying Cost (P-3A, Line 8)	$556,530	$559,717	$563,558	$567,485	$570,511	$577,410	$6,653,521
16	2014 Total Recovery	$2,463,444	$2,994,692	$1,395,706	$773,114	$383,759	$6,082,707	$16,072,048

Revised - WP-5, Column 10, Line 20, Dkt No. 130009-EI

* Totals may not add due to rounding

Schedule T-2 (True-up)

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs
True-up Filing: Pre-Construction

[Section (6)(c)1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the calculation of the true-up of Pre-Construction costs based on actual Pre-Construction expenditures for the prior year and the previously filed expenditures.

For the Year Ended 12/31/2014

Witness: Jennifer Grant-Keene

Line No.			(A) Beginning of Period	(B) Actual January	(C) Actual February	(D) Actual March	(E) Actual April	(F) Actual May	(G) Actual June	(H) 6 Month Total
							Jurisdictional Dollars			
1	a. Nuclear CWIP Additions (Schedule T-6, Line 10 + Line 27)			$1,714,798	$1,625,438	$2,357,247	$1,553,798	$1,820,496	$2,558,568	$11,630,345
	b. Prior Month's (Over)/Under Recovery Eligible for Return (Prior Month's Line 1b + Prior Month's Line 9)			$0	$60,048	$2,141,938	$4,616,843	$4,277,787	$6,076,511	$8,039,623
2	Unamortized CWIP Base Eligible for Return (d)	(i)	($7,541,498)	($6,951,678)	($6,361,857)	($5,772,036)	($5,182,216)	($4,592,395)	($4,002,574)	
3	Amortization of CWIP Base Eligible for Return/Prior Period (Over)/Under Recoveries (e)		($7,077,848)	($589,821)	($589,821)	($589,821)	($589,821)	($589,821)	($589,821)	($3,538,924)
4	Average Net Unamortized CWIP Base Eligible for Return			($7,246,588)	($6,626,743)	($4,965,954)	($2,097,735)	($439,990)	$879,664	
5	Return on Average Net Unamortized CWIP Eligible for Return									
	a. Equity Component (Line 5b x .61425) (a)			($28,338)	($25,914)	($19,419)	($8,203)	($1,721)	$3,440	($80,154)
	b. Equity Component grossed up for taxes (Line 4 x 0.00636626) (a) (b) (c)	(h)	($993,915)	($46,133.70)	($42,188)	($31,615)	($13,355)	($2,801)	$5,600	($130,492)
	c. Debt Component (Line 4 x 0.00122587) (c)	(h)	($181,950)	($8,883.38)	($8,124)	($6,088)	($2,572)	($539)	$1,078	($25,127)
6	Total Return Requirements for the Period (Line 5b + Line 5c)		($1,175,865)	($1,230,882)	($50,311)	($37,702)	($15,926)	($3,340)	$6,679	($155,619)
7	Total Costs, Carrying Costs & Amortization for the Period (Lines 1a + 3 + 6 + 10)			($105,905)	$985,306	$1,729,724	$948,051	$1,227,335	$1,975,426	$6,759,938
8	Projected Carrying Costs for the period (Order No. PSC-13-0493-FOF-EI) (g)			($165,953)	($1,096,584)	($745,181)	$1,287,107	($571,389)	$12,314	($1,279,685)
9	(Over)/Under Recovery (True-up to Projections) (Line 7 - Line 8)			$60,048	$2,081,890	$2,474,905	($339,056)	$1,798,724	$1,963,112	$8,039,623
10	Adjustments			$0	$0	$0	$0	$0	$0	$0
11	(Over)/Under Recovery eligible for return			$60,048	$2,081,890	$2,474,905	($339,056)	$1,798,724	$1,963,112	$8,039,623
12	Actual/Estimated Revenue Requirements for the period (Order No. PSC-14-0617-FOF-EI)			($1,230,882)	($50,302)	($37,676)	($17,558)	($6,616)	$1,177	($1,341,858)
13	Final True-up for the Period (Line 7 - Line 12)			$1,124,977	$1,035,608	$1,767,401	$965,609	$1,233,951	$1,974,249	$8,101,795

* Totals may not add due to rounding

See notes on Page 3 of 3

Schedule T-2 (True-up)

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs
True-up Filing: Pre-Construction

[Section (6)(c)1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the calculation of the true-up of Pre-Construction costs based on actual Pre-Construction expenditures for the prior year and the previously filed expenditures.

For the Year Ended 12/31/2014

Witness: Jennifer Grant-Keene

Line No.		(I) Actual July	(J) Actual August	(K) Actual September	(L) Actual October	(M) Actual November	(N) Actual December	(O) 12 Month Total
		Jurisdictional Dollars						
1	a. Nuclear CWIP Additions (Schedule T-6, Line 10 + Line 27)	$237,878	$1,048,090	$1,922,126	$1,707,363	$970,691	$932,172	$18,448,666
	b. Prior Month's (Over)/Under Recovery Eligible for Return (Prior Month's Line 1b + Prior Month's Line 9)	$8,039,623	$5,806,203	$3,858,385	$4,376,036	$5,304,492	$5,898,626	
2	Unamortized CWIP Base Eligible for Return (f)	($3,412,754)	($2,822,933)	($2,233,112)	($1,643,292)	($1,053,471)	($463,650)	
3	Amortization of CWIP Base Eligible for Return/Prior Period (Over)/Under Recoveries (e)	($589,821)	($589,821)	($589,821)	($589,821)	($589,821)	($589,821)	($7,077,848)
4	Average Net Unamortized CWIP Base Eligible for Return	$3,350,403	$3,805,069	$2,304,271	$2,179,009	$3,491,883	$4,842,999	
5	Return on Average Net Unamortized CWIP Eligible for Return							
	a. Equity Component (Line 5b x .61425) (a)	$13,102	$14,880	$9,011	$8,521	$13,655	$18,938	($2,048)
	b. Equity Component grossed up for taxes (Line 4 x 0.00636626) (a) (b) (c)	21,330	$24,224	$14,670	$13,872	$22,230	$30,832	($997,249)
	c. Debt Component (Line 4 x 0.00122587) (c)	$4,107	$4,665	$2,825	$2,671	$4,281	$5,937	($182,592)
6	Total Return Requirements for the Period (Line 5b + 5c)	$25,437	$28,889	$17,494	$16,543	$26,511	$36,769	($1,179,841)
7	Total Costs, Carrying Costs & Amortization for the Period (Lines 1a + 3 + 6 + 10)	($326,506)	$487,158	$1,349,800	$1,134,085	$407,382	$379,120	$10,190,977
8	Projected Carrying Costs for the period (Order No. PSC-13-0493-FOF-EI) (g)	$1,906,914	$2,434,976	$832,149	$205,629	($186,752)	$5,505,297	$9,418,527
9	(Over)/Under Recovery (True-up to Projections) (Line 7 - Line 8)	($2,233,420)	($1,947,817)	$517,651	$928,456	$594,134	($5,126,177)	$772,449
10	Adjustments	$0	$0	$0	$0	$0	$0	$0
11	(Over)/Under Recovery eligible for return	($2,233,420)	($1,947,817)	$517,651	$928,456	$594,134	($5,126,177)	$772,449
12	Actual/Estimated Revenue Requirements for the period (Order No. PSC-14-0617-FOF-EI)	$14,271	$18,102	$10,942	$8,788	$14,711	$22,491	($1,252,553)
13	Final True-up for the Period (Line 7 - Line 12)	($340,777)	$469,056	$1,338,857	$1,125,297	$392,671	$356,630	$11,443,530

* Totals may not add due to rounding

See notes on Page 3 of 3

Schedule T-2 (True-up)

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs
True-up Filing: Pre-Construction

[Section (6)(c)1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the calculation of the true-up of Pre-Construction costs based on actual Pre-Construction expenditures for the prior year and the previously filed expenditures.

For the Year Ended 12/31/2014

Witness: Jennifer Grant-Keene

(a) For carrying charge purposes the monthly equity component reflects a 10.5% return on equity.
(b) Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5%, for an effective rate of 38.575%.
(c) In order to gross up the equity component for taxes a monthly rate of 0.00636626 (Equity) and 0.00122587 (Debt), results in the annual pre-tax rate of 9.63%.
(d) Line 2 (Column A) - Unamortized CWIP Base Eligible for Return consists of the total over recovered balance beginning in 2014. This amount is reduced by the 2014 amounts refunded (Line 3) and a carrying charge calculated on the unrefunded balance.

Line 2 Beginning Balances includes:	Docket No. 120009-EI 2013 Projections	Docket No. 140009-EI 2013 True-up		Docket No. 140009-EI 2012/2013 Over Recovery	
2012 Over/Under Recovery (2013 T-2, Line 2 Ending Balance)	$0	($5,602,801)		($5,602,801)	
2013 Pre-Construction Costs + Carrying Costs (P-2, Line 7 / T-2, Line 1 + Line 6)	$27,916,433	$26,684,372	$32,874,575 JGK-1, Col. B, Line 13, Dkt. No. 140009-EI	($1,232,061)	($1,938,697) JGK-1, Column C, Line 13, Dkt. No. 140009-EI
2013 DTA/DTL Carrying Cost (P-3A, Line 8 / T-3A, Line 8)	$6,896,839	$6,190,204		($706,636)	
	$34,813,272	$27,271,774		($7,541,498)	

(e) Line 3 (Column A) - Amortization of CWIP Base Eligible for Return is the amount that was refunded over 12 months in 2014 as approved by the Commission in Order No. PSC 13-0493-FOF-EI. Docket No. 130009-EI.

Line 3 Beginning Balance includes:	2012 Final True-Up/2013 A/E (Over)/Under Recovery	
2012 Over Recovery of Carrying Costs (T-2, Line 13)	($5,488,746)	($5,602,800) Revised WP-5, Column 3, Line 20, Dkt. No. 130009-EI
2012 Over Recovery of Carrying Costs on DTA/DTL (T-3A, Line 12)	($114,054)	
2013 Under Recovery of Costs & Carrying Cost (AE-2, Line 9)	($745,422)	$(1,475,047) JGK-1, Column F, Line 13, Dkt. No. 140009-EI
2013 Over Recovery of Carrying Costs on DTA/DTL (AE-3A, Line 10)	($729,625)	
	($7,077,848)	

(f) Line 2 (Column N) - Ending Balance consists of the 2013 final true-up amount which will be refunded over 12 months in 2015.

Line 2 Ending Balance includes:	Docket No. 130009-EI 2013 Actual/Estimate	Docket No. 140009-EI 2013 True-up	Docket No. 140009-EI 2013 Final True-up	
2013 Pre-Construction Costs + Carrying Costs (AE-2, Line 1 + 6 / T-2, Line 1 + Line 6)	$27,171,010	$26,684,372	($486,639)	($463,649) JGK-1, Column I, Line 13, Dkt. No. 140009-EI
2013 DTA/DTL Carrying Cost (AE-3A, Line 8 / T-3A, Line 8)	$6,167,214	$6,190,204	$22,989	
	$33,338,225	$32,874,575	($463,649)	

(g) Total being recovered in 2014 as approved in Order No. PSC-13-0493-FOF-EI in Docket No. 130009-EI:

	January	February	March	April	May	June	6 Month Total
2012 Final True-Up (2012 T-1, Line 10)	($5,137)	($65)	($1,193,576)	$107,924	($2,045,915)	($293,584)	($3,430,352)
2013 (Over)/Under Recovery (AE-1, Line 8)	($1,320,718)	($1,916,213)	($952,611)	$58,354	$232,183	($1,187,448)	($5,086,454)
2014 Projected Cost / Carrying Cost (P-2, Line 7)	$1,159,902	$819,694	$1,401,006	$1,120,829	$1,242,343	$1,493,347	$7,237,120
2014 (Over)/Under Recovery P-2	($165,953)	($1,096,584)	($745,181)	$1,287,107	($571,389)	$12,314	($1,279,685)

	July	August	September	October	November	December	12 Month Total	
2012 Final True-Up (2012 T-1, Line 10)	$139,743	($77,716)	($909,817)	($738,602)	($1,343,584)	$757,529	($5,602,800)	($7,077,847) Revised WP-5, Column 8, Line 20, Dkt. No. 130009-EI
2013 (Over)/Under Recovery (AE-1, Line 8)	$706,970	$1,494,077	$236,455	($140,818)	$242,404	$1,072,318	($1,475,048)	
2014 Projected Cost / Carrying Cost (P-2, Line 7)	$1,060,202	$1,018,614	$1,505,510	$1,085,049	$914,429	$3,675,451	$16,496,375	JGK-7, Column 4, Line 13 + Line 16, Dkt. No. 140009-EI
2014 (Over)/Under Recovery P-2	$1,906,914	$2,434,976	$832,149	$205,629	($186,752)	$5,505,297	$9,418,527	

(h) Beginning balance adjustments for Column (A), Line 5b and 5c

Carrying Charge Adjustment for Tax Deductions on Prior Year T-2 Doc #105984044	
5b. Equity Component grossed up for taxes	($120,498)
5c. Debt Component	($22,169)
	($142,667)
Carrying Charge Adjustment for Tax Deductions on Prior Year T-3A Doc #105984044	
5b. Equity Component grossed up for taxes	($873,417)
5c. Debt Component	($159,781)
	($1,033,198)
Total Adjustments	
5b. Equity Component grossed up for taxes	($993,915)
5c. Debt Component	($181,950)
	($1,175,865)

(i) Beginning balance adjustment on Line 2 includes ($1,029,218) from Tax Deductions Adjustment.

* Totals may not add due to rounding

Schedule T-3A (True-up)

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs
True-up Filing: Deferred Tax Carrying Costs

[Section (6)(c)1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the actual deferred tax carrying costs.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2014

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.			(A) Beginning of Period	(B) Actual January	(C) Actual February	(D) Actual March	(E) Actual April	(F) Actual May	(G) Actual June	(H) 6 Month Total
							Jurisdictional Dollars			
1	Construction Period Interest			$0	$0	$0	$0	$0	$0	$0
2	Recovered Costs Excluding AFUDC (Schedule T-2, Line 1a + Line 10)			$1,714,798	$1,625,438	$2,357,247	$1,553,798	$1,820,496	$2,558,568	$11,630,345
3	Other Adjustments (e)			($186,441)	($186,441)	($186,441)	($186,441)	($186,441)	($186,441)	($1,118,649)
4	Tax Basis Less Book Basis (Prior Month's Balance + Lines 1 + 2 + 3) (f)		$166,571,254	$168,099,611	$169,538,607	$171,709,413	$173,076,770	$174,710,824	$177,082,951	$177,082,951
5	Deferred Tax Asset/(Liability) DTA/(DTL) on Tax Basis in Excess of Book (Line 4 x Tax Rate) (b)	**38.575%**	$64,254,861	$64,844,425	$65,399,518	$66,236,906	$66,764,364	$67,394,700	$68,309,748	$68,309,748
6	a. Average Accumulated DTA/(DTL)			$64,549,643	$65,121,971	$65,818,212	$66,500,635	$67,079,532	$67,852,224	
	b. Prior months cumulative Return on DTA/(DTL) (d)		$0	$0	($44,198)	($87,507)	($129,327)	($170,190)	($210,623)	($249,696)
	c. Average DTA/(DTL) including prior period return subtotal (Line 6a + Line 6b)			$64,549,643	$65,077,773	$65,730,705	$66,371,308	$66,909,342	$67,641,601	
7	Carrying Cost on DTA/(DTL)									
	a. Equity Component (Line 7b x .61425) (a) (b)			$252,420	$254,485	$257,038	$259,544	$261,648	$264,511	$1,549,646
	b. Equity Component grossed up for taxes (Line 6c x 0.00636626) (a) (b) (c)			$410,940	$414,302	$418,459	$422,537	$425,963	$430,624	$2,522,826
	c. Debt Component (Line 6c x 0.00122587) (c)			$79,130	$79,777	$80,577	$81,363	$82,022	$82,920	$485,788
8	Total Return Requirements Carrying Costs on DTA/(DTL) for the Period (Line 7b + Line 7c)			$490,070	$494,079	$499,036	$503,900	$507,985	$513,544	$3,008,614
9	Projected Carrying Cost on DTA/(DTL) for the Period (Order No. PSC-13-0493-FOF-EI)			$534,268	$537,388	$540,857	$544,763	$548,418	$552,617	$3,258,311
10	Difference True-up to Projection (Over)/Under Recovery (Line 8 - Line 9)			($44,198)	($43,309)	($41,820)	($40,863)	($40,433)	($39,073)	($249,696)
11	Actual/Estimated Revenue Requirements for the period (Order No. PSC-14-0617-FOF-EI)			$488,301	$492,221	$496,443	$500,572	$503,698	$506,970	$2,988,206
12	Final True-up for the Period (Line 8 - Line 11)			$1,769	$1,858	$2,594	$3,328	$4,287	$6,574	$20,408

* Totals may not add due to rounding

See notes on Page 3 of 3

Schedule T-3A (True-up)

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs
True-up Filing: Deferred Tax Carrying Costs

[Section (6)(c)1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the actual deferred tax carrying costs.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2014

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.			(I) Beginning of Period	(J) Actual July	(K) Actual August	(L) Actual September	(M) Actual October	(N) Actual November	(O) Actual December	(P) 12 Month Total
							Jurisdictional Dollars			
1	Construction Period Interest			$0	$0	$0	$0	$0	$0	$0
2	Recovered Costs Excluding AFUDC (Schedule T-2, Line 1a + Line 10)			$237,878	$1,048,090	$1,922,126	$1,707,363	$970,691	$932,172	$18,448,666
3	Other Adjustments (e)			($186,441)	($186,441)	($186,441)	($186,441)	($186,441)	($186,441)	($2,237,297)
4	Tax Basis Less Book Basis (Prior Month's Balance + Lines 1 + 2 + 3)		$177,082,951	$177,134,388	$177,996,036	$179,731,721	$181,252,642	$182,036,892	$182,782,623	$182,782,623
5	Deferred Tax Asset/(Liability) DTA/(DTL) on Tax Basis in Excess of Book (Line 4 x Tax Rate) (b)	38.575%	$68,309,748	$68,329,590	$68,661,971	$69,331,511	$69,918,207	$70,220,731	$70,508,397	$70,508,397
6	a. Average Accumulated DTA/(DTL)			$68,319,669	$68,495,781	$68,996,741	$69,624,859	$70,069,469	$70,364,564	
	b. Prior months cumulative Return on DTA/(DTL)			($249,696)	($289,430)	($331,315)	($373,556)	($415,275)	($456,962)	($503,624)
	c. Average DTA/(DTL) including prior period return subtotal (Line 6a + Line 6b)			$68,069,973	$68,206,351	$68,665,426	$69,251,303	$69,654,194	$69,907,602	
7	Carrying Cost on DTA/(DTL)									
	a. Equity Component (Line 7b x .61425) (a) (b)			$266,186	$266,719	$268,515	$270,806	$272,381	$273,372	$3,167,625
	b. Equity Component grossed up for taxes (Line 6c x 0.00636626) (a) (b) (c)			$433,351	$434,220	$437,142	$440,872	$443,437	$445,050	$5,156,899
	c. Debt Component (Line 6c x 0.00122587) (c)			$83,445	$83,612	$84,175	$84,893	$85,387	$85,698	$992,998
8	Total Return Requirements Carrying Costs on DTA/(DTL) for the Period (Line 7b + Line 7c)			$516,796	$517,832	$521,317	$525,765	$528,824	$530,748	$6,149,897
9	Projected Carrying Cost on DTA/(DTL) for the Period (Order No. PSC-13-0493-FOF-EI)			$556,530	$559,717	$563,558	$567,485	$570,511	$577,410	$6,653,521
10	Difference True-up to Projection (Over)/Under Recovery (Line 8 - Line 9)			($39,734)	($41,885)	($42,241)	($41,720)	($41,687)	($46,662)	($503,624)
11	Actual/Estimated Revenue Requirements for the period (Order No. PSC-14-0617-FOF-EI)			$510,261	$512,830	$515,756	$518,540	$520,535	$526,188	$6,092,317
12	Final True-up for the Period (Line 8 - Line 11)			$6,535	$5,002	$5,561	$7,225	$8,289	$4,560	$57,580

* Totals may not add due to rounding

See notes on Page 3 of 3

Schedule T-3A (True-up)

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs
True-up Filing: Deferred Tax Carrying Costs

[Section (6)(c)1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the actual deferred tax carrying costs.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2014

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

(a) For carrying charge purposes the monthly equity component reflects a 10.5% return on equity.
(b) Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5%, for an effective rate of 38.575%.
(c) In order to gross up the equity component for taxes a monthly rate of 0.00636626 (Equity) and 0.00122587 (Debt) results in the annual pre-tax rate of 9.39%.
(d) Line 6b - Beginning Balance on Prior months cumulative Return on DTA/(DTL) is not shown on T-3A, because it is included on Schedule T-2 footnote (d), Page 3 of 3 Lines 9 & 11.
(e) Line 3 - Other Adjustments represents Estimated 2014 deductions under IRS Regulations Section, Internal Payroll (Reg. Sec. 1.263(a)-4). These deductions have been applied ratably over the 12 months in 2014. Since FPL has not filed its 2014 tax return at the time of this filing, deductions taken on the 2014 tax return will be trued up in the 2015 T-3A schedule to be filed in 2016.

Tax Deduction Description	FPL System Qualifying Expenditures	System Deductions Attributed to Qualifying Expenditures	Jurisdictional Separation Factor	Jurisdictional Deductions	Monthly Amortization
Estimated 2014 Internal Payroll	$ (2,353,091)	$ (2,353,091)	0.95079073	($2,237,297)	($186,441)

(f) The Beginning Balance of T-3A, Line 4 has been revised to reflect the Jurisdictional Separation Factor effective in 2014 for CPI (Line 1) and other adjustments (Line 3).

	Docket No. 140009-EI 2013 Ending Balance as filed March 3, 2014 (h)	Tax Deductions from prior years Not included in T-3A (i)	Tax Deductions at January 2014 Jurisdictional Factor (g)	T-3A Beginning Balance at January 2014 Jurisdictional Factor
Line 4, Column (A) Tax Basis Less Book Basis	$176,953,371	($11,369,130)	$987,014	$166,571,254

(g) Calculation of 2013 beginning balance of Tax Deductions at the 2014 Jurisdictional Separation Factor.

	2007	2008	2009	2010	2011	2012	2013 (j)	Total	Difference
Tax Deductions included in T-3A, Line 4 balance	($256,524)	($3,277,789)	($5,536,849)	($3,538,559)	$0	$0	$0	($12,609,721)	
Tax Deductions from prior years not included in T-3A	($1,640,075)	$0	$0	($275,000)	($3,787,562)	($3,118,389)	($2,704,494)	($11,525,520)	
Total Tax Deductions	($1,896,599)	($3,277,789)	($5,536,849)	($3,813,559)	($3,787,562)	($3,118,389)	($2,704,494)	($24,135,241)	
Annual Jurisdictional Factor	0.99648888	0.99648888	0.99648888	0.99648888	0.98818187	0.98202247	0.98194011		
Total Jurisdictionalized Tax Deductions	($1,889,940)	($3,266,280)	($5,517,408)	($3,800,169)	($3,742,800)	($3,062,328)	($2,655,651)	($23,934,577)	
Tax Deductions included in T-3A, Line 4 balance	($256,524)	($3,277,789)	($5,536,849)	($3,538,559)	$0	$0	$0	($12,609,721)	
Tax Deductions from prior years not included in T-3A	($1,640,075)	$0	$0	($275,000)	($3,787,562)	($3,118,389)	($2,704,494)	($11,525,520)	
Total Tax Deductions	($1,896,599)	($3,277,789)	($5,536,849)	($3,813,559)	($3,787,562)	($3,118,389)	($2,704,494)	($24,135,241)	
2014 Jurisdictional Factor	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073		
Total revised Jurisdictionalized Tax Deductions	($1,803,269)	($3,116,492)	($5,264,384)	($3,625,897)	($3,601,179)	($2,964,935)	($2,571,408)	($22,947,563)	$987,014

(h) Beginning Balance comes from 2013 T-3A Ending Balance, Line 4 (Column P).
(i) Beginning balance includes a correction of ($11,369,130) for Tax Deduction adjustment booked in 2014.

(j) Estimated 2013 income tax deductions have been applied ratably over the 12 months in 2013 as the estimated tax payments for 2013 were being made and are included in the 2013 T-3A schedule Other Adjustments Line 3. Since FPL had not filed its 2013 tax return at the time of the 2014 Actual/Estimated filing, deductions taken on the 2013 tax return filed in 2014 are being trued up in the 2014 T-3A schedule. The schedule below shows the estimate used versus the actual amount filed and thus illustrates that no true-up entry is needed.

Tax Deduction Description	FPL System Qualifying Expenditures	System Deductions Attributed to Qualifying Expenditures	Jurisdictional Separation Factor	Jurisdictional Deductions
Estimated 2013 Internal payroll	($2,704,494)	($2,704,494)	0.98194011	($2,655,651)
True-up of the 2013 Internal payroll in 2014	($2,704,494)	($2,704,494)	0.98194011	($2,655,651)
True-up of 2013 (Line 21 - Line 18)	$0	$0		$0

* Totals may not add due to rounding

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs (a)
True-up Filing: Monthly Expenditures

[Section (6)(c)1.a.]

[Section (9)(d)]

Schedule T-6 (True-up)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the actual monthly expenditures by major tasks performed within Pre-Construction categories.

For the Year Ended 12/31/2014

Witness: Jennifer Grant-Keene and Steven D. Scroggs

Line No.	Description	(A) Actual January	(B) Actual February	(C) Actual March	(D) Actual April	(E) Actual May	(F) Actual June	(G) Actual July	(H) Actual August	(I) Actual September	(J) Actual October	(K) Actual November	(L) Actual December	(M) 12 Month Total
1	**Pre-Construction:**													
2	Generation:													
3	Licensing	$1,348,231	$1,374,682	$2,026,954	$1,512,218	$1,458,669	$1,452,559	$1,102,425	$1,059,840	$1,458,082	$1,445,318	$972,028	$861,484	$16,072,491
4	Permitting	$45,918	$40,737	$32,791	$33,065	$34,636	$38,142	$28,741	$28,263	$45,648	$30,212	$24,538	$32,013	$414,704
5	Engineering and Design	$409,400	$294,145	$419,504	$88,934	$421,413	$1,200,289	($880,977)	$14,233	$517,877	$320,199	$24,365	$86,921	$2,916,303
6	Long lead procurement advanced payments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7	Power Block Engineering and Procurement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Total Generation Costs	$1,803,549	$1,709,564	$2,479,249	$1,634,217	$1,914,718	$2,690,990	$250,190	$1,102,335	$2,021,608	$1,795,729	$1,020,931	$980,418	$19,403,498
9	Jurisdictional Factor	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073
10	Total Jurisdictional Generation Costs	$1,714,798	$1,625,438	$2,357,247	$1,553,798	$1,820,496	$2,558,568	$237,878	$1,048,090	$1,922,126	$1,707,363	$970,691	$932,172	$18,448,666
11	**Adjustments**													
12	Non-Cash Accruals	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Other Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Total Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Jurisdictional Factor	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073
16	Total Jurisdictional Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
17														
18	Total Jurisdictional Generation Costs Net of Adjustments	$1,714,798	$1,625,438	$2,357,247	$1,553,798	$1,820,496	$2,558,568	$237,878	$1,048,090	$1,922,126	$1,707,363	$970,691	$932,172	$18,448,666
19														
20	Transmission:													
21	Line Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	Substation Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	Clearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	Total Transmission Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Jurisdictional Factor	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196
27	Total Jurisdictional Transmission Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	**Adjustments**													
29	Non-Cash Accruals	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	Other Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31	Total Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	Jurisdictional Factor	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196
33	Total Jurisdictional Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
34														
35	Total Jurisdictional Transmission Costs Net of Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
36														
37	Total Jurisdictional Pre-Construction Costs Net of Adjustments	$1,714,798	$1,625,438	$2,357,247	$1,553,798	$1,820,496	$2,558,568	$237,878	$1,048,090	$1,922,126	$1,707,363	$970,691	$932,172	$18,448,666
38														
39	**Construction:**													
40														
41	N/A- At this stage, construction has not commenced in the project.													
42														
43	* Totals may not add due to rounding													
44														
45	Notes:													
46	(a) Effective with the filing of FPL's need petition on October 16, 2007, Pre-Construction began.													

Schedule T-6A (True-up)

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs
True-up Filing: Monthly Expenditures

[Section (5)(c)1.a.]
[Section (8)(d)]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide a description of the major tasks performed within Pre-Construction.

For the Year Ended 12/31/2014

Witness: Steven D. Scroggs

Line No.	Major Task	Description - Includes, but is not limited to:
1	**Pre-Construction period:**	
2	**Generation:**	
3	1 License Application	
4		a. Preparation of Nuclear Regulatory Commission Combined License submittal.
5		b. Preparation of Florida Department of Environmental Protection Site Certification Application.
6		c. Transmission facilities studies, stability analysis, Florida Reliability Coordinating Council studies.
7		d. Studies required as Conditions of Approval for local zoning.
8	2 Permitting	
9		a. Communications outreach.
10		b. Legal and application fees.
11	3 Engineering and Design	
12		a. Site specific civil, mechanical and structural requirements to support design.
13		b. Water supply design.
14		c. Construction logistical and support planning.
15		d. Long lead procurement advanced payments.
16		e. Power Block Engineering and Procurement.

Schedule T-6B (True-up)

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs
True-up Filing: Variance Explanations

[Section (8)(d)]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide annual variance explanations comparing the prior year actual expenditures to the actual/estimated expenditures filed in the prior year.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2014

DOCKET NO.: 150009-EI

Witness: Steven D. Scroggs

Line No.		(A) Total Actual	(B) Total Actual/Estimated	(C) Total Variance	(D) Explanation
1					
2					
3	**Pre-Construction:**				
4	Generation:				
5	Licensing	$16,072,491	$16,582,678	($510,187)	Variance primarily due to the reduced necessity for budgeted contingency partially offset by increased costs related to external licensing support, fees, & additional third party reviews of NRC RAI's.
6					
7					
8					
9					
10	Permitting	$414,704	$588,412	($173,708)	Variance primarily due to reduction to internal payroll support costs.
11					
12					
13	Engineering and Design	$2,916,303	$3,069,539	($153,236)	Variance primarily due to reduction to internal payroll support costs.
14					
15					
16					
17	Long lead procurement advanced payments			$0	
18	Power Block Engineering and Procurement			$0	
19	Total Generation Costs	$19,403,497	$20,240,629	($837,132)	

* Totals may not add due to rounding

Turkey Point 6&7
Pre-Construction Costs and Carrying Costs
True-up Filing: Contracts Executed

Schedule T-7A

[Section (9)(c)]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Florida Power & Light Company

DOCKET NO.: 150009-EI

EXPLANATION: For all executed contracts exceeding $250,000, (including change orders), provide the contract number or identifier, status, original and current contract terms, original amount, amount expended as of the end of the prior year, amount expended in the current year, estimated final contract amount, name of contractor and affiliations if any, method of selection including identification of justification documents, and description of work.

For the Year Ended: 12/31/2014
Witness: Steven D. Scroggs

	(A)	(B)	(C)	(D)	(E) CONFIDENTIAL	(F) CONFIDENTIAL	(G) CONFIDENTIAL	(H) CONFIDENTIAL	(I)	(J)	(K)
Line No.	Contract No.	Status of Contract	Original Term of Contract	Current Term of Contract	Original Amount	Actual Expended as of Prior Year End (2013)	expended in Current Year (2014)	Estimate of Final Contract Amount	Name of Contractor (and Affiliation if any)	Method of Selection and Document ID	Work Description
1	2000062412	Open - CO#6	02/2012 - 12/2012	02/2012 - 06/2015					AMEC E&I	SSJ	PTN 6&7 RFI Response Review
2	2000115705	Open - CO#1	10/2013 - 08/2015	10/2013 - 02/2016					AMEC E&I	SSJ	PTN 6&7 RFI Response Review/FSAR 2.5.4
3	4500681284	Open - CO#4	06/2011 - 12/2012	06/2011 - 06/2014					Atkins North American	SSJ	PTN 6&7 Expert Scientific Analysis
4	4500395492	Open - CO#57	11/2007 - 12/2011	11/2007 - 02/2016					Bechtel Power Co.	Comp Bid/SSJ/ PDS	PTN 6&7 Engineering Services to support Preparation of COLA and SCA, and Response to Post-Submittal RAIs
5	2000102617	Open - CO#1	07/2013 - 07/2013	07/2013 - 01/2014					Blue Lagoon/Sofitel	SSJ	PTN 6&7 Hearing; Provide Lodging and Meals
6	2000060695	Open - CO#2	02/2012 - 12/2012	02/2012 - 05/2015					Burns & McDonnell	Comp Bid/SSJ	PTN 6&7 Preliminary Design of the Radial Collector Well System
7	4500443122	Open - CO #5	08/2008 - 08/2010	06/2008 - 06/2015					Eco-Metrics, Inc.	SSJ	PTN 6&7 Environmental Consulting Services
8	4500518167	Open - CO#11	07/2009 - 12/2009	07/2009 - 06/2015					Environmental Consulting and Technology Inc.	SSJ/PDS	PTN 6&7 Post SCA Submittal Support
9	4500430034	Open - CO#2	06/2008 - 07/2011	06/2008 - 12/2014					EPRI	SSJ	Advanced Nuclear Technology; Near term deployment of Advanced Light Water Reactors
10	4500492222	Closed - CO#2	03/2009 - 12/2009	03/2009 - 06/2013					Experis Finance(formerly Jefferson Wells)	SSJ	New Nuclear Audit
11	4500518160	Open - CO#11	07/2009 - 12/2009	07/2009 - 04/2015					Golder & Associates, Inc.	SSJ/PDS	PTN 6&7 Post SCA Submittal Support
12	4500425707	Open - CO#8	05/2008 - 08/2008	05/2008 - 06/2015					HDR Engineering, Inc.	Comp Bid/SSJ	Conceptual Engineering of Cooling Water Supply and Discharge
13	2000123867	Open - CO#1	12/2013 - 12/2014	12/2013 - 06/2015					Layne Christensen Company	Comp Bid	PTN 6&7 DIW-1 Injection Test
14	4500652043	Closed - CO#3	03/2011 - 03/2012	03/2011 - 08/2013					Layne Christensen Company	Comp Bid/SSJ	PTN 6&7 Exploratory/UIC Well Installation
15	4500645896	Open - CO#3	02/2011 - 03/2012	02/2011 - 12/2014					McCallum Turner	SSJ	PTN 6&7 COLA Site Selection RAI Support
16	4500517152	Open - CO#7	10/2009 - 12/2010	10/2009 - 06/2015					McNabb Hydrogeologic Consulting, Inc.	SSJ/PDS	PTN 6&7 Post SCA Submittal and UIC Licensing Support
17	4500536449	Closed - CO#4	10/2009 - 12/2011	10/2009 - 06/2013					McNabb Hydrogeologic Consulting, Inc.	Comp Bid/Single Source	PTN 6&7 UIC Subject Matter Expert
18	2000102364	Open - CO#9	05/2013 - 12/2014	05/2013 - 06/2015					Paul C. Rizzo Associates, Inc.	SSJ	PTN 6&7 Field Investigation and FSAR 2.5 Revision
19	2000053246	Open	11/2011 - 06/2014	11/2011 - 06/2015					Power Engineers, Inc.	SSJ	PTN 6&7 Prelim Analysis for Miami River Crossing and Davis/Miami Line
20	4500527549	Open - CO#5	08/2009 - 12/2009	07/2009 - 04/2015					TetraTechGeo (formerly GeoTrans, Inc.)	SSJ	PTN 6&7 APT Review and Collector Well Modeling Support
21	2000140558	Closed - CO#2	06/2014 - 12/2014	06/2014 - 12/2014					HDR Engineering, Inc.	Comp Bid	PTN 6&7 Develop Submittals for USACE Section 408 Authorization
22	4500404639	Open - CO#8	01/2008 - 12/2011	01/2008 - 02/2016					Westinghouse Electric Co	SSJ/ PDS	PTN 6&7 Engineering Services to Support Preparation of COLA and Response to Post-Submittal RAIs

Turkey Point 6&7
Pre-Construction Costs and Carrying Costs
True-up Filing: Contracts Executed Details

Schedule T-7B [Section (9)(c)]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Florida Power & Light Company

DOCKET NO.: 150009-EI

EXPLANATION: Provide additional details of contracts executed in excess of $1 million including, the nature and scope of the work, the nature of any affiliation with selected vendor, the method of vendor selection, brief description of vendor selection process, and current status of the contract.

For the Year Ended 12/31/2014

Witness: Steven D. Scroggs

Line No.	Contract No.:	Major Task or Tasks Associated With:	Vendor Identity:	Vendor Affiliation (specify 'direct' or 'indirect'):	Number of Vendors Solicited:	Number of Bids Received:	Brief Description of Selection Process:	Dollar Value:	Contract Status:	Term Begin:	Term End:	Nature and Scope of Work:
1												
2	4500395492	COLA and SCA Preparation and Support	Bechtel Power Corporation	Direct	Two	Two	Initial contract competitively bid. Change Orders 1-11 issued as Single Source. Designated as Predetermined Source January 2009 through July 2013. Subsequent change orders justified as Single Source.	[redacted]	Open - CO#57	11/06/07	08/01/15	Engineering Services to support preparation of COLA and SCA, including post-submittal support for RAI
3	4500518167	PTN 6&7 Post SCA Submittal Support	Environmental Consulting and Technology Inc.	Direct	SSJ/PDS	NA	ECT can build off of their Phase I analysis and project specific experience to complete the transmission corridor environmental licensing with a minimum of mobilization time or bringing project staff up to speed with prior work.	[redacted]	Open - CO#11	07/15/09	Open	PTN 6&7 Post SCA Submittal Support
4	4500430034	Conducts research, development and demonstration (RD&D) relating to the generation, delivery and use of electricity for the benefit of the public.	EPRI	Direct	SSJ	NA	EPRI is non-profit origination with the unique capability to fulfill the needs of this Contract.	[redacted]	Open - CO#2	06/10/08	Open	Advanced Nuclear Technology; Near term deployment of Advanced Light Water Reactors
5	4500518160	PTN 6&7 Post SCA Submittal Support	Golder & Associates, Inc.	Direct	SSJ/PDS	NA	Golder & Associates, Inc. has performed a significant amount of related Phase I tasks and can build off of their Phase I work and project specific experience to complete the environmental licensing with a minimum of mobilization time or bringing project staff up to speed with prior work.	[redacted]	Open - CO#11	09/29/09	04/30/15	Conceptual Engineering of Cooling Water Supply and Discharge
6	4500425707	Conceptual engineering of cooling water supply & disposal.	HDR Engineering, Inc.	Direct	Comp Bid/SSJ	Three	Initial contract competitively bid. Subsequent change orders were issued as Single Source and notes relative experience as the basis for award.	[redacted]	Open - CO#8	05/19/08	Open	Conceptual Engineering of Cooling Water Supply and Discharge
7	4500652043	Installation of exploratory underground injection control well & associated monitoring.	Layne Christensen Company	Direct	Comp Bid/SSJ	Three	Initial contract competitively bid. Subsequent change orders were issued as Single Source and notes relative experience as the basis for award.	[redacted]	Closed - CO#3	03/03/11	08/31/13	PTN 6&7 Exploratory/UIC Well Installation
8	4500536449	PTN 6&7 UIC Subject Matter Expert	McNabb Hydrogeologic Consulting, Inc.	Direct	Comp Bid/SSJ	Three	Initial contract competitively bid. Subsequent change orders were issued as Single Source and notes relative experience as the basis for award.	[redacted]	Closed - CO#4	12/30/11	12/31/12	PTN 6&7 Post SCA Submittal and UIC Licensing Support
9	2000102364	FSAR & NRC RAI Geotechnical Support.	Paul C. Rizzo Associates, Inc.	Direct	SSJ	NA	Rizzo Associates recent interaction with the NRC and their familiarity with Florida geology, would reduce familiarization and development time to prepare the analysis and FSAR revision.	[redacted]	Open - CO#9	04/30/13	12/31/14	PTN 6&7 Field Investigation and FSAR 2.5 Revision
10	4500404639	Support of COL application during NRC review & updating of 10CFR part 21 notification.	Westinghouse Electric Co	Direct	SSJ/ PDS	NA	Initial contract award was based on the designation as Predetermined Source. Subsequent change orders were issued as Single Source and notes relative experience as the basis for award.	[redacted]	Open - CO#8	01/31/08	08/31/15	PTN 6&7 Engineering Services to Support Preparation of COLA and Response to Post-Submittal RAIs

FEDERAL AUTHORIZATIONS

Jurisdictional Agency	Authority, Law, or Regulation	Description of Requirement	Activity Covered
NRC	10 CFR Part 30	By-Product License	Possession of fuel
NRC	10 CFR Part 40	Source Material License	Possession of source material
NRC	10 CFR Part 50	Licensing of nuclear power plant	Approval for construction of nuclear power plant
NRC	10 CFR Part 51 10 CFR Part 52	NRC approval of an Environmental Report	Evaluation of environmental impacts from construction and operation of a nuclear power plant
NRC	10 CFR Part 52	COL	Safety review of the nuclear power plant site
NRC	10 CFR Part 61	Licensing requirements for land disposal of radioactive wastes	Land disposal of radioactive waste that contains by-product source and Special Nuclear Material (SNM)
NRC	10 CFR Part 70	SNM License	Possession of SNM
NRC	10 CFR Part 71	Packaging and transportation of radioactive material	Packaging and transportation of licensed radioactive material
Department of Energy	Nuclear Waste Policy Act (42 U.S.C 10101 et seq.) 10 CFR Part 961	Spent Fuel Contract	Disposal of spent nuclear fuel
USACE	Clean Water Act of 1976 /33 U.S.C section 1344	Section 404 Permit	Discharge of dredge and fill materials into waters of the US
USACE	Rivers and Harbors Act of 1899/ 33 U.S.C. section 401 et. seq.	Section 10 -Rivers and Harbors Act Permit	Excavation or filling within navigable waters of the US
USACE	Rivers and Harbors Act of 1899/ CWA section 14 (33 USC 408)	Section 408. Taking possession of, use of, or injury to harbor or river improvements.	Control of all potential changes to navigable waters or to flood control structures.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 3
PARTY: FLORIDA POWER & LIGHT (FPL)
(DIRECT)
DESCRIPTION: Steve Scroggs SDS-2

FEDERAL AUTHORIZATIONS (CONT.)

Jurisdictional Agency	Authority, Law, or Regulation	Description of Requirement	Activity Covered
USACE	Secretary of the Army	License for use of government owned lands; Modified water deliveries to Everglades National Park	Use of Government owned lands for the purpose of onsite investigations in support of a Phase 1 Environmental Site Assessment, Wetland delineation, preparation of legal description and soil borings
Federal Aviation Agency (FAA)	14 CFR Part 77 - Safe, Efficient Use, and Preservation of Navigable Airspace	FAA Obstruction Permit for Unit 6 Containment Building	FAA Obstruction Permit for Unit 6 Containment Building
FAA	14 CFR Part 77 - Safe, Efficient Use, and Preservation of Navigable Airspace	FAA Obstruction Permit for Unit 7 Containment Building	FAA Obstruction Permit for Unit 7 Containment Building
FAA	14 CFR Part 77 - Safe, Efficient Use, and Preservation of Navigable Airspace	FAA Obstruction Permit for Construction Cranes	FAA Obstruction Permit for Construction Cranes - to be obtained as necessary
Department of the Interior (DOI)	RE-DO-53	Special Use Permit; Temporary Construction Easement	Provide access to delineate wetland boundaries within the proposed utility line right of way relocation in Everglades National Park
DOI	RE-DO-53	Special Use Permit; Temporary Construction Easement	Provide access to conduct visual and pedestrian surveys for Phase I environmental assessment within the proposed utility line right of way relocation in Everglades National Park

FEDERAL AUTHORIZATIONS (CONT.)

Jurisdictional Agency	Authority, Law, or Regulation	Description of Requirement	Activity Covered
US Fish and Wildlife Service (USFWS)	16 U.S.C 1539(a)(1)(A) 50 CFR Parts 13, 17	Endangered species permit to take American crocodile during monitoring	Provides authorization to take (capture, examine, weigh, identify sex, collect tissue samples, mark, radio-tag, radio-track, relocate, release) endangered American crocodile individuals during population monitoring
USFWS	16 U.S.C 703-712	Special purpose salvage permit, migratory birds	Provides authorization to: salvage dead migratory birds, abandoned nests, and addled eggs after nesting season; salvage dead bald or golden eagles; and possess live migratory birds for transport to permitted rehabilitator
USFWS	16 U.S.C. 703-7121 50 CFR Part 13:50 CFR 21.41	Federal Fish and Wildlife Permit	Emergency relocation of active migratory bird nests when birds, nests, or eggs pose a direct threat to human health and safety or when the safety of the bird is at risk if the nest and/or birds are not removed

STATE OF FLORIDA AUTHORIZATIONS

Jurisdictional Agency	Authority, Law, or Regulation	Description of Requirement	Activity Covered
FDEP, Siting Board	F.S. § 403.501-.518, F.S	Power Plant Site Certification*	Construction and operation of a power plant with more than 75 MW of steam generated power and associated facilities

*Pursuant to the Florida Electrical Power Plant Siting Act (PPSA) all state, regional and local permits, except for certain local land use and zoning approvals and certain state issued licenses required under federally delegated or approved permit programs, are covered under a single "Certification". Because the Certification is the sole license of the state and any agency required for construction and operation of the proposed electrical power plant, it is not necessary to apply for permits individually.

STATE OF FLORIDA AUTHORIZATIONS (CONT.)

Jurisdictional Agency	Authority, Law, or Regulation	Description of Requirement	Activity Covered
FDEP, US Environmental Protection Agency (EPA) Region IV review	F.A.C. 62-621	National Pollutant Discharge Elimination System (NPDES) Storm water Operations Permit for Industrial Activities	Operation of an industrial facility
FDEP	Chapter 403 F.S.	Exploratory Well Construction Permit	Allows for the construction of the exploratory well and dual-zone monitor well
FDEP	Chapter 403 F.S.	UIC Well Construction Permit	Allows for the conversion of the exploratory well to an injection well and perform operational testing for up to 2 years
FDEP	Chapter 403 F.S.	UIC Well Construction Permit	Allows for the construction of up to 12 additional injection wells and associated dual - zone monitoring wells and perform operational testing for up to 2 years
FDEP	Chapter 403 F.S.	Class I Well Operation Permit	Allows for the operation of the injection wells. This permit must be renewed every 5 years
FDEP, EPA Region IV review	F.A.C. 62-621	Prevention of Significant Deterioration Construction Permit	Construction and operation of facilities that generate air emissions
FDEP, EPA Region IV review	403.0885 F.S.	Modification of Industrial Wastewater Treatment Facility (IWW) permit	Construction of Units 6 & 7 within the industrial wastewater facility
FDEP/EPA	F.A.C. 62-25, 62-40	NPDES Construction Storm water Permit	Construction of any facility that disturbs 1 acre or more

STATE OF FLORIDA AUTHORIZATIONS (CONT.)

Jurisdictional Agency	Authority, Law, or Regulation	Description of Requirement	Activity Covered
Florida Fish and Wildlife Conservation Commission (FWCC)	F.A.C. 68A-9.002; 68A-25.002; 68A-27.003	Special purpose live-capture permit	Provides authorization for live-capture, insertion of data loggers in nests, and collection of samples, on FPL properties of American crocodiles for mark/recapture and scientific data collection; also provides for live-capture, relocation, and release of American alligators and eastern indigo snakes and other endangered or threatened species or species of special concern
FDEP	403.087, F.S. and F.A.C. 62-4, 62-520, 62-522, 62-528 62-550, 62-600, 62-601	Operation of Class V, Group 3 domestic wastewater injection (gravity flow) well	Operation of treated domestic sewage injection well
FDEP	403, F.S. and F.A.C. 62-600, 62-601, 62-602, 62-620, 62-640, 62-699	Operation of domestic wastewater treatment facility (WWTF)	Operation of Turkey Point Power Plant WWTF
FDEP	F.A.C. 62-213	Title V Operations Permit	Operations of facilities that generate air emissions
FDEP	253.12 F.S. F.A.C. 18-18, 18-20, 18-21, 18-22	Sovereign Submerged Lands Easements	Obtain easements for facilities to be located below surface water bodies in state owned lands
FDEP	253.12 F.S. F.A.C. 18-2	Upland Easements	Obtain easements for facilities to be located in state owned lands (uplands)
FDEP, South Florida Water Management District (SFWMD)	F.A.C. 40B-3	Well Construction Permit	Construct, repair, modify, or abandon a well

STATE OF FLORIDA AUTHORIZATIONS (CONT.)

Jurisdictional Agency	Authority, Law, or Regulation	Description of Requirement	Activity Covered
SFWMD	F.A.C. 40E-3	Well Abandonment Permit	Well abandonment permits
SFWMD, USACE	33 USC S 408	Federal Jurisdiction Per Section 14 of the Rivers and Harbors Act of 1899	Permission to place facilities in the vicinity of or otherwise use levees owned or controlled by the SFWMD originally constructed by the
SFWMD	Chapter 373 F.S.	Water well construction permits	Pump test for test wells
State of Florida	F.A.C. 40E-3	Well Abandonment Permit	Application to construct, repair, modify, or abandon well
FWCC	F.A.C. 68A-9.002, 68A-9.025, 68A-27	Carcass Salvage Permit	Salvage, mount, and display wildlife carcasses upon encounter for educational or scientific purposes
FWCC	F.A.C. 68A-9.002, 68A-27.005	Removal of nests and ospreys	Removal and replacement of inactive nests of ospreys and other migratory birds

FOREIGN STATE AUTHORIZATIONS

Jurisdictional Agency	Authority, Law, or Regulation	Description of Requirement	Activity Covered
Utah Department of Environmental Quality Division of Radiation Control	R313-26 of the Utah Radiation Control Rules	Revision of existing General Site Access Permit	Transport of radioactive materials into the State of Utah

FOREIGN STATE AUTHORIZATIONS (CONT.)

Jurisdictional Agency	Authority, Law, or Regulation	Description of Requirement	Activity Covered
Tennessee Department of Environment and Conservation Division of Radiological Health	TDEC Rule 1200-2-10.32	Revision of existing Tennessee Radioactive Waste License-for-Delivery	Transport of radioactive waste into the State of Tennessee

LOCAL AUTHORIZATIONS

Jurisdictional Agency	Authority, Law, or Regulation	Description of Requirement	Activity Covered
Miami-Dade County	Chapter 163 F.S.; Miami-Dade County Comprehensive Plan and adopted regulations	Land use and zoning conditional approval (unusual use approval)	Unusual Use (zoning approval) to permit a nuclear power plant (atomic reactors) and ancillary structures and equipment
Miami-Dade County	Chapter 163 F.S.; Miami-Dade County Comprehensive Plan (CDMP) and adopted regulations	CDMP text amendment	Excavation for fill source. Application was withdrawn 03/05/2010
Miami-Dade County	Chapter 163 F.S.; Miami-Dade County Comprehensive Plan (CDMP) and adopted regulations	CDMP text amendment	Temporary access roads

LOCAL AUTHORIZATIONS (CONT.)

Jurisdictional Agency	Authority, Law, or Regulation	Description of Requirement	Activity Covered
Miami-Dade County	Miami-Dade County Ordinances	IW6 Permit (Industrial Well field) for site investigation	Land use -non-residential, within major well field protection areas not served by sanitary sewers
Miami-Dade County Health Department	Chapter 373 F.S.	Water well construction permits	Well installation for hydrologic investigation
Miami-Dade County	Miami-Dade County Code Chapter 24	Domestic wastewater annual operating permit	Stabilization treatment facility
Miami-Dade County	Miami-Dade County Code Chapter 24	Operation of pollution control facility permit	Operation of fleet vehicle maintenance facility that generates waste oil, coolant, and used batteries with a solvent wash tank and served by septic tank
Miami-Dade County	Miami-Dade County Ordinances, Chapter 14	Burn Permit	Onsite combustion of construction debris. Annual permit issued
Miami-Dade County	Miami-Dade County Ordinances, Section 24-35	IW5 Permit (or waiver)	Hazardous materials or hazardous waste – large user or generator. Hazardous waste permit issued 10/01/2008
Miami-Dade County	Miami-Dade County Ordinances, Section 24	Stratospheric Ozone Protection Annual Operations Permit	Use of refrigerants R-12, R-22, R-502 for Robinair Recovery Units, Models 25200, 25200A, 25200B
Miami-Dade County	Miami-Dade County Ordinances, Section 24	Industrial Waste Annual Operations Permit	Onsite disposal of Class III industrial solid waste consisting of earth and earth-like products, concrete, rock, bricks, and land clearing debris
Miami-Dade County	Miami-Dade County Ordinances, 89-104	Marine Facilities Annual Operations Permit	Operation of 1 wet slip, 1 dry slip, 2 commercial vessels

COMPARISON OF PRIOR & CURRENT TURKEY POINT 6 & 7 PROJECT SCHEDULE

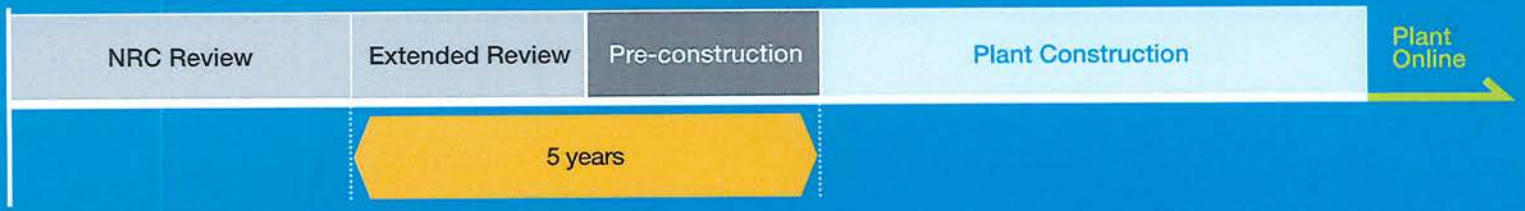
Prior Schedule - 2022 & 2023 In-Service Dates

Prior schedule included pre-construction work in parallel with NRC review



Current Schedule - 2027 & 2028 In-Service Dates

Current schedule includes 2 ½ years of extended NRC review, and pursuant to amended NCR statute, pre-construction must now follow NRC approval



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 4
PARTY: FLORIDA POWER & LIGHT (FPL) (DIRECT)
DESCRIPTION: Steve Scroggs SDS-3

Extended Nuclear Regulatory Commission Review & Amended Nuclear Cost Recovery Statute Drive 5 Year Project Schedule Change

Docket No. 150009-EI
Comparison of Prior and Current Turkey Point 6 & 7 Project Schedules
Exhibit SDS-3, Page 1 of 1

PROCEDURES AND WORK INSTRUCTIONS

QI4-NSC-1 Rev13 Procurement Control
BO-AA-102-1008 r6 Procurement Control
FPL - Affiliate Charge Review Process
FPL - Affiliate Charging FPL
FPL - Clause Recovery Charging Guideline
FPL - Clause Recovery Training Costs
FPL - Shopping Cart Training
FPL - Utility Retention Process
NEE - Project Controls Framework
E&C Monthly Accrual Process
Acquiring/Developing FPL Fixed Assets
PTN 67 - Expense Report Review
PTN 67 - Invoice Review
PTN 67 - Monthly Cost Report Process
PTN 67 - Payroll Distr Review Process
PTN 67 - Project Structure

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 5
PARTY: FLORIDA POWER & LIGHT (FPL) (DIRECT)
DESCRIPTION: Steve Scroggs SDS-4

PROJECT REPORTS

Report	Report Description	Periodicity	Audience
FPL/Bechtel COL Weekly Status Updates	FPL/Bechtel COL Project action items, applicable schedules and RAI review table.	Weekly	Project staff personnel, project management and project controls
FPL COL Weekly Status Updates	FPL COL Project action items, applicable schedules, Action Request look ahead report, Bechtel RAI report and FPL status report	Weekly	Project staff personnel, project management and project controls
Corporate Variance (Cost)	Financial status compared to corporate budget including Current Month (CM), Quarter (QTR), Year-To-Date (YTD) and End-Of-Year (EOY) with variance explanations	Monthly	Executive Management
NFR Variance	Compares filing projections for CM, YTD, EOY, and Prior Month Forecast	Monthly	Project Management and department heads
NFR Summary	Compares filing projections to actual/forecast with major milestone schedule dates	Monthly	Project Management and department heads

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 6
PARTY: FLORIDA POWER & LIGHT (FPL) (DIRECT)
DESCRIPTION: Steve Scroggs SDS-5

PROJECT REPORTS (CONT.)

Report	Report Description	Periodicity	Audience
Project Cost Summary	Financial status by WBS Element including CM, YTD and EOY	Monthly	Project Management
Cost Recovery by Detail	Compares Pre-construction NFR filing projection details to actual/forecast for CM, YTD and EOY	Monthly	Project Management
Pre-construction Cumulative Spend Graph	Visually compares Corporate Budget and NFR Projection to actual and forecast costs	Monthly	Project Management and department heads
Due Diligence Report	Project status for financial reporting process	Quarterly	Executive Management
Quarterly Risk Assessment	Risk assessment focuses on the licensing, permitting and general development activities	Quarterly	Project Management

PROJECT INSTRUCTIONS & FORMS

Procedure Number	Title	Revision Number	Effective Date
NNP-PI-01	REQUEST FOR INFORMATION (RFI) AND RFI RESPONSE	3	10/04/12
NNP-PI-02	PREPARATION, REVISION, REVIEW AND APPROVAL OF NEW NUCLEAR PROJECTS PROJECT INSTRUCTIONS	3	12/09/13
NNP-PI-03	PROJECT DOCUMENT RETENTION AND RECORDS PROCESSING	4	10/03/13
NNP-PI-04	COLA CONFIGURATION CONTROL AND RESPONSES TO REQUEST FOR ADDITIONAL INFORMATION FOR PROJECT APPLICATIONS	4	04/09/13
NNP-PI-05	NNP PROJECT CORRESPONDENCE	2	10/16/13
NNP-PI-06	NNP NRC CORRESPONDENCE	5	05/07/13
NNP-PI-07	DEPARTMENT TRAINING	5	02/15/13
NNP-PI-08	COLA REVIEW AND ACCEPTANCE PROCESS	6	01/07/13
NNP-PI-09	NNP COMBINED LICENSE APPLICATION SUBMITTAL	2	Cancelled 09/15/10
NNP-PI-10	NNP PTN COLA RELATED PROJECT MANAGEMENT BRIEFS, PROJECT MEMORANDA, AND COLA RELATED DOCUMENT REVIEWS	3	12/11/13
NNP-PI-11	CHANGE CONTROL FOR COL APPLICATION INFORMATION	4	Cancelled 11/13/14
NNP-PI-12	HOSTING VISITING DIGNITARIES AT THE FPL JUNO CAMPUS AND PRECONSTRUCTION TOURS OF THE PTN 6 & 7 SITE	2	12/06/11
NNP-PI-13	TECHNICAL REVIEW OF COMMERCIAL PROJECT DOCUMENTS	2	10/09/13
NNP-PI-14	DISCOVERY PRODUCTION INSTRUCTIONS RELATED TO TURKEY POINT 6 & 7 COMBINED LICENSE HEARING	3	08/20/13

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 7
PARTY: FLORIDA POWER & LIGHT (FPL) (DIRECT)
DESCRIPTION: Steve Scroggs SDS-6

Procedure Number	Title	Revision Number	Effective Date
NNP-PI-15	EXPLORATORY AND DUAL ZONE MONITORING WELL PROJECT INCIDENT RESPONSE INSTRUCTIONS	1	07/22/13
NNP-PI-100	PROJECT SCHEDULE CONFIGURATION AND CONTROL	0	Cancelled 02/11/14
NNP-PI-301	REVIEW OF WEC DESIGN CHANGE PROPOSALS (DCPS)	0	11/7/14
NNP-PI-302	PRE-COL DEPARTURE PROCESS	0	11/7/14
NNP-PI-303	PREPARATION OF INTERIM STAFF GUIDANCE – 011 SCREENS/EVALUATIONS	1	12/16/14

NNP Form Number	Title	Revision Number	Effective Date
NNP-AA-01	REGULATORY ITEMS & COMMITMENTS	0	4/12/13
NNP-PI-01-01	FPL NNP PTN 6 & 7 COL APPLICATION REQUEST FOR INFORMATON	1	11/12/13
NNP-PI-02-01	PROJECT INSTRUCTION REVIEW AND APPROVAL FORM	1	12/09/13
NNP-PI-03-01	QA RECORDS TRANSMITTAL FORM	2	9/8/11
NNP-PI-06-01	NNP OUTGOING NRC CORRESPONDENCE REVIEW & APPROVAL SHEET	3	6/10/14
NNP-PI-07-01	TRAINING ATTENDANCE FORM	0	3/19/08
NNP-PI-07-02	TRAINING EXEMPTION FORM	0	3/19/08
NNP-PI-07-03	REQUIRED READING FORM	7	11/17/14
NNP-PI-08-01	NNP COMMENT RESOLUTION ACCEPTANCE FORM	1	8/18/08
NNP-PI-08-02	NNP LRB MEETING SUMMARY FORM	1	9/8/08
NNP-PI-09-01	CERTIFICATION REFERENCE FORM	0	1/20/10
NNP-PI-10-01	NNP DOCUMENT REVIEW COMMENT FORM	0	4/12/13
NNP-PI-10-02	NNP PROJECT MANAGEMENT BRIEF/PROJECT MEMORANDUM	1	4/12/13

NNP Form Number	Title	Revision Number	Effective Date
	REVIEW AND APPROVAL FORM		
NNP-PI-11-01	SCREEN AND EVALUATION OF COL APPLICANT CHANGES TO A DCD	1	Cancelled 6/10/09
NNP-PI-11-03	10 CFR PART 52 SCREENER TRAINING AND QUALIFICATION FORM	1	Cancelled 6/12/09
NNP-PI-11-04	DEPARTURE SCREENING / EVALUATION REVIEW AND APPROVAL FORM	1	Cancelled 6/12/09
NNP-PI-13-01	REVIEW AND APPROVAL FORM	0	3/17/10
NNP-PI-13-02	DOCUMENT REVIEW CHECKLIST	1	3/22/11
NNP-PI-14	BUSINESS UNIT COMPLIANCE CERTIFICATION FORM	0	3/8/11
NNP-PI-14	BUSINESS UNIT DOCUMENT SEARCH CERTIFICATION FORM	0	3/8/11
NNP-PI-14	INDIVIDUAL DISCOVERY CERTIFICATION FORM	0	3/8/11
NNP-PI-302-01	SCREEN AND EVALUATION OF COL APPLICANT CHANGES TO THE PLANT-SPECIFIC DCD	0	11/7/14
NNP-PI-302-02	VENDOR GENERATED DEPARTURE COMPLETENESS REVIEW	0	11/7/14
NNP-PI-302-03	10 CFR PART 52 SCREENER TRAINING AND QUALIFICATION FORM	0	11/7/14
NNP-PI-302-04	DEPARTURE SCREENING/EVALUATION REVIEW AND APPROVAL FORM	0	11/7/14
NNP-PI-303-01	ISG-011 SCREEN OF CHANGES	1	12/16/14
NNP-PI-303-02	ISG-011 EVALUATION OR ACCEPTANCE REVIEW WORKSHEET	1	12/16/14
NNP-PI-303-03	INTERIM STAFF GUIDANCE 011 (ISG-011) TRAINING/QUALIFICATIONS	1	12/16/14

Table 1. 2014 Preconstruction Costs

Category	2014 Actual Costs ($)
Licensing	16,072,490
Permitting	414,704
Engineering & Design	2,916,303
Long Lead Procurement	0
Power Block Engineering & Procurement	0
Total Preconstruction Costs	**19,403,497**
Transmission	0
Total Preconstruction Costs & Transmission	**19,403,497**

Note: Totals may not appear to add due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 8
PARTY: FLORIDA POWER & LIGHT (FPL)
(DIRECT)
DESCRIPTION: Steve Scroggs SDS-7

Table 2. 2014 Licensing Costs

Category	2014 Actual Costs ($)
New Nuclear Project (NNP) Team Costs - NNP FPL Payroll and Expenses, FPL Project Team Facilities, FPL Engineering, FPL Licensing	4,832,581
Application Production - COLA/SCA Contractor, Project Architecture & Engineering, NRC and Design Center Working Group fees	7,930,124
SCA Oversight	0
SCA Subcontractors:	
• ECT - Transmission	125,667
• Golder - Environmental	115,601
• McNabb - Underground Injection	0
Total SCA	241,268
Environmental Services - FPL Payroll and Expenses, External Support Expenses	449,364
Power Systems - FPL Payroll and Expenses, System Studies, Licensing and Permitting Support and Design Activities	75,707
Licensing Legal - FPL Payroll and Expenses, External Legal Services, Expert Witnesses	1,953,620
Regulatory Affairs	417,239
New Nuclear Accounting	172,588
Total Regulatory Support	589,827
Total Licensing	**16,072,490**

Note: Totals may not appear to add due to rounding.

Table 3. 2014 Permitting Costs

Category	2014 Actual Costs ($)
Project Communication Support	30,709
Development - FPL Payroll and Expenses, Various Studies	317,087
Permitting-Legal Specialists Support	66,909
Total Permitting	**414,704**

Table 4. 2014 Engineering and Design Costs

Category	2014 Actual Costs ($)
Engineering and Construction Team - FPL Payroll and Expenses, Preconstruction Project Management	414,383
Pre-construction External Engineering - Construction Planning	526,920
APOG Membership Participation	1,700,000
EPRI Advanced Nuclear Technology	275,000
FEMA Fees	0
Total Engineering and Design	**2,916,303**

Table 5. 2014 Power Block Engineering and Procurement

Category	2014 Actual Costs ($)
No costs in 2013	0
Total Power Block Engineering and Procurement	**0**

Note: Totals may not appear to add due to rounding.

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DOCUMENT NO. 02474-15
FPSC - COMMISSION CLERK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 150009-EI
FLORIDA POWER & LIGHT COMPANY

MAY 1, 2015

IN RE: NUCLEAR POWER PLANT COST RECOVERY
FOR THE YEARS ENDING
JANUARY 2015 - DECEMBER 2016

Nuclear Filing Requirements Book

SDS-8
Turkey Point 6 & 7 Site Selection and Pre-Construction NFRs

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 9
PARTY: FLORIDA POWER & LIGHT (FPL)
(DIRECT)
DESCRIPTION: Steve Scroggs and Jennifer Grant-Keene SDS-8

Turkey Point 6 & 7 Site Selection and Pre-Construction Costs
Nuclear Filing Requirements (NFRs)
2015 AE-Schedules (Actual/Estimated)
2016 P-Schedules (Projections)
TOR-Schedules (True-up to Original)
January 2015 - December 2016

Site Selection &

Pre-Construction

Turkey Point 6 & 7 Site Selection & Pre-Construction
Nuclear Filing Requirements (NFRs)
2015 AE-Schedules (Actual/Estimated)
2016 P-Schedules (Projections)
TOR-Schedules (True-up to Original)
January 2015 - December 2016

Site Selection Table of Contents

Page (s)	Schedule	Year	Description	Sponsor
4-5	AE-1	2015	Retail Revenue Requirements Summary	J. Grant-Keene
6-8	AE-2	2015	True-up of Site Selection Carrying Costs	J. Grant-Keene
9-11	AE-3A	2015	Deferred Tax Carrying Costs	J. Grant-Keene
13-14	P-1	2016	Retail Revenue Requirements Summary	J. Grant-Keene
15-16	P-2	2016	Summary of Projected Site Selection Carrying Costs	J. Grant-Keene
17-18	P-3A	2016	Deferred Tax Carrying Costs	J. Grant-Keene
20	TOR-1	2016	NCRC Summary	J. Grant-Keene
21	TOR-3	2016	Summary of Annual Clause Recovery Amounts	J. Grant-Keene & S. Scroggs
22	TOR-6	2016	Capital Additions/Expenditures	J. Grant-Keene & S. Scroggs

Pre-Construction Table of Contents

Page (s)	Schedule	Year	Description	Sponsor
24-25	AE-1	2015	Retail Revenue Requirements Summary	J. Grant-Keene
26-28	AE-2	2015	True-up of Pre-Construction Costs	J. Grant-Keene
29-31	AE-3A	2015	Deferred Tax Carrying Costs	J. Grant-Keene
32	AE-6	2015	Monthly Expenditures	J. Grant-Keene & S. Scroggs
33	AE-6A	2015	Description of Major Tasks Performed	S. Scroggs
34	AE-6B	2015	Variance Explanations	S. Scroggs
35	AE-7A	2015	Contracts Executed > $250,000	S. Scroggs
36	AE-7B	2015	Contracts Executed > $1,000,000	S. Scroggs
38-39	P-1	2016	Retail Revenue Requirements Summary	J. Grant-Keene
40-42	P-2	2016	Summary of Projected Pre-Construction Costs	J. Grant-Keene
43-44	P-3A	2016	Deferred Tax Carrying Costs	J. Grant-Keene
45	P-6	2016	Monthly Expenditures	J. Grant-Keene & S. Scroggs
46	P-6A	2016	Description of Major Tasks Performed	S. Scroggs
47	P-7A	2016	Contracts Executed > $250,000	S. Scroggs
48	P-7B	2016	Contracts Executed > $1,000,000	S. Scroggs
49-50	P-8	2016	Estimated Rate Impact	J. Grant-Keene & S. Scroggs
52	TOR-1	2016	NCRC Summary	J. Grant-Keene
53	TOR-2	2016	Budgeted and Actual Power Plant In-Service Costs	J. Grant-Keene & S. Scroggs
54	TOR-3	2016	Summary of Annual Clause Recovery Amounts	J. Grant-Keene & S. Scroggs
55	TOR-6	2016	Capital Additions/ Expenditures	J. Grant-Keene & S. Scroggs
56	TOR-6A	2016	Description of Major Tasks Performed	S. Scroggs
57	TOR-7	2016	Power Plant Milestones	S. Scroggs

Site Selection Actual/Estimated

2015

Schedule AE-1 (Actual/Estimated)

Turkey Point Units 6&7
Site Selection Carrying Costs on Site Selection Cost Balance
Actual & Estimated Filing: Retail Revenue Requirements Summary

[Section (6)(c)1.b.]

EXPLANATION: Provide the calculation of the true-up of total retail revenue requirements based on projected carrying costs filed in the prior year and the current year actual/estimated carrying costs.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2015

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.		(A) Actual January	(B) Actual February	(C) Projected March	(D) Projected April	(E) Projected May	(F) Projected June	(G) 6 Month Total
		Jurisdictional Dollars						
1	Site Selection Revenue Requirements (Schedule AE-2, Line 7)	($188)	($184)	($176)	($168)	($160)	($152)	($1,027)
2	Construction Carrying Cost Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
3	Recoverable O&M Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
4	DTA/(DTL) Carrying Cost (Schedule AE-3A, Line 8)	$13,297	$13,297	$13,297	$13,297	$13,298	$13,298	$79,784
5	Other Adjustments	$0	$0	$0	$0	$0	$0	$0
6	Total Period Revenue Requirements (Lines 1 though 5)	$13,108	$13,113	$13,121	$13,130	$13,138	$13,146	$78,756
7	Projected Carrying Cost on DTA/(DTL) for the Period	$12,209	$12,212	$12,212	$12,212	$12,212	$12,212	$73,270
8	Actual/Estimated (Over)/Under Recovery for the Period (Line 6 - Line 7)	$899	$901	$909	$917	$925	$934	$5,486

* Totals may not add due to rounding

Schedule AE-1 (Actual/Estimated)

Turkey Point Units 6&7
Site Selection Carrying Costs on Site Selection Cost Balance
Actual & Estimated Filing: Retail Revenue Requirements Summary

[Section (6)(c)1.b.]

EXPLANATION: Provide the calculation of the true-up of total retail revenue requirements based on projected carrying costs filed in the prior year and the current year actual/estimated carrying costs.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2015

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.		(H) Projected July	(I) Projected August	(J) Projected September	(K) Projected October	(L) Projected November	(M) Projected December	(N) 12 Month Total
		Jurisdictional Dollars						
1	Site Selection Revenue Requirements (Schedule AE-2, Line 7)	($144)	($142)	($146)	($151)	($156)	($162)	($1,928)
2	Construction Carrying Cost Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
3	Recoverable O&M Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
4	DTA/(DTL) Carrying Cost (Schedule AE-3A, Line 8)	$13,300	$13,300	$13,300	$13,301	$13,301	$13,301	$159,586
5	Other Adjustments	$0	$0	$0	$0	$0	$0	$0
6	Total Period Revenue Requirements (Lines 1 though 5)	$13,156	$13,158	$13,154	$13,149	$13,144	$13,139	$157,658
7	Projected Carrying Cost on DTA/(DTL) for the Period	$13,905	$13,924	$13,950	$13,977	$14,003	$14,030	$157,060
8	Actual/Estimated (Over)/Under Recovery for the Period (Line 6 - Line 7)	($748)	($766)	($796)	($827)	($859)	($891)	$598

* Totals may not add due to rounding

Schedule AE-2 (Actual/Estimated)

Turkey Point Units 6&7
Carrying Costs on Site Selection Cost Balance
Actual & Estimated Filing: Carrying Costs

[Section (6)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the calculation of the true-up of projected carrying costs filed in the prior year and the current year actual/estimated carrying costs.

For the Year Ended 12/31/2015

Witness: Jennifer Grant-Keene

Line No.		(A) Beginning of Period	(B) Actual January	(C) Actual February	(D) Projected March	(E) Projected April	(F) Projected May	(G) Projected June	(H) 6 Month Total
					Jurisdictional Dollars				
1	a. Nuclear CWIP Additions		$0	$0	$0	$0	$0	$0	$0
	b. Prior Month's (Over)/Under Recovery Eligible for Return (Line 9)		$0	$873	$1,747	$2,629	$3,519	$4,417	$5,323
2	Unamortized Carrying Costs Eligible for Return (d)	($2,007)	($1,833)	($1,659)	($1,485)	($1,311)	($1,138)	($964)	($964)
3	Amortization of Carrying Costs Eligible for Return (e)	($2,086)	($174)	($174)	($174)	($174)	($174)	($174)	($1,043)
4	Average Net Unamortized Carrying Costs Eligible for Return		($1,920)	($1,310)	($262)	$789	$1,849	$2,917	
5	Return on Average Net Prior Year (Over)/Under Recoveries								
	a. Equity Component (Line 5b x .61425) (a)		($8)	($5)	($1)	$3	$7	$11	$8
	b. Equity Component grossed up for taxes (Line 4 x 0.00636821) (a) (b) (c)		($12)	($8)	($2)	$5	$12	$19	$13
	c. Debt Component (Line 4 x 0.00122335) (c)		($2)	($2)	($0)	$1	$2	$4	$3
6	Actual/Estimated Carrying Cost for the Period (Line 5b + Line 5c)		($15)	($10)	($2)	$6	$14	$22	$16
7	Actual/Estimated Carrying Costs & Amortization for the Period		($188)	($184)	($176)	($168)	($160)	($152)	($1,027)
8	Projected Carrying Costs & Amortization (g)		($1,061)	($1,058)	($1,058)	($1,058)	($1,058)	($1,058)	($6,350)
9	Actual/Estimated (Over)/Under Recovery (Line 7 - Line 8)		$873	$874	$882	$890	$898	$906	$5,323

* Totals may not add due to rounding

See Notes on Pages 3 of 3

Schedule AE-2 (Actual/Estimated)

Turkey Point Units 6&7
Carrying Costs on Site Selection Cost Balance
Actual & Estimated Filing: Carrying Costs

[Section (6)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the calculation of the true-up of projected carrying costs filed in the prior year and the current year actual/estimated carrying costs.

For the Year Ended 12/31/2015

Witness: Jennifer Grant-Keene

Line No.		(I) Projected July	(J) Projected August	(K) Projected September	(L) Projected October	(M) Projected November	(N) Projected December	(O) 12 Month Total
		Jurisdictional Dollars						
1	a. Nuclear CWIP Additions	$0	$0	$0	$0	$0	$0	$0
	b. Prior Month's (Over)/Under Recovery Eligible for Return (Line 9)	$5,323	$4,545	$3,749	$2,922	$2,064	$1,174	$252
2	Unamortized Carrying Costs Eligible for Return (d) (f)	($790)	($616)	($442)	($268)	($94)	$79	
3	Amortization of Carrying Costs Eligible for Return (e)	($174)	($174)	($174)	($174)	($174)	($174)	($2,086)
4	Average Net Unamortized Carrying Costs Eligible for Return	$3,993	$4,231	$3,618	$2,981	$2,312	$1,611	
5	Return on Average Net Prior Year (Over)/Under Recoveries							
	a. Equity Component (Line 5b x 0.61425) (a)	$16	$17	$14	$12	$9	$6	$81
	b. Equity Component grossed up for taxes (Line 4 x 0.00636821) (a) (b) (c)	$25	$27	$23	$19	$15	$10	$133
	c. Debt Component (Line 4 x 0.00122335) (c)	$5	$5	$4	$4	$3	$2	$25
6	Actual/Estimated Carrying Cost for the Period (Line 5b + Line 5c)	$30	$32	$27	$23	$18	$12	$158
7	Actual/Estimated Carrying Costs & Amortization for the Period	($144)	($142)	($146)	($151)	($156)	($162)	($1,928)
8	Projected Carrying Costs & Amortization (g)	$634	$654	$680	$707	$733	$760	($2,181)
9	Actual/Estimated (Over)/Under Recovery (Line 7 - Line 8)	($778)	($796)	($827)	($858)	($890)	($922)	$253

* Totals may not add due to rounding

See Notes on Pages 3 of 3

Schedule AE-2 (Actual/Estimated)

Turkey Point Units 6&7
Carrying Costs on Site Selection Cost Balance
Actual & Estimated Filing: Carrying Costs

[Section (6)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the calculation of the true-up of projected carrying costs filed in the prior year and the current year actual/estimated carrying costs.

For the Year Ended 12/31/2015

Witness: Jennifer Grant-Keene

Notes:

(a) For carrying charge purposes the monthly equity component reflects a 10.5% return on equity.

(b) Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5% for an effective rate of 38.575%.

(c) In order to gross up the equity component for taxes a monthly rate of 0.00636821 (Equity) and 0.00122335 (Debt) results in the annual pre-tax rate of 9.39%, effective January 1, 2015.

(d) Line 2, Column (A) - Unamortized CWIP Base Eligible for Return consists of the total over recovered balance beginning in 2015. This amount is reduced by 2015 amounts refunded (Line 3) and a carrying charge is calculated on the unrefunded balance.

Line 2 Beginning Balances include:	Docket No. 130009-EI 2014 Projections	Docket No. 150009-EI 2014 True-up	2014 (Over) Recovery
2014 Site Selection Carrying Costs (P-2/T-2, Line 6)	$0	($742)	($742)
2014 DTA/DTL Carrying Cost (P-3A/T-3A, Line 8)	$160,488	$159,224	($1,265)
	$160,488	$158,482	($2,007)

(e) Line 3, Column (A) - Amortization of CWIP Base Eligible for Return is the amount that will be refunded over 12 months in 2015, as approved by the Commission in Docket No. 140009-EI (see Order No. PSC-14-0617-FOF-EI).

Beginning Balance includes:

	2014 A/E Over Recovery
2014 Site Selection Carrying Costs (AE-2, Line 9)	($742)
2014 DTA/DTL Carrying Cost (Revised AE-3A, Line 10)	($1,344)
	($2,086)

(f) Line 2, Column (N) - Ending 2014 Final True-up Balance is $79.

Line 2 Beginning Balance includes:	Docket No. 140009-EI 2014 Actual/Estimated	Docket No. 150009-EI 2014 True-up	2014 Final True-up
2014 Site Selection Costs + Carrying Costs (Revised AE-2, Line 6/T-2, Line 6)	($742)	($742)	$0
2014 DTA/DTL Carrying Cost (Revised AE-3A, Line 8/T-3A, Line 8)	$159,144	$159,224	$79
	$158,402	$158,482	$79

(g) Total being refunded in 2015 as approved in Order No PSC-14-0617-FOF-EI in Docket No. 140009-EI.

	January	February	March	April	May	June	July	August	September	October	November	December	12 Month
2013 Final True-Up (2013 T-1, Line 10)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2014 (Over)/Under Recovery (Revised AE-1, Line 8)	($1,046)	($1,044)	($1,045)	($1,047)	($1,048)	($1,049)	$642	$660	$685	$710	$735	$761	($2,086)
2015 Projected Carrying Cost (Revised P-2, Line 7)	($15)	($14)	($13)	($11)	($10)	($9)	($7)	($6)	($5)	($3)	($2)	($1)	($95)
2015 (Over)/Under Recovery Projections	($1,061)	($1,058)	($1,058)	($1,058)	($1,058)	($1,058)	$634	$654	$680	$707	$733	$760	($2,181)

* Totals may not add due to rounding

Schedule AE-3A (Actual/Estimated)

Turkey Point Units 6&7
Carrying Costs on Site Selection Cost Balance
Actual & Estimated Filing: Deferred Tax Carrying Costs

[Section (6)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the actual/estimated deferred tax Carrying Costs.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2015

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.			(A) Beginning of Period	(B) Actual January	(C) Actual February	(D) Projected March	(E) Projected April	(F) Projected May	(G) Projected June	(H) 6 Month Total
						Jurisdictional Dollars				
1	Construction Period Interest			$0	$0	$0	$0	$0	$0	$0
2	Recovered Costs Excluding AFUDC			$0	$0	$0	$0	$0	$0	$0
3	Other Adjustments			$0	$0	$0	$0	$0	$0	$0
4	Tax Basis Less Book Basis (Prior Month Balance + Lines 1 + 2 + 3) (d) (f)		$4,540,552	$4,540,552	$4,540,552	$4,540,552	$4,540,552	$4,540,552	$4,540,552	$4,540,552
5	Deferred Tax Asset DTA(DTL) on Tax Basis in Excess of Book (Line 4 x Tax Rate) (b)	**38.575%**	$1,751,518	$1,751,518	$1,751,518	$1,751,518	$1,751,518	$1,751,518	$1,751,518	$1,751,518
6	a. Average Accumulated DTA/(DTL)			$1,751,518	$1,751,518	$1,751,518	$1,751,518	$1,751,518	$1,751,518	
	b. Prior months cumulative Return on DTA/(DTL)			$0	$27	$54	$81	$108	$135	$404
	c. Average DTA including prior period return subtotal			$1,751,518	$1,751,545	$1,751,571	$1,751,598	$1,751,626	$1,751,653	
7	Carrying Cost on DTA/(DTL)									
	a. Equity Component (Line 7b **x** .61425) (a)			$6,851	$6,851	$6,852	$6,852	$6,852	$6,852	$41,110
	b. Equity Component grossed up for taxes (Line 6c x 0.00636821) (a) (b) (c)			$11,154	$11,154	$11,154	$11,155	$11,155	$11,155	$66,927
	c. Debt Component (Line 6c x 0.00122335) (c)			$2,143	$2,143	$2,143	$2,143	$2,143	$2,143	$12,857
8	Actual/Estimated Carrying Costs on DTA/(DTL) for the Period (Line 7b + Line 7c)			$13,297	$13,297	$13,297	$13,297	$13,298	$13,298	$79,784
9	Projected Carrying Cost on DTA/(DTL) for the Period (e)			$13,270	$13,270	$13,270	$13,270	$13,270	$13,270	$79,621
10	Actual/Estimated (Over)/Under Recovery (Line 8 - Line 9)			$27	$27	$27	$27	$27	$28	$163

* Totals may not add due to rounding

See Notes on Page 3 of 3

Schedule AE-3A (Actual/Estimated)

Turkey Point Units 6&7
Carrying Costs on Site Selection Cost Balance
Actual & Estimated Filing: Deferred Tax Carrying Costs

[Section (6)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the actual/estimated deferred tax Carrying Costs.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2015

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.			(I) Beginning of Month	(J) Projected July	(K) Projected August	(L) Projected September	(M) Projected October	(N) Projected November	(O) Projected December	(P) 12 Month Total
						Jurisdictional Dollars				
1	Construction Period Interest			$0	$0	$0	$0	$0	$0	$0
2	Recovered Costs Excluding AFUDC			$0	$0	$0	$0	$0	$0	$0
3	Other Adjustments			$0	$0	$0	$0	$0	$0	$0
4	Tax Basis Less Book Basis (Prior Month Balance + Lines 1 + 2 + 3)		$4,540,552	$4,540,552	$4,540,552	$4,540,552	$4,540,552	$4,540,552	$4,540,552	$4,540,552
		38.575%								
5	Deferred Tax Asset DTA(DTL) on Tax Basis in Excess of Book (Line 4 x Tax Rate) (b)		$1,751,518	$1,751,518	$1,751,518	$1,751,518	$1,751,518	$1,751,518	$1,751,518	$1,751,518
6	a. Average Accumulated DTA/(DTL)			$1,751,518	$1,751,518	$1,751,518	$1,751,518	$1,751,518	$1,751,518	
	b. Prior months Cumulative Return on DTA/(DTL)			$404	$434	$464	$494	$524	$555	$586
	c. Average DTA including prior period return subtotal			$1,751,922	$1,751,952	$1,751,981	$1,752,012	$1,752,042	$1,752,073	
7	Carrying Cost on DTA/(DTL)									
	a. Equity Component (Line 7b x .61425) (a)			$6,853	$6,853	$6,853	$6,853	$6,853	$6,854	$82,229
	b. Equity Component grossed up for taxes (Line 6c x 0.00636821) (a) (b) (c)			$11,157	$11,157	$11,157	$11,157	$11,157	$11,158	$133,869
	c. Debt Component (Line 6c x 0.00122335) (c)			$2,143	$2,143	$2,143	$2,143	$2,143	$2,143	$25,717
8	Actual/Estimated Carrying Costs on DTA/(DTL) for the Period (Line 7b + Line 7c)			$13,300	$13,300	$13,300	$13,301	$13,301	$13,301	$159,586
9	Projected Carrying Cost on DTA/(DTL) for the Period (e)			$13,270	$13,270	$13,270	$13,270	$13,270	$13,270	$159,241
10	Actual/Estimated (Over)/Under Recovery (Line 8 - Line 9)			$30	$30	$30	$30	$31	$31	$345

* Totals may not add due to rounding

See Notes on Page 3 of 3

Schedule AE-3A (Actual/Estimated)

Turkey Point Units 6&7
Carrying Costs on Site Selection Cost Balance
Actual & Estimated Filing: Deferred Tax Carrying Costs

[Section (6)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the actual/estimated deferred tax Carrying Costs.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2015

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Notes:
(a) For carrying charge purposes the monthly equity component reflects a 10.5% return on equity.
(b) Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5% for an effective rate of 38.575%.
(c) In order to gross up the equity component for taxes, a monthly rate of 0.00636821 (Equity) and 0.00122335 (Debt) results in the annual pre-tax rate of 9.39%, effective January 1, 2015.
(d) Line 4 - Beginning Balance comes from 2014 T-3A, Line 4, Column (P), Docket No. 150009-EI.
(e) As approved by the Commission in Docket No. 140009-EI (see Order No. PSC-14-0617-FOF-EI).

(f) The Beginning Balance of T-3A, Line 4 has been revised to reflect the Jurisdictional Separation Factor effective in 2015 for CPI (Line 1) and other adjustments (Line 3).

	Docket No. 150009-EI 2014 Ending Balance as filed March 2, 2015	Tax Deductions at January 2015 Jurisdictional Factor (g)	T-3A Beginning Balance at January 2015 Jursidicitional Factor
Line 4, Column (A) Tax Basis Less Book Basis	$4,533,203	$7,349	$4,540,552

(g) Calculation of 2014 beginning balance of Tax Deductions at the 2015 Jurisdictional Separation Factor.

	2006	2007	Total	Difference
Tax Deductions included in T-3A, Line 4 balance	($336,073)	($1,304,002)	($1,640,075)	
2014 Jurisdictional Factor	0.95079073	0.95079073		
Total Jurisdictionalized Tax Deductions	($319,535)	($1,239,833)	($1,559,368)	
Tax Deductions included in T-3A, Line 4 balance	($336,073)	($1,304,002)	($1,640,075)	
2015 Jurisdictional Factor	0.94630981	0.94630981		
Total revised Jurisdictionalized Tax Deductions	($318,029)	($1,233,990)	($1,552,019)	$7,349

* Totals may not add due to rounding

Site Selection Projections

2016

Schedule P-1 (Projection)

Turkey Point Units 6&7
Carrying Costs on Site Selection Cost Balance
Projection Filing: Retail Revenue Requirements Summary

[Section (6)(c)1.c.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide a summary of the projected total retail revenue requirements.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2016

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.		(A) Projected January	(B) Projected February	(C) Projected March	(D) Projected April	(E) Projected May	(F) Projected June	(G) 6 Month Total
		Jurisdictional Dollars						
1	Site Selection Revenue Requirements (Schedule P-2, Line 7)	$4	$4	$4	$3	$3	$2	$20
2	Construction Carrying Cost Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
3	Recoverable O&M Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
4	DTA Carrying Cost (Schedule P-3A, Line 8)	$13,297	$13,297	$13,297	$13,297	$13,297	$13,297	$79,781
5	Other Adjustments	$0	$0	$0	$0	$0	$0	$0
6	Total Projected Period Revenue Requirements (Lines 1 through 5)	$13,301	$13,301	$13,300	$13,300	$13,300	$13,299	$79,801

* Totals may not add due to rounding

Schedule P-1 (Projection)

Turkey Point Units 6&7
Carrying Costs on Site Selection Cost Balance
Projection Filing: Retail Revenue Requirements Summary

[Section (6)(c)1.c.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide a summary of the projected total retail revenue requirements.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2016

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.		(H) Projected July	(I) Projected August	(J) Projected September	(K) Projected October	(L) Projected November	(M) Projected December	(N) 12 Month Total
		Jurisdictional Dollars						
1	Site Selection Revenue Requirements (Schedule P-2, Line 7)	$2	$2	$1	$1	$1	$0	$27
2	Construction Carrying Cost Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
3	Recoverable O&M Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
4	DTA Carrying Cost (Schedule P-3A, Line 8)	$13,297	$13,297	$13,297	$13,297	$13,297	$13,297	$159,561
5	Other Adjustments	$0	$0	$0	$0	$0	$0	$0
6	Total Projected Period Revenue Requirements (Lines 1 through 5)	$13,299	$13,298	$13,298	$13,298	$13,297	$13,297	$159,588

* Totals may not add due to rounding

Schedule P-2 (Projection)

Turkey Point Units 6&7
Carrying Costs on Site Selection Cost Balance
Projection Filing: Carrying Costs

[Section (6)(c)1.c.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide a summary of the projected site selection carrying costs.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2016

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.		(A) Beginning of Period	(B) Projected January	(C) Projected February	(D) Projected March	(E) Projected April	(F) Projected May	(G) Projected June	(H) 6 Month Total
					Jurisdictional Dollars				
1	Nuclear CWIP Additions		$0	$0	$0	$0	$0	$0	$0
2	Unamortized Carrying Costs Eligible for Return (d)	$598	$548	$498	$448	$399	$349	$299	
3	Amortization of Carrying Costs Eligible for Return (d)		$50	$50	$50	$50	$50	$50	$299
4	Average Net Unamortized Carrying Costs Eligible for Return ([Prior months Line 2 + Line 2]/2)		$573	$523	$473	$423	$374	$324	
5	Return on Average Net Prior Year (Over)/Under Recoveries								
	a. Equity Component (Line 5b x .61425) (a)		$2	$2	$2	$2	$1	$1	$11
	b. Equity Component grossed up for taxes (Line 4 x 0.00636821) (a) (b) (c)		$4	$3	$3	$3	$2	$2	$17
	c. Debt Component (Line 4 x 0.00122335) (c)		$1	$1	$1	$1	$0	$0	$3
6	Projected Carrying Costs for the Period (Line 5b + Line 5c)		$4	$4	$4	$3	$3	$2	$20
7	Total Projected Costs and Carrying Costs for the Period (Line 1 + Line 6)		$4	$4	$4	$3	$3	$2	$20

* Totals may not add due to rounding

See Notes on Page 2 of 2

Schedule P-2 (Projection)

Turkey Point Units 6&7
Carrying Costs on Site Selection Cost Balance
Projection Filing: Carrying Costs

[Section (6)(c)1.c.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide a summary of the projected site selection carrying costs.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2016

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.		(I) Projected July	(J) Projected August	(K) Projected September	(L) Projected October	(M) Projected November	(N) Projected December	(O) 12 Month Total
		Jurisdictional Dollars						
1	Nuclear CWIP Additions	$0	$0	$0	$0	$0	$0	$0
2	Unamortized Carrying Costs Eligible for Return (d)	$249	$199	$149	$100	$50	($0)	
3	Amortization of Carrying Costs Eligible for Return (d)	$50	$50	$50	$50	$50	$50	$598
4	Average Net Unamortized Carrying Costs Eligible for Return ([Prior months Line 2 + Line 2]/2)	$274	$224	$174	$125	$75	$25	
5	Return on Average Net Prior Year (Over)/Under Recoveries							
	a. Equity Component (Line 5b x .61425) (a)	$1	$1	$1	$0	$0	$0	$14
	b. Equity Component grossed up for taxes (Line 4 x 0.00636821) (a) (b) (c)	$2	$1	$1	$1	$0	$0	$23
	c. Debt Component (Line 4 x 0.00122335) (c)	$0	$0	$0	$0	$0	$0	$4
6	Projected Carrying Costs for the Period (Line 5b + Line 5c)	$2	$2	$1	$1	$1	$0	$27
7	Total Projected Costs and Carrying Costs for the Period (Line 1 + Line 6)	$2	$2	$1	$1	$1	$0	$27

Notes:

8 (a) For carrying charge purposes the monthly equity component reflects a 10.5% return on equity.
9 (b) Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5% for an effective rate of 38.575%.
10 (c) In order to gross up the equity component for taxes a monthly rate of 0.00636821 (Equity) and 0.00122335 (Debt) results in the annual pre-tax rate of 9.39%, effective January 1, 2015.
11 (d) Line 2, Column (A) - Unamortized CWIP Base Eligible for Return consists of the total over recovered balance beginning in 2016. This amount will be amortized ratably over 12 months (Line 3) and a carrying charge will be calculated
12 on the unrefunded balance.
13 Line 2 Beginning Balance includes:
14

15	2015 Site Selection Carrying Costs (AE-2, Line 9)	$253
16	2015 DTA/(DTL) Carrying Cost (AE-3A, Line 10)	$345
17	Total over recovery beginning in 2016 (AE-1, Line 8) (JGK-3, Column 6, Line 8)	$598

* Totals may not add due to rounding

Schedule P-3A (Projection)

Turkey Point Units 6&7
Carrying Costs on Site Selection Cost Balance
Projection Filing: Deferred Tax Carrying Costs

[Section (6)(c)1.c.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the projected deferred tax carrying costs.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2016

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.			(A) Beginning of Period	(B) Projected January	(C) Projected February	(D) Projected March	(E) Projected April	(F) Projected May	(G) Projected June	(H) 6 Month Total
						Jurisdictional Dollars				
1	Construction Period Interest			$0	$0	$0	$0	$0	$0	$0
2	Recovered Costs Excluding AFUDC			$0	$0	$0	$0	$0	$0	$0
3	Other Adjustments			$0	$0	$0	$0	$0	$0	$0
4	Tax Basis Less Book Basis (Prior Month Balance + Lines 1 + 2 + 3) (d)		$4,540,552	$4,540,552	$4,540,552	$4,540,552	$4,540,552	$4,540,552	$4,540,552	$4,540,552
5	Deferred Tax Asset (DTA) on Tax Basis in Excess of Book (Line 4 x Tax Rate) (b)	38.575%	$1,751,518	$1,751,518	$1,751,518	$1,751,518	$1,751,518	$1,751,518	$1,751,518	$1,751,518
6	Average Accumulated DTA			$1,751,518	$1,751,518	$1,751,518	$1,751,518	$1,751,518	$1,751,518	
7	Carrying Cost on DTA									
	Equity Component (Line 7b x .61425) (a)			$6,851	$6,851	$6,851	$6,851	$6,851	$6,851	$41,108
	b. Equity Component grossed up for taxes (Line 6 x 0.00636821) (a) (b) (c)			$11,154	$11,154	$11,154	$11,154	$11,154	$11,154	$66,924
	c. Debt Component (Line 6 x 0.00122335) (c)			$2,143	$2,143	$2,143	$2,143	$2,143	$2,143	$12,856
8	Projected Carrying Costs on DTA/(DTL) (Line 7b + Line 7c)			$13,297	$13,297	$13,297	$13,297	$13,297	$13,297	$79,781

* Totals may not add due to rounding

See Notes on Page 2 of 2

Schedule P-3A (Projection)

Turkey Point Units 6&7
Carrying Costs on Site Selection Cost Balance
Projection Filing: Deferred Tax Carrying Costs

[Section (6)(c)1.c.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the projected deferred tax carrying costs.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2016

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.			(I) Beginning of Month	(J) Projected July	(K) Projected August	(L) Projected September	(M) Projected October	(N) Projected November	(O) Projected December	(P) 12 Month Total
						Jurisdictional Dollars				
1	Construction Period Interest			$0	$0	$0	$0	$0	$0	$0
2	Recovered Costs Excluding AFUDC			$0	$0	$0	$0	$0	$0	$0
3	Other Adjustments			$0	$0	$0	$0	$0	$0	$0
4	Tax Basis Less Book Basis (Prior Month Balance + Lines 1 + 2 + 3) (d)		$4,540,552	$4,540,552	$4,540,552	$4,540,552	$4,540,552	$4,540,552	$4,540,552	$4,540,552
5	Deferred Tax Asset (DTA) on Tax Basis in Excess of Book (Line 4 x Tax Rate) (b)	**38.575%**	$1,751,518	$1,751,518	$1,751,518	$1,751,518	$1,751,518	$1,751,518	$1,751,518	$1,751,518
6	Average Accumulated DTA			$1,751,518	$1,751,518	$1,751,518	$1,751,518	$1,751,518	$1,751,518	
7	Carrying Cost on DTA									
	a. Equity Component (Line 7b x .61425) (a)			$6,851	$6,851	$6,851	$6,851	$6,851	$6,851	$82,216
	b. Equity Component grossed up for taxes (Line 6 x 0.00636821) (a) (b) (c)			$11,154	$11,154	$11,154	$11,154	$11,154	$11,154	$133,848
	c. Debt Component (Line 6 x 0.00122335) (c)			$2,143	$2,143	$2,143	$2,143	$2,143	$2,143	$25,713
8	Projected Carrying Costs on DTA/(DTL) (Line 7b + Line 7c)			$13,297	$13,297	$13,297	$13,297	$13,297	$13,297	$159,561

Notes:

9 (a) For carrying charge purposes the monthly equity component reflects a 10.5% return on equity.

10 (b) Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5% for an effective rate of 38.575%.

11 (c) In order to gross up the equity component for taxes a monthly rate of 0.00636821 (Equity) and 0.00122335 (Debt) results in the annual pre-tax rate of 9.39%, effective January 1, 2015.

12 (d) Line 4 - Beginning Balance comes from 2015 AE-3A, Line 4, Column (P), Docket No. 150009-EI.

* Totals may not add due to rounding

Site Selection
True-Up to Original

FLORIDA POWER & LIGHT COMPANY
Turkey Point Units 6&7 - Site Selection Costs
NCRC Summary - Dkt. 150009

Schedule TOR-1 (True-Up to Original)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER LIGHT & COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Show the jurisdictional amounts used to calculate the final true-up estimated true-up, projection, deferrals, and recovery of deferrals for each project included in the NCRC. The sum of the amounts should be the total amount requested for recovery in the projected period.

For the Period Ended 12/31/2016

Witness: Jennifer Grant-Keene

		2014			2015			2016	Subtotals	Deferred Recovery			Net Amounts
		A	B	C	D	E	F	G	H	I	J	K	L
		(a)		(B)-(A)	(a)		(E)-(D)		(C)+(F)+(G)				
Line No.	Costs by Project	Approved Actual & Estimated Amounts in Docket No. 140009-EI	Final Actual Amounts in Docket No. 150009-EI	Final True-up for 2014	Approved Projected Amounts in Docket No. 140009-EI	Actual & Estimated Amounts in Docket No. 150009-EI	Estimated True-up for 2015	Initial Projected Amounts for 2016 in Docket No. 150009-EI	Amounts for 2016 to be Recovered in Docket No. 150009-EI	Increase in Deferred Balance	Decrease in Deferred Balance	2016 Deferred Balance	Net Amount Requested for Recovery in 2016 in Docket No. 150009-EI
	Site Selection Costs						Jurisdictional Dollars						
1	Additions	$0	$0	$0	$0	$0	$0	$0	$0			$0	$0
2	Carrying Costs - Construction	($742)	($742)	$0	($95)	$158	$253	$27	$280			$0	$280
3	Carrying Costs - DTA/(DTL)	$159,144	$159,224	$79	$159,241	$159,586	$345	$159,561	$159,985			$0	$159,985
4	O&M	$0	$0	$0	$0	$0	$0	$0	$0			$0	$0
5	Base Rate Revenue Requirements	$0	$0	$0	$0	$0	$0	$0	$0			$0	$0
6	Subtotal (Sum 1-5)	$158,402	$158,482	$79	$159,146	$159,744	$598	$159,588	$160,265	$0	$0	$0	$160,265
7													
8	Pre-Construction Costs (b)												
9													
10	Additions												
11	Carrying Costs - Construction												
12	Carrying Costs - DTA/(DTL)												
13	O&M												
14	Base Rate Revenue Requirements												
15	Subtotal (Sum 10-14)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
16													
17	Construction Costs												
18													
19	CWIP Balance												
20	Carrying Costs - Construction												
21	Carrying Costs - DTA/(DTL)												
22	O&M												
23	Base Rate Revenue Requirements												
24	Subtotal (Sum 20-23)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25													
26	Total (Sum 6,15,24)	$158,402	$158,482	$79	$159,146	$159,744	$598	$159,588	$160,265	$0	$0	$0	$160,265
27													

28 Notes:
29 (a) The amounts referenced were approved by the Commission in Docket No. 140009-EI (see Order No. PSC-14-0617-FOF-EI).
30 (b) Please refer to Pre-Construction TORs for futher detail.

* Totals may not add due to rounding

Turkey Point Units 6&7
Site Selection Costs and Carrying Costs on Site Selection Cost Balance
Summary of Annual Clause Recovery Amounts

Schedule TOR-3 (True-up to Original)

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide a summary of the actual to date and projected total amounts for the duration of the project.

COMPANY: FLORIDA POWER LIGHT & COMPANY

For the Period Ended 12/31/2016

DOCKET NO.:150009-EI

Witness: Jennifer Grant-Keene and Steven D. Scroggs

Line No.	Description	(A) Actual 2006	(B) Actual 2007 (a)	(C) Actual 2008	(D) Actual 2009	(E) Actual 2010	(F) Actual 2011	(G) Actual 2012	(H) Actual 2013	(I) Actual 2014	(J) Total Actual PTD	(K) Actual/Estimated 2015	(L) Projected 2016	(M) To-Date Total Through 12/31/2016
							Jurisdictional Dollars							
1	**Site Selection Category**													
	a. Additions		$6,092,571	$0	$0	$0	$0	$0	$0		$6,092,571	$0	$0	$6,092,571
	b. O&M		$0	$0	$0	$0	$0	$0	$0		$0	$0	$0	$0
	c. Carrying Costs on Additions		$134,731	$689,750	$343,600	($31,207)	($9,831)	$0	$0	($742)	$1,126,301	$158	$27	$1,126,486
	d. Carrying Costs on DTA/(DTL)		($90)	($3,023)	$29,562	$177,172	$180,883	$180,883	$170,485	$159,224	$895,096	$159,586	$159,561	$1,214,243
	e. Total Site Selection Amounts (Lines 1.a through 1.d)	$0	$6,227,213	$686,727	$373,162	$145,965	$171,052	$180,883	$170,485	$158,482	$8,113,969	$159,744	$159,588	$8,433,301
2	**Pre-Construction Category**(b)													
	a. Additions													
	b. O&M													
	c. Carrying Costs on Additions													
	d. Carrying Costs on DTA/(DTL)													
	e. Total Pre-Construction Amounts (Lines 2.a through 2.d)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	**Construction Category**													
	Additions													
	CWIP Base Eligible for a return													
	a. O&M													
	b. Carrying Costs on Additions													
	c. Carrying Costs on DTA/(DTL)													
	d. Total Construction Amounts (Lines 3.a through 3.c)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4	Other Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5	Total Actual Annual Amounts (Lines 1.e + 2.e + 3.d + 4)	$0	$6,227,213	$686,727	$373,162	$145,965	$171,052	$180,883	$170,485	$158,482	$8,113,969	$159,744	$159,588	$8,433,301
6	Original Projected Total Annual Amounts		$6,539,167	$723,484	$509,050	$233,136	$171,052	$180,883	$180,883	$158,402	$8,537,655	$159,146	N/A	$8,696,801
7	Difference (Line 5 - Line 6)	$0	($311,953)	($36,758)	($135,888)	($87,171)	($0)	$0	($10,398)	$79	($423,686)	$598	$0	($263,500)
8	Percent Difference [(7 ÷ 6) x 100%]	0%	-5%	-5%	-27%	-37%	0%	0%	-6%	0%	-5%	0%	N/A	N/A

9 (a) Effective with the filing of FPL's need petition on October 16, 2007, all costs were transferred to Construction Work in Progress, Account 107, and site selection costs ceased.
10 (b) Please refer to Pre-Construction TORs for further detail.

* Totals may not add due to rounding

Turkey Point Units 6&7
Site Selection Costs and Carrying Costs on Site Selection Cost Balance
True-up to Original: Site Selection Category - Capital Additions/Expenditures

Schedule TOR-6 (True-up to Original)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER LIGHT & COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the actual to date and projected annual expenditures by major tasks performed within the site selection category for the duration of the project.

All site selection category costs also included in pre-construction costs or construction costs must be identified.

For the Period Ended 12/31/2016

Witness: Jennifer Grant-Keene and Steven D. Scroggs

Line No.	Description	(A) Actual 2006 (a)	(B) Actual 2007 (a),(b)	(C) Total Actual
1	**Site Selection:**			
2				
3	Activities (c)			
4	Project Staffing	$442,676	$320,164	$762,840
5	Engineering	$2,077,555	$1,274,189	$3,351,744
6	Environmental Services	$113,473	$1,106,817	$1,220,290
7	Legal Services	$22,482	$760,749	$783,231
8	Total Site Selection Costs:	$2,656,186	$3,461,919	$6,118,105
9	Jurisdictional Factor	0.9958099	0.9958265	0.9958265
10	Total Jurisdictionalized Site Selection Costs:	$2,645,056	$3,447,471	$6,092,571
11	Adjustments (d)			
12	Other Adjustments		($20,516)	($20,516)
13	Jurisdictional Factor	0.9958099	0.9958265	0.9958265
14	Total Jurisdictionalized Adjustments:	$0	($20,430)	($20,430)
15				
16	Total Jurisdictionalized Site Selection net of adjustments	$2,645,056	$3,467,901	$6,113,001

Notes:

17 (a) As filed in Docket No. 090009-EI for 2006-2007.
18 (b) Effective with the filing of FPL's need petition on October 16, 2007, all costs were transferred to Construction Work in Progress, Account 107,
19 and site selection costs ceased.
20 (c) See March 2, 2009 WP-2 Page 1 of 2 in Docket No. 090009-EI.
21 (d) See revised March 2, 2009 T-6, Line 10 in Docket No. 090009-EI.

*Totals may not add to rounding

Pre-Construction Actual/Estimated

2015

Schedule AE-1 (Actual/Estimated)

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Actual & Estimated Filing: Retail Revenue Requirements Summary

[Section (6)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the calculation of the true-up of total retail revenue requirements based on projected expenditures filed in the prior year and the current year actual/estimated expenditures.

For the Year Ended 12/31/2015

Witness: Jennifer Grant-Keene

Line No.		(A) Actual January	(B) Actual February	(C) Projected March	(D) Projected April	(E) Projected May	(F) Projected June	(G) 6 Month Total
		Jurisdictional Dollars						
1	Pre-Construction Revenue Requirements (Schedule AE-2, Line 7)	$1,082,530	$2,420,677	$1,583,615	$1,585,878	$1,686,474	$1,330,020	$9,689,195
2	Construction Carrying Cost Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
3	Recoverable O&M Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
4	DTA/(DTL) Carrying Cost (Schedule AE-3A, Line 8)	$536,871	$541,346	$546,571	$550,605	$554,812	$558,645	$3,288,850
5	Other Adjustments	$0	$0	$0	$0	$0	$0	$0
6	Total Period Actual/Estimated Revenue Requirements (Lines 1 though 5)	$1,619,401	$2,962,023	$2,130,186	$2,136,483	$2,241,286	$1,888,665	$12,978,045
7	Projected Carrying Cost for the Period (a)	$1,270,611	$3,366,449	$3,827,540	$405,086	$2,401,325	$4,091,939	$15,362,951
8	Actual/Estimated (Over)/Under Recovery for the Period (Line 6 - Line 7)	$348,790	($404,426)	($1,697,354)	$1,731,397	($160,039)	($2,203,274)	($2,384,906)
	Notes:							
9	(a) Total being recovered in 2015 as approved by the Commission in Docket No. 140009-EI (see Order No. PSC-14-0617-FOF-EI).							
10								
11	2013 Final True-Up (T-1, Line 10)	($0)	($0)	$216,800	($637,117)	($438,138)	$1,491,429	$632,975
12	2014 (Over)/Under Recovery (AE-1, Line 8)	$16,386	$2,038,917	$1,991,752	($377,746)	$1,162,282	$1,016,967	$5,848,558
13	2015 Projected Cost and Carrying Cost (P-2, Line 7)	$718,182	$789,292	$1,078,022	$876,130	$1,130,431	$1,033,631	$5,625,689
14	2015 Projected DTA/DTL Carrying Cost (P-3A, Line 8)	$536,043	$538,240	$540,966	$543,819	$546,750	$549,912	$3,255,730
15	2015 Total (Over)/Under Recovery	$1,270,611	$3,366,449	$3,827,540	$405,086	$2,401,325	$4,091,939	$15,362,951

* Totals may not add due to rounding

Schedule AE-1 (Actual/Estimated)

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Actual & Estimated Filing: Retail Revenue Requirements Summary

[Section (6)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the calculation of the true-up of total retail revenue requirements based on projected expenditures filed in the prior year and the current year actual/estimated expenditures.

For the Year Ended 12/31/2015

Witness: Jennifer Grant-Keene

Line No.		(H) Projected July	(I) Projected August	(J) Projected September	(K) Projected October	(L) Projected November	(M) Projected December	(N) 12 Month Total	
		Jurisdictional Dollars							
1	Pre-Construction Revenue Requirements (Schedule AE-2, Line 7)	$1,295,233	$1,199,312	$1,274,571	$1,261,311	$1,193,313	$3,159,199	$19,072,135	
2	Construction Carrying Cost Revenue Requirements	$0	$0	$0	$0	$0	$0	$0	
3	Recoverable O&M Revenue Requirements	$0	$0	$0	$0	$0	$0	$0	
4	DTA/(DTL) Carrying Cost (Schedule AE-3A, Line 8)	$561,917	$565,021	$568,086	$571,214	$574,221	$580,023	$6,709,332	
5	Other Adjustments	$0	$0	$0	$0	$0	$0	$0	
6	Total Period Actual/Estimated Revenue Requirements (Lines 1 though 5)	$1,857,149	$1,764,333	$1,842,658	$1,832,525	$1,767,534	$3,739,222	$25,781,467	
7	Projected Carrying Cost for the Period (a)	$659,031	($710,602)	$2,252,935	$2,411,124	$1,706,501	($2,001,503)	$19,680,436	
8	Actual/Estimated (Over)/Under Recovery for the Period (Line 6 - Line 7)	$1,198,119	$2,474,935	($410,277)	($578,599)	$61,034	$5,740,725	$6,101,031	
	Notes:								
9	(a) Total being recovered in 2015 as approved by the Commission in Docket No. 140009-EI (see Order No. PSC-14-0617-FOF-EI).								
10									
11	2013 Final True-Up (T-1, Line 10)	$556,215	($187,115)	$569,101	$846,185	($151,998)	($2,729,012)	($463,649)	
12	2014 (Over)/Under Recovery (AE-1, Line 8)	($1,279,278)	($1,879,653)	$37,860	$245,950	$525,006	($2,538,104)	$960,338	
13	2015 Projected Cost and Carrying Cost (P-2, Line 7)	$829,459	$801,148	$1,088,193	$758,507	$770,773	$2,697,815	$12,571,584	**$19,183,748**
14	2015 Projected DTA/DTL Carrying Cost (P-3A, Line 8)	$552,635	$555,018	$557,781	$560,482	$562,720	$567,798	$6,612,164	
15	2015 Total (Over)/Under Recovery	$659,031	($710,602)	$2,252,935	$2,411,124	$1,706,501	($2,001,503)	$19,680,436	**JGK-3, Column 4, Line 20**

* Totals may not add due to rounding

Schedule AE-2 (Actual/Estimated)

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Actual & Estimated Filing: Pre-Construction Costs

[Section (6)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the true-up of pre-construction costs based on projected expenditures filed in the prior year and the current year actual/estimated expenditures.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2015

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.		(A) Beginning of Period	(B) Actual January	(C) Actual February	(D) Projected March	(E) Projected April	(F) Projected May	(G) Projected June	(H) 6 Month Total
						Jurisdictional Dollars			
1	a. Nuclear CWIP Additions (Schedule AE-6, Line 18 + Line 35)		$1,042,775	$2,379,916	$1,543,395	$1,553,983	$1,654,810	$1,292,763	$9,467,642
	b. Prior Month's (Over)/Under Recovery Eligible for Return (Prior Month's Line 1b + Prior Month's Line 9)		$0	$347,962	($59,570)	($1,762,529)	($37,918)	($206,019)	($2,418,027)
2	Unamortized CWIP Base Eligible for Return (d)	($194,825)	($236,216)	($277,607)	($318,997)	($360,388)	($401,779)	($443,169)	
3	Amortization of CWIP Base Eligible for Return (e)	$496,688	$41,391	$41,391	$41,391	$41,391	$41,391	$41,391	$248,344
4	Average Net Unamortized CWIP Base Eligible for Return		($215,520)	($82,930)	($154,106)	($1,250,742)	($1,281,307)	($544,443)	
5	Return on Average Net Unamortized CWIP Eligible for Return								
	a. Equity Component (Line 5b x .61425) (a)		($843)	($324)	($603)	($4,892)	($5,012)	($2,130)	($13,804)
	b. Equity Component grossed up for taxes (Line 4 x 0.00636821) (a) (b) (c)		($1,372)	($528)	($981)	($7,965)	($8,160)	($3,467)	($22,474)
	c. Debt Component (Line 4 x 0.00122335) (c)		($264)	($101)	($189)	($1,530)	($1,567)	($666)	($4,317)
6	Actual/Estimated Carrying Cost for the Period (Line 5b + Line 5c)		($1,636)	($630)	($1,170)	($9,495)	($9,727)	($4,133)	($26,791)
7	Actual/Estimated Costs, Carrying Costs & Amortization for the Period (Lines 1a + 3 + 6 +10)		$1,082,530	$2,420,677	$1,583,615	$1,585,878	$1,686,474	$1,330,020	$9,689,195
8	Projected Carrying Costs for the period (g)		$734,568	$2,828,209	$3,286,575	($138,733)	$1,854,575	$3,542,027	$12,107,222
9	Actual/Estimated (Over)/Under Recovery (Line 7 - Line 8)		$347,962	($407,532)	($1,702,959)	$1,724,611	($168,101)	($2,212,007)	($2,418,027)
10	Adjustments		$0	$0	$0	$0	$0	$0	$0
11	(Over)/Under Recovery Eligible for Return		$347,962	($407,532)	($1,702,959)	$1,724,611	($168,101)	($2,212,007)	($2,418,027)

* Totals may not add due to rounding

See Notes on Page 3 of 3

Schedule AE-2 (Actual/Estimated)

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Actual & Estimated Filing: Pre-Construction Costs

[Section (6)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the calculation of the true-up of pre-construction costs based on projected expenditures filed in the prior year and the current year actual/estimated expenditures.

For the Year Ended 12/31/2015

Witness: Jennifer Grant-Keene

Line No.		(I) Projected July	(J) Projected August	(K) Projected September	(L) Projected October	(M) Projected November	(N) Projected December	(O) 12 Month Total
					Jurisdictional Dollars			
1	a. Nuclear CWIP Additions (Schedule AE-6, Line 18 + Line 35)	$1,267,324	$1,175,601	$1,237,306	$1,216,600	$1,152,749	$3,120,999	$18,638,220
	b. Prior Month's (Over)/Under Recovery Eligible for Return (Prior Month's Line 1b + Prior Month's Line 9)	($2,418,027)	($1,229,190)	$1,235,743	$815,160	$225,830	$275,362	
2	Unamortized CWIP Base Eligible for Return (f)	($484,560)	($525,951)	($567,341)	($608,732)	($650,123)	($691,513)	
3	Amortization of CWIP Base Eligible for Return	$41,391	$41,391	$41,391	$41,391	$41,391	$41,391	$496,688
4	Average Net Unamortized CWIP Base Eligible for Return	($1,775,888)	($2,328,864)	($543,370)	$437,415	($108,932)	($420,222)	
5	Return on Average Net Unamortized CWIP Eligible for Return							
	a. Equity Component (Line 5b x .61425) (a)	($6,947)	($9,110)	($2,125)	$1,711	($426)	($1,644)	($32,345)
	b. Equity Component grossed up for taxes (Line 4 x 0.00636821) (a) (b) (c)	($11,309)	($14,831)	($3,460)	$2,786	($694)	($2,676)	($52,658)
	c. Debt Component (Line 4 x 0.00122335) (c)	($2,173)	($2,849)	($665)	$535	($133)	($514)	($10,116)
6	Actual/Estimated Carrying Cost for the Period (Line 5b + Line 5c)	($13,482)	($17,680)	($4,125)	$3,321	($827)	($3,190)	($62,774)
7	Actual/Estimated Costs, Carrying Costs & Amortization for the Period (Lines 1a + 3 + 6 +10)	$1,295,233	$1,199,312	$1,274,571	$1,261,311	$1,193,313	$3,159,199	$19,072,135
8	Projected Carrying Costs for the period (g)	$106,396	($1,265,620)	$1,695,154	$1,850,642	$1,143,781	($2,569,301)	$13,068,273
9	Actual/Estimated (Over)/Under Recovery (Line 7 - Line 8)	$1,188,837	$2,464,933	($420,582)	($589,331)	$49,532	$5,728,500	$6,003,862
10	Adjustments	$0	$0	$0	$0	$0	$0	$0
11	(Over)/Under Recovery Eligible for Return	$1,188,837	$2,464,933	($420,582)	($589,331)	$49,532	$5,728,500	$6,003,862

* Totals may not add due to rounding

See Notes on Page 3 of 3

Schedule AE-2 (Actual/Estimated)

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Actual & Estimated Filing: Pre-Construction Costs

[Section (6)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the calculation of the true-up of pre-construction costs based on projected expenditures filed in the prior year and the current year actual/estimated expenditures.

For the Year Ended 12/31/2015

Witness: Jennifer Grant-Keene

Notes:

(a) For carrying charge purposes the monthly equity component reflects a 10.5% return on equity.

(b) Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5% for an effective rate of 38.575%.

(c) In order to gross up the equity component for taxes a monthly rate of 0.00636821 (Equity) and 0.00122335 (Debt) results in the annual pre-tax rate of 9.39%, effective January 1, 2015.

(d) Line 2, Column (A) - Unamortized CWIP Base Eligible for Return consists of the total over recovered balance beginning in 2015. This amount is reduced by 2015 amounts refunded (Line 3) and a carrying charge is calculated on the unrefunded balance.

	Docket No. 130009-EI	Docket No. 150009-EI	Docket No. 150009-EI
Line 2 Beginning Balances includes:	2014 Projections	2014 True ups	2013/2014 Over Recovery
2013 (Over)/Under Recovery (P-2/T-2, Line 2 Ending Balance)	$0	($463,650)	($463,650)
2014 Pre-construction Costs + Carrying Costs (P-2, Line 7 / T-2, Line 1a + Line 6)	$16,496,375	$17,268,824	$772,449
2014 DTA/DTL Carrying Cost (P-3A, Line 8 / T-3A, Line 8)	$6,653,521	$6,149,897	($503,624)
	$23,149,896	$22,955,071	($194,825)

(e) Line 3 (Column A) - Amortization of carrying charge is the amount that will be collected over 12 months in 2015 as approved by the Commission in Docket No. 140009-EI (see Order No. PSC 14-0617-FOF-EI).

	2013 Final True-Up/2014 A/E (Over)/Under Recovery		
Line 3 Beginning Balance includes:			
2013 (Over)/Under Recovery of Carrying Costs (T-2, Line 13)	($486,639)		
2013(Over)/Under Recovery of Carrying Costs on DTA/DTL (T-3A, Line 12)	$22,989		
2014 (Over)/Under Recovery of Costs & Carrying Cost (AE-2, Line 9)	$1,521,542		
2014 (Over)/Under Recovery of Carrying Costs on DTA/DTL (AE-3A, Line 10)	($561,204)		
	$496,688	$41,391	Monthly Amortization

(f) Line 2, Column (N) - Ending Balance of 2014 consists of final true-up amount which will be refunded over 12 months in 2016. This amount will reduce the Capacity Cost Recovery Clause (CCRC) charge paid by customers in 2016.

	Docket No. 140009-EI	Docket No. 150009-EI	Docket No. 140009-EI
Line 2 Ending Balance includes:	2014 Actual/Estimated	2014 True-up	2013 Final True-up
2014 Pre-construction Costs + Carrying Costs (AE-2, Line 1a + 6 / T-2, Line 1a + Line 6)	$18,017,917	$17,268,824	($749,092)
2014 DTA/DTL Carrying Cost (AE-3A, Line 8 / T-3A, Line 8)	$6,092,317	$6,149,897	$57,580
	$24,110,234	$23,418,721	($691,512)

(g) Total being collected in 2015 as approved by the Commission in Docket No. 140009-EI (see Order No. PSC-14-0617-FOF-EI).

	January	February	March	April	May	June	6 Month
2013 Final True-Up (T-1, Line 10)	($0)	($0)	$216,800	($637,117)	($438,138)	$1,491,429	$632,975
2014 (Over)/Under Recovery (AE-1, Line 8)	$16,386	$2,038,917	$1,991,752	($377,746)	$1,162,282	$1,016,967	$5,848,558
2015 Projected Cost / Carrying Cost (P-2, Line 7)	$718,182	$789,292	$1,078,022	$876,130	$1,130,431	$1,033,631	$5,625,689
2015 (Over)/Under Recovery (P-2)	$734,568	$2,828,209	$3,286,575	($138,733)	$1,854,575	$3,542,027	$12,107,222

	July	August	September	October	November	December	12 Month
2013 Final True-Up (T-1, Line 10)	$556,215	($187,115)	$569,101	$846,185	($151,998)	($2,729,012)	($463,649)
2014 (Over)/Under Recovery (AE-1, Line 8)	($1,279,278)	($1,879,653)	$37,860	$245,950	$525,006	($2,538,104)	$960,338
2015 Projected Cost / Carrying Cost (P-2, Line 7)	$829,459	$801,148	$1,088,193	$758,507	$770,773	$2,697,815	$12,571,584
2015 (Over)/Under Recovery (P-2)	$106,396	($1,265,620)	$1,695,154	$1,850,642	$1,143,781	($2,569,301)	$13,068,273

* Totals may not add due to rounding

Schedule AE-3A (Actual/Estimated)

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Actual & Estimated Filing: Deferred Tax Carrying Costs

[Section (6)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the actual/estimated deferred tax carrying costs.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2015

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.			(A) Beginning of Period	(B) Actual January	(C) Actual February	(D) Projected March	(E) Projected April	(F) Projected May	(G) Projected June	(H) 6 Month Total
						Jurisdictional Dollars				
1	Construction Period Interest			$0	$0	$0	$0	$0	$0	$0
2	Recovered Costs Excluding AFUDC (AE-2, Line 1a + Line 10)			$1,042,775	$2,379,916	$1,543,395	$1,553,983	$1,654,810	$1,292,763	$9,467,642
3	Other Adjustments (h)			($185,563)	($185,563)	($185,563)	($185,563)	($185,563)	($185,563)	($1,113,377)
4	Tax Basis Less Book Basis (Prior Month Balance + Lines 1 + 2 + 3) (d) (f)		$182,901,315	$183,758,528	$185,952,881	$187,310,713	$188,679,133	$190,148,380	$191,255,580	$191,255,580
5	Deferred Tax Asset/(Liability) DTA/(DTL) on Tax Basis in Excess of Book (Line 4 x Tax Rate) (b)	38.575%	$70,554,182	$70,884,852	$71,731,324	$72,255,107	$72,782,975	$73,349,738	$73,776,840	$73,776,840
6 a.	Average Accumulated DTA/(DTL)			$70,719,517	$71,308,088	$71,993,216	$72,519,041	$73,066,357	$73,563,289	
b.	Prior Months Cumulative Return on DTA/(DTL) (e)		$0	$0	$828	$3,934	$9,539	$16,325	$24,387	$33,120
c.	Average DTA/(DTL) including prior period return subtotal (Line 6a + Line 6b)			$70,719,517	$71,308,916	$71,997,150	$72,528,580	$73,082,682	$73,587,676	
7	Carrying Cost on DTA/(DTL)									
a.	Equity Component (Line 7b x .61425) (a) (b)			$276,632	$278,937	$281,629	$283,708	$285,876	$287,851	$1,694,633
b.	Equity Component grossed up for taxes (Line 6c x 0.00636821) (a) (b) (c)			$450,357	$454,110	$458,493	$461,877	$465,406	$468,622	$2,758,865
c.	Debt Component (Line 6c x 0.00122335) (c)			$86,515	$87,236	$88,078	$88,728	$89,406	$90,023	$529,985
8	Actual/Estimated Carrying Costs on DTA/(DTL) for the Period (Line 7b + Line 7c)			$536,871	$541,346	$546,571	$550,605	$554,812	$558,645	$3,288,850
9	Projected Carrying Cost on DTA/(DTL) for the Period			$536,043	$538,240	$540,966	$543,819	$546,750	$549,912	$3,255,730
10	Actual/Estimated (Over)/Under Recovery (Line 8 - Line 9)			$828	$3,106	$5,605	$6,786	$8,062	$8,733	$33,120

* Totals may not add due to rounding

See Notes on Pages 3 of 3

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Actual & Estimated Filing: Deferred Tax Carrying Costs

Schedule AE-3A (Actual/Estimated) [Section (6)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the actual/estimated deferred tax carrying costs.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2015

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.			(I) Beginning of Month	(J) Projected July	(K) Projected August	(L) Projected September	(M) Projected October	(N) Projected November	(O) Projected December	(P) 12 Month Total
						Jurisdictional Dollars				
1	Construction Period Interest			$0	$0	$0	$0	$0	$0	$0
2	Recovered Costs Excluding AFUDC (AE-2, Line 1a + Line 10)			$1,267,324	$1,175,601	$1,237,306	$1,216,600	$1,152,749	$3,120,999	$18,638,220
3	Other Adjustments (h)			($185,563)	($185,563)	($185,563)	($185,563)	($185,563)	($185,563)	($2,226,753)
4	Tax Basis Less Book Basis (Prior Month Balance + Lines 1 + 2 + 3)		$191,255,580	$192,337,341	$193,327,380	$194,379,123	$195,410,160	$196,377,346	$199,312,782	$199,312,782
5	Deferred Tax Asset/(Liability) DTA/(DTL) on Tax Basis in Excess of Book (Line 4 x Tax Rate) (b)	38.575%	$73,776,840	$74,194,129	$74,576,037	$74,981,747	$75,379,469	$75,752,561	$76,884,906	$76,884,906
6	a. Average Accumulated DTA/(DTL)			$73,985,485	$74,385,083	$74,778,892	$75,180,608	$75,566,015	$76,318,733	
	b. Prior Months Cumulative Return on DTA/(DTL)			$33,120	$42,402	$52,405	$62,710	$73,442	$84,944	$97,168
	c. Average DTA/(DTL) including prior period return subtotal (Line 6a + Line 6b)			$74,018,605	$74,427,485	$74,831,297	$75,243,318	$75,639,457	$76,403,677	
7	Carrying Cost on DTA/(DTL)									
	a. Equity Component (Line 7b x .61425) (a) (b)			$289,537	$291,136	$292,716	$294,327	$295,877	$298,866	$3,457,091
	b. Equity Component grossed up for taxes (Line 6c x 0.00636821) (a) (b) (c)			$471,366	$473,970	$476,541	$479,165	$481,688	$486,555	$5,628,150
	c. Debt Component (Line 6c x 0.00122335) (c)			$90,551	$91,051	$91,545	$92,049	$92,534	$93,468	$1,081,182
8	Actual/Estimated Carrying Costs on DTA/(DTL) for the Period (Line 7b + Line 7c)			$561,917	$565,021	$568,086	$571,214	$574,221	$580,023	$6,709,332
9	Projected Carrying Cost on DTA/(DTL) for the Period			$552,635	$555,018	$557,781	$560,482	$562,720	$567,798	$6,612,164
10	Actual/Estimated (Over)/Under Recovery (Line 8 - Line 9)			$9,282	$10,003	$10,305	$10,732	$11,502	$12,225	$97,168

* Totals may not add due to rounding

See Notes on Pages 3 of 3

Schedule AE-3A (Actual/Estimated)

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Actual & Estimated Filing: Deferred Tax Carrying Costs

[Section (6)(c)1.b.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the actual/estimated deferred tax carrying costs.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2015

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Notes:

(a) For carrying charge purposes the monthly equity component reflects a 10.5% return on equity.
(b) Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5% for an effective rate of 38.575%.
(c) In order to gross up the equity component for taxes a monthly rate of 0.00636821 (Equity) and 0.00122335 (Debt) results in the annual pre-tax rate of 9.39% effective January 1, 2015.
(d) Line 4 - Beginning Balance comes from 2014 T-3A, Line 4, Column (P) (See also footnote (f)).
(e) Line 6b - Beginning Balance on Prior Months Cumulative Return on DTA/(DTL) is not shown on AE-3A, because it is included on Schedule AE-2 footnote (d), Page 3.
(f) The Beginning Balance of AE-3A, Line 4 has been revised to reflect the Jurisdictional Separation Factor effective January 2015.

	Docket No. 150009-EI 2014 Ending Balance as filed March 1, 2015	Tax Deductions from prior years	AE-3A Beginning Balance at January 2015 Jurisdictional Factor
Line 4, Column (A) Tax Basis Less Book Basis	$182,782,623	$118,692 (g)	$182,901,315

(g) Calculation of 2014 ending balance of Tax Deductions at the 2015 Projected Jurisdictional Separation Factor.

	2007	2008	2009	2010	2011	2012	2013	2014	Total	Difference
Tax Deductions included in T-3A, Line 4 balance	($256,524)	($3,277,789)	($5,536,849)	($3,538,559)	$0	$0	$0	$0	($12,609,721)	
Tax Deductions from prior years not included in T-3A	($1,640,075)	$0	$0	($275,000)	($3,787,562)	($3,118,389)	($2,704,494)	($2,353,091)	($13,878,611)	
Total Tax Deductions	($1,896,599)	($3,277,789)	($5,536,849)	($3,813,559)	($3,787,562)	($3,118,389)	($2,704,494)	($2,353,091)	($26,488,332)	
2014 Jurisdictional Factor	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073		
Total Jurisdictionalized Tax Deductions	($1,803,269)	($3,116,492)	($5,264,384)	($3,625,897)	($3,601,179)	($2,964,935)	($2,571,408)	($2,237,297)	($25,184,860)	
Tax Deductions included in T-3A, Line 4 balance	($256,524)	($3,277,789)	($5,536,849)	($3,538,559)	$0	$0	$0	$0	($12,609,721)	
Tax Deductions from prior years not included in T-3A	($1,640,075)	$0	$0	($275,000)	($3,787,562)	($3,118,389)	($2,704,494)	($2,353,091)	($13,878,611)	
Total Tax Deductions	($1,896,599)	($3,277,789)	($5,536,849)	($3,813,559)	($3,787,562)	($3,118,389)	($2,704,494)	($2,353,091)	($26,488,332)	
2015 Jurisdictional Factor	0.94630981	0.94630981	0.94630981	0.94630981	0.94630981	0.94630981	0.94630981	0.94630981		
Total revised Jurisdictionalized Tax Deductions	($1,794,770)	($3,101,804)	($5,239,574)	($3,608,808)	($3,584,207)	($2,950,962)	($2,559,289)	($2,226,753)	($25,066,168)	$118,692

(h) Line 3 - Other Adjustments represents Estimated 2015 deductions under IRS Regulations Section, Internal Payroll (Reg. Sec. 1.263(a)-4). These deductions have been applied ratably over the 12 months in 2015. Since FPL has not filed its 2015 tax return at the time of this filing, deductions taken on the 2015 tax return will be trued up in the 2016 T-3A Schedule filed on March 1, 2017.

Tax Deduction Description	FPL System Qualifying Expenditures	System Deductions Attributed to Qualifying Expenditures	Jurisdictional Separation Factor	Jurisdictional Deductions	Monthly Amortization
Estimated 2015 Internal Payroll	$ (2,353,091)	$ (2,353,091)	0.94630981	($2,226,753)	($185,563)

* Totals may not add due to rounding

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Actual & Estimated Filing: Monthly Expenditures

[Section (6)(c)1.b.]

[Section (9)(d)]

Schedule AE-6 (Actual/Estimated)

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the actual/estimated monthly expenditures by major tasks to be performed within pre-construction categories.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2015

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene and Steven D. Scroggs

Line No.	Description	(A) Actual January	(B) Actual February	(C) Projected March	(D) Projected April	(E) Projected May	(F) Projected June	(G) Projected July	(H) Projected August	(I) Projected September	(J) Projected October	(K) Projected November	(L) Projected December	(M) 12 Month Total
1	**Pre-Construction:**													
2	Generation:													
3	Licensing	$1,060,001	$1,223,337	$1,577,426	$1,357,893	$1,450,856	$1,090,352	$1,063,556	$969,458	$1,031,749	$1,011,368	$945,247	$2,596,521	$15,377,764
4	Permitting	$15,637	$17,700	$23,869	$22,369	$22,054	$23,869	$22,684	$22,054	$23,869	$22,369	$22,115	$52,761	$291,349
5	Engineering and Design	$26,301	$1,273,907	$29,666	$261,888	$275,789	$251,888	$252,988	$250,789	$251,888	$251,888	$250,789	$648,791	$4,026,573
6	Long lead procurement advanced payments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7	Power Block Engineering and Procurement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Initial Assessment (a)	$0	$0	$0	$0	$0	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$1,842,105
9	Total Generation Costs	$1,101,939	$2,514,944	$1,630,961	$1,642,150	$1,748,698	$1,629,267	$1,602,385	$1,505,459	$1,570,664	$1,548,783	$1,481,310	$3,561,231	$21,537,791
10														
11	**Adjustments**													
12	Non-Cash Accruals	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Other Adjustments (a)	$0	$0	$0	$0	$0	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$1,842,105
14	Total Adjustments	$0	$0	$0	$0	$0	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$1,842,105
15														
16	Total Generation Costs Net of Adjustments (Line 9 - Line 14)	$1,101,939	$2,514,944	$1,630,961	$1,642,150	$1,748,698	$1,366,109	$1,339,227	$1,242,301	$1,307,506	$1,285,625	$1,218,152	$3,298,073	$19,695,685
17	Jurisdictional Factor	0.94630981	0.94630981	0.94630981	0.94630981	0.94630981	0.94630981	0.94630981	0.94630981	0.94630981	0.94630981	0.94630981	0.94630981	0.94630981
18	Total Jurisdictional Generation Costs Net of Adjustments	$1,042,775	$2,379,916	$1,543,395	$1,553,983	$1,654,810	$1,292,763	$1,267,324	$1,175,601	$1,237,306	$1,216,600	$1,152,749	$3,120,999	$18,638,220
19														
20	Transmission:													
21	Line Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	Substation Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	Clearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	Total Transmission Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Jurisdictional Factor	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019
27	Total Jurisdictional Transmission Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	**Adjustments**													
29	Non-Cash Accruals	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	Other Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31	Total Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	Jurisdictional Factor	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019
33	Total Jurisdictional Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
34														
35	Total Jurisdictional Transmission Costs Net of Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
36														
37	Total Jurisdictional Pre-Construction Costs Net of Adjustments	$1,042,775	$2,379,916	$1,543,395	$1,553,983	$1,654,810	$1,292,763	$1,267,324	$1,175,601	$1,237,306	$1,216,600	$1,152,749	$3,120,999	$18,638,220
38														
39														
40	* Totals may not add due to rounding													
41														
42	Notes:													
43	(a) Reflected on line 8 are initial assessment costs which FPL is not seeking to recover in 2016, and therefore these costs are adjusted out on line 13.													
44	Instead, FPL will capitalize these costs as incurred and accrue allowance for funds used during construction (AFUDC).													

Schedule AE-6A (Actual/Estimated)

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Actual & Estimated Filing: Description of Major Tasks Performed

[Section (6)(c)1.b.]
[Section (9)(d)]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide a description of the major tasks performed within Pre-Construction.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2015

DOCKET NO.: 150009-EI

Witness: Steven D. Scroggs

Line No.	Major Task	Description - Includes, but is not limited to:
1	Pre-Construction period:	
2	Generation:	
3	1 License Application	
4		a. Preparation of Nuclear Regulatory Commission Combined License submittal.
5		b. Preparation of Florida Department of Environmental Protection Site Certification Application.
6		c. Transmission facilities studies, stability analysis, Florida Reliability Coordinating Council studies.
7		d. Studies required as Conditions of Approval for local zoning.
8	2 Permitting	
9		a. Communications outreach.
10		b. Legal and application fees.
11	3 Engineering and Design	
12		a. Site specific civil, mechanical and structural requirements to support design.
13		b. Water supply design.
14		c. Construction logistical and support planning.
15		d. Long lead procurement advanced payments.
16		e. Power Block Engineering and Procurement.
17		
18	Transmission:	
19	1 Line / Substation Engineering	
20		a. Transmission interconnection design
21		b. Transmission integration design

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Actual & Estimated Filing: Variance Explanations

Schedule AE-6B (Actual/Estimated) [Section (9)(d)]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide annual variance explanations comparing the current year actual/estimated expenditures to the projected expenditures filed in the prior year.

COMPANY: FLORIDA POWER & LIGHT COMPANY For the Year Ended 12/31/2015

DOCKET NO.: 150009-EI Witness: Steven D. Scroggs

Line No.		(A) Total Actual/Estimated	(B) Total Projected	(C) Total Variance	(D) Explanation
1					
2					
3	**Pre-Construction:**				
4	Generation:				
5	Licensing	$15,377,764	$11,027,251	$4,350,513	Variance increase due to NRC requesting additional level of detail. Third party resource increases related to these NRC requests.
6					
7					
8					
9	Permitting	$291,349	$245,684	$45,665	Contingency adjustment was made in 2014 lowering the 2015 projection. Current projection increases contingency based on current needs.
10					
11					
12					
13	Engineering and Design	$4,026,573	$1,907,788	$2,118,785	Increase to APOG membership participation due to additional costs related to design & licensing activities.
14					
15					
16					
17	Long lead procurement advanced payments	$0	$0	$0	
18	Power Block Engineering and Procurement	$0	$0	$0	
19	Total Generation Costs	$19,695,685	$13,180,723	$6,514,962	

* Totals may not add due to rounding

Turkey Point 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Actual & Estimated Filing: All Contracts Executed in Excess of $250,000

Schedule AE-7A [Section (9)(c)]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Florida Power & Light Company

DOCKET NO.: 150009-EI

EXPLANATION: For all executed contracts exceeding $250,000, (including change orders), provide the contract number or identifier, status, original and current contract terms, original amount, amount expended as of the end of the prior year, amount expended in the year, estimated final contract amount, name of contractor and affiliations if any, method of selection including identification of justification

For the Year Ended 12/31/2015

Witness: Steven D. Scroggs

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.	Contract No.	Status of Contract	Original Term of Contract	Current Term of Contract	Original Amount	Actual Expended as of Prior Year End (2014)	Estimate of amount to be expended in Current Year (2015)	Estimated Contract Amount	Name of Contractor (and Affiliation if any)	Method of Selection and Document ID	Work Description
1	2000062412	Open - CO#6	02/2012 - 12/2012	02/2012 - 06/2015	[redacted]				AMEC E&I	SSJ	PTN 6&7 RFI Response Review
2	2000115705	Open - CO#1	10/2013 - 08/2015	10/2013 - 02/2016					AMEC E&I	SSJ	PTN 6&7 RFI Response Review/FSAR 2.5.4
3	4500681284	Open - CO#4	06/2011 - 12/2012	06/2011 - 06/2014					Atkins North American	SSJ	PTN 6&7 Expert Scientific Analysis
4	4500395492	Open - CO#58	11/2007 - 12/2011	11/2007 - 05/2016					Bechtel Power Co.	Comp Bid/SSJ/ PDS	PTN 6&7 Engineering Services to support Preparation of COLA and SCA, and Response to Post-Submittal RAIs
5	2000060695	Open - CO#2	02/2012 - 12/2012	02/2012 - 05/2015					Burns & McDonnell	Comp Bid/SSJ	PTN 6&7 Preliminary Design of the Radial Collector Well System
6	4500443122	Open - CO #5	08/2008 - 08/2010	06/2008 - 06/2015					Eco-Metrics, Inc.	SSJ	PTN 6&7 Environmental Consulting Services
7	4500518167	Open - CO#11	07/2009 - 12/2009	07/2009 - 06/2015					Environmental Consulting and Technology Inc.	SSJ/PDS	PTN 6&7 Post SCA Submittal Support
8	4500430034	Open - CO#3	06/2008 - 07/2011	06/2008 - 12/2015					EPRI	SSJ	Advanced Nuclear Technology; Near term deployment of Advanced Light Water Reactors
9	4500518160	Open - CO#11	07/2009 - 12/2009	07/2009 - 04/2015					Golder & Associates, Inc.	SSJ/PDS	PTN 6&7 Post SCA Submittal Support
10	4500425707	Open - CO#8	05/2008 - 08/2008	05/2008 - 06/2015					HDR Engineering, Inc.	Comp Bid/SSJ	Conceptual Engineering of Cooling Water Supply and Discharge
11	2000123867	Open - CO#1	12/2013 - 12/2014	12/2013 - 06/2015					Layne Christensen Company	Comp Bid	PTN 6&7 DIW-1 Injection Test
12	4500645896	Open - CO#3	02/2011 - 03/2012	02/2011 - 12/2014					McCallum Turner	SSJ	PTN 6&7 COLA Site Selection RAI Support
13	4500517152	Open - CO#7	10/2009 - 12/2010	10/2009 - 06/2015					McNabb Hydrogeologic Consulting, Inc.	SSJ/PDS	PTN 6&7 Post SCA Submittal and UIC Licensing Support
14	2000102364	Open - CO#9	05/2013 - 12/2014	05/2013 - 06/2015					Paul C. Rizzo Associates, Inc.	SSJ	PTN 6&7 Field Investigation and FSAR 2.5 Revision
15	2000053246	Open	11/2011 - 06/2014	11/2011 - 06/2015					Power Engineers, Inc.	SSJ	PTN 6&7 Prelim Analysis for Miami River Crossing and Davis/Miami Line
16	4500527549	Open - CO#5	08/2009 - 12/2009	07/2009 - 04/2015					TetraTechGeo (formerly GeoTrans, Inc.)	SSJ	PTN 6&7 APT Review and Collector Well Modeling Support
17	4500404639	Open - CO#8	01/2008 - 12/2011	01/2008 - 02/2016					Westinghouse Electric Co	SSJ/ PDS	PTN 6&7 Engineering Services to Support Preparation of COLA and Response to Post-Submittal RAIs

Turkey Point 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
True-up Filing: Contracts Executed Details

Schedule AE-7B [Section (9)(c)]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Florida Power & Light Company

DOCKET NO.: 150009-EI

EXPLANATION: Provide additional details of contracts executed in excess of $1 million including, the nature and scope of the work, the nature of any affiliation with selected vendor, the method of vendor selection, brief description of vendor selection process, and current status of the contract.

For the Year Ended 12/31/2015

Witness: Steven D. Scroggs

Contract No.:	Major Task or Tasks Associated With:	Vendor Identity:	Vendor Affiliation (specify 'direct' or 'indirect'):	Number of Vendors Solicited:	Number of Bids Received:	Brief Description of Selection Process:	Dollar Value:	Expected CO	Estimate	Contract Status:	Term Begin:	Term End:	Nature and Scope of Work:
4500395492	COLA and SCA Preparation and Support	Bechtel Power Corporation	Direct	Two	Two	Initial contract competitively bid. Change Orders 1-11 issued as Single Source. Designated as Predetermined Source January 2009 through July 2013. Subsequent change orders justified as Single Source.	[redacted]			Open - CO#58	11/06/07	05/31/16	Engineering Services to support preparation of COLA and SCA, including post-submittal support for RAI responses.
4500518167	PTN 6&7 Post SCA Submittal Support	Environmental Consulting and Technology Inc.	Direct	SSJ/PDS	NA	ECT can build off their Phase I analysis and project specific experience to complete the transmission corridor environmental licensing with a minimum of mobilization time or bringing project staff up to speed with prior work.				Open - CO#11	07/15/09	Open	PTN 6&7 Post SCA Submittal Support
4500430034	Conducts research, development and demonstration (RD&D) relating to the generation, delivery and use of electricity for the benefit of the public	EPRI	Direct	SSJ	NA	EPRI is non-profit origination with the unique capability to fulfill the needs of this Contract.				Open - CO#2	06/10/08	Open	Advanced Nuclear Technology; Near term deployment of Advanced Light Water Reactors
4500518160	PTN 6&7 Post SCA Submittal Support	Golder & Associates, Inc.	Direct	SSJ/PDS	NA	Golder & Associates, Inc. has performed a significant amount of related Phase I tasks and can build off their Phase I work and project specific experience to complete the environmental licensing with a minimum of mobilization time or bringing project staff up to speed with prior work.				Open - CO#11	09/29/09	04/30/15	Conceptual Engineering of Cooling Water Supply and Discharge
4500425707	Conceptual engineering of cooling water supply & disposal	HDR Engineering, Inc.	Direct	Comp Bid/SSJ	Three	Initial contract competitively bid. Subsequent change orders were issued as Single Source and notes relatives experience as the basis for award.				Open - CO#8	05/19/08	06/29/15	Conceptual Engineering of Cooling Water Supply and Discharge
2000102364	FSAR & NRC RAI Geotechnical Support	Paul C. Rizzo Associates, Inc.	Direct	SSJ	NA	Rizzo Associates recent interaction with the NRC and their familiarity with Florida geology, would reduce familiarization and development time to prepare the analysis and FSAR revision.				Open - CO#10	04/30/13	12/31/14	PTN 6&7 Field Investigation and FSAR 2.5 Revision
4500404639	Support of COL application during NRC review & updating of 10CFR part 21 notification.	Westinghouse Electric Co	Direct	SSJ/ PDS	NA	Initial contract award was based on the designation as Predetermined Source. Subsequent change orders were issued as Single Source and notes relatives experience as the basis for award.				Open - CO#8	01/31/08	02/27/16	PTN 6&7 Engineering Services to Support Preparation of COLA and Response to Post-Submittal RAIs

Pre-Construction Projections

2016

Schedule P-1 (Projection)

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Projection Filing: Retail Revenue Requirements Summary

[Section (6)(c)1.c.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide a summary of the projected total retail revenue requirement for the subsequent year.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2016

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.		(A) Projected January	(B) Projected February	(C) Projected March	(D) Projected April	(E) Projected May	(F) Projected June	(G) 6 Month Total
		Jurisdictional Dollars						
1	Pre-Construction Revenue Requirements (Schedule P-2, Line 7)	$1,036,807	$2,050,826	$4,065,223	$1,225,413	$1,532,191	$2,076,988	$11,987,448
2	Construction Carrying Cost Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
3	Recoverable O&M Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
4	DTA/(DTL) Carrying Cost (Schedule P-3A, Line 8)	$585,137	$589,548	$598,403	$606,059	$610,017	$615,231	$3,604,394
5	Other Adjustments	$0	$0	$0	$0	$0	$0	$0
6	Total Projected Period Revenue Requirements (Lines 1 through 5)	$1,621,943	$2,640,374	$4,663,625	$1,831,472	$2,142,208	$2,692,219	$15,591,842
7	Total to be recovered in 2016							
		January	**February**	**March**	**April**	**May**	**June**	**6 Month**
8	2014 Final True-Up (T-1, Line 10)	($536)	($336)	$441,332	($2,173)	$596,009	$907,072	$1,941,369
9	2015 True-Up AE cost / carrying cost (AE-1, Line 8)	$348,790	($404,426)	($1,697,354)	$1,731,397	($160,039)	($2,203,274)	($2,384,906)
10	Total 2014 & 2015	$348,254	($404,762)	($1,256,022)	$1,729,225	$435,970	($1,296,202)	($443,538)
11	2016 Projected cost and carrying cost (P-2, Line 7)	$1,036,807	$2,050,826	$4,065,223	$1,225,413	$1,532,191	$2,076,988	$11,987,448
12	2016 Projected DTA/DTL carrying cost (P-3A, Line 8)	$585,137	$589,548	$598,403	$606,059	$610,017	$615,231	$3,604,394
13	Total to be recovered in 2015	$1,970,197	$2,235,612	$3,407,604	$3,560,697	$2,578,177	$1,396,017	$15,148,305

* Totals may not add due to rounding

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Projection Filing: Retail Revenue Requirements Summary

Schedule P-1 (Projection) [Section (6)(c)1.c.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide a summary of the projected total retail revenue requirement for the subsequent year.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2016

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.		(H) Projected July	(I) Projected August	(J) Projected September	(K) Projected October	(L) Projected November	(M) Projected December	(N) 12 Month Total
		Jurisdictional Dollars						
1	Pre-Construction Revenue Requirements (Schedule P-2, Line 7)	$943,961	$978,906	$1,871,390	$865,027	$876,864	$3,780,114	$21,303,710
2	Construction Carrying Cost Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
3	Recoverable O&M Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
4	DTA/(DTL) Carrying Cost (Schedule P-3A, Line 8)	$619,594	$622,360	$626,493	$630,470	$633,000	$639,809	$7,376,121
5	Other Adjustments	$0	$0	$0	$0	$0	$0	$0
6	Total Projected Period Revenue Requirements (Lines 1 through 5)	$1,563,555	$1,601,266	$2,497,883	$1,495,497	$1,509,865	$4,419,923	$28,679,830
7	Total to be recovered in 2016							
		July	**August**	**September**	**October**	**November**	**December**	**12 Month**
8	2014 Final True-Up (T-1, Line 10)	($993,876)	($110,049)	$437,551	$640,787	$27,441	($2,634,734)	($691,512)
9	2015 True-Up AE cost / carrying cost (AE-1, Line 8)	$1,198,119	$2,474,935	($410,277)	($578,599)	$61,034	$5,740,725	$6,101,031
10	Total 2014 & 2015	$204,243	$2,364,886	$27,274	$62,188	$88,474	$3,105,991	$5,409,518
11	2016 Projected cost and carrying cost (P-2, Line 7)	$943,961	$978,906	$1,871,390	$865,027	$876,864	$3,780,114	$21,303,710
12	2016 Projected DTA/DTL carrying cost (P-3A, Line 8)	$619,594	$622,360	$626,493	$630,470	$633,000	$639,809	$7,376,121
13	Total to be recovered in 2016 (JGK-3, Column 10, Line 20)	$1,767,798	$3,966,153	$2,525,157	$1,557,685	$1,598,339	$7,525,913	$34,089,349

* Totals may not add due to rounding

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Projection Filing: Pre-Construction Costs

Schedule P-2 (Projection) [Section (6)(c)1.c.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide a summary of the projected pre-construction costs for the subsequent year.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2016

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.		(A) Beginning of Period	(B) Projected January	(C) Projected February	(D) Projected March	(E) Projected April	(F) Projected May	(G) Projected June	(H) 6 Month Total
					Jurisdictional Dollars				
1	Nuclear CWIP Additions (Schedule P-6 Line 37)		$997,451	$2,014,893	$4,032,712	$1,196,324	$1,506,524	$2,054,744	$11,802,648
2	Unamortized CWIP Base Eligible for Return (d)	$5,409,518	$4,958,725	$4,507,932	$4,057,139	$3,606,346	$3,155,552	$2,704,759	
3	Amortization of CWIP Base Eligible for Return (d)		$450,793	$450,793	$450,793	$450,793	$450,793	$450,793	
4	Average Net Unamortized CWIP Base Eligible for Return ([Prior month Line 2 + Current month Line 2]/2)		$5,184,122	$4,733,328	$4,282,535	$3,831,742	$3,380,949	$2,930,156	
5	Return on Average Net Unamortized CWIP Eligible for Return								
	a. Equity Component (Line 5b x .61425) (a)		$20,279	$18,515	$16,752	$14,989	$13,225	$11,462	$95,221
	b. Equity Component grossed up for taxes (Line 4 x 0.00636821) (a) (b) (c)		$33,014	$30,143	$27,272	$24,401	$21,531	$18,660	$155,020
	c. Debt Component (Line 4 x 0.00122335) (c)		$6,342	$5,791	$5,239	$4,688	$4,136	$3,585	$29,780
6	Projected Carrying Costs for the Period (Line 5b + Line 5c)		$39,356	$35,933	$32,511	$29,089	$25,667	$22,244	$184,800
7	Total Projected Costs and Carrying Costs for 2015 (Line 1 + Line 6)		$1,036,807	$2,050,826	$4,065,223	$1,225,413	$1,532,191	$2,076,988	$11,987,448

* Totals may not add due to rounding

See Notes on Page 3 of 3

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Projection Filing: Pre-Construction Costs

Schedule P-2 (Projection) [Section (6)(c)1.c.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide a summary of the projected pre-construction costs for the subsequent year.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2016

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.		(I) Projected July	(J) Projected August	(K) Projected September	(L) Projected October	(M) Projected November	(N) Projected December	(O) 12 Month Total
		Jurisdictional Dollars						
1	Nuclear CWIP Additions (Schedule P-6 Line 37)	$925,138	$963,506	$1,859,412	$856,471	$871,731	$3,778,402	$21,057,310
2	Unamortized CWIP Base Eligible for Return	$2,253,966	$1,803,173	$1,352,380	$901,586	$450,793	$0	
3	Amortization of CWIP Base Eligible for Return (d)	$450,793	$450,793	$450,793	$450,793	$450,793	$450,793	
4	Average Net Unamortized CWIP Base Eligible for Return ([Prior month Line 2 + Current month Line 2]/2)	$2,479,363	$2,028,569	$1,577,776	$1,126,983	$676,190	$225,397	
5	Return on Average Net Unamortized CWIP Eligible for Return							
	a. Equity Component (Line 5b x .61425) (a)	$9,698	$7,935	$6,172	$4,408	$2,645	$882	$126,962
	b. Equity Component grossed up for taxes (Line 4 x 0.00636821) (a) (b) (c)	$15,789	$12,918	$10,048	$7,177	$4,306	$1,435	$206,694
	c. Debt Component (Line 4 x 0.00122335) (c)	$3,033	$2,482	$1,930	$1,379	$827	$276	$39,706
6	Projected Carrying Costs for the Period (Line 5b + Line 5c)	$18,822	$15,400	$11,978	$8,556	$5,133	$1,711	$246,400
7	Total Projected Costs and Carrying Costs for 2015 (Line 1 + Line 6)	$943,961	$978,906	$1,871,390	$865,027	$876,864	$3,780,114	$21,303,710

* Totals may not add due to rounding

See Notes on Page 3 of 3

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Projection Filing: Pre-Construction Costs

Schedule P-2 (Projection) [Section (6)(c)1.c.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide a summary of the projected pre-construction costs for the subsequent year.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2016

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Notes:

1 (a) For carrying charge purposes the monthly equity component reflects a 10.5% return on equity.
2 (b) Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5% for an effective rate of 38.575%.
3 (c) In order to gross up the equity component for taxes a monthly rate of 0.00636821 (Equity) and 0.00122335 (Debt) results in the annual pre-tax rate of 9.39%, effective January 1, 2015.
4 (d) Line 2, Column (A) - Unamortized CWIP Base Eligible for Return consists of the total under recovered balance beginning in 2016. This amount will be amortized ratably over 12 months (Line 3) and a carrying charge will be calculated on the unrecovered balance.
5
6 Line 2 Beginning balance includes:

7	2014 Pre-construction Costs and Carrying Costs (T-2, Line 13)	($749,092)	($691,512)	2014 T-1, Line 10 (Column N) Docket No. 150009-EI
8	2014 DTA/(DTL) Carrying Cost (T-3A, Line 12)	$57,580		
9	2015 Pre-construction (Over)/Under Recovery of Costs and Carrying Costs (AE-2, Line 11)	$6,003,862	$6,101,031	2015 AE-1, Line 8 (Column N) Docket No. 150009-EI
10	2015 Pre-construction (Over)/Under Recovery of Carrying Costs on DTA/(DTL) (AE-3A, Line 10)	$97,168		
11	Total under recovery beginning in 2016	$5,409,518	$450,793	Monthly Amortization

* Totals may not add due to rounding

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Projection Filing: Deferred Tax Carrying Costs

Schedule P-3A (Projection) [Section (6)(c)1.c.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the projected deferred tax carrying costs for the subsequent year.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2016

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.			(A) Beginning of Month	(B) Projected January	(C) Projected February	(D) Projected March	(E) Projected April	(F) Projected May	(G) Projected June	(H) 6 Month Total
						Jurisdictional Dollars				
1	Construction Period Interest			$0	$0	$0	$0	$0	$0	$0
2	Recovered Costs Excluding AFUDC (Schedule P-6, Line 37)			$997,451	$2,014,893	$4,032,712	$1,196,324	$1,506,524	$2,054,744	$11,802,648
3	Other Adjustments			$0	$0	$0	$0	$0	$0	$0
4	Tax Basis Less Book Basis (Prior Month Balance + Lines 1 + 2 + 3) (d)		$199,312,782	$200,310,233	$202,325,126	$206,357,838	$207,554,162	$209,060,687	$211,115,430	$211,115,430
5	Deferred Tax Asset/(Liability) DTA/(DTL) on Tax Basis in Excess of Book (Line 4 x Tax Rate) (b)	38.575%	$76,884,906	$77,269,672	$78,046,917	$79,602,536	$80,064,018	$80,645,160	$81,437,777	$81,437,777
6	Average Accumulated DTA/(DTL)			$77,077,289	$77,658,295	$78,824,727	$79,833,277	$80,354,589	$81,041,469	
7	Carrying Cost on DTA/(DTL)									
a.	Equity Component (Line 7b x .61425) (a)			$301,501	$303,774	$308,337	$312,282	$314,321	$317,008	$1,857,222
b.	Equity Component grossed up for taxes (Line 6 x 0.00636821) (a) (b) (c)			$490,844	$494,544	$501,972	$508,395	$511,715	$516,089	$3,023,560
c.	Debt Component (Line 6 x 0.00122335) (c)			$94,293	$95,003	$96,430	$97,664	$98,302	$99,142	$580,834
8	Projected Carrying Costs on DTA/(DTL) (Line 7b + Line 7c)			$585,137	$589,548	$598,403	$606,059	$610,017	$615,231	$3,604,394

* Totals may not add due to rounding

See Notes on Page 2 of 2

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Projection Filing: Deferred Tax Carrying Costs

Schedule P-3A (Projection) [Section (6)(c)1.c.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the projected deferred tax carrying costs for the subsequent year.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2016

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.			(I) Beginning of Period	(J) Projected July	(K) Projected August	(L) Projected September	(M) Projected October	(N) Projected November	(O) Projected December	(P) 12 Month Total
						Jurisdictional Dollars				
1	Construction Period Interest			$0	$0	$0	$0	$0	$0	$0
2	Recovered Costs Excluding AFUDC (Schedule P-6, Line 37)			$925,138	$963,506	$1,859,412	$856,471	$871,731	$3,778,402	$21,057,310
3	Other Adjustments			$0	$0	$0	$0	$0	$0	$0
4	Tax Basis Less Book Basis (Prior Month Balance + Lines 1 + 2 + 3)		$211,115,430	$212,040,569	$213,004,075	$214,863,487	$215,719,958	$216,591,689	$220,370,092	$220,370,092
5	Deferred Tax Asset/(Liability) DTA/(DTL) on Tax Basis in Excess of Book (Line 4 x Tax Rate) (b)	38.575%	$81,437,777	$81,794,649	$82,166,322	$82,883,590	$83,213,974	$83,550,244	$85,007,763	$85,007,763
6	Average Accumulated DTA/(DTL)			$81,616,213	$81,980,486	$82,524,956	$83,048,782	$83,382,109	$84,279,004	
7	Carrying Cost on DTA/(DTL)									
	a. Equity Component (Line 7b x .61425) (a)			$319,256	$320,681	$322,811	$324,860	$326,164	$329,672	$3,800,664
	b. Equity Component grossed up for taxes (Line 6 x 0.00636821) (a) (b) (c)			$519,749	$522,069	$525,536	$528,872	$530,995	$536,706	$6,187,488
	c. Debt Component (Line 6 x 0.00122335) (c)			$99,845	$100,291	$100,957	$101,598	$102,006	$103,103	$1,188,633
8	Projected Carrying Costs on DTA/(DTL) (Line 7b + Line 7c)			$619,594	$622,360	$626,493	$630,470	$633,000	$639,809	$7,376,121

Notes:
9 (a) For carrying charge purposes the monthly equity component reflects a 10.5% return on equity.
10 (b) Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5% for an effective rate of 38.575%.
11 (c) In order to gross up the equity component for taxes a monthly rate of 0.00636821 (Equity) and 0.00122335 (Debt) results in the annual pre-tax rate of 9.39%, effective January 1, 2015.
12 (d) Line 4 - Beginning Balance comes from 2015 AE-3A, Line 4 (Column P), Docket No. 150009-EI

* Totals may not add due to rounding

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Projection Filing: Monthly Expenditures

Schedule P-6 (Projection) [Section (6)(c)1.c.] [Section (9)(e)]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the projected monthly expenditures by major tasks to be performed within pre-construction categories for the subsequent year.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2016

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene and Steven D. Scroggs

Line No.	Description	(A) Projected January	(B) Projected February	(C) Projected March	(D) Projected April	(E) Projected May	(F) Projected June	(G) Projected July	(H) Projected August	(I) Projected September	(J) Projected October	(K) Projected November	(L) Projected December	(M) 12 Month Total
1	**Pre-Construction:**													
2	Generation:													
3	Licensing	$956,346	$1,031,514	$4,153,468	$1,165,332	$1,198,543	$1,067,866	$878,760	$910,127	$861,452	$806,197	$817,733	$3,199,837	$17,047,175
4	Permitting	$36,270	$36,270	$39,767	$36,396	$38,082	$38,082	$36,396	$39,767	$38,082	$36,396	$38,082	$107,051	$520,642
5	Engineering and Design	$61,427	$1,061,427	$68,278	$62,471	$355,374	$1,065,374	$62,471	$68,278	$1,065,374	$62,471	$65,374	$685,887	$4,684,208
6	Long lead procurement advanced payments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7	Power Block Engineering and Procurement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	Initial Assessment (a)	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$3,157,895
9	Total Generation Costs	$1,317,201	$2,392,369	$4,524,671	$1,527,357	$1,855,157	$2,434,480	$1,240,785	$1,281,330	$2,228,066	$1,168,222	$1,184,348	$4,255,933	$25,409,920
10														
11	**Adjustments**													
12	Non-Cash Accruals	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	Other Adjustments (a)	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$3,157,895
14	Total Adjustments	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$263,158	$3,157,895
15														
16	Total Generation Costs Net of Adjustments (Line 9 - Line 14)	$1,054,043	$2,129,211	$4,261,513	$1,264,199	$1,591,999	$2,171,322	$977,627	$1,018,172	$1,964,908	$905,064	$921,190	$3,992,775	$22,252,025
17	Jurisdictional Factor	0.94630981	0.94630981	0.94630981	0.94630981	0.94630981	0.94630981	0.94630981	0.94630981	0.94630981	0.94630981	0.94630981	0.94630981	0.94630981
18	Total Jurisdictional Generation Costs Net of Adjustments	$997,451	$2,014,893	$4,032,712	$1,196,324	$1,506,524	$2,054,744	$925,138	$963,506	$1,859,412	$856,471	$871,731	$3,778,402	$21,057,310
19														
20	Transmission:													
21	Line Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	Substation Engineering	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	Clearing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Other	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	Total Transmission Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
26	Jurisdictional Factor	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019
27	Total Jurisdictional Transmission Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	**Adjustments**													
29	Non-Cash Accruals	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	Other Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
31	Total Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
32	Jurisdictional Factor	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019	0.88718019
33	Total Jurisdictional Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
34														
35	Total Jurisdictional Transmission Costs Net of Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
36														
37	Total Jurisdictional Pre-Construction Costs Net of Adjustments	$997,451	$2,014,893	$4,032,712	$1,196,324	$1,506,524	$2,054,744	$925,138	$963,506	$1,859,412	$856,471	$871,731	$3,778,402	$21,057,310
38														
39	* Totals may not add due to rounding													
40														
41	Notes:													
42	(a) Reflected on line 8 are initial assessment costs which FPL is not seeking to recover in 2016, and therefore these costs are adjusted out on line 13.													
43	Instead, FPL will capitalize these costs as incurred and accrue allowance for funds used during construction (AFUDC).													

Schedule P-6A (Projection)

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Projection Filing: Description of Major Tasks Performed

[Section (6)(c)1.c.]
[Section (9)(e)]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide a description of the major tasks to be performed within Pre-Construction categories for the subsequent year.

For the Year Ended 12/31/2016

Witness: Steven D. Scroggs

Line No.	Major Task	Description - Includes, but is not limited to:
1	**Pre-Construction period:**	
2	**Generation:**	
3	1 License Application	
4		a. Preparation of Nuclear Regulatory Commission Combined License submittal.
5		b. Preparation of Florida Department of Environmental Protection Site Certification Application.
6		c. Transmission facilities studies, stability analysis, Florida Reliability Coordinating Council studies.
7		d. Studies required as Conditions of Approval for local zoning.
8	2 Permitting	
9		a. Communications outreach.
10		b. Legal and application fees.
11	3 Engineering and Design	
12		a. Site specific civil, mechanical and structural requirements to support design.
13		b. Water supply design.
14		c. Construction logistical and support planning.
15		d. Long lead procurement advanced payments.
16		e. Power Block Engineering and Procurement.
17		
18	**Transmission:**	
19	1 Line / Substation Engineering	
20	a. Transmission interconnection design	
21	b. Transmission integration design	

Turkey Point 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Actual & Estimated Filing: All Contracts Executed in Excess of $250,000

Schedule P-7A [Section (9)(c)]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Florida Power & Light Company

DOCKET NO.: 150009-EI

EXPLANATION: For all executed contracts exceeding $250,000, (including change orders), provide the contract number or identifier, status, original and current contract terms, original amount, amount expended as of the end of the prior year, amount expended in the year, estimated final contract amount, name of contractor and affiliations if any, method of selection including identification of

For the Year Ended 12/31/2016

Witness: Steven D. Scroggs

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.	Contract No.	Status of Contract	Original Term of Contract	Current Term of Contract	Original Amount	Actual Expended as of Current Year End (2015)	Estimate of amount to be expended in Subsequent Year (2016)	Estimate of Final Contract Amount	Name of Contractor (and Affiliation if any)	Method of Selection and Document ID	Work Description
1	2000062412	Open - CO#6	02/2012 - 12/2012	02/2012 - 06/2015	[redacted]				AMEC E&I	SSJ	PTN 6&7 RFI Response Review
2	2000115705	Open - CO#1	10/2013 - 08/2015	10/2013 - 02/2016					AMEC E&I	SSJ	PTN 6&7 RFI Response Review/FSAR 2.5.4
3	4500681284	Open - CO#4	06/2011 - 12/2012	06/2011 - 06/2014					Atkins North American	SSJ	PTN 6&7 Expert Scientific Analysis
4	4500395492	Open - CO#58	11/2007 - 12/2011	11/2007 - 05/2016					Bechtel Power Co.	Comp Bid/SSJ/ PDS	PTN 6&7 Engineering Services to support Preparation of COLA and SCA, and Response to Post-Submittal RAIs
5	2000060695	Open - CO#2	02/2012 - 12/2012	02/2012 - 05/2015					Burns & McDonnell	Comp Bid/SSJ	PTN 6&7 Preliminary Design of the Radial Collector Well System
6	4500443122	Open - CO #5	08/2008 - 08/2010	06/2008 - 06/2015					Eco-Metrics, Inc.	SSJ	PTN 6&7 Environmental Consulting Services
7	4500518167	Open - CO#11	07/2009 - 12/2009	07/2009 - 06/2015					Environmental Consulting and Technology Inc.	SSJ/PDS	PTN 6&7 Post SCA Submittal Support
8	4500430034	Open - CO#3	06/2008 - 07/2011	06/2008 - 12/2015					EPRI	SSJ	Advanced Nuclear Technology; Near term deployment of Advanced Light Water Reactors
9	4500518160	Open - CO#11	07/2009 - 12/2009	07/2009 - 04/2015					Golder & Associates, Inc.	SSJ/PDS	PTN 6&7 Post SCA Submittal Support
10	4500425707	Open - CO#8	05/2008 - 08/2008	05/2008 - 06/2015					HDR Engineering, Inc.	Comp Bid/SSJ	Conceptual Engineering of Cooling Water Supply and Discharge
11	2000123867	Open - CO#1	12/2013 - 12/2014	12/2013 - 06/2015					Layne Christensen Company	Comp Bid	PTN 6&7 DIW-1 Injection Test
12	4500645896	Open - CO#3	02/2011 - 03/2012	02/2011 - 12/2014					McCallum Turner	SSJ	PTN 6&7 COLA Site Selection RAI Support
13	4500517152	Open - CO#7	10/2009 - 12/2010	10/2009 - 06/2015					McNabb Hydrogeologic Consulting, Inc.	SSJ/PDS	PTN 6&7 Post SCA Submittal and UIC Licensing Support
14	2000102364	Open - CO#9	05/2013 - 12/2014	05/2013 - 06/2015					Paul C. Rizzo Associates, Inc.	SSJ	PTN 6&7 Field Investigation and FSAR 2.5 Revision
15	2000053246	Open	11/2011 - 06/2014	11/2011 - 06/2015					Power Engineers, Inc.	SSJ	PTN 6&7 Prelim Analysis for Miami River Crossing and Davis/Miami Line
16	4500527549	Open - CO#5	08/2009 - 12/2009	07/2009 - 04/2015					TetraTechGeo (formerly GeoTrans, Inc.)	SSJ	PTN 6&7 APT Review and Collector Well Modeling Support
17	4500404639	Open - CO#8	01/2008 - 12/2011	01/2008 - 02/2016					Westinghouse Electric Co	SSJ/ PDS	PTN 6&7 Engineering Services to Support Preparation of COLA and Response to Post-Submittal RAIs

Turkey Point 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
True-up Filing: Contracts Executed Details

Schedule P-7B [Section (9)(c)]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: Florida Power & Light Company

DOCKET NO.: 150009-EI

EXPLANATION: Provide additional details of contracts executed in excess of $1 million including, the nature and scope of the work, the nature of any affiliation with selected vendor, the method of vendor selection, brief description of vendor selection process, and current status of the contract.

For the Year Ended 12/31/2016

Witness: Steven D. Scroggs

Contract No.:	Major Task or Tasks Associated With:	Vendor Identity:	Vendor Affiliation (specify 'direct' or 'indirect'):	Number of Vendors Solicited:	Number of Bids Received:	Brief Description of Selection Process:	Dollar Value:	Expected CO	Estimate	Contract Status:	Term Begin:	Term End:	Nature and Scope of Work:
4500395492	COLA and SCA Preparation and Support	Bechtel Power Corporation	Direct	Two	Two	Initial contract competitively bid. Change Orders 1-11 issued as Single Source. Designated as Predetermined Source January 2009 through July 2013. Subsequent change orders justified as Single Source.	[redacted]			Open - CO#58	11/06/07	05/31/16	Engineering Services to support preparation of COLA and SCA, including post-submittal support for RAI responses.
4500518167	PTN 6&7 Post SCA Submittal Support	Environmental Consulting and Technology Inc.	Direct	SSJ/PDS	NA	ECT can build off their Phase I analysis and project specific experience to complete the transmission corridor environmental licensing with a minimum of mobilization time or bringing project staff up to speed with prior work.				Open - CO#11	07/15/09	Open	PTN 6&7 Post SCA Submittal Support
4500430034	Conducts research, development and demonstration (RD&D) relating to the generation, delivery and use of electricity for the benefit of the public	EPRI	Direct	SSJ	NA	EPRI is non-profir orgination with the unipue cpability to fulfill the needs of this Contract.				Open - CO#2	06/10/08	Open	Advanced Nuclear Technology; Near term deployment of Advanced Light Water Reactors
4500518160	PTN 6&7 Post SCA Submittal Support	Golder & Associates, Inc.	Direct	SSJ/PDS	NA	Golder & Associates, Inc. has performed a significant amount of related Phase I tasks and can build off their Phase I work and project specific experience to complete the environmental licensing with a minimum of mobilization time or bringing project staff up to speed with prior work.				Open - CO#11	09/29/09	04/30/15	Conceptual Engineering of Cooling Water Supply and Discharge
4500425707	Conceptual engineering of cooling water supply & disposal	HDR Engineering, Inc.	Direct	Comp Bid/SSJ	Three	Initial contract competitively bid. Subsequet change orders were issued as Single Source and notes relatives experience as the basis for award.				Open - CO#8	05/19/08	06/29/15	Conceptual Engineering of Cooling Water Supply and Discharge
2000102364	FSAR & NRC RAI Geotechnical Support	Paul C. Rizzo Associates, Inc.	Direct	SSJ	NA	Rizzo Associates recent interaction with the NRC and their familiarity with Florida geology, would reduce familiarization and development time to prepare the analysis and FSAR revision.				Open - CO#10	04/30/13	12/31/14	PTN 6&7 Field Investigation and FSAR 2.5 Revision
4500404639	Support of COL application during NRC review & updating of 10CFR part 21 notification.	Westinghouse Electric Co	Direct	SSJ/ PDS	NA	Initial contract award was based on the designation as Predetermined Source. Subsequet change orders were issued as Single Source and notes relatives experience as the basis for award.				Open - CO#8	01/31/08	02/27/16	PTN 6&7 Engineering Services to Support Preparation of COLA and Response to Post-Submittal RAIs

Turkey Point Units 6 & 7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Projection Filing: Estimated Rate Impact

Schedule P-8

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Using the most recent billing determinants and allocation factors available, provide an estimate of the rate impact by class of the costs requested for recovery.

For the Year Ended 12/31/2016

Witness: Jennifer Grant-Keene

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
JANUARY 2016 THROUGH DECEMBER 2016

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
RATE SCHEDULE	AVG 12CP Load Factor at Meter (%) [a]	Projected Sales at Meter (kwh) [b]	Projected AVG 12CP at Meter (kW) [c]	Demand Loss Expansion Factor [d]	Energy Loss Expansion Factor [e]	Projected Sales at Generation (kwh) [f]	Projected AVG 12CP at Generation (kW) [g]	Percentage of Sales at Generation (%) [h]	Percentage of Demand at Generation (%) [i]
RS1/RTR1	61.787%	$59,217,744,919	$10,940,926	1.07414658	1.05718681	$62,604,218,846	$11,752,158	54.20013%	59.00463%
GS1/GST1/WIES1	68.268%	$5,968,723,003	$998,061	1.07414658	1.05718681	$6,310,055,231	$1,072,064	5.46298%	5.38256%
GSD1/GSDT1/HLFT1	73.605%	$25,780,251,707	$3,998,322	1.07403957	1.05710545	$27,252,444,582	$4,294,356	23.59403%	21.56088%
OS2	71.268%	$10,815,996	$1,732	1.06488168	1.02949371	$11,135,000	$1,844	0.00964%	0.00926%
GSLD1/GSLDT1/CS1/CST1/HLFT2	73.574%	$10,617,262,134	$1,647,334	1.07268811	1.05609401	$11,212,826,942	$1,767,076	9.70760%	8.87204%
GSLD2/GSLDT2/CS2/CST2/HLFT3	81.995%	$2,553,194,139	$355,463	1.06218410	1.04781257	$2,675,268,912	$377,567	2.31614%	1.89567%
GSLD3/GSLDT3/CS3/CST3	84.406%	$163,603,794	$22,127	1.02407597	1.01925186	$166,753,471	$22,660	0.14437%	0.11377%
SST1T	87.195%	$84,383,192	$11,047	1.02407597	1.01925186	$86,007,725	$11,313	0.07446%	0.05680%
SST1D1/SST1D2/SST1D3	68.277%	$14,030,773	$2,346	1.03754043	1.02949371	$14,444,593	$2,434	0.01251%	0.01222%
CILC D/CILC G	87.853%	$2,774,212,820	$360,479	1.06077360	1.04734246	$2,905,550,879	$382,387	2.51551%	1.91987%
CILC T	86.880%	$1,352,648,209	$177,731	1.02407597	1.01925186	$1,378,689,203	$182,010	1.19361%	0.91383%
MET	67.583%	$90,613,286	$15,306	1.03754043	1.02949371	$93,285,808	$15,881	0.08076%	0.07973%
OL1/SL1/PL1	363.322%	$637,607,559	$20,034	1.07414658	1.05718681	$674,070,301	$21,519	0.58358%	0.10804%
SL2, GSCU1	99.590%	$114,374,076	$13,110	1.07414658	1.05718681	$120,914,765	$14,082	0.10468%	0.07070%
TOTAL		$109,379,465,607	$18,564,018			$115,505,666,260	$19,917,351	100.00000%	100.00000%

[a] AVG 12 CP load factor based on 2011-2013 load research data and 2015 projections.
[b] Projected kwh sales for the period January 2016 through December 2016.
[c] Calculated: Col(3)/(8760 hours * Col(2))
[d] Based on 2014 demand losses.
[e] Based on 2014 energy losses.
[f] Col(3) * Col(6)
[g] Col(4) * Col(5)
[h] Col(7) / Total for Col(7)
[i] Col(8) / Total for Col(8)

Note: There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 factor.

Totals may not add due to rounding.

Turkey Point Units 6 & 7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Projection Filing: Estimated Rate Impact

Schedule P-8

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Using the most recent billing determinants and allocation factors available, provide an estimate of the rate impact by class of the costs requested for recovery.

For the Year Ended 12/31/2016

Witness: Jennifer Grant-Keene

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY PAYMENT RECOVERY FACTOR
JANUARY 2016 THROUGH DECEMBER 2016

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
RATE SCHEDULE	Percentage of Sales at Generation (%) [a]	Percentage of Demand at Generation (%) [b]	Energy Related Cost ($) [c]	Demand Related Cost ($) [d]	Total Capacity Costs ($) [e]	Projected Sales at Meter (kwh) [f]	Billing KW Load Factor (%) [g]	Projected Billed KW at Meter (KW) [h]	Capacity Recovery Factor ($/KW) [i]	Capacity Recovery Factor ($/kwh) [j]	RDC ($/KW) [k]	SDD ($/KW) [l]
RS1/RTR1	54.20013%	59.00463%	$1,428,977	$18,667,760	$20,096,737	$59,217,744,919	-	-	-	0.00034	-	-
GS1/GST1/WIES1	5.46298%	5.38256%	$144,031	$1,702,924	$1,846,954	$5,968,723,003	-	-	-	0.00031	-	-
GSD1/GSDT1/HLFT1	23.59403%	21.56088%	$622,053	$6,821,386	$7,443,439	$25,780,251,707	51.59919%	$68,441,791	0.11	-	-	-
OS2	0.00964%	0.00926%	$254	$2,930	$3,184	$10,815,996	-	$0	-	0.00029	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	9.70760%	8.87204%	$255,939	$2,806,918	$3,062,857	$10,617,262,134	55.38308%	$26,261,081	0.12	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	2.31614%	1.89567%	$61,065	$599,748	$660,812	$2,553,194,139	66.25679%	$5,278,744	0.13	-	-	-
GSLD3/GSLDT3/CS3/CST3	0.14437%	0.11377%	$3,806	$35,994	$39,800	$163,603,794	70.96216%	$315,823	0.13	-	-	-
SST1T	0.07446%	0.05680%	$1,963	$17,970	$19,933	$84,383,192	13.13777%	$879,855	-	-	$0.01	$0.01
SST1D1/SST1D2/SST1D3	0.01251%	0.01222%	$330	$3,866	$4,196	$14,030,773	24.52531%	$78,369	-	-	$0.01	$0.01
CILC D/CILC G	2.51551%	1.91987%	$66,321	$607,403	$673,724	$2,774,212,820	74.25097%	$5,118,171	0.13	-	-	-
CILC T	1.19361%	0.91383%	$31,469	$289,115	$320,584	$1,352,648,209	76.89032%	$2,409,852	0.13	-	-	-
MET	0.08076%	0.07973%	$2,129	$25,226	$27,355	$90,613,286	65.32709%	$190,010	0.14	-	-	-
OL1/SL1/PL1	0.58358%	0.10804%	$15,386	$34,183	$49,569	$637,607,559	-	$0	-	0.00008	-	-
SL2, GSCU1	0.10468%	0.07070%	$2,760	$22,369	$25,129	$114,374,076	-	$0	-	0.00022	-	-
TOTAL			$2,636,483	$31,637,791	$34,274,274	$109,379,465,607		$108,973,696				

[a] Obtained from Page 1, Col(9)
[b] Obtained from Page 1, Col(10)
[c] (Total Capacity Costs/13) * Col(2)
[d] (Total Capacity Costs/13 * 12) * Col(3)
[e] Col(4) + Col(5)
[f] Projected kwh sales for the period January 2016 through December 2016.
[g] (kWh sales / 8760 hours)/((avg customer NCP)(8760 hours))
[h] Col(7) / (Col(8) *730)
[i] Col(6) / Col(9)
[j] Col(6) / Col(7)
[k] RDC = Reservation Demand Charge - (Total Col 6)/(Page 1 Total Col 8)(.10)(Page 1 Col 5)/12 Months
[l] SDD = Sum of Daily Demand Charge - (Total Col 6)/(Page 1 Total Col 8)/(21 onpeak days)(Page 1 Col 5)/12 Months

Note: There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 factor.

Totals may not add due to rounding.

Pre-Construction
True-Up to Original

FLORIDA POWER & LIGHT COMPANY
Turkey Point Units 6&7 - Pre-Construction Costs
NCRC Summary - Dkt. 150009

Schedule TOR-1 (True-up to Original)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER LIGHT & COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Show the jurisdictional amounts used to calculate the final true-up, estimated true-up, projection, deferrals, and recovery of deferrals for each project included in the NCRC. The sum of the amounts should be the total amount requested for recovery in the projected period.

For the Period Ended 12/31/2016

Witness: Jennifer Grant-Keene

		2014			2015			2016	Subtotals	Deferred Recovery			Net Amounts
		A	B	C	D	E	F	G	H	I	J	K	L
		(b)		(B)-(A)	(b)		(E)-(D)		(C)+(F)+(G)				
Line No.	Costs by Project	Approved Actual & Estimated Amounts in Docket No. 140009-EI	Final Actual Amounts in Docket No. 150009-EI	Final True-up for 2014	Approved Projected Amounts in Docket No. 140009-EI	Actual & Estimated Amounts in Docket No. 150009-EI (d)	Estimated True-up for 2015	Initial Projected Amounts for 2016 in Docket No. 150009-EI (d)	Amounts to be Recovered in Docket No. 150009-EI (d)	Increase in Deferred Balance	Decrease in Deferred Balance	2016 Deferred Balance	Net Amount Requested for Recovery in 2016 in Docket No. 150009-EI
	Site Selection Costs (c)						Jurisdictional Dollars						
1	Additions												
2	Carrying Costs - Construction												
3	Carrying Costs - DTA/(DTL)												
4	O&M												
5	Base Rate Revenue Requirements												
6	Subtotal (Sum 1-5)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7													
8	Pre-Construction Costs												
9													
10	Additions (a)	$19,270,470	$18,448,666	($821,804)	$12,548,959	$18,638,220	$6,089,262	$21,057,310	$26,324,767	-	-	-	$26,324,767
11	Carrying Costs - Construction	($1,252,553)	($1,179,841)	$72,712	$22,626	($62,774)	($85,399)	$246,400	$233,713	-	-	-	$233,713
12	Carrying Costs - DTA/(DTL)	$6,092,317	$6,149,897	$57,580	$6,612,164	$6,709,332	$97,168	$7,376,121	$7,530,869	-	-	-	$7,530,869
13	O&M			$0	$0	$0	$0	$0	$0	-	-	-	$0
14	Base Rate Revenue Requirements			$0	$0	$0	$0	$0	$0	-	-	-	$0
15	Subtotal (Sum 10-14)	$24,110,234	$23,418,721	($691,512)	$19,183,748	$25,284,779	$6,101,031	$28,679,830	$34,089,349	$0	$0	$0	$34,089,349
16													
17	Construction Costs												
18													
19	CWIP Balance												
20	Carrying Costs - Construction												
21	Carrying Costs - DTA/(DTL)												
22	O&M												
23	Base Rate Revenue Requirements												
24	Subtotal (Sum 20-23)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25													
26	Total (Sum 6,15,24)	$24,110,234	$23,418,721	($691,512)	$19,183,748	$25,284,779	$6,101,031	$28,679,830	$34,089,349	$0	$0	$0	$34,089,349
27													
28													

29 (a) Additions are pre-construction that, absent Section 366.93, F.S., would be recorded as CWIP.
30 (b) The amounts referenced were approved by the Commission in Docket No. 140009-EI (see Order No. PSC-14-0617-FOF-EI).
31 (c) Refer to Site Selection TORs for further details.
32 (d) Initial assessment costs reflected on TOR-6 are not included in additions for 2015 Actual/Estimated and 2016 Projected. FPL is not
33 seeking to recover these costs in 2016.

* Totals may not add due to rounding

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
True-up to Original: Budgeted and Actual Power Plant In-Service Costs

Schedule TOR-2 (True-Up to Original) [Section (9)(f)]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER LIGHT & COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Report the budgeted and actual costs as compared to the estimated in-service costs of the proposed power plant as provided in the petition for need determination or revised estimate as necessary.

For the Period Ended 12/31/2016

Witness: Jennifer Grant-Keene and Steven D. Scroggs

Line No.		Actual Costs as of December 31, 2014	Remaining Budget Costs to Complete Plant		Total Estimated In-Service Cost		Estimated Cost Provided in the Petition for Need Determination	
		(a)	Low Range	High Range	Low Range	High Range	Low Range	High Range
1	Site Selection	$6,118,105	$0	$0	$6,118,105	$6,118,105	$8,000,000	$8,000,000
2	Pre-Construction	$215,472,357	$89,037,576	$121,705,540	$304,509,934	$337,177,897	$465,000,000	$465,000,000
3	Construction	$0	$10,149,263,190	$14,906,444,521	$10,149,263,190	$14,906,444,521	$8,149,000,000	$12,124,000,000
4	AFUDC (b)(c)(d)	$33,103,347 (A)	$3,208,114,024	$4,711,827,136	$3,241,217,371	$4,744,930,484	$3,461,000,000	$5,160,000,000
5	Total	$254,693,810	$13,446,414,790	$19,739,977,197	$13,701,108,600	$19,994,671,007	$12,083,000,000	$17,757,000,000

*Totals may not add due to rounding.

Errata Notes:	AFUDC	Estimated In-Service Cost Low Range	Estimated In-Service Cost High Range
Line 4, TOR-2 as filed	$32,493,666	$3,240,607,689	$4,744,320,802
Line 4, TOR-2 revised for Errata	$33,103,347	$3,241,217,371	$4,744,930,484
Difference	$609,682	$609,682	$609,682

(A) The figures included with the originally filed TOR-2, inadvertently included carrying charges on (over)/under recoveries, thereby understating the AFUDC for sunk costs.

(a) Actual Sunk Costs represent costs incurred on the project as of December 31, 2014. This amount does not include any termination or other cancellation costs that could be incurred in the event of project cancellation or deferral.
(b) Carrying Charges on (over)/under recoveries are not included as part of Sunk Costs.
(c) AFUDC is calculated on the non-incremental costs total company and includes carrying charges.
(d) Actual AFUDC through December 31, 2014 represents the retail jurisdictional portion.

* Totals may not add due to rounding

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
True-up to Original: Budgeted and Actual Power Plant In-Service Costs

Schedule TOR-2 (True-Up to Original) [Section (9)(f)]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER LIGHT & COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Report the budgeted and actual costs as compared to the estimated in-service costs of the proposed power plant as provided in the petition for need determination or revised estimate as necessary.

For the Period Ended 12/31/2016

Witness: Jennifer Grant-Keene and Steven D. Scroggs

Line No.		Actual Costs as of December 31, 2014	Remaining Budget Costs to Complete Plant		Total Estimated In-Service Cost		Estimated Cost Provided in the Petition for Need Determination	
		(a)	Low Range	High Range	Low Range	High Range	Low Range	High Range
1	Site Selection	$6,118,105	$0	$0	$6,118,105	$6,118,105	$8,000,000	$8,000,000
2	Pre-Construction	$215,472,357	$89,037,576	$121,705,540	$304,509,934	$337,177,897	$465,000,000	$465,000,000
3	Construction	$0	$10,149,263,190	$14,906,444,521	$10,149,263,190	$14,906,444,521	$8,149,000,000	$12,124,000,000
4	AFUDC (b)(c)(d)	$32,493,666	$3,208,114,024	$4,711,827,136	$3,240,607,689	$4,744,320,802	$3,461,000,000	$5,160,000,000
5	Total	$254,084,128	$13,446,414,790	$19,739,977,197	$13,700,498,918	$19,994,061,326	$12,083,000,000	$17,757,000,000

*Totals may not add due to rounding.

(a) Actual Sunk Costs represent costs incurred on the project as of December 31, 2014. This amount does not include any termination or other cancellation costs that could be incurred in the event of project cancellation or deferral.
(b) Carrying Charges on (over)/under recoveries are not included as part of Sunk Costs.
(c) AFUDC is calculated on the non-incremental costs total company and includes carrying charges.
(d) Actual AFUDC through December 31, 2014 represents the retail jurisdictional portion.

* Totals may not add due to rounding

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Summary of Annual Clause Recovery Amounts

[Section (6)(c)1.b.]

Schedule TOR-3 (True-up to Original)

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide a summary of the actual to date and projected total amounts for the duration of the project.

COMPANY: FLORIDA POWER LIGHT & COMPANY

For the Period Ended 12/31/2016

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene and Steven D. Scroggs

Line No.	Description	(A) Actual 2006	(B) Actual 2007	(C) Actual 2008	(D) Actual 2009	(E) Actual 2010	(F) Actual 2011	(G) Actual 2012	(H) Actual 2013	(I) Actual 2014	(J) Total Actual	(K) Actual/Estimated 2015 (b)	(L) Projected 2016 (b)	(M) To-Date Total Through 12/31/2016
		Jurisdictional Dollars												
1	**Site Selection Category** (a)													
	a. Additions													
	b. O&M													
	c. Carrying Costs on Additions													
	d. Carrying Costs on DTA/(DTL)													
	e. Total Site Selection Amounts (Lines 1.a through 1.d)	$0	$0	$0	$0	$0	$0	$0	$0		$0	$0	$0	$0
2	**Pre-Construction Category**													
	a. Additions	$0	$2,522,692	$47,049,854	$37,599,045	$25,287,720	$22,877,377	$29,034,114	$28,209,654	$18,448,666	$211,029,121	$18,638,220	$21,057,310	$250,724,651
	b. O&M	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	c. Carrying Costs on Additions	$0	$20,555	$2,204,114	($691,521)	($9,331,680)	($5,974,180)	($2,666,490)	($1,525,282)	($1,179,841)	($19,144,326)	($62,774)	$246,400	($18,960,699)
	d. Carrying Costs on DTA/(DTL)	$0	($8)	($4,359)	$1,549,215	$3,481,362	$4,418,565	$5,406,452	$6,190,204	$6,149,897	$27,191,326	$6,709,332	$7,376,121	$41,276,779
	e. Total Pre-Construction Amounts (Lines 2.a through 2.d)	$0	$2,543,239	$49,249,608	$38,456,738	$19,437,402	$21,321,762	$31,774,076	$32,874,575	$23,418,721	$219,076,122	$25,284,779	$28,679,830	$273,040,731
3	**Construction Category**													
	Additions	-	-	-	-	-	-	-	-		-	-	-	-
	CWIP Base Eligible for a return	-	-	-	-	-	-	-	-		-	-	-	-
	a. O&M	-	-	-	-	-	-	-	-		-	-	-	-
	b. Carrying Costs on Additions	-	-	-	-	-	-	-	-		-	-	-	-
	c. Carrying Costs on DTA/(DTL)	-	-	-	-	-	-	-	-		-	-	-	-
	d. Total Construction Amounts (Lines 3.a through 3.c)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4	Other Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5	Total Actual Annual Amounts (Lines 1.e + 2.e + 3.d + 4)	$0	$2,543,239	$49,249,608	$38,456,738	$19,437,402	$21,321,762	$31,774,076	$32,874,575	$23,418,721	$219,076,122	$25,284,779	$28,679,830	$273,040,731
6	Original Projected Total Annual Amounts	$0	$2,543,239	$73,042,554	$116,885,727	$91,627,859	$31,310,395	$36,642,378	$34,813,272	$23,970,235	$386,865,425	$19,183,748	N/A	$406,049,173
7	Difference (Line 5 - Line 6)	$0	$0	($23,792,946)	($78,428,989)	($72,190,457)	($9,988,634)	($4,868,302)	($1,938,697)	($551,513)	($167,789,303)	$6,101,031	N/A	($133,008,442)
8	Percent Difference [(7 + 6) x 100%]	N/A	N/A	-33%	-67%	-79%	-32%	-13%	-6%	-2%	-43%	32%	N/A	N/A

(a) Refer to Site Selection TORs for further details.
(b) Initial assessment costs reflected on TOR-6 are not included in additions for 2015 Actual/Estimated and 2016 Projected. FPL is not seeking to recover these costs in 2016.

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
True-up to Original: Pre-Construction Capital Additions/Expenditures

Schedule TOR-6 (True-up to Original)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER LIGHT & COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the actual to date and projected annual expenditures by major tasks performed within pre-construction for the duration of the project.

All pre-construction category costs also included in site selection costs or construction costs must be identified.

For the Period Ended 12/31/2016

Witness: Jennifer Grant-Keene and Steven D. Scroggs

Line No.	Description	(A) Actual 2007	(B) Actual 2008	(C) Actual 2009	(D) Actual 2010	(E) Actual 2011	(F) Actual 2012	(G) Actual 2013	(H) Actual 2014	(I) Total Actual	(J) Actual/Estimated 2015	(K) Projected 2016
1	**Pre-Construction:**											
2												
3	Generation:											
4	Licensing	$2,017,181	$31,085,381	$30,271,612	$23,181,548	$19,339,344	$22,569,507	$25,637,988	$16,072,491	$170,175,051	$15,301,340	$17,047,175
5	Permitting	$516,084	$1,694,555	$991,090	$1,223,203	$679,397	$1,004,333	$1,231,174	$414,704	$7,754,540	$296,505	$520,642
6	Engineering and Design	$0	$3,542,947	$6,445,161	$1,185,396	$3,132,238	$5,991,791	$1,859,326	$2,916,303	$25,073,163	$4,097,840	$4,684,208
7	Long lead procurement advanced payments	$0	$10,860,960	$0	$0	$0	$0	$0	$0	$10,860,960	$0	$0
8	Power Block Engineering and Procurement	$0	$31,789	$23,662	$0	$0	$0	$0	$0	$55,451	$0	$0
9	Initial Assessment (a)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,842,105	$3,157,895
10	Total Generation Costs	$2,533,265	$47,215,633	$37,731,525	$25,590,147	$23,150,978	$29,565,631	$28,728,488	$19,403,498	$213,919,165	$21,537,791	$25,409,920
11	Adjustments											
12	Non-Cash Accruals	$587,128	$6,678,052	($4,978,314)	$931,345	$1,204,389	$0	$0	$0	$4,422,600	$0	$0
13	Other Adjustments	($14,344)	($176,256)	($187,874)	($110,607)	($137,153)	$0	$0	$0	($626,235)	$1,842,105	$3,157,895
14	Total Adjustments	$572,783	$6,501,796	($5,166,188)	$820,738	$1,067,236	$0	$0	$0	$3,796,365	$1,842,105	$3,157,895
15												
16	Total Generation Costs Net of Adjustments (Line 10 - Line 14)	$1,960,482	$40,713,837	$42,897,713	$24,769,409	$22,083,742	$29,565,631	$28,728,488	$19,403,498	$210,122,799	$19,695,685	$22,252,025
17	Jurisdictional Factor	0.9958265	0.99648888	0.99648888	0.98818187	0.98818187	0.98202247	0.98194011	0.95079073		0.94630981	0.94630981
18	Total Jurisdictional Generation Costs Net of Adjustments	1,952,300	40,570,886	42,747,094	24,476,681	21,822,754	29,034,114	28,209,654	18,448,666	207,262,148	18,638,220	21,057,310
19												
20	Transmission:											
21	Line Engineering	$0	$0	$0	$0	$0	$0	$0		$0	$0	$0
22	Substation Engineering	$0	$0	$0	$0	$0	$0	$0		$0	$0	$0
23	Clearing	$0	$0	$0	$0	$0	$0	$0		$0	$0	$0
24	Other	$0	$0	$0	$0	$0	$0	$0		$0	$0	$0
25	Total Transmission Costs	$0	$0	$0	$0	$0	$0	$0		$0	$0	$0
26	Jurisdictional Factor	0.99412116	0.99412116	0.99412116	0.88696801	0.88696801	0.90431145	0.89472420	0.88498196		0.88718019	0.88718019
27	Total Jurisdictional Transmission Costs	$0	$0	$0	$0	$0	$0	$0		$0	$0	$0
28	Adjustments											
29	Non-Cash Accruals	$0	$0	$0	$0	$0	$0	$0		$0	$0	$0
30	Other Adjustments	$0	$0	$0	$0	$0	$0	$0		$0	$0	$0
31	Total Adjustments	$0	$0	$0	$0	$0	$0	$0		$0	$0	$0
32	Jurisdictional Factor	0.99412116	0.99412116	0.99412116	0.88696801	0.88696801	0.90431145	0.89472420	0.88498196		0.88718019	0.88718019
33	Total Jurisdictional Adjustments	$0	$0	$0	$0	$0	$0	$0		$0	$0	$0
34												
35	Total Jurisdictional Transmission Costs Net of Adjustments	$0	$0	$0	$0	$0	$0	$0		$0	$0	$0
36												
37	Total Jurisdictional Pre-Construction Costs	$1,952,300	$40,570,886	$42,747,094	$24,476,681	$21,822,754	$29,034,114	$28,209,654	18,448,666	$207,262,148	$18,638,220	$21,057,310
38												
39	**Construction:**											
40												
41	N/A- At this stage, construction has not commenced.											
42												
43												
44	(a) Reflected on line 9 are initial assessment costs which FPL is not seeking to recover in 2016, and therefore these costs are adjusted out on line 13.											
45	Instead, FPL will capitalize these costs as incurred and accrue allowance for funds used during construction (AFUDC).											

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
True-up to Original: Pre-Construction Category - Description of Major Tasks Performed

Schedule TOR-6A (True-up to Original)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER LIGHT & COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide a description of the major tasks performed within the pre-construction category for the year. List generation expenses separate from transmission in the same order appearing on schedule TOR-6.

For the Period Ended 12/31/2016
Witness: Steven D. Scroggs

Line No.	Pre-Construction Major Task & Description for amounts on Schedule TOR-6 Description
1	**Pre-Construction period:**
2	**Generation:**
3	1 License Application
4	a. Processing of Nuclear Regulatory Commission Combined License submittal
5	b. Processing of Florida Department of Environmental Protection Site Certification Application
6	c. Transmission facilities studies, stability analysis, Florida Reliability Coordinating Council studies
7	d. Studies required as Conditions of Approval for local zoning
8	2 Permitting
9	a. Communications outreach
10	b. Legal and application fees
11	3 Engineering and Design
12	a. Site specific civil, mechanical and structural requirements to support design
13	b. Water supply design
14	c. Construction logistical and support planning
15	4 Long lead procurement advanced payments
16	5 Power Block Engineering and Procurement
17	
18	**Transmission:**
19	1 Line / Substation Engineering
20	a. Transmission interconnection design
21	b. Transmission integration design

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs on Construction Cost Balance
Power Plant Milestones

Schedule TOR-7 (True-up to Original)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide initial project milestones in terms of costs, budget levels, initiation dates and completion dates. Provide all revised milestones and reasons for each revision.

For the Period Ended 12/31/2016

Witness: Steven D. Scroggs

		Initial Milestones	Revised Milestones	Reasons for Variance(s)
Licensing/Permits/Authorizations/Legal	Initiate	2007	no change	N/A
	Complete	2012	2017	Current expectation for COL issuance
Site/Site Preparation	Initiate	2010	2019	Construction will await license approvals
	Complete	2012	2022	Initial date has changed
Related Facilities [1]	Initiate	2010	2019	Construction will await license approvals
	Complete	2018/2020	2027/2028	Initial date has changed
Generation Plant	Initiate	2013/2015	2022	Construction will await license approvals
	Complete	2018/2020	2027/2028	Initial date has changed
Transmission Facilities	Initiate	2010	2017	Construction will await license approvals
	Complete	2020	2028	Initial date has changed

	Estimated Cost Provided in the Petition for Need Determination			Total Current Estimated in Service Costs	
Year	Case A	Case B	Case C	Low Range	High Range
2006	$4	$4	$4	$9	$9
2007	$8	$8	$8	$59	$59
2008	$113	$113	$113	$98	$98
2009	$223	$223	$223	$128	$128
2010	$373	$373	$373	$156	$156
2011	$523	$523	$523	$191	$191
2012	$1,293	$1,183	$1,506	$227	$227
2013	$2,483	$2,201	$3,025	$253	$253
2014	$4,023	$3,521	$4,993	$273	$273
2015	$6,091	$5,291	$7,632	$282	$286
2016	$8,522	$7,373	$10,736	$299	$311
2017	$10,610	$9,161	$13,402	$343	$376
2018	$12,705	$10,956	$16,077	$390	$445
2019	$13,431	$11,578	$17,005	$802	$1,050
2020	$14,020	$12,082	$17,757	$1,738	$2,424
2021				$3,184	$4,548
2022				$5,036	$7,268
2023				$7,138	$10,356
2024				$9,259	$13,470
2025				$11,388	$16,598
2026				$13,222	$19,291
2027				$13,700	$19,994
2028					

(1) Turkey Point Unit 6 targeted for 2027, Unit 7 targeted for 2028.
Values include Site Selection, Pre-Construction and Construction Costs.

Table 1. 2015 Preconstruction Costs

Category	2015 Actual/ Estimated Costs ($)	2016 Projected Costs ($)
Licensing	15,377,764	17,047,175
Permitting	291,349	520,642
Engineering & Design	4,026,573	4,684,208
Long Lead Procurement	-	-
Power Block Engineering & Procurement	-	-
Total Preconstruction Costs	**19,695,685**	**22,252,025**
Transmission	-	-
Total Preconstruction Costs & Transmission	**19,695,685**	**22,252,025**
Initial Assessments	1,842,105	3,157,895
Total Preconstruction Costs, Transmission & Initial Assessments	**21,537,791**	**25,409,920**

Note: Totals may not appear to add due to rounding.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 10
PARTY: FLORIDA POWER & LIGHT (FPL)
(DIRECT)
DESCRIPTION: Steve Scroggs SDS-9

Table 2. 2015 Licensing Costs

Category	2015 Actual/ Estimated Costs ($)	2016 Projected Costs ($)
NNP Team Costs - NNP FPL Payroll and Expenses, FPL Project Team Facilities, FPL Engineering, FPL Licensing	3,439,461	6,102,657
Application Production - COLA/SCA Contractor, Project Architecture & Engineering, NRC and Design Center Working Group fees	8,188,773	5,881,139
SCA Oversight	-	-
SCA Subcontractors:		
• Transmission	70,219	-
• Environmental	52,681	30,000
• Underground Injection	-	-
Total SCA	122,899	30,000
Environmental Services - FPL Payroll and Expenses, External Support Expenses	257,610	772,575
Power Systems - FPL Payroll and Expenses, System Studies, Licensing and Permitting Support and Design Activities	33,673	57,403
Licensing Legal - FPL Payroll and Expenses, External Legal Services, Expert Witnesses	1,069,688	1,267,019
• Regulatory Affairs	432,750	273,330
• New Nuclear Accounting	238,048	277,657
Total Regulatory Support	670,797	550,987
Licensing Contingency	1,594,863	2,385,395
Total Licensing	**15,377,764**	**17,047,175**

Note: Totals may not appear to add due to rounding.

Table 3. 2015 Permitting Costs

Category	2015 Actual/ Estimated Costs ($)	2016 Projected Costs ($)
Project Communication Support	37,133	58,527
Development - FPL Payroll and Expenses, Various Studies	148,421	287,953
Permitting - Legal Specialists Support	77,155	105,193
Permitting Contingency	28,639	68,969
Total Permitting	**291,349**	**520,642**

Table 4. 2015 Engineering and Design Costs

Category	2015 Actual/ Estimated Costs ($)	2016 Projected Costs ($)
Engineering and Construction Team - FPL Payroll and Expenses, Preconstruction Project Management	345,770	773,695
Pre-construction External Engineering - Construction Planning	20,000	-
APOG Membership Participation	3,000,000	3,000,000
EPRI Advanced Nuclear Technology	250,000	275,000
FEMA Fees	15,000	15,000
Engineering and Design Contingency	395,803	620,513
Total Engineering and Design	**4,026,573**	**4,684,208**

Table 5. 2015 Initial Assessment Costs

Category	2015 Actual/ Estimated Costs ($)	2016 Projected Costs ($)
Total Initial Assessments	**1,842,105**	**3,157,895**

Note: Totals may not appear to add due to rounding.

Turkey Point 6 & 7 Project Benefits at a Glance

Projected first year fossil fuel savings for customers

$570 million

Projected lifetime fossil fuel savings for customers

40 years:
$47 billion

60 years:
$101 billion

Enough energy to power
1,251,000 customer homes
without burning coal, natural gas or foreign oil

Fewer greenhouse gas emissions

CO_2 reduction of
290 million tons
40 years

U.S. EPA annual **equivalent of removing more than**
61 million cars
from the road

Decreased reliance on natural gas and foreign oil

Annual fossil fuel reduction of the equivalent of
29 million barrels of oil
or
184 million mmBTU of natural gas

FPL's reliance on natural gas reduced by
13%
beginning in the first full year of operation

Higher electric grid stability

Turkey Point 6 & 7– more electricity where it is needed



The quantifications of these benefits are set forth in FPL Witness Brown's testimony and Exhibit ROB-1

Docket No. 150009-EI
Turkey Point 6 & 7 Project Benefits at a Glance
Exhibit SDS-10, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 11
PARTY: FLORIDA POWER & LIGHT (FPL) (DIRECT)
DESCRIPTION: Steve Scroggs SDS-10

Florida's Nuclear Cost Recovery Law Saves FPL Customers Money

Recovery of carrying costs through the Nuclear Cost Recovery Clause reduces rates for customers over the life of the Turkey Point 6 & 7 plant



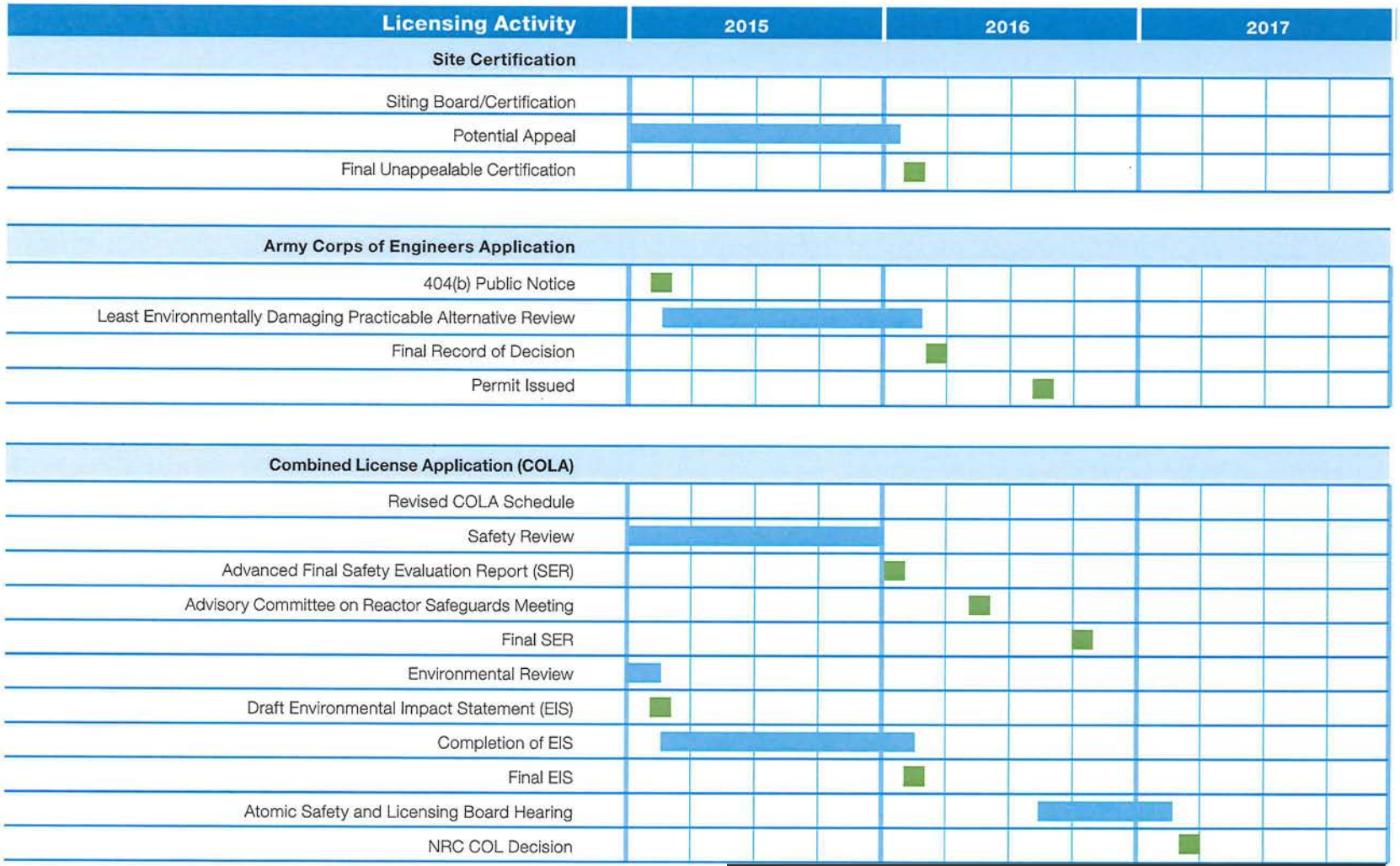
FPL customers save more than $12 billion* over the life of the plant

** Based on the high end of the non-binding cost estimate range and an assumed 40 year operating life*
** Net present value in 2015 dollars is more than $580 million*

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 12
PARTY: FLORIDA POWER & LIGHT (FPL)
(DIRECT)
DESCRIPTION: Steve Scroggs SDS-11

Docket No. 150009-EI
Turkey Point 6 & 7 Customer Savings from
Nuclear Cost Recovery Law
Exhibit SDS-11, Page 1 of 1

Remaining Steps to Obtain Key State and Federal Licenses for Turkey Point 6 & 7



All dates are estimated based on recent state or federal communications

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 13
PARTY: FLORIDA POWER & LIGHT (FPL) (DIRECT)
DESCRIPTION: Steve Scroggs SDS-12

Docket No. 150009-EI
Remaining Steps in Turkey Point 6 & 7 Licensing
Exhibit SDS-12, Page 1 of 1

Dr. Nils J. Diaz is the Managing Director of The ND2 Group, an expert and policy advisor group with a strong focus on the national and international nuclear power development and deployment arena, including new and existing plant licensing, regulatory, financial, policy and communications issues, and the Chief Strategic Officer of Blue Castle Holdings, Inc. The ND2 Group is presently or was recently engaged by governments developing new nuclear options and infrastructure, a major nuclear reactor vendor, US nuclear utilities, international engineering/ consulting firms, and the U.S. Department of Energy. He also provides developmental policy advice to OECD's Nuclear Energy Agency, and serves on two Boards of Directors. He recently served as a Commissioner, Florida Energy and Climate Commission, October 2008-October 2010.

Nils Diaz is a past Chairman of the U.S. Nuclear Regulatory Commission (NRC). Dr. Diaz was designated Chairman of the NRC by President Bush on April 1, 2003 and he served as such until his retirement from government service on June 30, 2006. As Chairman of the NRC, Dr. Diaz served as the principal executive officer of and the official spokesman for the NRC, and had ultimate authority for all NRC functions pertaining to an emergency involving an NRC license; he was directly responsible for all high level interactions with the US Executive Branch and the Congress, as well as the international relationships and the policy development under NRC's charter, including the nuclear security policies and implementation of nuclear plants safety enhancements after 9/11. Dr. Diaz was first nominated by President Clinton and confirmed by the Senate as a Commissioner with the NRC in August 1996, nominated by President Bush and confirmed by the US Senate again in 2001, and exercised the responsibilities of the position until he assumed the Chairmanship of the Commission. As Chairman, he was responsible for the exercise and direction of the Commission's policy-making, licensing and regulatory functions, and employed practical managerial, technical, and entrepreneurial skills to effect changes that enhanced new reactor licensing, license renewal, reactor oversight, enforcement and licensing processes, security and adjudication. Dr. Diaz created and implemented a multi-national initiative to improve the process for safety certification of reactors; the Multinational Design Evaluation Program continues under the umbrella of the Nuclear Energy Agency, OECD.

Prior to his appointment to the NRC, Dr. Diaz was the Director (1985-1996) of a national consortium for advanced nuclear power and propulsion (INSPI) for the Ballistic Missile Defense Organization (BMDO), Department of Defense, Professor of Nuclear Engineering Sciences at the University of Florida (1969-1996, and Dean for Research at CSULB (1984-1986). As a Director for BMDO, he exercised prime contractor management and Lead Scientist responsibilities for a diverse group of industries (including Aeroject, Boeing, Pratt& Whitney, Hughes Electronics, Rocketdyne and SRI), several national laboratories (including Los Alamos NL, Sandia NL, and Lawrence Livermore NL) and seven major universities, under contracts with the Department of Defense, the Defense Nuclear Agency, the Department of Energy and NASA. From 1969

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 14
PARTY: FLORIDA POWER & LIGHT (FPL)
(DIRECT)
DESCRIPTION: Nils Diaz NJD-1

to 1996, Dr. Diaz held senior positions at universities, Boards and industry, and consulted for the U.S. Government and other governments on civilian nuclear energy development. He also owned six small corporations serving the nuclear industry and government during that period, and spent six years at nuclear utilities and reactor vendors, often troubleshooting technical and management performance issues. He lived in Europe in 1981-1982, while serving as Principal Advisor to Spain's Consejo de Seguridad Nuclear, and consulting for nuclear industries and vendors in other European countries.

Dr. Diaz is internationally recognized for his broad expertise and contributions to nuclear sciences, reactor systems and fuels, to the regulation of nuclear facilities and radioactive materials, to the development of nuclear policy and deployment infrastructure. He has worked extensively in the international arena, including interacting and contributing to major policy, fora and decision-making efforts focusing on energy infrastructure development.

Dr. Diaz has published over 70 refereed technical articles and has participated in more than 200 international forums on nuclear energy, sciences and technology. He has been recognized worldwide for his statesmanship on nuclear affairs, including chairing the G8Nuclear Summit in Russia and leading the US Delegation to the International Atomic Energy Agency General Conference in 2005. He has received many national and international awards, including the Henry DeWolf Smyth 2008 Nuclear Statesman Award, awarded by the Nuclear Energy Institute, representing the nuclear industry, and by the American Nuclear Society. Dr. Diaz has been elected a Member of the Hispanic Hall of Fame and recognized as one of the top 50 Hispanics in Sciences and Engineering, and was named the National Hispanic Scientist of the Year for 2009.

Dr. Diaz holds a Ph.D. and M.S. in Nuclear Engineering Sciences from the University of Florida, and a B.S. Degree in Mechanical Engineering from the University of Villanova, Havana. He was licensed as a Senior Reactor Operator by the NRC and has formal training and practice in health physics, radiological sciences and nuclear medicine. He is a Fellow of the American Nuclear Society, the American Society of Mechanical Engineers, and the American Association for the Advancement of Sciences. He recently chaired the ASME Presidential Task Force in response to the Fukushima accidents.

February 2015

John J. Reed
Chairman and Chief Executive Officer

John J. Reed is a financial and economic consultant with more than 35 years of experience in the energy industry. Mr. Reed has also been the CEO of an NASD member securities firm, and Co-CEO of the nation's largest publicly traded management consulting firm (NYSE: NCI). He has provided advisory services in the areas of mergers and acquisitions, asset divestitures and purchases, strategic planning, project finance, corporate valuation, energy market analysis, rate and regulatory matters and energy contract negotiations to clients across North and Central America. Mr. Reed's comprehensive experience includes the development and implementation of nuclear, fossil, and hydroelectric generation divestiture programs with an aggregate valuation in excess of $20 billion. Mr. Reed has also provided expert testimony on financial and economic matters on more than 150 occasions before the FERC, Canadian regulatory agencies, state utility regulatory agencies, various state and federal courts, and before arbitration panels in the United States and Canada. After graduation from the Wharton School of the University of Pennsylvania, Mr. Reed joined Southern California Gas Company, where he worked in the regulatory and financial groups, leaving the firm as Chief Economist in 1981. He served as executive and consultant with Stone & Webster Management Consulting and R.J. Rudden Associates prior to forming REED Consulting Group (RCG) in 1988. RCG was acquired by Navigant Consulting in 1997, where Mr. Reed served as an executive until leaving Navigant to join Concentric as Chairman and Chief Executive Officer.

REPRESENTATIVE PROJECT EXPERIENCE

Executive Management

As an executive-level consultant, worked with CEOs, CFOs, other senior officers, and Boards of Directors of many of North America's top electric and gas utilities, as well as with senior political leaders of the U.S. and Canada on numerous engagements over the past 25 years. Directed merger, acquisition, divestiture, and project development engagements for utilities, pipelines and electric generation companies, repositioned several electric and gas utilities as pure distributors through a series of regulatory, financial, and legislative initiatives, and helped to develop and execute several "roll-up" or market aggregation strategies for companies seeking to achieve substantial scale in energy distribution, generation, transmission, and marketing.

Financial and Economic Advisory Services

Retained by many of the nation's leading energy companies and financial institutions for services relating to the purchase, sale or development of new enterprises. These projects included major new gas pipeline projects, gas storage projects, several non-utility generation projects, the purchase and sale of project development and gas marketing firms, and utility acquisitions. Specific services provided include the development of corporate expansion plans, review of acquisition candidates, establishment of divestiture standards, due diligence on acquisitions or financing, market entry or expansion studies, competitive assessments, project financing studies, and negotiations relating to these transactions.

Litigation Support and Expert Testimony

Provided expert testimony on more than 200 occasions in administrative and civil proceedings on a wide range of energy and economic issues. Clients in these matters have included gas distribution utilities, gas pipelines, gas producers, oil producers, electric utilities, large energy consumers, governmental and regulatory agencies, trade associations, independent energy project developers, engineering firms, and gas and power marketers. Testimony has focused on issues ranging from broad regulatory and economic policy to virtually

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 15
PARTY: FLORIDA POWER & LIGHT (FPL) (DIRECT)
DESCRIPTION: John J. Reed JJR-1

all elements of the utility ratemaking process. Also frequently testified regarding energy contract interpretation, accepted energy industry practices, horizontal and vertical market power, quantification of damages, and management prudence. Has been active in regulatory contract and litigation matters on virtually all interstate pipeline systems serving the U.S. Northeast, Mid-Atlantic, Midwest, and Pacific regions.

Also served on FERC Commissioner Terzic's Task Force on Competition, which conducted an industry-wide investigation into the levels of and means of encouraging competition in U.S. natural gas markets and served on a "Blue Ribbon" panel established by the Province of New Brunswick regarding the future of natural gas distribution service in that province.

Resource Procurement, Contracting and Analysis

On behalf of gas distributors, gas pipelines, gas producers, electric utilities, and independent energy project developers, personally managed or participated in the negotiation, drafting, and regulatory support of hundreds of energy contracts, including the largest gas contracts in North America, electric contracts representing billions of dollars, pipeline and storage contracts, and facility leases.

These efforts have resulted in bringing large new energy projects to market across North America, the creation of hundreds of millions of dollars in savings through contract renegotiation, and the regulatory approval of a number of highly contested energy contracts.

Strategic Planning and Utility Restructuring

Acted as a leading participant in the restructuring of the natural gas and electric utility industries over the past fifteen years, as an adviser to local distribution companies, pipelines, electric utilities, and independent energy project developers. In the recent past, provided services to most of the top 50 utilities and energy marketers across North America. Managed projects that frequently included the redevelopment of strategic plans, corporate reorganizations, the development of multi-year regulatory and legislative agendas, merger, acquisition and divestiture strategies, and the development of market entry strategies. Developed and supported merchant function exit strategies, marketing affiliate strategies, and detailed plans for the functional business units of many of North America's leading utilities.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)
Chairman and Chief Executive Officer

CE Capital Advisors (2004 – Present)
Chairman, President, and Chief Executive Officer

Navigant Consulting, Inc. (1997 – 2002)
President, Navigant Energy Capital (2000 – 2002)
Executive Director (2000 – 2002)
Co-Chief Executive Officer, Vice Chairman (1999 – 2000)
Executive Managing Director (1998 – 1999)
President, REED Consulting Group, Inc. (1997 – 1998)

REED Consulting Group (1988 – 1997)
Chairman, President and Chief Executive Officer

R.J. Rudden Associates, Inc. (1983 – 1988)
Vice President

Stone & Webster Management Consultants, Inc. (1981 – 1983)
Senior Consultant
Consultant

Southern California Gas Company (1976 – 1981)
Corporate Economist
Financial Analyst
Treasury Analyst

EDUCATION AND CERTIFICATION

B.S., Economics and Finance, Wharton School, University of Pennsylvania, 1976
Licensed Securities Professional: NASD Series 7, 63, 24, 79 and 99 Licenses

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BOARDS OF DIRECTORS (PAST AND PRESENT)

Concentric Energy Advisors, Inc.
Navigant Consulting, Inc.
Navigant Energy Capital
Nukem, Inc.
New England Gas Association
R. J. Rudden Associates
REED Consulting Group

AFFILIATIONS

American Gas Association
Energy Bar Association
Guild of Gas Managers
International Association of Energy Economists
National Association of Business Economists
New England Gas Association
Society of Gas Lighters

ARTICLES AND PUBLICATIONS

"Maximizing U.S. federal loan guarantees for new nuclear energy," *Bulletin of the Atomic Scientists* (with John C. Slocum), July 29, 2009
"Smart Decoupling – Dealing with unfunded mandates in performance-based ratemaking," *Public Utilities Fortnightly*, May 2012

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Alaska Public Utilities Commission				
Chugach Electric	12/86	Chugach Electric	Docket No. U-86-11	Cost Allocation
Chugach Electric	6/87	Enstar Natural Gas Company	Docket No. U-87-2	Tariff Design
Chugach Electric	12/87	Enstar Natural Gas Company	Docket No. U-87-42	Gas Transportation
Chugach Electric	11/87, 2/88	Chugach Electric	Docket No. U-87-35	Cost of Capital
Alberta Utilities Commission				
Alberta Utilities (AltaLink, EPCOR, ATCO, ENMAX, FortisAlberta, Alta Gas)	1/13	Alberta Utilities	Application 1566373, Proceeding ID 20	Stranded Costs
Arizona Corporation Commission				
Tucson Electric Power	7/12	Tucson Electric Power	Docket No. E-01933A-12-0291	Cost of Capital
UNS Energy and Fortis Inc.	1/14	UNS Energy, Fortis Inc	Docket No. E-04230A-00011 and Docket No. E-01933A-14-0011	Merger
California Energy Commission				
Southern California Gas Co.	8/80	Southern California Gas Co.	Docket No. 80-BR-3	Gas Price Forecasting
California Public Utility Commission				
Southern California Gas Co.	3/80	Southern California Gas Co.	TY 1981 G.R.C.	Cost of Service, Inflation
Pacific Gas Transmission Co.	10/91, 11/91	Pacific Gas & Electric Co.	App. 89-04-033	Rate Design
Pacific Gas Transmission Co.	7/92	Southern California Gas Co.	A. 92-04-031	Rate Design

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 16
PARTY: FLORIDA POWER & LIGHT (FPL) (DIRECT)
DESCRIPTION: John J. Reed JJR-2

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Colorado Public Utilities Commission				
AMAX Molybdenum	2/90	Commission Rulemaking	Docket No. 89R-702G	Gas Transportation
AMAX Molybdenum	11/90	Commission Rulemaking	Docket No. 90R-508G	Gas Transportation
Xcel Energy	8/04	Xcel Energy	Docket No. 031-134E	Cost of Debt
CT Dept. of Public Utilities Control				
Connecticut Natural Gas	12/88	Connecticut Natural Gas	Docket No. 88-08-15	Gas Purchasing Practices
United Illuminating	3/99	United Illuminating	Docket No. 99-03-04	Nuclear Plant Valuation
Southern Connecticut Gas	2/04	Southern Connecticut Gas	Docket No. 00-12-08	Gas Purchasing Practices
Southern Connecticut Gas	4/05	Southern Connecticut Gas	Docket No. 05-03-17	LNG/Trunkline
Southern Connecticut Gas	5/06	Southern Connecticut Gas	Docket No. 05-03-17PH01	LNG/Trunkline
Southern Connecticut Gas	8/08	Southern Connecticut Gas	Docket No. 06-05-04	Peaking Service Agreement
District Of Columbia PSC				
Potomac Electric Power Company	3/99, 5/99, 7/99	Potomac Electric Power Company	Docket No. 945	Divestiture of Gen. Assets & Purchase Power Contracts
Fed'l Energy Regulatory Commission				
Safe Harbor Water Power Corp.	8/82	Safe Harbor Water Power Corp.		Wholesale Electric Rate Increase
Western Gas Interstate Company	5/84	Western Gas Interstate Company	Docket No. RP84-77	Load Fcst. Working Capital

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Southern Union Gas	4/87, 5/87	El Paso Natural Gas Company	Docket No. RP87-16-000	Take-or-Pay Costs
Connecticut Natural Gas	11/87	Penn-York Energy Corporation	Docket No. RP87-78-000	Cost Alloc./Rate Design
AMAX Magnesium	12/88, 1/89	Questar Pipeline Company	Docket No. RP88-93-000	Cost Alloc./Rate Design
Western Gas Interstate Company	6/89	Western Gas Interstate Company	Docket No. RP89-179-000	Cost Alloc./Rate Design, Open-Access Transportation
Associated CD Customers	12/89	CNG Transmission	Docket No. RP88-211-000	Cost Alloc./Rate Design
Utah Industrial Group	9/90	Questar Pipeline Company	Docket No. RP88-93-000, Phase II	Cost Alloc./Rate Design
Iroquois Gas Trans. System	8/90	Iroquois Gas Transmission System	Docket No. CP89-634-000/001; CP89-815-000	Gas Markets, Rate Design, Cost of Capital, Capital Structure
Boston Edison Company	1/91	Boston Edison Company	Docket No. ER91-243-000	Electric Generation Markets
Cincinnati Gas and Electric Co., Union Light, Heat and Power Company, Lawrenceburg Gas Company	7/91	Texas Gas Transmission Corp.	Docket No. RP90-104-000, RP88-115-000, RP90-192-000	Cost Alloc./Rate Design Comparability of Svc.
Ocean State Power II	7/91	Ocean State Power II	ER89-563-000	Competitive Market Analysis, Self-dealing
Brooklyn Union/PSE&G	7/91	Texas Eastern	RP88-67, et al	Market Power, Comparability of Service
Northern Distributor Group	9/92, 11/92	Northern Natural Gas Company	RP92-1-000, et al	Cost of Service

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Canadian Association of Petroleum Producers and Alberta Pet. Marketing Comm.	10/92. 7/97	Lakehead Pipe Line Co. L.P.	IS92-27-000	Cost Allocation, Rate Design
Colonial Gas, Providence Gas	7/93, 8/93	Algonquin Gas Transmission	RP93-14	Cost Allocation, Rate Design
Iroquois Gas Transmission	94	Iroquois Gas Transmission	RP94-72-000	Cost of Service and Rate Design
Transco Customer Group	1/94	Transcontinental Gas Pipeline Corporation	Docket No. RP92-137-000	Rate Design, Firm to Wellhead
Pacific Gas Transmission	2/94, 3/95	Pacific Gas Transmission	Docket No. RP94-149-000	Rolled-In vs. Incremental Rates; rate design
Tennessee GSR Group	1/95, 3/95, 1/96	Tennessee Gas Pipeline Company	Docket Nos. RP93-151-000, RP94-39-000, RP94-197-000, RP94-309-000	GSR Costs
PG&E and SoCal Gas	8/96, 9/96	El Paso Natural Gas Company	RP92-18-000	Stranded Costs
Iroquois Gas Transmission System, L.P.	97	Iroquois Gas Transmission System, L.P.	RP97-126-000	Cost of Service, Rate Design
BEC Energy - Commonwealth Energy System	2/99	Boston Edison Company/ Commonwealth Energy System	EC99-33-000	Market Power Analysis – Merger
Central Hudson Gas & Electric, Consolidated Co. of New York, Niagara Mohawk Power Corporation, Dynegy Power Inc.	10/00	Central Hudson Gas & Electric, Consolidated Co. of New York, Niagara Mohawk Power Corporation, Dynegy Power Inc.	Docket No. EC01-7-000	Market Power 203/205 Filing
Wyckoff Gas Storage	12/02	Wyckoff Gas Storage	CP03-33-000	Need for Storage Project

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Indicated Shippers/Producers	10/03	Northern Natural Gas	Docket No. RP98-39-029	Ad Valorem Tax Treatment
Maritimes & Northeast Pipeline	6/04	Maritimes & Northeast Pipeline	Docket No. RP04-360-000	Rolled-In Rates
ISO New England	8/04 2/05	ISO New England	Docket No. ER03-563-030	Cost of New Entry
Transwestern Pipeline Company, LLC	9/06	Transwestern Pipeline Company, LLC	Docket No. RP06-614-000	
Portland Natural Gas Transmission System	6/08	Portland Natural Gas Transmission System	Docket No. RP08-306-000	Market Assessment, natural gas transportation; rate setting
Portland Natural Gas Transmission System	5/10, 3/11, 4/11	Portland Natural Gas Transmission System	Docket No. RP10-729-000	Business risks; extraordinary and non-recurring events pertaining to discretionary revenues
Morris Energy	7/10	Morris Energy	Docket No. RP10-79-000	Affidavit re: Impact of Preferential Rate
Gulf South Pipeline	10/14	Gulf South Pipeline	Docket No. RP15-65-000	Business risk, rate design
BNP Paribas Energy Trading, GP South Jersey Resource Group, LLC	2/15	Transcontinental Gas Pipe Line Corporation	Docket No. RP06-569-008 and RP07-376-005	Regulatory policy, incremental rates, stacked rate
Florida Public Service Commission				
Florida Power and Light Co.	10/07	Florida Power & Light Co.	Docket No. 070650-EI	Need for new nuclear plant
Florida Power and Light Co.	5/08	Florida Power & Light Co.	Docket No. 080009-EI	New Nuclear cost recovery, prudence

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Florida Power and Light Co.	3/09	Florida Power & Light Co.	Docket No. 080677-EI	Benchmarking in support of ROE
Florida Power and Light Co.	3/09, 5/09, 8/09	Florida Power & Light Co.	Docket No. 090009-EI	New Nuclear cost recovery, prudence
Florida Power and Light Co.	3/10, 5/10, 8/10	Florida Power & Light Co.	Docket No. 100009-EI	New Nuclear cost recovery, prudence
Florida Power and Light Co.	3/11, 7/11	Florida Power & Light Co.	Docket No. 110009-EI	New Nuclear cost recovery, prudence
Florida Power and Light Co.	3/12 7/12	Florida Power & Light Co.	Docket No. 120009-EI	New Nuclear cost recovery , prudence
Florida Power and Light Co.	3/12 8/12	Florida Power & Light Co.	Docket No. 120015-EI	Benchmarking in support of ROE
Florida Power and Light Co.	3/13, 7/13	Florida Power & Light Co.	Docket No. 130009	New Nuclear cost recovery, prudence
Florida Power and Light Co.	3/14	Florida Power & Light Co.	Docket No. 140009	New Nuclear cost recovery, prudence
Florida Senate Committee on Communication, Energy and Utilities				
Florida Power and Light Co.	2/09	Florida Power & Light Co.		Securitization
Hawaii Public Utility Commission				
Hawaiian Electric Light Company, Inc. (HELCO)	6/00	Hawaiian Electric Light Company, Inc.	Docket No. 99-0207	Standby Charge

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Illinois Commerce Commission				
Renewables Suppliers (Algonquin Power Co., EDP Renewables North America, Invenergy, NextEra Energy Resources)	3/14	Renewables Suppliers	Docket No. 13-0546	Application for Rehearing and Reconsideration; long-term purchase power agreements
WE Energies Corporation	8/14 12/14 2/15	WE Energies/Integrys	Docket No. 14-0496	Merger Application
Indiana Utility Regulatory Commission				
Northern Indiana Public Service Company	10/01	Northern Indiana Public Service Company	Cause No. 41746	Valuation of Electric Generating Facilities
Northern Indiana Public Service Company	01/08, 03/08	Northern Indiana Public Service Company	Cause No. 43396	Asset Valuation
Northern Indiana Public Service Company	08/08	Northern Indiana Public Service Company	Cause No. 43526	Fair Market Value Assessment
Iowa Utilities Board				
Interstate Power and Light	7/05	Interstate Power and Light and FPL Energy Duane Arnold, LLC	Docket No. SPU-05-15	Sale of Nuclear Plant
Interstate Power and Light	5/07	City of Everly, Iowa	Docket No. SPU-06-5	Municipalization
Interstate Power and Light	5/07	City of Kalona, Iowa	Docket No. SPU-06-6	Municipalization
Interstate Power and Light	5/07	City of Wellman, Iowa	Docket No. SPU-06-10	Municipalization
Interstate Power and Light	5/07	City of Terril, Iowa	Docket No. SPU-06-8	Municipalization
Interstate Power and Light	5/07	City of Rolfe, Iowa	Docket No. SPU-06-7	Municipalization

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Maine Public Utility Commission				
Northern Utilities	5/96	Granite State and PNGTS	Docket No. 95-480, 95-481	Transportation Service and PBR
Maryland Public Service Commission				
Eastalco Aluminum	3/82	Potomac Edison	Docket No. 7604	Cost Allocation
Potomac Electric Power Company	8/99	Potomac Electric Power Company	Docket No. 8796	Stranded Cost & Price Protection
Mass. Department of Public Utilities				
Haverhill Gas	5/82	Haverhill Gas	Docket No. DPU #1115	Cost of Capital
New England Energy Group	1/87	Commission Investigation		Gas Transportation Rates
Energy Consortium of Mass.	9/87	Commonwealth Gas Company	Docket No. DPU-87-122	Cost Alloc./Rate Design
Mass. Institute of Technology	12/88	Middleton Municipal Light	DPU #88-91	Cost Alloc./Rate Design
Energy Consortium of Mass.	3/89	Boston Gas	DPU #88-67	Rate Design
PG&E Bechtel Generating Co./ Constellation Holdings	10/91	Commission Investigation	DPU #91-131	Valuation of Environmental Externalities
Coalition of Non-Utility Generators		Cambridge Electric Light Co. & Commonwealth Electric Co.	DPU 91-234 EFSC 91-4	Integrated Resource Management
The Berkshire Gas Company Essex County Gas Company Fitchburg Gas and Elec. Light Co.	5/92	The Berkshire Gas Company Essex County Gas Company Fitchburg Gas & Elec. Light Co.	DPU #92-154	Gas Purchase Contract Approval

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Boston Edison Company	7/92	Boston Edison	DPU #92-130	Least Cost Planning
Boston Edison Company	7/92	The Williams/Newcorp Generating Co.	DPU #92-146	RFP Evaluation
Boston Edison Company	7/92	West Lynn Cogeneration	DPU #92-142	RFP Evaluation
Boston Edison Company	7/92	L'Energia Corp.	DPU #92-167	RFP Evaluation
Boston Edison Company	7/92	DLS Energy, Inc.	DPU #92-153	RFP Evaluation
Boston Edison Company	7/92	CMS Generation Co.	DPU #92-166	RFP Evaluation
Boston Edison Company	7/92	Concord Energy	DPU #92-144	RFP Evaluation
The Berkshire Gas Company Colonial Gas Company Essex County Gas Company Fitchburg Gas and Electric Company	11/93	The Berkshire Gas Company Colonial Gas Company Essex County Gas Company Fitchburg Gas and Electric Co.	DPU #93-187	Gas Purchase Contract Approval
Bay State Gas Company	10/93	Bay State Gas Company	Docket No. 93-129	Integrated Resource Planning
Boston Edison Company	94	Boston Edison	DPU #94-49	Surplus Capacity
Hudson Light & Power Department	4/95	Hudson Light & Power Dept.	DPU #94-176	Stranded Costs
Essex County Gas Company	5/96	Essex County Gas Company	Docket No. 96-70	Unbundled Rates
Boston Edison Company	8/97	Boston Edison Company	D.P.U. No. 97-63	Holding Company Corporate Structure
Berkshire Gas Company	6/98	Berkshire Gas Mergeco Gas Co.	D.T.E. 98-87	Merge approval
Eastern Edison Company	8/98	Montaup Electric Company	D.T.E. 98-83	Marketing for divestiture of its generation business.
Boston Edison Company	98	Boston Edison Company	D.T.E. 97-113	Fossil Generation Divestiture

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Boston Edison Company	2/99	Boston Edison Company	D.T.E. 98-119	Nuclear Generation Divestiture
Eastern Edison Company	12/98	Montaup Electric Company	D.T.E. 99-9	Sale of Nuclear Plant
NStar	9/07, 12/07	NStar, Bay State Gas, Fitchburg G&E, NE Gas, W. MA Electric	DPU 07-50	Decoupling, risk
NStar	6/11	NStar, Northeast Utilities	DPU 10-170	Merger approval
Mass. Energy Facilities Siting Council				
Mass. Institute of Technology	1/89	M.M.W.E.C.	EFSC-88-1	Least-Cost Planning
Boston Edison Company	9/90	Boston Edison	EFSC-90-12	Electric Generation Mkts
Silver City Energy Ltd. Partnership	11/91	Silver City Energy	D.P.U. 91-100	State Policies; Need for Facility
Michigan Public Service Commission				
Detroit Edison Company	9/98	Detroit Edison Company	Case No. U-11726	Market Value of Generation Assets
Consumers Energy Company	8/06, 1/07	Consumers Energy Company	Case No. U-14992	Sale of Nuclear Plant
WE Energies	12/11	Wisconsin Electric Power Co	Case No. U-16830	Economic Benefits/Prudence
Consumer Energy Company	6/2013	Consumers Energy Company	Case No. U-17429	Certificate of Need, Integrated Resource Plan
WE Energies	08/14	WE Energies/Integrys	Case No. U-17682	Merger Application
Minnesota Public Utilities Commission				
Xcel Energy/No. States Power	9/04	Xcel Energy/No. States Power	Docket No. G002/GR-04-1511	NRG Impacts

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Interstate Power and Light	8/05	Interstate Power and Light and FPL Energy Duane Arnold, LLC	Docket No. E001/PA-05-1272	Sale of Nuclear Plant
Northern States Power Company d/b/a Xcel Energy	11/05	Northern States Power Company	Docket No. E002/GR-05-1428	NRG Impacts on Debt Costs
Northern States Power Company d/b/a Xcel Energy	09/06, 10/06, 11/06	NSP v. Excelsior	Docket No. E6472/M-05-1993	PPA, Financial Impacts
Northern States Power Company d/b/a Xcel Energy	11/06	Northern States Power Company	Docket No. G002/GR-06-1429	Return on Equity
Northern States Power	11/08, 05/09	Northern States Power Company	Docket No. E002/GR-08-1065	Return on Equity
Northern States Power	11/09 6/10	Northern States Power Company	Docket No. G002/GR-09-1153	Return on Equity
Northern States Power	11/10, 5/11	Northern States Power Company	Docket No. E002/GR-10-971	Return on Equity
Missouri Public Service Commission				
Missouri Gas Energy	1/03 04/03	Missouri Gas Energy	Case No. GR-2001-382	Gas Purchasing Practices; Prudence
Aquila Networks	2/04	Aquila-MPS, Aquila_L&P	Case Nos. ER-2004-0034 HR-2004-0024	Cost of Capital, Capital Structure
Aquila Networks	2/04	Aquila-MPS, Aquila_L&P	Case No. GR-2004-0072	Cost of Capital, Capital Structure
Missouri Gas Energy	11/05 2/06 7/06	Missouri Gas Energy	Case Nos. GR-2002-348 GR-2003-0330	Capacity Planning

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Missouri Gas Energy	11/10, 1/11	KCP&L	Case No. ER-2010-0355	Natural Gas DSM
Missouri Gas Energy	11/10, 1/11	KCP&L GMO	Case No. ER-2010-0356	Natural Gas DSM
Laclede Gas Company	5/11	Laclede Gas Company	Case No. CG-2011-0098	Affiliate Pricing Standards
Union Electric Company d/b/a Ameren Missouri	2/12, 8/12	Union Electric Company	Case. No. ER-2012-0166	ROE/earnings attrition/regulatory lag
Union Electric Company d/b/a Ameren Missouri	08/14	Noranda Aluminum Inc.	Case No. EC-2014-0223	Ratemaking; regulatory and economic policy
Union Electric Company d/b/a Ameren Missouri	1/15 2/15	Union Electric Company	Case No. ER-2014-0258	Revenue requirements, ratemaking policies
Montana Public Service Commission				
Great Falls Gas Company	10/82	Great Falls Gas Company	Docket No. 82-4-25	Gas Rate Adjust. Clause
Nat. Energy Board of Canada				
Alberta-Northeast	2/87	Alberta Northeast Gas Export Project	Docket No. GH-1-87	Gas Export Markets
Alberta-Northeast	11/87	TransCanada Pipeline	Docket No. GH-2-87	Gas Export Markets
Alberta-Northeast	1/90	TransCanada Pipeline	Docket No. GH-5-89	Gas Export Markets
Indep. Petroleum Association of Canada	1/92	Interprovincial Pipe Line, Inc.	RH-2-91	Pipeline Valuation, Toll
The Canadian Association of Petroleum Producers	11/93	Transmountain Pipe Line	RH-1-93	Cost of Capital
Alliance Pipeline L.P.	6/97	Alliance Pipeline L.P.	GH-3-97	Market Study
Maritimes & Northeast Pipeline	97	Sable Offshore Energy Project	GH-6-96	Market Study

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Maritimes & Northeast Pipeline	2/02	Maritimes & Northeast Pipeline	GH-3-2002	Natural Gas Demand Analysis
TransCanada Pipelines	8/04	TransCanada Pipelines	RH-3-2004	Toll Design
Brunswick Pipeline	5/06	Brunswick Pipeline	GH-1-2006	Market Study
TransCanada Pipelines Ltd.	12/06, 04/07	TransCanada Pipelines Ltd.: Gros Cacouna Receipt Point Application	RH-1-2007	Toll Design
Repsol Energy Canada Ltd	3/08	Repsol Energy Canada Ltd	GH-1-2008	Market Study
Maritimes & Northeast Pipeline	7/10	Maritimes & Northeast Pipeline	RH-4-2010	Regulatory policy, toll development
TransCanada Pipelines Ltd	9/11, 5/12	TransCanada Pipelines Ltd.	RH-3-2011	Business Services and Tolls Application
Trans Mountain Pipeline LLC	6/12, 1/13	Trans Mountain Pipeline LLC	RH-1-2012	Toll Design
TransCanada Pipelines Ltd	8/13	TransCanada Pipelines Ltd	RE-001-2013	Toll Design
NOVA Gas Transmission Ltd	11/13	NOVA Gas Transmission Ltd	OF-Fac-Gas-N081-2013-10 01	Toll Design
Trans Mountain Pipeline LLC	12/13	Trans Mountain Pipeline LLC	OF-Fac-Oil-T260-2013-03 01	Economic and Financial Feasibility and Project Benefits
Energy East Pipeline Ltd.	10/14	Energy East Pipeline		Economic and Financial Feasibility and Project Benefits
New Brunswick Energy and Utilities Board				
Atlantic Wallboard/JD Irving Co	1/08	Enbridge Gas New Brunswick	MCTN #298600	Rate Setting for EGNB

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Atlantic Wallboard/Flakeboard	09/09, 6/10, 7/10	Enbridge Gas New Brunswick	NBEUB 2009-017	Rate Setting for EGNB
Atlantic Wallboard/Flakeboard	1/14	Enbridge Gas New Brunswick	NBEUB Matter 225	Rate Setting for EGNB
NH Public Utilities Commission				
Bus & Industry Association	6/89	P.S. Co. of New Hampshire	Docket No. DR89-091	Fuel Costs
Bus & Industry Association	5/90	Northeast Utilities	Docket No. DR89-244	Merger & Acq. Issues
Eastern Utilities Associates	6/90	Eastern Utilities Associates	Docket No. DF89-085	Merger & Acq. Issues
EnergyNorth Natural Gas	12/90	EnergyNorth Natural Gas	Docket No. DE90-166	Gas Purchasing Practices
EnergyNorth Natural Gas	7/90	EnergyNorth Natural Gas	Docket No. DR90-187	Special Contracts, Discounted Rates
Northern Utilities, Inc.	12/91	Commission Investigation	Docket No. DR91-172	Generic Discounted Rates
Public Service Co. of New Hampshire	7/14	Public Service Co. of NH	Docket No. DE 11-250	Prudence
New Jersey Board of Public Utilities				
Hilton/Golden Nugget	12/83	Atlantic Electric	B.P.U. 832-154	Line Extension Policies
Golden Nugget	3/87	Atlantic Electric	B.P.U. No. 837-658	Line Extension Policies
New Jersey Natural Gas	2/89	New Jersey Natural Gas	B.P.U. GR89030335J	Cost Alloc./Rate Design
New Jersey Natural Gas	1/91	New Jersey Natural Gas	B.P.U. GR90080786J	Cost Alloc./Rate Design

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
New Jersey Natural Gas	8/91	New Jersey Natural Gas	B.P.U. GR91081393J	Rate Design; Weather Norm. Clause
New Jersey Natural Gas	4/93	New Jersey Natural Gas	B.P.U. GR93040114J	Cost Alloc./Rate Design
South Jersey Gas	4/94	South Jersey Gas	BRC Dock No. GR080334	Revised levelized gas adjustment
New Jersey Utilities Association	9/96	Commission Investigation	BPU AX96070530	PBOP Cost Recovery
Morris Energy Group	11/09	Public Service Electric & Gas	BPU GR 09050422	Discriminatory Rates
New Jersey American Water Co.	4/10	New Jersey American Water Co.	BPU WR 1040260	Tariff Rates and Revisions
Electric Customer Group	01/11	Generic Stakeholder Proceeding	BPU GR10100761 and ER10100762	Natural gas ratemaking standards and pricing
New Mexico Public Service Commission				
Gas Company of New Mexico	11/83	Public Service Co. of New Mexico	Docket No. 1835	Cost Alloc./Rate Design
Southwestern Public Service Co., New Mexico	12/12	SPS New Mexico	Case No. 12-00350-UT	Rate Case, Return on Equity
PNM Resources	12/13 10/14 12/14	Public Service Co. of New Mexito	Case No. 13-00390-UT	Nuclear Valuation/In support of stipulation
New York Public Service Commission				
Iroquois Gas. Transmission	12/86	Iroquois Gas Transmission System	Case No. 70363	Gas Markets
Brooklyn Union Gas Company	8/95	Brooklyn Union Gas Company	Case No. 95-6-0761	Panel on Industry Directions

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Central Hudson, ConEdison and Niagara Mohawk	9/00	Central Hudson, ConEdison and Niagara Mohawk	Case No. 96-E-0909 Case No. 96-E-0897 Case No. 94-E-0098 Case No. 94-E-0099	Section 70, Approval of New Facilities
Central Hudson, New York State Electric & Gas, Rochester Gas & Electric	5/01	Joint Petition of NiMo, NYSEG, RG&E, Central Hudson, Constellation and Nine Mile Point	Case No. 01-E-0011	Section 70, Rebuttal Testimony
Rochester Gas & Electric	12/03	Rochester Gas & Electric	Case No. 03-E-1231	Sale of Nuclear Plant
Rochester Gas & Electric	01/04	Rochester Gas & Electric	Case No. 03-E-0765 Case No. 02-E-0198 Case No. 03-E-0766	Sale of Nuclear Plant; Ratemaking Treatment of Sale
Rochester Gas and Electric and NY State Electric & Gas Corp	2/10	Rochester Gas & Electric NY State Electric & Gas Corp	Case No. 09-E-0715 Case No. 09-E-0716 Case No. 09-E-0717 Case No. 09-E-0718	Depreciation policy
Nova Scotia Utility and Review Board				
Nova Scotia Power	9/12	Nova Scotia Power	Docket No. P-893	Audit Reply
Nova Scotia Power	8/14	Nova Scotia Power	Docket No. P-887	Audit Reply
Oklahoma Corporation Commission				
Oklahoma Natural Gas Company	6/98	Oklahoma Natural Gas Company	Case PUD No. 980000177	Storage issues
Oklahoma Gas & Electric Company	9/05	Oklahoma Gas & Electric Company	Cause No. PUD 200500151	Prudence of McLain Acquisition
Oklahoma Gas & Electric Company	03/08	Oklahoma Gas & Electric Company	Cause No. PUD 200800086	Acquisition of Redbud generating facility

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Oklahoma Gas & Electric Company	08/14 01/15	Oklahoma Gas & Electric Company	Cause No. PUD 201400229	Integrated Resource Plan
Ontario Energy Board				
Market Hub Partners Canada, L.P.	5/06	Natural Gas Electric Interface Roundtable	File No. EB-2005-0551	Market-based Rates For Storage
Pennsylvania Public Utility Commission				
ATOC	4/95	Equitrans	Docket No. R-00943272	Rate Design, unbundling
ATOC	3/96 4/96	Equitrans	Docket No. P-00940886	Rate Design, unbundling
Rhode Island Public Utilities Commission				
Newport Electric	7/81	Newport Electric	Docket No. 1599	Rate Attrition
South County Gas	9/82	South County Gas	Docket No. 1671	Cost of Capital
New England Energy Group	7/86	Providence Gas Company	Docket No. 1844	Cost Alloc./Rate Design
Providence Gas	8/88	Providence Gas Company	Docket No. 1914	Load Forecast., Least-Cost Planning
Providence Gas Company and The Valley Gas Company	1/01 3/02	Providence Gas Company and The Valley Gas Company	Docket No. 1673 and 1736	Gas Cost Mitigation Strategy
The New England Gas Company	3/03	New England Gas Company	Docket No. 3459	Cost of Capital
Texas Public Utility Commission				
Southwestern Electric	5/83	Southwestern Electric		Cost of Capital, CWIP
P.U.C. General Counsel	11/90	Texas Utilities Electric Company	Docket No. 9300	Gas Purchasing Practices, Prudence

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Oncor Electric Delivery Company	8/07	Oncor Electric Delivery Company	Docket No. 34040	Regulatory Policy, Rate of Return, Return of Capital and Consolidated Tax Adjustment
Oncor Electric Delivery Company	6/08	Oncor Electric Delivery Company	Docket No.35717	Regulatory policy
Oncor Electric Delivery Company	10/08, 11/08	Oncor, TCC, TNC, ETT, LCRA TSC, Sharyland, STEC, TNMP	Docket No. 35665	Competitive Renewable Energy Zone
CenterPoint Energy	6/10 10/10	CenterPoint Energy/Houston Electric	Docket No. 38339	Regulatory policy, risk, consolidated taxes
Oncor Electric Delivery Company	1/11	Oncor Electric Delivery Company	Docket No. 38929	Regulatory policy, risk
Cross Texas Transmission	08/12 11/12	Cross Texas Transmission	Docket No. 40604	Return on Equity
Southwestern Public Service	11/12	Southwestern Public Service	Docket No. 40824	Return on Equity
Lone Star Transmission	5/14	Lone Star Transmission	Docket No. 42469	Return on Equity, Debt, Cost of Capital
Texas Railroad Commission				
Western Gas Interstate Company	1/85	Southern Union Gas Company	Docket 5238	Cost of Service
Atmos Pipeline Texas	9/10, 1/11	Atmos Pipeline Texas	GUD 10000	Ratemaking Policy, risk

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Texas State Legislature				
CenterPoint Energy	4/13	Association of Electric Companies of Texas	SB 1364	Consolidated Tax Adjustment Clause Legislation
Utah Public Service Commission				
AMAX Magnesium	1/88	Mountain Fuel Supply Company	Case No. 86-057-07	Cost Alloc./Rate Design
AMAX Magnesium	4/88	Utah P&L/Pacific P&L	Case No. 87-035-27	Merger & Acquisition
Utah Industrial Group	7/90 8/90	Mountain Fuel Supply	Case No. 89-057-15	Gas Transportation Rates
AMAX Magnesium	9/90	Utah Power & Light	Case No. 89-035-06	Energy Balancing Account
AMAX Magnesium	8/90	Utah Power & Light	Case No. 90-035-06	Electric Service Priorities
Questar Gas Company	12/07	Questar Gas Company	Docket No. 07-057-13	Benchmarking in support of ROE
Vermont Public Service Board				
Green Mountain Power	8/82	Green Mountain Power	Docket No. 4570	Rate Attrition
Green Mountain Power	12/97	Green Mountain Power	Docket No. 5983	Cost of Service
Green Mountain Power	7/98, 9/00	Green Mountain Power	Docket No. 6107	Rate development

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Wisconsin Public Service Commission				
WEC & WICOR	11/99	WEC	Docket No. 9401-YO-100 Docket No. 9402-YO-101	Approval to Acquire the Stock of WICOR
Wisconsin Electric Power Company	1/07	Wisconsin Electric Power Co.	Docket No. 6630-EI-113	Sale of Nuclear Plant
Wisconsin Electric Power Company	10/09	Wisconsin Electric Power Co.	Docket No. 6630-CE-302	CPCN Application for wind project
Northern States Power Wisconsin	10/13	Xcel Energy (dba Northern States Power Wisconsin)	Docket No. 4220-UR-119	Fuel Cost Adjustments
Wisconsin Electric Power Company	11/1/13	Wisconsin Electric Power Co.	Docket No. 6630-FR-104	Fuel Cost Adjustment
WE Energy	08/14 1/15	WE Energy/Integrys	Docket No. 9400-YO-100	Merger approval

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
American Arbitration Association				
Michael Polsky	3/91	M. Polsky vs. Indeck Energy		Corporate Valuation, Damages
ProGas Limited	7/92	ProGas Limited v. Texas Eastern		Gas Contract Arbitration
Attala Generating Company	12/03	Attala Generating Co v. Attala Energy Co.	Case No. 16-Y-198-00228-03	Power Project Valuation; Breach of Contract; Damages
Nevada Power Company	4/08	Nevada Power v. Nevada Cogeneration Assoc. #2		Power Purchase Agreement
Sensata Technologies, Inc./EMS Engineered Materials Solutions, LLC	1/11	Sensata Technologies, Inc./EMS Engineered Materials Solutions, LLC v. Pepco Energy Services	Case No. 11-198-Y-00848-10	Change in usage dispute/damages
Commonwealth of Massachusetts, Appellate Tax Board				
NStar Electric Company	8/14	NStar Electric Company		Valuation Methodology
Commonwealth of Massachusetts, Suffolk Superior Court				
John Hancock	1/84	Trinity Church v. John Hancock	C.A. No. 4452	Damages Quantification
State of Colorado District Court, County of Garfield				
Questar Corporation, et al	11/00	Questar Corporation, et al.	Case No. 00CV129-A	Partnership Fiduciary Duties

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
State of Delaware, Court of Chancery, New Castle County				
Wilmington Trust Company	11/05	Calpine Corporation vs. Bank Of New York and Wilmington Trust Company	C.A. No. 1669-N	Bond Indenture Covenants
Illinois Appellate Court, Fifth Division				
Norweb, plc	8/02	Indeck No. America v. Norweb	Docket No. 97 CH 07291	Breach of Contract; Power Plant Valuation
Independent Arbitration Panel				
Alberta Northeast Gas Limited	2/98	ProGas Ltd., Canadian Forest Oil Ltd., AEC Oil & Gas		
Ocean State Power	9/02	Ocean State Power vs. ProGas Ltd.	2001/2002 Arbitration	Gas Price Arbitration
Ocean State Power	2/03	Ocean State Power vs. ProGas Ltd.	2002/2003 Arbitration	Gas Price Arbitration
Ocean State Power	6/04	Ocean State Power vs. ProGas Ltd.	2003/2004 Arbitration	Gas Price Arbitration
Shell Canada Limited	7/05	Shell Canada Limited and Nova Scotia Power Inc.		Gas Contract Price Arbitration
International Court of Arbitration				
Wisconsin Gas Company, Inc.	2/97	Wisconsin Gas Co. vs. Pan-Alberta	Case No. 9322/CK	Contract Arbitration
Minnegasco, A Division of NorAm Energy Corp.	3/97	Minnegasco vs. Pan-Alberta	Case No. 9357/CK	Contract Arbitration

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Utilicorp United Inc.	4/97	Utilicorp vs. Pan-Alberta	Case No. 9373/CK	Contract Arbitration
IES Utilities	97	IES vs. Pan-Alberta	Case No. 9374/CK	Contract Arbitration
State of New Jersey, Mercer County Superior Court				
Transamerica Corp., et. al.	7/07, 10/07	IMO Industries Inc. vs. Transamerica Corp., et. al.	Docket No. L-2140-03	Breach-Related Damages, Enterprise Value
State of New York, Nassau County Supreme Court				
Steel Los III, LP	6/08	Steel Los II, LP & Associated Brook, Corp v. Power Authority of State of NY	Index No. 5662/05	Property seizure
Province of Alberta, Court of Queen's Bench				
Alberta Northeast Gas Limited	5/07	Cargill Gas Marketing Ltd. vs. Alberta Northeast Gas Limited	Action No. 0501-03291	Gas Contracting Practices
State of Rhode Island, Providence City Court				
Aquidneck Energy	5/87	Laroche vs. Newport		Least-Cost Planning
State of Texas Hutchinson County Court				
Western Gas Interstate	5/85	State of Texas vs. Western Gas Interstate Co.	Case No. 14,843	Cost of Service

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
State of Texas District Court of Nueces County				
Northwestern National Insurance Company	11/11	ASARCO LLC	No. 01-2680-D	Damages
State of Utah Third District Court				
PacifiCorp & Holme, Roberts & Owen, LLP	1/07	USA Power & Spring Canyon Energy vs. PacifiCorp. et. al.	Civil No. 050903412	Breach-Related Damages
U.S. Bankruptcy Court, District of New Hampshire				
EUA Power Corporation	7/92	EUA Power Corporation	Case No. BK-91-10525-JEY	Pre-Petition Solvency
U.S. Bankruptcy Court, District Of New Jersey				
Ponderosa Pine Energy Partners, Ltd.	7/05	Ponderosa Pine Energy Partners, Ltd.	Case No. 05-21444	Forward Contract Bankruptcy Treatment
U.S. Bankruptcy Court, No. District of New York				
Cayuga Energy, NYSEG Solutions, The Energy Network	09/09	Cayuga Energy, NYSEG Solutions, The Energy Network	Case No. 06-60073-6-sdg	Going concern

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
U.S. Bankruptcy Court, So. District Of New York				
Johns Manville	5/04	Enron Energy Mktg. v. Johns Manville; Enron No. America v. Johns Manville	Case No. 01-16034 (AJG)	Breach of Contract; Damages
U.S. Bankruptcy Court, Northern District Of Texas				
Southern Maryland Electric Cooperative, Inc. and Potomac Electric Power Company	11/04	Mirant Corporation, et al. v. SMECO	Case No. 03-4659; Adversary No. 04-4073	PPA Interpretation; Leasing
U. S. Court of Federal Claims				
Boston Edison Company	7/06, 11/06	Boston Edison v. Department of Energy	No. 99-447C No. 03-2626C	Spent Nuclear Fuel Litigation
Consolidated Edison of New York	08/07	Consolidated Edison of New York, Inc. and subsidiaries v. United States	No. 06-305T	Leasing, tax dispute
Consolidated Edison Company	2/08, 6/08	Consolidated Edison Company v. United States	No. 04-0033C	SNF Expert Report
Vermont Yankee Nuclear Power Corporation	6/08	Vermont Yankee Nuclear Power Corporation	No. 03-2663C	SNF Expert Report
U. S. District Court, Boulder County, Colorado				
KN Energy, Inc.	3/93	KN Energy vs. Colorado GasMark, Inc.	Case No. 92 CV 1474	Gas Contract Interpretation

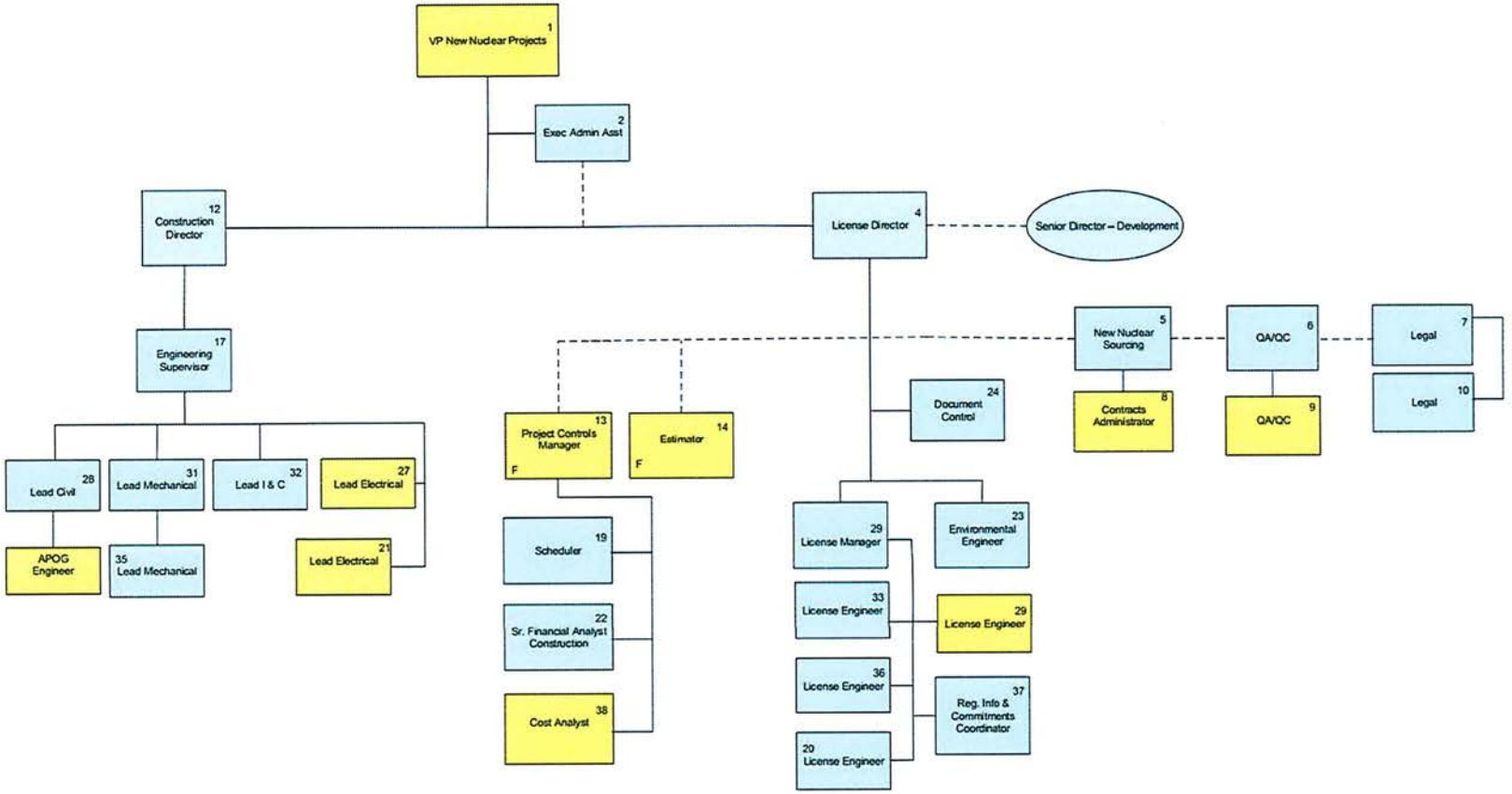
SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
U. S. District Court, Northern California				
Pacific Gas & Electric Co./PGT PG&E/PGT Pipeline Exp. Project	4/97	Norcen Energy Resources Limited	Case No. C94-0911 VRW	Fraud Claim
U. S. District Court, District of Connecticut				
Constellation Power Source, Inc.	12/04	Constellation Power Source, Inc. v. Select Energy, Inc.	Civil Action 304 CV 983 (RNC)	ISO Structure, Breach of Contract
U.S. District Court, Northern District of Illinois, Eastern Division				
U.S. Securities and Exchange Commission	4/12	U.S. Securities and Exchange Commission v. Thomas Fisher, Kathleen Halloran, and George Behrens	Case No. 07 C 4483	Prudence, PBR
U. S. District Court, Massachusetts				
Eastern Utilities Associates & Donald F. Pardus	3/94	NECO Enterprises Inc. vs. Eastern Utilities Associates	Civil Action No. 92-10355-RCL	Seabrook Power Sales
U. S. District Court, Montana				
KN Energy, Inc.	9/92	KN Energy v. Freeport MacMoRan	Docket No. CV 91-40-BLG-RWA	Gas Contract Settlement

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
U.S. District Court, New Hampshire				
Portland Natural Gas Transmission and Maritimes & Northeast Pipeline	9/03	Public Service Company of New Hampshire vs. PNGTS and M&NE Pipeline	Docket No. C-02-105-B	Impairment of Electric Transmission Right-of-Way
U. S. District Court, Southern District of New York				
Central Hudson Gas & Electric	11/99, 8/00	Central Hudson v. Riverkeeper, Inc., Robert H. Boyle, John J. Cronin	Civil Action 99 Civ 2536 (BDP)	Electric restructuring, environmental impacts
Consolidated Edison	3/02	Consolidated Edison v. Northeast Utilities	Case No. 01 Civ. 1893 (JGK) (HP)	Industry Standards for Due Diligence
Merrill Lynch & Company	1/05	Merrill Lynch v. Allegheny Energy, Inc.	Civil Action 02 CV 7689 (HB)	Due Diligence, Breach of Contract, Damages
U. S. District Court, Eastern District of Virginia				
Aquila, Inc.	1/05, 2/05	VPEM v. Aquila, Inc.	Civil Action 304 CV 411	Breach of Contract, Damages
U. S. District Court, Portland Maine				
ACEC Maine, Inc. et al.	10/91	CIT Financial vs. ACEC Maine	Docket No. 90-0304-B	Project Valuation
Combustion Engineering	1/92	Combustion Eng. vs. Miller Hydro	Docket No. 89-0168P	Output Modeling; Project Valuation
U.S. Securities and Exchange Commission				
Eastern Utilities Association	10/92	EUA Power Corporation	File No. 70-8034	Value of EUA Power

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Council of the District of Columbia Committee on Consumer and Regulatory Affairs				
Potomac Electric Power Co.	7/99	Potomac Electric Power Co.	Bill 13-284	Utility restructuring

CONCENTRIC ENERGY ADVISORS

PTN Units 6 & 7 Project Organization
New Nuclear Projects

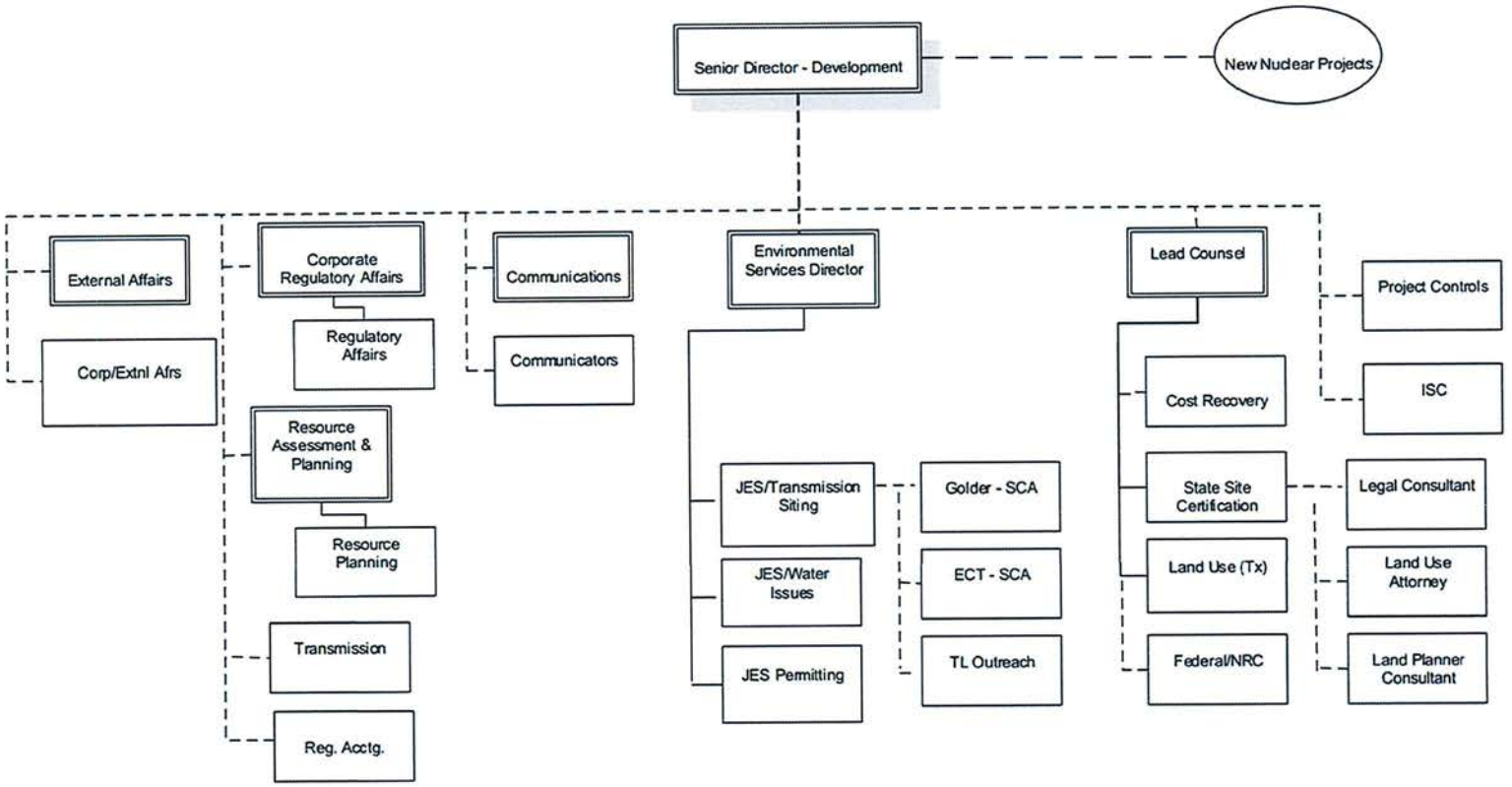


Docket No. 150009-EI
PTN 6 & 7 Organization Charts
Exhibit JJR-3, Page 1 of 2

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 17
PARTY: FLORIDA POWER & LIGHT (FPL) (DIRECT)
DESCRIPTION: John J. Reed JJR-3

CONCENTRIC ENERGY ADVISORS

Turkey Point 6 & 7
Development Project Organization
Licensing Phase



Docket No. 150009-EI
PTN 6 & 7 Organization Charts
Exhibit JJR-3, Page 2 of 2

Florida Power & Light Company
Final True-Up of 2014 Revenue Requirements
(Jurisdictional, Net of Participants)
Exhibit JGK-1

March 2, 2015 True-up filing
(Docket No. 150009-EI)

Line No.		(A) 2014 AE's 2014 Actual/Estimated Costs Docket No. 140009-EI	(B) 2014 T's 2014 Actual Costs Docket No. 150009-EI	(C) (Over)/Under Recovery
1				
2	**Turkey Point 6 & 7 Project**			
3	Site Selection Costs	$0	$0	$0
4	Carrying Costs	($742)	($742)	$0
5	Carrying Costs on Deferred Tax Asset/(Deferred Tax Liability)	$159,144	$159,224	$79
6	Total Carrying Costs	$158,402	$158,482	$79
7	Total Site Selection	$158,402	$158,482	$79
8				
9	Pre-construction Costs	$19,270,470	$18,448,666	($821,804)
10	Carrying Costs	($1,252,553)	($1,179,841)	$72,712
11	Carrying Costs on Deferred Tax Asset/(Deferred Tax Liability)	$6,092,317	$6,149,897	$57,580
12	Total Carrying Costs	$4,839,764	$4,970,056	$130,292
13	Total Pre-construction	$24,110,234	$23,418,721	($691,512)
14	**Total Turkey Point 6 & 7 Project**	**$24,268,636**	**$23,577,203**	**($691,433)**
15	**Uprate Project**			
16	Construction Costs (Completed)	$0	$0	$0
17	Carrying Costs	$911,804	$911,804	$0
18	Carrying Costs on Deferred Tax Asset/(Deferred Tax Liability)	$0	$0	$0
19	Total Carrying Costs	$911,804	$911,804	$0
20				
21	Recoverable Operations & Maintenance and Interest	(1,187,084)	(1,185,456)	$1,628
22	Adjustment	$0	($1,628)	($1,628)
23	Total Recoverable Operations & Maintenance and Interest	(1,187,084)	(1,187,084)	$0
24	Base Rate Revenue Requirements	($796,243)	($795,076)	$1,167
25	Carrying Costs (Over)/Under Recovery	$27,161	$27,236	$75
26	Adjustment	$0	($1,243)	($1,243)
27	Total Base Revenue Requirements and Carrying Costs	($769,082)	($769,082)	$0
28	**Total Uprate Project**	**($1,044,362)**	**($1,044,362)**	**$0**
29				
30	**Total Turkey Point 6 & 7 and Uprate Project**	**$23,224,274**	**$22,532,841**	**($691,433)**
31				
32	Totals may not add due to rounding			

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 18
PARTY: FLORIDA POWER & LIGHT (FPL) (DIRECT)
DESCRIPTION: Jennifer Grant-Keene JGK-1

Docket No. 150009-EI
2014 EPU T-Schedules
Exhibit JGK-2, Pages 1-13

Extended Power Uprate Construction Costs
Nuclear Filing Requirements (NFRs)
2014 T-Schedules (Actual)
January 2014 - December 2014

Uprate

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 19
PARTY: FLORIDA POWER & LIGHT (FPL)
(DIRECT)
DESCRIPTION: Jennifer Grant-Keene JGK-2

Extended Power Uprate Construction Costs
Nuclear Cost Recovery
Nuclear Filing Requirements (NFRs)
2014 T-Schedules
January 2014 - December 2014

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St. Lucie and Turkey Point Uprate Project
Carrying Costs on Prior Period (Over)/Under Recoveries of O&M and Construction Costs
True-Up Filing: Retail Revenue Requirements Summary

[Section (6)(c)1.a.]

Schedule T-1 (True-up)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the calculation of the true-up of total retail revenue requirements based on actual costs for the prior year and the previously filed costs.

For the Year Ended 12/31/2014

Witness: Jennifer Grant-Keene

Line No.		(A) Actual January	(B) Actual February	(C) Actual March	(D) Actual April	(E) Actual May	(F) Actual June	(G) 6 Month Total
		Jurisdictional Dollars						
1	Construction Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
2	Construction Carrying Cost Revenue Requirements (Schedule T-3, Line 9)	$162,823	$160,296	$141,801	$123,368	$104,937	$86,506	$779,730
3	Recoverable O&M Revenue Requirements (Schedule T-4, Page 2, Line 19)	($85)	($80)	($67)	($63)	($39)	($1,184,854)	($1,185,188)
4	DTA/(DTL) Carrying Cost	$0	$0	$0	$0	$0	$0	$0
5	Other Adjustments (a)	($60,536)	($61,014)	($61,475)	($61,940)	($62,409)	($64,309)	($371,683)
6	Total Period Revenue Requirements (Lines 1 though 5)	$102,202	$99,202	$80,259	$61,365	$42,489	($1,162,656)	($777,140)
7	Projected Revenue Requirements for the period (Order No. PSC 13-0493-FOF-EI)	$213,828	$195,234	$176,640	$158,046	$139,453	$120,859	$1,004,060
8	Difference (Line 6 - Line 7)	($111,626)	($96,032)	($96,381)	($96,681)	($96,963)	($1,283,516)	($1,781,200)
9	Actual/Estimated Revenue Requirements for the period (Order No. PSC-14-0617-FOF-EI)	$102,103	$99,097	$80,154	$61,269	$42,382	($1,164,362)	($779,357)
10	Final True-up of Uprate Construction Carrying Costs (Line 6 - Line 9)	$98	$105	$105	$96	$108	$1,705	$2,218

*Totals may not add due to rounding

See notes on Page 2

St. Lucie and Turkey Point Uprate Project
Carrying Costs on Prior Period (Over)/Under Recoveries of O&M and Construction Costs
True-Up Filing: Retail Revenue Requirements Summary

Schedule T-1 (True-up) [Section (6)(c)1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the calculation of the true-up of total retail revenue requirements based on actual costs for the prior year and the previously filed costs.

For the Year Ended 12/31/2014

Witness: Jennifer Grant-Keene

Line No.		(H) Actual July	(I) Actual August	(J) Actual September	(K) Actual October	(L) Actual November	(M) Actual December	(N) 12 Month Total	(O) Adjustment (b)	(P) Revised 12 Month Total
		Jurisdictional Dollars								
1	Construction Revenue Requirements	$0	$0	$0	$0	$0	$0	$0		
2	Construction Carrying Cost Revenue Requirements (Schedule T-3, Line 9)	$68,077	$49,649	$31,223	$12,798	($5,626)	($24,048)	$911,804		
3	Recoverable O&M Revenue Requirements (Schedule T-4, Page 2, Line 19)	($45)	($68)	($55)	($42)	($34)	($24)	($1,185,456)		
4	DTA/(DTL) Carrying Cost	$0	$0	$0	$0	$0	$0	$0		
5	Other Adjustments (a)	($64,794)	($65,282)	($65,774)	($66,269)	($66,768)	($67,271)	($767,839)		
6	Total Period Actual Revenue Requirements (Lines 1 though 5)	$3,238	($15,701)	($34,606)	($53,513)	($72,428)	($91,342)	($1,041,491)		
7	Projected Revenue Requirements for the period (Order No. PSC 13-0493-FOF-EI)	$102,265	$83,672	$65,078	$46,484	$27,891	$9,297	$1,338,746		
8	Actual/Estimated (Over)/Under Recovery for the Period (Line 6 - Line 7)	($99,027)	($99,372)	($99,684)	($99,998)	($100,318)	($100,639)	($2,380,237)		
9	Actual/Estimated Revenue Requirements for the period (Order No. PSC-14-0617-FOF-EI)	$3,126	($15,811)	($34,716)	($53,624)	($72,534)	($91,446)	($1,044,362)		
10	Final True-up of Uprate Construction Carrying Costs (Line 6 - Line 9)	$112	$111	$111	$110	$106	$104	$2,871	($2,871)	$0

*Totals may not add due to rounding

(a) Other Adjustments, Line 5 represents Base Rate Revenue Requirements for 2014 and carrying costs on over/under recoveries. Refer to Appendix C Line 8.
(b) Changes in FPL's 2014 jurisdictional separation factor, base rate revenue requirements and associated carrying charges (not reflected in FPL's 2014 Actual/Estimated filing in Docket No. 140009-EI) have resulted in an under recovery of $2,871. FPL will not seek the recovery resulting from these changes and will adjust out the associated under recovery in the NCRC filing.

Schedule T-3 (True-up)

St. Lucie and Turkey Point Uprate Project
Carrying Costs on Prior Period (Over)/Under Recoveries of Construction Costs
True-Up Filing: Construction Costs

[Section (5)(c)1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the calculation of the true-up of carrying costs on construction expenditures, based on actual carrying costs on construction expenditures for the previous year and the previously filed carrying costs.

For the Year Ended 12/31/2014

Witness: Jennifer Grant-Keene

Line No.		(A) Beginning of Period	(B) Actual January	(C) Actual February	(D) Actual March	(E) Actual April	(F) Actual May	(G) Actual June	(H) 6 Month Total
					Jurisdictional Dollars				
1	Nuclear CWIP Additions (d)	$0	$0	$0	$0	$0	$0	$0	$0
2	Adjustments (i)	($64,856)	$0	$0	$0	$0	$0	$0	$0
3	Transfers to Plant in Service (d)	$0	$0	$0	$0	$0	$0	$0	$0
4	Unamortized Carrying charge Eligible for return (e) (g)	$24,793,093	$22,400,237	$20,007,382	$17,614,526	$15,221,670	$12,828,814	$10,435,959	$10,435,959
5	Amortization of Carrying charge (f)	$28,714,269	$2,392,856	$2,392,856	$2,392,856	$2,392,856	$2,392,856	$2,392,856	$14,357,135
6	CWIP Base Eligible for Return (Lines 1 + 2 - 3 - 5) + Prior Months (Line 6 + Line 11)	$24,728,237	$22,335,381	$19,891,352	$17,463,404	$15,035,570	$12,607,912	$10,180,430	$10,145,982
7	Average Net CWIP Additions		$23,531,809	$21,113,367	$18,677,378	$16,249,487	$13,821,741	$11,394,171	
8	Return on Average Net CWIP Additions								
	a. Equity Component (Line 8b x .61425) (a)		$92,021	$82,563	$73,037	$63,543	$54,050	$44,557	$409,771
	b. Equity Component grossed up for taxes (Line 7 x 0.005365265) (a) (b) (c) (h)	($12,632)	$149,810	$134,413	$118,905	$103,449	$87,993	$72,538	$667,108
	c. Debt Component (Line 7 x 0.001225871) (c) (h)	($3,202)	$28,847	$25,882	$22,896	$19,920	$16,944	$13,968	$128,456
9	Total Return Requirements (Line 8b + Line 8c)	($15,834)	$162,823	$160,296	$141,801	$123,368	$104,937	$86,506	$779,730
10	Projected Carrying Costs for the Period (Order No. PSC 13-0493-FOF-EI)		$213,996	$195,388	$176,779	$158,171	$139,563	$120,954	$1,004,851
11	Difference (Line 9 - Line 10)		($51,173)	($35,092)	($34,978)	($34,803)	($34,626)	($34,448)	($225,121)
12	Actual/Estimated Revenue Requirements for the period (Order No. PSC-14-0617-FOF-EI)		$162,823	$160,296	$141,801	$123,368	$104,937	$86,506	$779,730
13	Final True-up Amount for the Period (Line 9 - Line 12)		$0	$0	$0	$0	$0	$0	$0

*Totals may not add due to rounding

See notes on Pages 3 and 4

Schedule T-3 (True-up)

St. Lucie and Turkey Point Uprate Project
Carrying Costs on Prior Period (Over)/Under Recoveries of Construction Costs
True-Up Filling: Construction Costs

[Section (6)(c)1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the calculation of the true-up of carrying costs on construction expenditures, based on actual carrying costs on construction expenditures for the previous year and the previously filed carrying costs.

For the Year Ended 12/31/2014

Witness: Jennifer Grant-Keene

Line No.		(I) Beginning of Period	(J) Actual July	(K) Actual August	(L) Actual September	(M) Actual October	(N) Actual November	(O) Actual December	(P) 12 Month Total	(Q) PTD Total
						Jurisdictional Dollars				
1	Nuclear CWIP Additions (d)		$0	$0	$0	$0	$0	$0	$0	$0
2	Adjustments (i)		$0	$0	$0	$0	$0	$0	$0	$0
3	Transfers to Plant in Service (d)		$0	$0	$0	$0	$0	$0	$0	$0
4	Unamortized Carrying charge Eligible for return (e) (g)		$8,043,103	$5,650,247	$3,257,391	$864,536	($1,528,320)	($3,921,176)		
5	Amortization of Carrying charge (f)		$2,392,856	$2,392,856	$2,392,856	$2,392,856	$2,392,856	$2,392,856	$28,714,269	
6	CWIP Base Eligible for Return (Line 1 + 2 - 3 - 5) + Prior Months (Line 6 + Line 11)	$10,180,430	$7,753,126	$5,326,001	$2,899,057	$472,295	($1,954,284)	($4,380,678)	($4,414,030)	($427,998)
7	Average Net CWIP Additions		$8,966,778	$6,539,563	$4,112,529	$1,685,676	($740,994)	($3,167,481)		
8	Return on Average Net CWIP Additions									
	a. Equity Component (Line 8b x .61425) (a)		$35,064	$25,573	$16,082	$6,592	($2,898)	($12,386)	$477,798	$477,798
	b. Equity Component grossed up for taxes (Line 7 x 0.006366265) (a) (b) (c) (h)		$57,085	$41,633	$26,181	$10,731	($4,717)	($20,165)	$777,856	$765,224
	c. Debt Component (Line 7 x 0.001225871) (c) (h)		$10,992	$8,017	$5,041	$2,066	($908)	($3,883)	$149,782	$146,580
9	Total Return Requirements (Line 8b + Line 8c)		$68,077	$49,649	$31,223	$12,798	($5,626)	($24,048)	$911,804	$911,804
10	Projected Carrying Costs for the Period (Order No. PSC 13-0493-FOF-EI)		$102,346	$83,738	$65,129	$46,521	$27,913	$9,304	$1,339,801	$1,339,801
11	Difference (Line 9 - Line 10)		($34,269)	($34,088)	($33,906)	($33,723)	($33,538)	($33,352)	($427,998)	($427,998)
12	Actual/Estimated Revenue Requirements for the period (Order No. PSC-14-0617-FOF-EI)		$68,077	$49,649	$31,223	$12,798	($5,626)	($24,048)	$911,804	
13	Final True-up Amount for the Period (Line 9 - Line 12)		$0	$0	$0	$0	$0	$0	$0	

*Totals may not add due to rounding

See notes on Pages 3 and 4

Schedule T-3 (True-up)

St. Lucie and Turkey Point Uprate Project
Carrying Costs on Prior Period (Over)/Under Recoveries of Construction Costs
True-Up Filling: Construction Costs

[Section (6)(c)1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the calculation of the true-up of carrying costs on construction expenditures, based on actual carrying costs on construction expenditures for the previous year and the previously filed carrying costs.

For the Year Ended 12/31/2014

Witness: Jennifer Grant-Keene

(a) For carrying charge purposes the monthly equity component reflects an 10.5% return on equity.
(b) Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5%, for an effective rate of 38.575%.
(c) In order to gross up the equity component for taxes a monthly rate of 0.006366265 (Equity) and 0.001225871 (Debt), results in the annual pre-tax rate of 9.39%.
(d) All EPU assets have been placed in service as of December 2013 and there are no EPU construction costs in 2014, therefore no transfers to plant took place in 2014.
(e) Line 4 (Column A) - Unamortized carrying charge eligible for return consists of the total under recovered balance beginning in 2014. This amount will be reduced by 2014 collections (Line 5) and a carrying charge will be calculated on the unrecovered balance.

	Docket 120009-EI Errata 2013 Projection	Docket 140009-EI Errata 2013 True-up	2012-2013 (Over)/Under Recovery		
Line 4 Beginning Balances include:					
2012 Over Recovery (2012 T-3, Line 4 Ending Balance)		$11,224,662	$11,224,662		
2013 EPU Carrying Costs (P-3, Line 9 /T-3, Line 9)	$15,449,079	$19,888,093	$4,439,014		
2013 DTA/(DTL) Carrying Cost (P-3A, Line 8/T-3A, Line 8)	($15,200)	($21,257)	($6,057)	$13,568,431	JGK-1, Column (C), Lines 18 + 24, Docket 140009-EI
2013 Base Rate Revenue Requirements (P-Appendix B, Line 33/T- Appendix C, Line 8)	$64,738,202	$73,873,676	$9,135,474		
	$80,172,080	$104,965,173	$24,793,093		

(f) Line 5 (Column A) - Amortization of carrying charge is the amount that was recovered over 12 months in 2014 as approved by the Commission in Order No. PSC 13-0493-FOF-EI. Revised Exhibit WP-5, Column 8, Lines 29 + 35 (July 3, 2013 Errata Filing).

Line 4 Beginning Balance includes:			
2012 Over/Under Recovery of Carrying Costs (WP-1, Col I, Line 16)	$5,938,623		
2012 Over/Under Recovery of Carrying Costs on DTA/(DTL) (WP-1, Col I, Line 17)	($233,218)	$11,224,660	Docket 130009-EI
2012 Over/Under Recovery of Carrying Cost (WP-1, Col I, Line 24)	$5,519,255		
2013 Over/Under Recovery of Carrying Cost (WP-5, Col 6, Line 27)	$4,767,782		
2013 Over/Under Recovery of Carrying Costs on DTA/(DTL) (WP-5, Col 6, Line 28)	($5,952)	$17,489,609	Docket 130009-EI
2013 Over/Under Recovery of Base Rate Revenue Requirements (WP-5, Col 6, Line 35)	$12,727,779		
	$28,714,269	$2,392,856	Monthly Amortization

(g) Line 4 (Column O) - Ending Balance of 2014 consists of the 2013 final true-up amount which will be recovered over 12 months in 2015. This amount does not include Recoverable O&M since (over)/under recoveries will be calculated at the AA Financial 30-day rate posted on the Federal Reserve website.

	Docket 130009-EI 2013 Actual/Estimated	Docket 140009-EI 2013 True-up	2013 (Over)/Under Recovery
2013 EPU Carrying Costs (AE-3, Line 8/T-3, Line 9)	$20,216,861	$19,888,093	($328,768)
2013 DTA/(DTL) Carrying Cost (AE-3A, Line 8/T-3A, Line 8)	($21,153)	($21,257)	($104)
2013 Base Rate Revenue Requirements (AE-Appendix C, Line 8/T-Appendix C, Line 8)	$77,465,981	$73,873,676	($3,592,305)
	$97,661,689	$93,740,511	($3,921,178)

*Totals may not add due to rounding

Schedule T-3 (True-up)

St. Lucie and Turkey Point Uprate Project
Carrying Costs on Prior Period (Over)/Under Recoveries of Construction Costs
True-Up Filling: Construction Costs

[Section (6)(c)1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the calculation of the true-up of carrying costs on construction expenditures, based on actual carrying costs on construction expenditures for the previous year and the previously filed carrying costs.

For the Year Ended 12/31/2014

Witness: Jennifer Grant-Keene

1	(h)	Beginning balance adjustments for Column (A), Line 8:	
2			
3		Prior Year Carrying Charge Adjustment for R&D Tax Deduction True-Up Doc #: 105988020	
4		8b. Equity Component grossed up for taxes	($9,733)
5		8c. Debt Component	($1,745)
6			($11,478)
7		Base Rate Rev Req for Prior Year EO's removed from EPU Doc #:105984032	
8		8b. Equity Component grossed up for taxes	($256)
9		8c. Debt Component	($131)
10			($387)
11		Carrying Charge on over under recovery for Prior Year EO's removed from EPU Doc #:105984032	
12		8b. Equity Component grossed up for taxes	($8)
13		8c. Debt Component	($2)
14			($10)
15		Base Rate Rev Req for Prior Year Capital Removed from EPU Doc #: 105984034	
16		8b. Equity Component grossed up for taxes	($258)
17		8c. Debt Component	($209)
18			($467)
19		Carrying Charge on over under recovery for Prior Year Capital removed from EPU Doc #: 105984034	
20		8b. Equity Component grossed up for taxes	($19)
21		8c. Debt Component	($4)
22			($23)
23		Carrying Charge on Prior Year Capital removed from EPU Doc #: 105987029	
24		8b. Equity Component grossed up for taxes	($504)
25		8c. Debt Component	($145)
26			($649)
27		Carrying Charge on Prior Year Capital removed from EPU Doc #: 105990130	
28		8b. Equity Component grossed up for taxes	($1,853)
29		8c. Debt Component	($967)
30			($2,820)
31		TOTAL Beginning Balance Adjustments for Column (A), Line 9	
32		8b. Equity Component grossed up for taxes	($12,632)
33		8c. Debt Component	($3,202)
34			($15,834)
35	(i)	Line 2 Beginning Balance Includes Adjustments made to Prior year	
36			
37		Adjusting Entry Doc #: 105984032	($6,046)
38		Participant Credit	$0
39		Total	($6,046)
40		Jurisdictional Factor	0.98194011
41		Jurisdictional Adjustment	($5,937)
42			
43		Adjusting Entry Doc #: 105984034	($13,217)
44		Participant Credit	$1,969
45		Total	($11,248)
46		Jurisdictional Factor	0.98194011
47		Jurisdictional Adjustment	($11,045)
48			
49		Adjusting Entry Doc #: 105987029	($5,465)
50		Participant Credit	$246
51		Total	($5,219)
52		Jurisdictional Factor	Various
53		Jurisdictional Adjustment	($5,125)
54			
55		Adjusting Entry Doc #: 105990130	($47,361)
56		Participant Credit	$3,827
57		Total	($43,534)
58		Jurisdictional Factor	Various
59		Jurisdictional Adjustment	($42,749)
60			
61		Total	
62		Adjustment Amount	($72,089)
63		Participant Credit	$6,042
64		Total Capital Adjustment	($66,047)
65			
66		Jurisdictional Adjustment	($64,856)

*Totals may not add due to rounding

St. Lucie and Turkey Point Uprate Project
Interest on Prior Period (Over)/Under Recoveries of O&M Construction Costs
True-Up Filing: Recoverable O&M Monthly Expenditures

[Section (6)(c)1.a.]
[Section (9)(e)]

Schedule T-4 (True-Up)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provide the CCRC Recoverable O&M actual monthly expenditures by function for the prior year.

For the Year Ended 12/31/2014

Witness: Jennifer Grant-Keene

Line No.	Description	(A) Beginning of Period	(B) Actual January	(C) Actual February	(D) Actual March	(E) Actual April	(F) Actual May	(G) Actual June	(H) Actual July	(I) Actual August	(J) Actual September	(K) Actual October	(L) Actual November	(M) Actual December	(N) 12 Month Total	(O) Adjustments (f)	(P) Revised 12 Month Total
1	Administrative & General		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
2	Subtotal A&G		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
3	Energy Delivery Florida																
4																	
5	Jurisdictional Factor (A&G)																
6	Jurisdictional Factor (Distribution)																
7	Jurisdictional Recoverable Costs (A&G) (Line 2 x Line 5)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
8	Jurisdictional Recoverable Costs (Distribution) (Line 3 x Line 6)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
9																	
10	Nuclear Generation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
11	Adjustments	$0	$0	$0	$0	$0	$0	($1,246,154)	$0	$0	$0	$0	$0	$0			
12	**Total Company Nuclear Generation Adjusted**		$0	$0	$0	$0	$0	($1,246,154)	$0	$0	$0	$0	$0	$0	($1,246,154)		
13	Participants Credit PSL Unit 2 (a)																
14	OUC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
15	FMPA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
16	Total Participants Credit PSL Unit 2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
17	Total Nuclear O&M Costs Net of Participants		$0	$0	$0	$0	$0	($1,246,154)	$0	$0	$0	$0	$0	$0	($1,246,154)		
18	Jurisdictional Factor (Nuclear - Production - Base) (f)		0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073	0.95079073		
19	Jurisdictional Recoverable Costs (Nuclear - Production - Base) (Line 17 x Line 18)		$0	$0	$0	$0	$0	($1,184,832)	$0	$0	$0	$0	$0	$0	($1,184,832)		
20																	
21	Transmission		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
22	Jurisdictional Factor (Transmission) (f)		0.88498196	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196	0.88498196		
23	Jurisdictional Recoverable Costs (Transmission) (Line 21 x Line 22)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
24																	
25	Actual Jurisdictional Recoverable O&M Costs for the Period (Line 19 + Line 23)		$0	$0	$0	$0	$0	($1,184,832)	$0	$0	$0	$0	$0	$0	($1,184,832)		
26																	
27	Total Interest Provision (Page 2, Line 17)		($85)	($80)	($67)	($63)	($39)	($22)	($45)	($68)	($55)	($42)	($34)	($24)	($624)		
28																	
29	Actual Jurisdictional Recoverable O&M Costs for the Period Including Interest		($85)	($80)	($67)	($63)	($39)	($1,184,854)	($45)	($68)	($55)	($42)	($34)	($24)	($1,185,456)		
30																	
31	Projected O&M Costs for the period (Order No. PSC 13-0493-FOF-EI)		($169)	($154)	($139)	($125)	($110)	($95)	($81)	($66)	($51)	($37)	($22)	($7)	($1,055)		
32																	
33	(Over)/Under Recovery of O&M Costs Including Interest (Line 29 - Line 31)		$83	$74	$72	$62	$71	($1,184,759)	$36	($2)	($4)	($5)	($12)	($16)	($1,184,400)		
34																	
35	Actual/Estimated Revenue Requirements for the period (Order No. PSC 14-0617-FOF-EI)		($85)	($86)	($72)	($59)	($45)	($1,186,455)	($52)	($73)	($59)	($46)	($32)	($18)	($1,187,084)		
36																	
37	Final True-up of O&M Costs (Line 29 - Line 35)		$0	$6	$5	($4)	$6	$1,602	$7	$5	$4	$3	($2)	($5)	$1,628	($1,628)	$0
38																	
39	**Total Company Generation and Transmission O&M Including Interest**		($85)	($80)	($67)	($63)	($39)	($1,246,176)	($45)	($68)	($55)	($42)	($34)	($24)	($1,246,778)		
40	(Line 12 + Line 21 + Line 27)																

*Totals may not add due to rounding

Schedule T-4 (True-Up)

St. Lucie and Turkey Point Uprate Project
Interest on Prior Period (Over)/Under Recoveries of O&M Construction Costs
True-Up Filing: Recoverable O&M Monthly Expenditures

[Section (6)(c)1.a.]
[Section (9)(e)]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the CCRC Recoverable O&M actual monthly expenditures by function for the prior year.

For the Year Ended 12/31/2014

COMPANY: FLORIDA POWER & LIGHT COMPANY

Witness: Jennifer Grant-Keene

DOCKET NO.: 150009-EI

Line No.	Description	(A) Beginning of Period	(B) Actual January	(C) Actual February	(D) Actual March	(E) Actual April	(F) Actual May	(G) Actual June	(H) Actual July	(I) Actual August	(J) Actual September	(K) Actual October	(L) Actual November	(M) Actual December	(N) 12 Month Total	(O) Adjustments (f)	(P) Revised 12 Month Total
	See notes on Page 2																
1	Total O&M Costs (Page 1, Line 12 + 21)		$0	$0	$0	$0	$0	($1,246,154)	$0	$0	$0	$0	$0	$0	($1,246,154)		
2																	
3	Total Jurisdictional Recoverable O&M Costs (Page 1, Line 25)		$0	$0	$0	$0	$0	($1,184,832)	$0	$0	$0	$0	$0	$0	($1,184,832)		
4																	
5	Prior Period Unrecovered O&M Balance Eligible for Interest (b) (d)	($1,826,036)	($1,591,544)	($1,357,051)	($1,122,559)	($888,066)	($653,574)	($419,082)	($184,589)	$49,903	$284,396	$518,888	$753,380	$987,873			
6																	
7	Prior Period O&M Costs Recovered (c)	($2,813,909)	($234,492)	($234,492)	($234,492)	($234,492)	($234,492)	($234,492)	($234,492)	($234,492)	($234,492)	($234,492)	($234,492)	($234,492)			
8																	
9	Prior Month (over)/under Recovery (Prior Month Line 23)		$0	$83	$74	$72	$62	$71	($1,184,759)	$36	($2)	($4)	($6)	($12)			
10																	
11	Balance Eligible for Interest	($1,826,036)	($1,591,544)	($1,356,968)	($1,122,402)	($887,837)	($653,283)	($418,719)	($1,368,986)	($1,134,457)	($899,967)	($665,478)	($430,991)	($196,511)			
12																	
13	Average Unamortized Balance		($1,708,790)	($1,474,256)	($1,239,685)	($1,005,120)	($770,560)	($536,001)	($893,852)	($1,251,721)	($1,017,212)	($782,722)	($548,235)	($313,751)			
14																	
15	AA Financial 30 Day rate (e)		0.005000%	0.005420%	0.005420%	0.006250%	0.005000%	0.004170%	0.005000%	0.005420%	0.005420%	0.005420%	0.006250%	0.007500%			
16																	
17	Interest Provision (Line 13 x Line 15)	$0	($85)	($80)	($67)	($63)	($39)	($22)	($45)	($68)	($55)	($42)	($34)	($24)	($624)		
18																	
19	Total Jurisdictional O&M Costs and Interest (Line 3 + Line 17)		($85)	($80)	($67)	($63)	($39)	($1,184,854)	($45)	($68)	($55)	($42)	($34)	($24)	($1,185,456)	($1,628)	($1,187,084)
20																	
21	Projected O&M Costs for the period (Order No. PSC 13-0493-FOF-EI)		($169)	($154)	($139)	($125)	($110)	($95)	($81)	($66)	($51)	($37)	($22)	($7)	($1,055)		
22																	
23	Difference (Line 19 - Line 21)		$83	$74	$72	$62	$71	($1,184,759)	$36	($2)	($4)	($6)	($12)	($16)	($1,184,400)	($1,628)	($1,186,029)
24																	
25	*Totals may not add due to rounding																

(a) Adjusted for participant ownership rates of 6.08951% for OUC & 8.806% for FMPA for St. Lucie Unit 2.

(b) Line 5 (Column A) Page 2 - Prior Period Unrecovered O&M Balance Eligible for Interest consists of the total unrecovered balance beginning in 2014. This amount was reduced by 2014 collections (Line 7) and interest was calculated on the unrecovered balance.

2012 Over Recovery (2013 T-4, Line 5, Column N, Page 2 of 2)	($7,347,934)
2013 Recoverable O&M (2013 T-4, Line 23, Column N, Page 2 of 2)	$5,521,898
	($1,826,036)

(c) Line 7 (Column A) Page 2 - Prior Period O&M Costs Recovered is the amount that was collected over 12 months in 2014 as approved by the Commission in Order No. PSC 13-0493-FOF-EI, Revised Exhibit WP-5 Column B, Line 30 (July 3, 2013 Errata Filing).

2012 Over Recovery (2013 T-4, Line 5, Column N, Page 2 of 2)	($7,347,934)	
2013 Recoverable O&M (2013 AE-4, Line 42)	$4,534,025	
	($2,813,909)	($234,492) Monthly Amortization

(d) Line 5 (Column M) Page 2 - Ending Balance consists of the 2013 final true-up amount which is reflected in the amount being refunded over 12 months in 2015.

	Docket 130009-EI 2013 Actual/Estimated	Docket 140009-EI 2013 True-up	2013 Final True-up
2013 Recoverable O&M and interest (AE-4, Line 38 /T-4, Line 38)	$9,611,895	$10,599,767	$987,873
	$9,611,895	$10,599,767	$987,873

(e) Over/under recoveries of recoverable O&M incur interest at the AA Financial 30-day rate posted on the Federal Reserve website.

(f) The under recovery of O&M costs and interest associated with a warranty refund as compared to FPL's May 2014 Actual/Estimated filing is the result of a restatement of the 2014 jurisdictional separation factor. FPL will not seek recovery of $1,628 to end the NCRC recoveries for the EPU project in 2015. This under recovery is adjusted out of the NCRC filing on Schedule T-1, Line 10.

St. Lucie and Turkey Point Uprate Project
Carrying Costs on Prior Years (Over)/Under Recoveries
True-up Filing: Carrying Costs on Base Rate Revenue Requirements

[Section (6)(c)1.b.]

Appendix C (True-up)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provides the calculation of the actual carrying costs on the over/under recovery of base rate revenue requirements (Actual/Estimated vs. Actual).

For the Year Ended 12/31/2014

Witness: Jennifer Grant-Keene

Line No.			(A) Actual January	(B) Actual February	(C) Actual March	(D) Actual April	(E) Actual May	(F) Actual June	(G) 6 Month Total
						Jurisdictional Dollars			
1	Actual Base Rate Revenue Requirements (f)		($65,430)	($65,430)	($65,430)	($65,430)	($65,430)	($66,852)	($394,001)
2	Projected Base Rate Revenue Requirements		$0	$0	$0	$0	$0	$0	$0
3	(Over)/Under Recovery (Line 1 - Line 2)		($65,430)	($65,430)	($65,430)	($65,430)	($65,430)	($66,852)	($394,001)
4	Base Eligible for Return (Line 3) + Prior Months (Line 4 + Line 7)	(e) $677,341	$611,911	$551,375	$490,361	$428,886	$366,946	$303,114	$303,114
5	Average Net Base Rate Revenue Requirements		$644,626	$581,643	$520,868	$459,624	$397,916	$335,030	
6	Return on Average Net Base Rate Revenue Requirements								
a.	Equity Component (Line 6b x .61425) (a)		$2,521	$2,275	$2,037	$1,797	$1,556	$1,310	$11,496
b.	Equity Component grossed up for taxes (Line 5 x 0.00636626) (a) (b) (c)		$4,104	$3,703	$3,316	$2,926	$2,533	$2,133	$18,715
c.	Debt Component (Line 5 x 0.00122587) (c)		$790	$713	$639	$563	$488	$411	$3,604
7	Total Return Requirements (Line 6b + Line 6c)		$4,894	$4,416	$3,955	$3,490	$3,021	$2,544	$22,319
8	2014 Base Rate Revenue Requirements (Line 1 + Line 7) (d)		($60,536)	($61,014)	($61,475)	($61,940)	($62,409)	($64,309)	($371,683)
9	Projected Base Rate Revenue Requirements		$0	$0	$0	$0	$0	$0	$0
10	(Over)/Under Recovery (Line 8 - Line 9)		($60,536)	($61,014)	($61,475)	($61,940)	($62,409)	($64,309)	($371,683)
11	Actual/Estimated Revenue Requirements for the period (Order No. PSC-14-0617-FOF-EI)		($60,634)	($61,113)	($61,575)	($62,041)	($62,510)	($64,413)	($372,285)
12	Final True-up of Base Rate Revenue Requirements (Line 8 - Line 11)		$98	$99	$100	$100	$101	$104	$603

*Totals may not add due to rounding

See notes on Page 3

St. Lucie and Turkey Point Uprate Project
Carrying Costs on Prior Years (Over)/Under Recoveries
True-up Filing: Carrying Costs on Base Rate Revenue Requirements

[Section (6)(c)1.b.]

Appendix C (True-up)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provides the calculation of the actual carrying costs on the over/under recovery of base rate revenue requirements (Actual/Estimated vs. Actual).

For the Year Ended 12/31/2014

Witness: Jennifer Grant-Keene

Line No.		(G) Actual July	(H) Actual August	(I) Actual September	(J) Actual October	(K) Actual November	(L) Actual December	(M) 12 Month Total	(N) Adjustment (g)	(O) Revised 12 Month Total
		Jurisdictional Dollars								
1	Actual Base Rate Revenue Requirements (f)	($66,851)	($66,849)	($66,847)	($66,845)	($66,842)	($66,840)	($795,076)		
2	Projected Base Rate Revenue Requirements	$0	$0	$0	$0	$0	$0	$0		
3	(Over)/Under Recovery (Line 1 - Line 2)	($66,851)	($66,849)	($66,847)	($66,845)	($66,842)	($66,840)	($795,076)		
4	Base Eligible for Return (Line 3) + Prior Months (Line 4 + Line 7)	$238,807	$174,015	$108,735	$42,964	($23,303)	($90,068)	($90,499)		
5	Average Net Base Rate Revenue Requirements	$270,961	$206,411	$141,375	$75,850	$9,831	($56,686)	N/A		
6	Return on Average Net Base Rate Revenue Requirements									
	a. Equity Component (Line 6b x .61425) (a)	$1,060	$807	$553	$297	$38	($222)	$14,029		
	b. Equity Component grossed up for taxes (Line 5 x 0.00636626) (a) (b) (c)	$1,725	$1,314	$900	$483	$63	($361)	$22,839		
	c. Debt Component (Line 5 x 0.00122587) (c)	$332	$253	$173	$93	$12	($69)	$4,398		
7	Total Return Requirements (Line 6b + Line 6c)	$2,057	$1,567	$1,073	$576	$75	($430)	$27,236		
8	2014 Base Rate Revenue Requirements (Line 1 + Line 7) (d)	($64,794)	($65,282)	($65,774)	($66,269)	($66,768)	($67,271)	($767,839)		
9	Projected Base Rate Revenue Requirements	$0	$0	$0	$0	$0	$0	$0		
10	(Over)/Under Recovery (Line 8 - Line 9)	($64,794)	($65,282)	($65,774)	($66,269)	($66,768)	($67,271)	($767,839)	($1,243)	($769,082)
11	Actual/Estimated Revenue Requirements for the period (Order No. PSC-14-0617-FOF-EI)	($64,899)	($65,387)	($65,880)	($66,376)	($66,876)	($67,379)	($769,082)		
12	Final True-up of Base Rate Revenue Requirements (Line 8 - Line 11)	$105	$105	$106	$107	$108	$109	$1,243	($1,243)	$0

*Totals may not add due to rounding

See notes on Page 3

St. Lucie and Turkey Point Uprate Project
Carrying Costs on Prior Years (Over)/Under Recoveries
True-up Filing: Carrying Costs on Base Rate Revenue Requirements

[Section (6)(c)1.b.]

Appendix C (True-up)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY

DOCKET NO.: 150009-EI

EXPLANATION: Provides the calculation of the actual carrying costs on the over/under recovery of base rate revenue requirements (Actual/Estimated vs. Actual).

For the Year Ended 12/31/2014

Witness: Jennifer Grant-Keene

Notes:

(a) For carrying charge purposes the monthly equity component reflects a 10.5% return on equity.

(b) Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 35% and a State Income Tax rate of 5.5% for an effective rate of 38.575%.

(c) In order to gross up the equity component for taxes, a monthly rate of 0.00636626 (Equity) and 0.00122587 (Debt) results in the annual pre-tax rate of 9.39%, effective January 1, 2014.

(d) The actual base rate revenue requirements on Line 8 are reflected on Schedule T-1, Line 5 "Other Adjustments".

(e) This amount represents the true-up of 2012 and 2013 Actual Net Book value of Retirements, Removal and Salvage (NBV) as of December 31, 2013 as filed in FPL's 2014 Base Rate Decrease filing, Docket No. 140197-EI. The NBV's are shown below along with the associated carrying charges:

	NBV	Carrying Charges on NBV
2013 True-up NBV	($202,503)	($19,170)
2012 True-up NBV	$879,843	$83,292
Total	$677,341	$64,122

(f) The Base Rate Revenue Requirements presented are a combination of three parts: (1) a true-up of 2012 Base Rate Increase filed in Docket No. 140197-EI, (2) a true-up of the 2013 Base Rate Increase as filed in Docket No. 140197-EI, and (3) Base Rate Revenue Requirements for a Warranty Claim refund received by FPL in June 2014. The amounts are shown below along with associated carrying charges:

	Revenue Requirements on Plant in Service	Carrying Charges on Revenue Requirements
2013 Reduction in Plant in Service	($779,959)	($36,376)
2012 Reduction in Plant in Service	($5,199)	($242)
2014 Warranty Claim Refund	($9,918)	($267)
Total	($795,076)	($36,886)

(g) The under recovery of Base Rate Revenue Requirements and associated carrying costs as compared to FPL's May 2014 Actual/Estimated filing is the result of a restatement of the 2014 jurisdictional separation factor and adjustments included in FPL's 2014 Base Rate Filing, Docket No. 140197-EI. FPL will not seek recovery of $1,243 to end the NCRC recoveries for the EPU project in 2015. This under recovery is adjusted out of the NCRC filing on Schedule T-1, Line 10.

*Totals may not add due to rounding

Florida Power Light Company
2016 Revenue Requirements (In Jurisdictional $'s net of participants)

Line No.		(1) Dkt. # 140009 2014 Actual/ Estimated	(2) Dkt. # 150009 2014 True-Up	(3)=(2)-(1) 2014 (Over)/ Under Recovery	(4) Dkt. # 140009 2015 Projected Costs	(5) Dkt. # 150009 2015 Actual/ Estimated	(6)=(5)-(4) 2015 (Over)/ Under Recovery	(7)=(2)+(5) Current True-up & Actual/Estimated for 2015	(8)=(3)+(6) Total 2014/2015 (Over)/Under Recovery	(9) Dkt. # 150009 2016 Projected Costs	(10)=(8)+(9) Net Costs to be Recovered/ (Refunded) in 2016	Line No.
1	**Turkey Point 6 & 7 Site Selection**											1
2	Site Selection Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	2
3												3
4	Carrying Costs (b)	($742)	($742)	$0	($95)	$158	$253	($584)	$253	$27	$280	4
5	Carrying Costs on DTA/DTL (d)	$159,144	$159,224	$79	$159,241	$159,586	$345	$318,809	$424	$159,561	$159,985	5
6	Total Carrying Costs	$158,402	$158,482	$79	$159,146	$159,744	$598	$318,225	$677	$159,588	$160,265	6
7												7
8	**Recovery of Costs & Carrying Costs**	$158,402	$158,482	$79	$159,146	$159,744	$598	$318,225	$677	$159,588	$160,265	8
9												9
10												10
11	**Turkey Point 6 & 7 Preconstruction**											11
12												12
13	Pre-Construction Costs	$19,270,470	$18,448,666	($821,804)	$12,548,959	$18,638,220	$6,089,262	$37,086,886	$5,267,457	$21,057,310	$26,324,767	13
14												14
15												15
16	Carrying Costs (b)	($1,252,553)	($1,179,841)	$72,712	$22,626	($62,774)	($85,399)	($1,242,615)	($12,687)	$246,400	$233,713	16
17	Carrying Costs on DTA/DTL (d)	$6,092,317	$6,149,897	$57,580	$6,612,164	$6,709,332	$97,168	$12,859,229	$154,749	$7,376,121	$7,530,869	17
18	Total Carrying Costs	$4,839,764	$4,970,056	$130,292	$6,634,789	$6,646,558	$11,769	$11,616,614	$142,061	$7,622,521	$7,764,582	18
19												19
20	**Recovery of Costs & Carrying Costs**	$24,110,234	$23,418,721	($691,512)	$19,183,748	$25,284,779	$6,101,031	$48,703,500	$5,409,518	$28,679,830	$34,089,349	20
21												21
22	**Total Turkey Point 6 & 7**	$24,268,636	$23,577,203	($691,433)	$19,342,894	$25,444,523	$6,101,628	$49,021,726	$5,410,195	$28,839,419	$34,249,614	22
23	**Uprate**											23
24												24
25	Construction Costs (a)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	25
26												26
27	Carrying Costs (b)	$911,804	$911,804	$0	($233,151)	($233,151)	$0	$678,653	$0	$0	$0	27
28	Carrying Costs on DTA/DTL (d)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	28
29	Total Carrying Costs	$911,804	$911,804	$0	($233,151)	($233,151)	$0	$678,653	$0	$0	$0	29
30	Recoverable O&M including Interest (c)	($1,187,084)	($1,185,456)	$1,628	($69)	($69)	($0)	($1,185,525)	$1,628	$0	$1,628	30
31	Adjustment	$0	($1,628)	($1,628)	$0	$0	$0	($1,628)	($1,628)	$0	($1,628)	31
32	Total Non-Base Rate Related Costs	($275,280)	($275,280)	$0	($233,220)	($233,220)	$0	($508,500)	$0	$0	$0	32
33												33
34	Base Rate Revenue Requirement (e)	($796,243)	($795,076)	$1,167	$0	$0	$0	($795,076)	$1,167	$0	$1,167	34
35	Carrying Costs (Over)/Under Recovery (f)	$27,161	$27,236	$75	$0	$0	$0	$27,236	$75	$0	$75	35
36	Adjustment	$0	($1,243)	($1,243)	$0	$0	$0	($1,243)	($1,243)	$0	($1,243)	36
37		($769,082)	($769,082)	$0	$0	$0	$0	($769,082)	$0	$0	$0	37
38												38
39	**Recovery of Costs, Carrying Costs, and Base**	($1,044,362)	($1,044,362)	$0	($233,220)	($233,220)	$0	($1,277,582)	$0	$0	$0	39
40	**Rate Revenue Requirements**											40
41												41
42												42
43	**Total Recovery**	**$23,224,274**	**$22,532,841**	**($691,433)**	**$19,109,674**	**$25,211,302**	**$6,101,628**	**$47,744,143**	**$5,410,195**	**$28,839,419**	**$34,249,614**	43
44												44

45 (a) Construction Costs are expenditures on major tasks performed.
46 (b) Carrying Costs are costs calculated on the average of the sum of CWIP Charges, Adjustments and Unamortized Carrying Charges from prior years less Monthly Amortization at the most recent effective AFUDC Rate.
47 (c) Recoverable O&M and/or prior year (Over)/Under Recoverable O&M including interest calculated at the AA Finacial 30 Day Rate.
48 (d) Current Year Carrying Costs on Deferred Tax Asset/Deferred Tax Liability are costs calculated on the average of the sum of Construction Period Interest and Recovered Costs Excluding AFUDC/Transfer to Plant at the most recent AFUDC Rate.
49 (e) Base Rate Revenue Requirements are calculated on Plant In-Service, Post In-service and Incremental or Decremental Plant In-Service in the year that the costs are not recognized in Base Rates.
50 (f) Carrying Costs calculated on the (Over)/Under Recovery of the current year Base Rate Revenue Requirements at the most recent AFUDC Rate.

*Totals may not add due to rounding

Docket No. 150009-EI
2016 Revenue Requirements
Exhibit JGK-3, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 20
PARTY: FLORIDA POWER & LIGHT (FPL)
(DIRECT)
DESCRIPTION: Jennifer Grant-Keene JGK-3

Summary of Results from FPL's 2015 Feasibility Analyses of the Turkey Point 6 & 7 Project (Plus Results from Additional Analyses)

	Case # 1 Analyses (40-Year Life)	Case # 2 Analyses (60-Year Life)
1) Number of fuel cost/environmental compliance cost scenarios in which the break-even cost is projected to be above the high-end of the non-binding cost estimate range for Turkey Point 6 & 7:	2 of 7	6 of 7
2) Projected fuel savings for FPL's customers in first full year of operation (approximate nominal $):*	570 million	570 million
3) Projected fuel savings for FPL's customers over the life of Turkey Point 6 & 7 (approximate nominal $):	47 billion	101 billion
4) Number of years of equivalent zero system fuel cost for FPL's customers based on projected nominal fuel savings over the life of Turkey Point 6 & 7 compared to FPL's 2014 annual system fuel cost (approximate years):	13 years	29 years
5) Projected percentage of total FPL energy produced from natural gas and nuclear in first full year of operation of the nuclear units (approximate %):*		
- without Turkey Point 6 & 7	75% Gas & 20% Nuclear	75% Gas & 20% Nuclear
- with Turkey Point 6 & 7	62% Gas & 33% Nuclear	62% Gas & 33% Nuclear
6) Equivalent approximate number of residential customers' annual energy use supplied by Turkey Point 6 & 7 in the first full year of operation*	1,251,000	1,251,000
7) Equivalent annual amount of fossil fuel saved by Turkey Point 6 & 7 beginning in the first full year of operation (approximate):*		
- Equivalent mmBTU of natural gas	184 million	184 million
- Equivalent barrels of oil	29 million	29 million
8) Projected amount of CO_2 emissions reduced by Turkey Point 6 & 7 over the life of the units:	290 million tons	481 million tons
9) Number of months in which FPL's generating system would operate with the equivalent of zero CO_2 emissions based on projected CO_2 emission reduction compared to FPL's 2014 system CO_2 emissions (approximate):	86 (or 7.2 years)	142 (or 11.8 years)

* The first full year of operation for both Turkey Point 6 & 7 units is assumed to be 2029 in both cases.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 21
PARTY: FLORIDA POWER & LIGHT (FPL)
(DIRECT)
DESCRIPTION: Richard O. Brown ROB-1

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear Cost Recovery Clause	DOCKET NO. 150009-EI FILED: July 31, 2015

REVISED ERRATA SHEET OF STEVEN SIM

May 1, 2015 Exhibits

EXHIBIT #	PAGE #	LINE #	
ROB-2	Page 4 of 4	Line 8	Change "$254" to "$255" and "$26" to "$27"

July 3, 2015 Rebuttal Testimony

PAGE #	LINE #	
Page 3	Line 4	Change: "...do…" to "…does…"
Page 6	Line 21	Insert: "total" in front of "nominal"
Page 8	Line 3	Change: "…is essentially unchanged…" to "…is still based on ICF's projections, but contains two modifications."
Page 8	Line 4	Change: "only exception…" to "the first modification…"
Page 8	Line 9	Add: "The second modification is to multiply the ENV II values by 0.80 to create the ENV I forecast, then multiply the ENV II values by 1.20 to create the ENV III forecast."
Page 10	Line 14	Insert after "2020" the following: "and made the other previously described modification to develop the ENV I and ENV III forecasts."
Page 15	Line 13	Insert: "6 & 7" after "Turkey Point"
Page 19	Line 15	Insert: "feasibility" after "economic"
Page 27	Line 7	Change: "many" to "any"

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 22
PARTY: FLORIDA POWER & LIGHT (FPL)
(DIRECT)
DESCRIPTION: Richard O. Brown ROB-2

Comparison of Key Assumptions Utilized in the 2014 and 2015
Feasibility Analyses of the Turkey Point 6 & 7 Project:
Projected Fuel Costs (Medium Fuel Cost Forecast)
(all $ values shown are in Nominal $)

	(1)	(2)	(3) = (2) - (1)
	Forecasted Natural Gas Cost ($/mmBTU)		
Selected Years	2014 Feasibility Analysis	2015 Feasibility Analysis	Change in 2015 Forecast
2027	$8.26	$6.89	($1.37)
2030	$9.19	$7.53	($1.66)
2040	$13.32	$9.63	($3.69)
2050	$19.31	$12.21	($7.10)
2060	$27.99	$15.47	($12.51)
2070	$40.58	$19.62	($20.96)
2080	$58.85	$24.87	($33.97)

	(1)	(2)	(3) = (2) - (1)
	Forecasted 1% S Oil Cost ($/mmBTU)		
Selected Years	2014 Feasibility Analysis	2015 Feasibility Analysis	Change in 2015 Forecast
2027	$21.78	$22.29	$0.51
2030	$23.08	$25.05	$1.97
2040	$27.07	$31.14	$4.07
2050	$31.78	$36.27	$4.50
2060	$37.31	$42.27	$4.96
2070	$43.82	$49.27	$5.46
2080	$51.47	$57.46	$5.99

	(1)	(2)	(3) = (2) - (1)
	Forecasted Nuclear Fuel Cost ($/mmBTU)		
Selected Years	2014 Feasibility Analysis	2015 Feasibility Analysis	Change in 2015 Forecast
2027	$1.01	$0.99	($0.01)
2030	$1.08	$1.11	$0.02
2040	$1.39	$1.28	($0.11)
2050	$1.77	$1.63	($0.14)
2060	$2.27	$2.09	($0.18)
2070	$2.84	$2.61	($0.23)
2080	$3.63	$3.34	($0.29)

Comparison of Key Assumptions Utilized in the 2014 and 2015
Feasibility Analyses of the Turkey Point 6 & 7 Project:
Projected Environmental Compliance Costs (Env II Forecast)
(all $ values shown are in Nominal $)

	(1)	(2)	(3) = (2) - (1)
	Forecasted SO_2 Compliance Cost ($/ton)		
Selected Years	2014 Feasibility Analysis	2015 Feasibility Analysis	Change in 2015 Forecast
2027	$76	$0	($76)
2030	$82	$0	($82)
2040	$105	$0	($105)
2050	$134	$0	($134)
2060	$172	$0	($172)
2070	$220	$0	($220)
2080	$282	$0	($282)

	(1)	(2)	(3) = (2) - (1)
	Forecasted NO_x Compliance Cost ($/ton)		
Selected Years	2014 Feasibility Analysis	2015 Feasibility Analysis	Change in 2015 Forecast
2027	$685	$125	($560)
2030	$737	$125	($612)
2040	$944	$125	($819)
2050	$1,208	$125	($1,083)
2060	$1,547	$125	($1,422)
2070	$1,980	$125	($1,855)
2080	$2,534	$125	($2,409)

	(1)	(2)	(3) = (2) - (1)
	Forecasted CO_2 Compliance Cost ($/ton)		
Selected Years	2014 Feasibility Analysis	2015 Feasibility Analysis	Change in 2015 Forecast
2027	$15	$21	$7
2030	$21	$31	$9
2040	$64	$85	$21
2050	$154	$195	$40
2060	$321	$377	$55
2070	$448	$482	$34
2080	$573	$617	$44

Comparison of Key Assumptions Utilized in the 2014 and 2015
Feasibility Analyses of the Turkey Point 6 & 7 Project:
Summer Peak Demand Load Forecast
(Summer MW)

	(1)	(2)	(3) = (2) - (1)	(4)	(5)
Selected Years	2014 Feasibility Analysis	2015 Feasibility Analysis	Change in 2015 Forecast	Annual Growth with 2015 Peak Demand Forecast	Cumulative Growth with 2015 Peak Demand Forecast
2015	23,356	23,286	(70)	---	---
2016	23,778	23,778	1	493	493
2017	24,190	24,252	62	474	967
2018	24,544	24,648	104	395	1,362
2019	24,896	25,045	149	397	1,759
2020	25,239	25,369	130	324	2,083
2021	25,439	25,497	58	128	2,211
2022	25,908	25,833	(75)	336	2,547
2023	26,528	26,286	(242)	453	3,000
2024	27,214	26,771	(444)	485	3,485
2025	27,877	27,272	(605)	501	3,986
2026	28,505	27,825	(680)	553	4,539
2027	29,135	28,451	(683)	627	5,166
2028	29,731	29,070	(661)	619	5,784
2029	30,261	29,695	(565)	625	6,410
2030	30,786	30,327	(459)	631	7,041
2035	33,444	33,041	(403)	*	*
2040	35,957	35,646	(311)	*	*

* Annual and cumulative growth values not shown due to load forecast projections in this exhibit changing from year-to-year values to 5-year intervals.

Comparison of Key Assumptions Utilized in the 2014 and 2015
Feasibility Analyses of the Turkey Point 6 & 7 Project: Other Assumptions

Assumption	(1) Value for 2014 Feasibility Analysis	(2) Value for 2015 Feasibility Analysis	(3) = (2) - (1) Change in 2015 Forecast
1) Financial/Economic Assumptions (Base Case):			
- Capital Structure (debt/equity)	40.38%/59.62%	40.38%/59.62%	---
- Cost of Debt	5.14%	5.05%	(0.09%)
- Return on Equity	10.50%	10.50%	---
- Discount Rate (after tax)	7.54%	7.51%	(0.03%)
2) CC Generator Capital ($/kW in 2022, w/o AFUDC) for 2014 Analysis ; CC Generator Capital ($/kW in 2027, w/o AFUDC) for 2015 Analysis	$883	$842	---
3) CC Heat Rate (Base 100%, BTU/kWh)	6,334	6,307	(27)
4) Firm Gas Transportation Cost ($/mmBTU in 2023) for 2014 Analysis ; Firm Gas Transportation Cost ($/mmBTU in 2027) for 2015 Analysis	$1.20	$1.37	---
5) Assumed In-Service Dates for Turkey Point Units 6 & 7	2022 & 2023	2027 & 2028	5 years
6) Assumed Operating Lives of Turkey Point Units 6 & 7	40 years or 60 years	40 years or 60 years	---
7) Non-Binding Overnight Cost Estimate for New Nuclear Units ($/kW)	$3,750 to $5,453 in 2014$	$3,844 to $5,589 in 2015$	Change
8) Previously Spent Capital Costs Now Excluded ($ millions, approx.)	$228	$254	$26
9) Cumulative Annual Capital Expenditure Percentage for TP 6 & 7 (assuming 2022 & 2023 in-service dates for the 2014 Analysis; assuming 2027 & 2028 in-service dates for the 2015 Analysis):			
2014	1.6%	1.4%	---
2015	I.7%	1.6%	---
2016	13.6%	1.7%	---
2017	27.1%	1.8%	---
2018	41.9%	2.3%	---
2019	57.6%	2.7%	---
2020	72.1%	6.4%	---
2021	85.4%	14.7%	---
2022	97.2%	26.9%	---
2023	100.0%	41.7%	---
2024	---	57.5%	---
2025	---	72.0%	---
2026	---	85.4%	---
2027	---	97.2%	---
2028	---	100.0%	---

Projection of FPL's Resource Needs Through 2030
(Assuming No Turkey Point 6 & 7 and No Other Generation Additions from 2027 - On)

August of the Year	(1) Projected FPL Unit Capability * (MW)	(2) Projected Firm Capacity Purchases (MW)	(3) Projected Scheduled Maintenance (MW)	(4) = (1) + (2) - (3) Projected Total Capacity (MW)	(5) Projected Peak Load (MW)	(6) Projected Summer DSM Capability ** (MW)	(7) = (5) - (6) Projected Firm Peak Load (MW)	(8) = (4) - (7) Projected Summer Reserves (MW)	(9) = (8) / (7) Projected Summer Total Reserve Margin w/o Additions (%)	(10) = ((7)*1.20)-(4) **Projected MW Needed to Meet 20% Total Reserve Margin*** (MW)**	(11) = ((4)-(5)) / (5) Projected Generation-Only Reserve Margin (GRM) w/o Additions (%)	(12) = ((5)*1.10)-(4) **Projected MW Needed to Meet 10% GRM**** (MW)**
2015	25,008	2,015	0	27,022	23,286	1,951	21,335	5,688	26.7%	**(1,421)**	16.0%	**(1,408)**
2016	25,585	837	0	26,421	23,778	2,000	21,779	4,643	21.3%	**(287)**	11.1%	**(265)**
2017	26,002	837	0	26,838	24,252	2,046	22,207	4,632	20.9%	**(190)**	10.7%	**(161)**
2018	26,230	837	0	27,067	24,648	2,092	22,555	4,512	20.0%	**(1)**	9.8%	**45**
2019	27,666	455	0	28,120	25,045	2,140	22,905	5,216	22.8%	**(635)**	12.3%	**(571)**
2020	27,666	455	0	28,120	25,369	2,188	23,181	4,939	21.3%	**(303)**	10.8%	**(214)**
2021	27,753	635	0	28,388	25,497	2,237	23,260	5,128	22.0%	**(476)**	11.3%	**(341)**
2022	27,839	635	0	28,473	25,833	2,287	23,546	4,927	20.9%	**(218)**	10.2%	**(57)**
2023	29,155	635	0	29,790	26,286	2,338	23,948	5,841	24.4%	**(1,052)**	13.3%	**(875)**
2024	29,155	635	0	29,789	26,771	2,389	24,381	5,408	22.2%	**(532)**	11.3%	**(342)**
2025	30,471	635	0	31,106	27,272	2,440	24,832	6,274	25.3%	**(1,308)**	14.1%	**(1,107)**
2026	30,471	305	0	30,775	27,825	2,490	25,335	5,441	21.5%	**(374)**	10.6%	**(168)**
2027	30,471	290	0	30,761	28,451	2,540	25,911	4,849	18.7%	**333**	8.1%	**536**
2028	30,471	290	0	30,761	29,070	2,590	26,480	4,281	16.2%	**1,015**	5.8%	**1,216**
2029	30,471	290	0	30,761	29,695	2,640	27,055	3,706	13.7%	**1,706**	3.6%	**1,904**
2030	30,471	290	0	30,761	30,327	2,690	27,637	3,124	11.3%	**2,403**	1.4%	**2,598**

* MW values shown in Column (1) include: the completion of the Port Everglades modernization project in 2016, the retirement of 44 of the 48 existing GTs in Broward County in late 2016 & the addition of 5 new CTs at the Lauderdale site and 2 CTs at the Ft.Myers site in late 2016, the upgraded capacity of Ft.Myers 3A&3B, the the addition of a new Okeechobee CC unit in 2019, the addition of firm capacity from the Eco-Gen PPA in 2021, the addition of a one-year 207 MW PPA in 2018, and 116 MW of firm PV in late 2016, and the addition of a new unsited CC in 2023 and 2025. (Note that the 2019 Okeechobee CC addition is a placeholder until a decision regarding FPL's capacity RFP is made.

** The DSM values shown in Column (6) account for incremental DSM additions as per the 2014 DSM Goals docket for 2015 through 2024, for projected annual participant attrition in FPL's existing residential load management program, and for assumed 50 MW/year of new DSM for 2025 through 2030.

*** MW values shown in Column (10) represent new generating capacity needed to meet the 20% total reserve margin criterion.

**** MW values shown in Column (12) represent new generating capacity needed to meet the 10% generation-only reserve margin criterion (GRM).

Docket No. 150009-EI
Projection of FPL's Resource Needs Through 2030
Exhibit ROB-3, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 23
PARTY: FLORIDA POWER & LIGHT (FPL) (DIRECT)
DESCRIPTION: Richard O. Brown ROB-3

The Two Resource Plans Utilized in FPL's 2015 Feasibility Analyses of the Turkey Point 6 & 7 Project

Resource Plan with TP 6&7	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030 - on
Unit(s)/capacity added	---	Port Everglades Modernization	223 MWs of Solar; 5 new CTs @ Lauderdale; 2 new CTs @ Ft.Myers	---	Okeechobee 3x1 CC Unit	---	---	---	(1) Greenfield 3x1 CC Unit	---	(1) Greenfield 3x1 CC Unit	---	Turkey Point 6	Turkey Point 7	---	*
Projected Summer Total Reserve Margin	26.7%	21.3%	20.9%	20.0%	22.8%	21.3%	22.0%	20.9%	24.4%	22.2%	25.3%	21.5%	23.0%	24.5%	21.8%	(meets criterion in all yrs)
Projected Summer Generation Only Reserve Margin	16.0%	11.1%	10.7%	9.8%	12.3%	10.8%	11.3%	10.2%	13.3%	11.3%	14.1%	10.6%	12.0%	13.4%	11.0%	(meets criterion in all yrs)
Resource Plan without TP 6&7	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030 - on**
Unit(s)/capacity added	---	Port Everglades Modernization	223 MWs of Solar; 5 new CTs @ Lauderdale; 2 new CTs @ Ft.Myers	---	Okeechobee 3x1 CC Unit	---	---	---	(1) Greenfield 3x1 CC Unit	---	(1) Greenfield 3x1 CC Unit	---	(1) Greenfield 3x1 CC Unit	---	(1) Greenfield 3x1 CC Unit	*
Projected Summer Total Reserve Margin	26.7%	21.3%	20.9%	20.0%	22.8%	21.3%	22.0%	20.9%	24.4%	22.2%	25.3%	21.5%	23.8%	21.1%	23.4%	(meets criterion in all yrs)
Projected Summer Generation Only Reserve Margin	16.0%	11.1%	10.7%	9.8%	12.3%	10.8%	11.3%	10.2%	13.3%	11.3%	14.1%	10.6%	12.7%	10.3%	12.5%	(meets criterion in all yrs)

Notes: - FPL's total reserve margin criterion is a minimum of 20.0% and its generation-only reserve margin is a minimum of 10%.
- Reserve margin values shown account for : the completion of the Port Everglades modernization project in 2016, the retirement of 44 of 48 existing GTs in Broward County in late 2016 & the addition of 5 new CTs at the Lauderdale site and 2 CTs at the Ft.Myers site in late 2016, the upgraded capacity of Ft.Myers 3A&3B, the the additiou of a new Okeechobee CC unit in 2019, the addition of firm capacity from the Eco-Gen PPA in 2021, the addition of a one-year 206 MW PPA in 2018, and 223 MW of PV capacity in late 2016 (which equates to 116 MW of firm capacity), and the addition of a new unsited CC in 2023 and 2025. (Note that the 2019 Okeechobee CC addition is a place holder until a final decision regarding FPL's capacity RFP is made.)

* The remaining unit additions starting in the year 2030 are 660 MW Filler Unit additions.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 24
PARTY: FLORIDA POWER & LIGHT (FPL) (DIRECT)
DESCRIPTION: Richard O. Brown ROB-4

Docket No. 150009-EI
The Two Resource Plans Utilized in FPL's 2015 Feasibility Analyses of the Turkey Point 6 & 7 Project
Exhibit ROB-4, Page 1 of 1

2015 Feasibility Analyses Results for the Turkey Point 6 & 7 Project: Case # 1 Analysis - 40-Year Operating Life; Total Costs, Total Cost Differentials, and Breakeven Costs for All Fuel and Environmental Compliance Cost Scenarios in 2015$ (millions, CPVRR, 2015 - 2068)

(1)	(2)	(3)	(4)	(5) = (3) - (4)	(6)
Fuel Cost Forecast	Environmental Compliance Cost Forecast	Total Costs for Plans		Total Cost Difference Plan with TP 6 & 7 minus Plan without TP 6 & 7 *	Breakeven Nuclear Capital Costs ($/kW in 2015$)
		Resource Plan w/ TP 6 & 7	Resource Plan w/o TP 6 & 7		
High Fuel Cost	Env I	140,810	151,571	(10,762)	5,254
High Fuel Cost	Env II	148,047	159,595	(11,548)	5,639
High Fuel Cost	Env III	155,298	167,645	(12,348)	6,031
Medium Fuel Cost	Env I	125,989	135,525	(9,536)	4,654
Medium Fuel Cost	Env II	133,186	143,498	(10,312)	5,034
Medium Fuel Cost	Env III	140,393	151,496	(11,103)	5,421
Low Fuel Cost	Env I	110,950	119,248	(8,298)	4,049

*The TP 6 & 7 savings values in Column (5) also represent CPVRR breakeven capital costs for each scenario.

Note: The TP 6 & 7 non-binding cost estimate range to which the breakeven cost is compared is $3,844/kW to $5,589/kW in 2015$.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 25
PARTY: FLORIDA POWER & LIGHT (FPL)
(DIRECT)
DESCRIPTION: Richard O. Brown ROB-5

2015 Feasibility Analyses Results for the Turkey Point 6 & 7 Project: Case # 2 Analysis - 60-Year Operating Life; Total Costs, Total Cost Differentials, and Breakeven Costs for All Fuel and Environmental Compliance Cost Scenarios in 2015$ (millions, CPVRR, 2015 - 2088)

(1)	(2)	(3)	(4)	(5) = (3) - (4)	(6)
Fuel Cost Forecast	Environmental Compliance Cost Forecast	Total Costs for Plans		Total Cost Difference Plan with TP 6 & 7 minus Plan without TP 6 & 7 *	Breakeven Nuclear Capital Costs ($/kW in 2015$)
		Resource Plan w/ TP 6 & 7	Resource Plan w/o TP 6 & 7		
High Fuel Cost	Env I	165,666	178,785	(13,119)	6,408
High Fuel Cost	Env II	177,061	191,427	(14,366)	7,018
High Fuel Cost	Env III	188,470	204,108	(15,638)	7,640
Medium Fuel Cost	Env I	149,624	161,367	(11,743)	5,734
Medium Fuel Cost	Env II	160,969	173,950	(12,982)	6,341
Medium Fuel Cost	Env III	172,319	186,565	(14,246)	6,959
Low Fuel Cost	Env I	133,349	143,709	(10,360)	5,058

*The TP 6 & 7 savings values in Column (5) also represent CPVRR breakeven capital costs for each scenario.

Note: The TP 6 & 7 non-binding cost estimate range to which the breakeven cost is compared is $3,844/kW to $5,589/kW in 2015$.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 26
PARTY: FLORIDA POWER & LIGHT (FPL)
(DIRECT)
DESCRIPTION: Richard O. Brown ROB-6

EDUCATION: Ph.D., Nuclear Engineering, Georgia Tech 1971
MS, Nuclear Engineering, Georgia Tech 1969
BS, Mechanical Engineering, Georgia Tech 1968

ENGINEERING REGISTRATION: Registered Professional Engineer

PROFESSIONAL MEMBERSHIP: American Nuclear Society

EXPERIENCE:

Dr. Jacobs has over thirty-five years of experience in a wide range of activities in the electric power generation industry. He has extensive experience in the construction, startup and operation of nuclear power plants. While at the Institute of Nuclear Power Operation (INPO), Dr. Jacobs assisted in development of INPO's outage management evaluation group. He has provided expert testimony related to nuclear plant operation and outages in Texas, Louisiana, South Carolina, Florida, Wisconsin, Indiana, Georgia and Arizona. He currently provides nuclear plant operational monitoring services for GDS clients. Dr. Jacobs was a witness in nuclear plant certification hearings in Georgia for the Plant Vogtle 3 and 4 project on behalf of the Georgia Public Service Commission and in South Carolina for the V.C. Summer 2 and 3 projects on behalf of the South Carolina Office of Regulatory Staff. His areas of expertise include evaluation of reactor technology, EPC contracting, risk management and mitigation, project cost and schedule. He is assisting the Florida Office of Public Counsel in monitoring the development of four new nuclear units in the State of Florida, Levy County Units 1 and 2 and Turkey Point Units 6 and 7. He also evaluated extended power uprates on five nuclear units for the Florida Office of Public Counsel. He has been selected by the Georgia Public Service Commission as the Independent Construction Monitor for Georgia Power Company's new AP1000 nuclear power plants, Plant Vogtle Units 3 and 4. He has assisted the Georgia Public Service Commission staff in development of energy policy issues related to supply-side resources and in evaluation of applications for certification of power generation projects and assists the staff in monitoring the construction of these projects. He has also assisted in providing regulatory oversight related to an electric utility's evaluation of responses to an RFP for a supply-side resource and subsequent negotiations with short-listed bidders. He has provided technical litigation support and expert testimony support in several complex law suits involving power generation facilities. He monitors power plant operations for GDS clients and has provided testimony on power plant operations and decommissioning in several jurisdictions. Dr. Jacobs represents a GDS client on the management committee of a large coal-fired power plant currently under construction. Dr. Jacobs has provided testimony before the Georgia Public Service Commission, the Public Utility Commission of Texas, the North Carolina Utilities Commission, the South Carolina Public Service Commission, the Iowa State Utilities Board, the Louisiana Public Service Commission, the Florida Public Service Commission, the Indiana

FLORIDA PUBLIC SERVICE COMMISSION
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Regulatory Commission, the Wisconsin Public Service Commission, the Arizona Corporation Commission and the FERC.

A list of Dr. Jacobs' testimony is available upon request.

1986-Present GDS Associates, Inc.

As Executive Consultant, Dr. Jacobs assists clients in evaluation of management and technical issues related to power plant construction, operation and design. He has evaluated and testified on combustion turbine projects in certification hearings and has assisted the Georgia PSC in monitoring the construction of the combustion turbine projects. Dr. Jacobs has evaluated nuclear plant operations and provided testimony in the areas of nuclear plant operation, construction prudence and decommissioning in nine states. He has provided litigation support in complex law suits concerning the construction of nuclear power facilities. Dr. Jacobs is the Georgia PSC's Independent Construction Monitor for the Plant Vogtle 3 and 4 nuclear project.

1985-1986 Institute of Nuclear Power Operations (INPO)

Dr. Jacobs performed evaluations of operating nuclear power plants and nuclear power plant construction projects. He developed INPO Performance Objectives and Criteria for the INPO Outage Management Department. Dr. Jacobs performed Outage Management Evaluations at the following nuclear power plants:

- Connecticut Yankee - Connecticut Yankee Atomic Power Co.
- Callaway Unit I - Union Electric Co.
- Surry Unit I - Virginia Power Co.
- Ft. Calhoun - Omaha Public Power District
- Beaver Valley Unit 1 - Duquesne Light Co.

During these outage evaluations, he provided recommendations to senior utility management on techniques to improve outage performance and outage management effectiveness.

1979-1985 Westinghouse Electric Corporation

As site manager at Philippine Nuclear Power Plant Unit No. 1, a 655 MWe PWR located in Bataan, Philippines, Dr. Jacobs was responsible for all site activities during completion phase of the project. He had overall management responsibility for startup, site engineering, and plant completion departments. He managed workforce of approximately 50 expatriates and 1700 subcontractor

personnel. Dr. Jacobs provided day-to-day direction of all site activities to ensure establishment of correct work priorities, prompt resolution of technical problems and on schedule plant completion.

Prior to being site manager, Dr. Jacobs was startup manager responsible for all startup activities including test procedure preparation, test performance and review and acceptance of test results. He established the system turnover program, resulting in a timely turnover of systems for startup testing.

As startup manager at the KRSKO Nuclear Power Plant, a 632 MWe PWR near Krsko, Yugoslavia, Dr. Jacobs' duties included development and review of startup test procedures, planning and coordination of all startup test activities, evaluation of test results and customer assistance with regulatory questions. He had overall responsibility for all startup testing from Hot Functional Testing through full power operation.

1973 - 1979 NUS Corporation

As Startup and Operations and Maintenance Advisor to Korea Electric Company during startup and commercial operation of Ko-Ri Unit 1, a 595 MWe PWR near Pusan, South Korea, Dr. Jacobs advised KECO on all phases of startup testing and plant operations and maintenance through the first year of commercial operation. He assisted in establishment of administrative procedures for plant operation.

As Shift Test Director at Crystal River Unit 3, an 825 MWe PWR, Dr. Jacobs directed and performed many systems and integrated plant tests during startup of Crystal River Unit 3. He acted as data analysis engineer and shift test director during core loading, low power physics testing and power escalation program.

As Startup engineer at Kewaunee Nuclear Power Plant and Beaver Valley, Unit 1, Dr. Jacobs developed and performed preoperational tests and surveillance test procedures.

1971 - 1973 Southern Nuclear Engineering, Inc.

Dr. Jacobs performed engineering studies including analysis of the emergency core cooling system for an early PWR, analysis of pressure drop through a redesigned reactor core support structure and developed a computer model to determine tritium build up throughout the operating life of a large PWR.

SIGNIFICANT CONSULTING ASSIGNMENTS:

Georgia Public Service Commission – Selected as the Independent Construction Monitor to assist the GPSC staff in monitoring all aspects of the design, licensing and construction of Plant Vogtle Units 3 and 4, two AP1000 nuclear power plants.

Georgia Public Service Commission – Assisted the Georgia Public Service Commission Staff and provided testimony related to the evaluation of Georgia Power Company's request for certification to construct two AP1000 nuclear power plants at the Plant Vogtle site.

South Carolina Office of Regulatory Staff – Assisted the South Carolina Office of Regulatory Staff in evaluation of South Carolina Electric and Gas' request for certification of two AP1000 nuclear power plants at the V.C. Summer site.

Florida Office of Public Counsel – Assists the Florida Office of Public Counsel in monitoring the development of four new nuclear power plants and extended power uprates on five nuclear units in Florida including providing testimony on the prudence of expenditures.

East Texas Electric Cooperative – Represented ETEC on the management committee of the Plum Point Unit 1 a 650 MW coal-fired plant under construction in Osceola, Arkansas and represents ETEC on the management committee of the Harrison County Power Project, a 525 MW combined cycle power plant located near Marshall, Texas.

Arizona Corporation Commission – Evaluated operation of the Palo Verde Nuclear Generating Station during the year 2005. Included evaluation of 11 outages and providing written and oral testimony before the Arizona Corporation Commission.

Citizens Utility Board of Wisconsin – Evaluated Spring 2005 outage at the Kewaunee Nuclear Power Plant and provided direct and surrebuttal testimony before the Wisconsin Public Service Commission.

Georgia Public Service Commission - Assisted the Georgia PSC staff in evaluation of Integrated Resource Plans presented by two investor owned utilities. Review included analysis of purchase power agreements, analysis of supply-side resource mix and review of a proposed green power program.

State of Hawaii, Department of Business, Economic Development and Tourism – Assisted the State of Hawaii in development and analysis of a Renewable Portfolio Standard to increase the amount of renewable energy resources developed to meet growing electricity demand. Presented the results of this work in testimony before the State of Hawaii, House of Representatives.

Georgia Public Service Commission - Assisted the Georgia PSC staff in providing oversight to the bid evaluation process concerning an electric utility's evaluation of responses to a Request for Proposals for supply-side resources. Projects evaluated include simple cycle combustion turbine projects, combined cycle combustion turbine projects and co-generation projects.

Millstone 3 Nuclear Plant Non-operating Owners – Evaluated the lengthy outage at Millstone 3 and provided analysis of outage schedule and cost on behalf of the non-operating owners of Millstone 3. Direct testimony provided an analysis of additional post-outage O&M costs that would result due to the outage. Rebuttal testimony dealt with analysis of the outage schedule.

H.C. Price Company – Evaluated project management of the Healy Clean Coal Project on behalf of the General Contractor, H.C. Price Company. The Healy Clean Coal Project is a 50 megawatt coal burning power plant funded in part by the DOE to demonstrate advanced clean coal technologies. This project involved analysis of the project schedule and evaluation of the impact of the owner's project management performance on costs incurred by our client.

Steel Dynamics, Inc. – Evaluated a lengthy outage at the D.C. Cook nuclear plant and presented testimony to the Indiana Utility Regulatory Commission in a fuel factor adjustment case Docket No. 38702-FAC40-S1.

Florida Office of Public Counsel - Evaluated lengthy outage at Crystal River Unit 3 Nuclear Plant. Submitted expert testimony to the Florida Public Service Commission in Docket No. 970261-EI.

United States Trade and Development Agency - Assisted the government of the Republic of Mauritius in development of a Request for Proposal for a 30 MW power plant to be built on a Build, Own, Operate (BOO) basis and assisted in evaluation of Bids.

Louisiana Public Service Commission Staff - Evaluated management and operation of the River Bend Nuclear Plant. Submitted expert testimony before the LPSC in Docket No. U-19904.

U.S. Department of Justice - Provided expert testimony concerning the in-service date of the Harris Nuclear Plant on behalf of the Department of Justice U.S. District Court.

City of Houston - Conducted evaluation of a lengthy NRC required shutdown of the South Texas Project Nuclear Generating Station.

Georgia Public Service Commission Staff - Evaluated and provided testimony on Georgia Power Company's application for certification of the Intercession City Combustion Turbine Project - Docket No. 4895-U.

Seminole Electric Cooperative, Inc. - Evaluated and provided testimony on nuclear decommissioning and fossil plant dismantlement costs - FERC Docket Nos. ER93-465-000, et al.

Georgia Public Service Commission Staff - Evaluated and prepared testimony on application for certification of the Robins Combustion Turbine Project by Georgia Power Company - Docket No. 4311-U.

North Carolina Electric Membership Corporation - Conducted a detailed evaluation of Duke Power Company's plans and cost estimate for replacement of the Catawba Unit 1 Steam Generators.

Georgia Public Service Commission Staff - Evaluated and prepared testimony on application for certification of the McIntosh Combustion Turbine Project by Georgia Power Company and Savannah Electric Power Company - Docket No. 4133-U and 4136-U.

New Jersey Rate Counsel - Review of Public Service Electric & Gas Company nuclear and fossil capital additions in PSE&G general rate case.

Corn Belt Electric Cooperative/Central Iowa Power Electric Cooperative - Directs an operational monitoring program of the Duane Arnold Energy Center (565 MWe BWR) on behalf of the non-operating owners.

Cities of Calvert and Kosse - Evaluated and submitted testimony of outages of the River Bend Nuclear Station - PUCT Docket No. 10894.

Iowa Office of Consumer Advocate - Evaluated and submitted testimony on the estimated decommissioning costs for the Cooper Nuclear Station - IUB Docket No. RPU-92-2.

Georgia Public Service Commission/Hicks, Maloof & Campbell - Prepared testimony related to Vogtle and Hatch plant decommissioning costs in 1991 Georgia Power rate case - Docket No. 4007-U.

City of El Paso - Testified before the Public Utility Commission of Texas regarding Palo Verde Unit 3 construction prudence - Docket No. 9945.

City of Houston - Testified before Texas Public Utility Commission regarding South Texas Project nuclear plant outages - Docket No. 9850.

NUCOR Steel Company - Evaluated and submitted testimony on outages of Carolina Power and Light nuclear power facilities - SCPSC Docket No. 90-4-E.

Georgia Public Service Commission/Hicks, Maloof & Campbell - Assisted Georgia Public Service Commission staff and attorneys in many aspects of Georgia Power Company's 1989 rate case including nuclear operation and maintenance costs, nuclear performance incentive plan for Georgia and provided expert testimony on construction prudence of Vogtle Unit 2 and decommissioning costs of Vogtle and Hatch nuclear units - Docket No. 3840-U.

Swidler & Berlin/Niagara Mohawk - Provided technical litigation support to Swidler & Berlin in law suit concerning construction mismanagement of the Nine Mile 2 Nuclear Plant.

Long Island Lighting Company/Shea & Gould - Assisted in preparation of expert testimony on nuclear plant construction.

North Carolina Electric Membership Corporation - Prepared testimony concerning prudence of construction of Carolina Power & Light Company's Shearon Harris Station - NCUC Docket No. E-2, Sub537.

City of Austin, Texas - Prepared estimates of the final cost and schedule of the South Texas Project in support of litigation.

Tex-La Electric Cooperative/Brazos Electric Cooperative - Participated in performance of a construction and operational monitoring program for minority owners of Comanche Peak Nuclear Station.

Tex-La Electric Cooperative/Brazos Electric Cooperative/Texas Municipal Power Authority (Attorneys - Burchette & Associates, Spiegel & McDiarmid, and Fulbright & Jaworski) - Assisted GDS personnel as consulting experts and litigation managers in all aspects of the lawsuit brought by Texas Utilities against the minority owners of Comanche Peak Nuclear Station.

State of Florida

Public Service Commission

Office of Auditing and Performance Analysis
Bureau of Auditing
Miami District Office

Auditor's Report

Florida Power & Light Company
Nuclear Cost Recovery Clause
Turkey Point Units 6 & 7

Twelve Months Ended December 31, 2014

Docket No. 150009-EI
Audit Control No. 15-005-4-1
June 8, 2015

Iliana H. Piedra
Audit Manager

Bety Maitre
Audit Staff

Jeffery A. Small
Reviewer

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 28
PARTY: STAFF RE: FPL
DESCRIPTION: Iliana H. Piedra IHP-1

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Purpose

To: Florida Public Service Commission

We have performed the procedures described later in this report to meet the agreed-upon objectives set forth by the Office of Industry Development and Market Analysis in its audit service request dated January 02, 2015. We have applied these procedures to the attached schedules prepared by Florida Power & Light Company, and to several of its related schedules in support of its 2014 filing for the Nuclear Cost Recovery Clause (Turkey Point Units 6 & 7 Project) in Docket No. 150009-EI.

This audit was performed following General Standards and Fieldwork Standards found in the AICPA Statements on Standards for Attestation Engagements. Our report is based on agreed-upon procedures. The report is intended only for internal Commission use.

Objectives and Procedures

General

Definitions

Site selection costs are costs that are expended prior to the selection of a site.

Pre-construction costs are costs that are expended after a site has been selected in preparation for the construction of a nuclear power plant, incurred up to and including the date the utility completes site clearing work.

FPL/Utility refers to Florida Power & Light Company.
CCRC refers to Capacity Cost Recovery Clause.
NCRC refers to Nuclear Cost Recovery Clause.

Objectives: The objective was to determine whether the Utility's 2014 NCRC filings in Docket No. 150009-EI are consistent and in compliance with Section 366.93, Florida Statutes (F.S.), and Rule 25-6.0423, Florida Administrative Code (F.A.C.)

Procedures: We performed the following specific objectives and procedures to satisfy the overall objective identified above.

Construction Work in Progress (CWIP)

Objectives: The objectives were to verify that pre-construction costs listed on the Utility's Schedule T-6 filing were supported by adequate documentation and that the capital additions were appropriately recoverable through the NCRC and in compliance with Section 366.93, F.S. and Rule 25-6.043, F.A.C.

Procedures: We sampled and verified the monthly pre-construction expenditures and traced to invoices and other supporting documentation including contracts. We verified various sample items to purchase orders for contracts over $250,000. We verified a sample of salary expenses and agreed to time sheets. We recalculated the respective overheads. We verified affiliate charges by comparing the cost rate to a market rate to determine that the lower rate was used. We performed an overall calculation of the affiliate rate per hour including overheads. We verified a sample of legal fees and agreed to invoices. We agreed the calculation of the jurisdictional factor to the Utility's documentation. We recalculated Schedule T-6. No exceptions were noted.

Recovery

Objectives: The objectives were to determine whether the Utility used the Commission approved CCRC factors to bill customers for the period January 1, 2014 through December 31, 2014 and whether Schedules T-2 and T3A reflect the amounts in Order No. PSC-13-0493-FOF-EI, issued October 18, 2013.

Procedures: We agreed the amount collected on the Schedule T-1 to the NCRC jurisdictional amount approved in Order No. PSC-13-0493-FOF-EI, and to the CCRC in Docket No. 150001-EI. No exceptions were noted.

Carrying Cost on Deferred Tax Adjustment

Objectives: The objectives were to determine whether Schedule T-3A - Carrying Cost on Deferred Tax Assets (DTA) included the correct balances from the supporting schedules and the deferred tax adjustment is accurately calculated.

Procedures: We traced the projected and estimated True-Up amount to prior NCRC Orders. We traced the beginning balances included in the schedule to the prior audit. We reconciled the monthly recovered costs to the supporting schedules in the filing. We traced the Allowance for Funds Used During Construction (AFUDC) rate applied to the rates approved in Order No. PSC-14-0193-PAA-EI, issued April 25, 2014. We recalculated Schedule T-3A and verified the Final True-Up amount. No exceptions were noted.

Other Issues

Objectives: The objectives were to determine whether the carrying cost for site selection and pre-construction costs listed on the Utility's Schedule T-2 include the correct balances from the supporting schedules of the filing and were appropriately calculated.

Procedures: We traced the projected and estimated true-up amounts to prior NCRC Orders. We traced the beginning balances included in the schedule to the prior docket. We reconciled the monthly costs to the supporting schedules in the filing. We traced the AFUDC rate applied by the Utility to the rate approved in Order No. PSC-14-0193-PAA-EI. We recalculated Schedule T-2 and verified the Final True-Up. We traced adjustments to proper source documentation. No exceptions were noted.

True-Up

Objectives: The objective was to determine whether the final True-Up filed on Schedule T-1 was properly calculated.

Procedures: We traced the December 31, 2013, Site Selection and Pre-Construction True-Up Provisions to the Commission Order. We recalculated the True-Up and Interest Provision amounts as of December 31, 2014 using the Commission approved beginning balances as of December 31, 2013, the approved AFUDC interest rate, and the 2014 costs. No exceptions were noted.

Audit Findings

None

Exhibits

Exhibit 1: Schedule T-1 True-Up of Site Selection Cost

Turkey Point Units 6&7
Carrying Costs on Prior Period Site Selection Cost Balance
True-up Filing: Retail Revenue Requirements Summary

Schedule T-1 (True-up) [Section (6)(c)1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the true-up of total retail revenue requirements based on actual expenditures for the prior year and the previously filed expenditures.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2014

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.		(A) Actual January	(B) Actual February	(C) Actual March	(D) Actual April	(E) Actual May	(F) Actual June	(G) 6 Month Total
		Jurisdictional Dollars						
1	Site Selection Revenue Requirements (Schedule T-2, Line 7)	($942)	($939)	($940)	($940)	($941)	($941)	($5,643)
2	Construction Carrying Cost Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
3	Recoverable O&M Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
4	DTA/(DTL) Carrying Cost (Schedule T-3A, Line 8)	$13,276	$13,275	$13,275	$13,274	$13,273	$13,272	$79,646
5	Other Adjustments	$0	$0	$0	$0	$0	$0	$0
6	Total Period Revenue Requirements (Lines 1 though 5)	$12,334	$12,336	$12,335	$12,334	$12,332	$12,331	$74,003
7	Projected Carrying Cost on DTA/(DTL) for the Period (Order No. PSC 13-0493-FOF-EI)	$13,374	$13,374	$13,374	$13,374	$13,374	$13,374	$80,244
8	Difference (True-up to Projections) (Over)/Under Recovery for the Period (Line 6 - Line 7)	($1,040)	($1,038)	($1,039)	($1,040)	($1,042)	($1,043)	($6,241)
9	Actual/Estimated Revenue Requirements for the period (Order No. PSC 14-0617-FOF-EI)	$13,194	$13,197	$13,195	$13,194	$13,193	$13,191	$79,164
10	Final True-up Amount for the Period (Line 6 - Line 9)	($860)	($860)	($860)	($860)	($860)	($860)	($5,161)

Turkey Point Units 6&7
Carrying Costs on Prior Period Site Selection Cost Balance
True-up Filing: Retail Revenue Requirements Summary

Schedule T-1 (True-up) [Section (6)(c)1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the true-up of total retail revenue requirements based on actual expenditures for the prior year and the previously filed expenditures.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2014

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.		(H) Actual July	(I) Actual August	(J) Actual September	(K) Actual October	(L) Actual November	(M) Actual December	(N) 12 Month Total
		Jurisdictional Dollars						
1	Site Selection Revenue Requirements (Schedule T-2, Line 7)	($942)	($936)	($924)	($911)	($898)	($885)	($11,140)
2	Construction Carrying Cost Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
3	Recoverable O&M Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
4	DTA/(DTL) Carrying Cost (Schedule T-3A, Line 8)	$13,265	$13,264	$13,263	$13,262	$13,262	$13,261	$159,224
5	Other Adjustments	$0	$0	$0	$0	$0	$0	$0
6	Total Period Revenue Requirements (Lines 1 though 5)	$12,323	$12,328	$12,340	$12,351	$12,363	$12,375	$148,084
7	Projected Carrying Cost on DTA/(DTL) for the Period (Order No. PSC 13-0493-FOF-EI)	$11,674	$11,661	$11,648	$11,635	$11,621	$11,607	$150,091
8	Difference (True-up to Projections) (Over)/Under Recovery for the Period (Line 6 - Line 7)	$649	$667	$692	$717	$742	$768	($2,007)
9	Actual/Estimated Revenue Requirements for the period (Order No. PSC 14-0617-FOF-EI)	$13,183	$13,188	$13,199	$13,211	$13,223	$13,235	$158,402
10	Final True-up Amount for the Period (Line 6 - Line 9)	($860)	($860)	($860)	($859)	($859)	($859)	($10,318)

Exhibit 2: Schedule T-1 True-Up of Pre-Construction Cost

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs
True-up Filing: Retail Revenue Requirements Summary

Schedule T-1 (True-up) [Section (6)(c) 1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the true-up of total retail revenue requirements based on actual expenditures for the prior year and previously filed expenditures.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2014

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.		(A) Actual January	(B) Actual February	(C) Actual March	(D) Actual April	(E) Actual May	(F) Actual June	(G) 6 Month Total
					Jurisdictional Dollars			
1	Pre-Construction Revenue Requirements (Schedule T-2, Line 7)	($105,905)	$985,306	$1,729,724	$948,051	$1,227,335	$1,975,426	$6,759,938
2	Construction Carrying Cost Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
3	Recoverable O&M Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
4	DTA/(DTL) Carrying Cost (Schedule T-3A, Line 8)	$490,070	$494,079	$499,036	$503,900	$507,985	$513,544	$3,008,614
5	Other Adjustments	$0	$0	$0	$0	$0	$0	$0
6	Total Period Revenue Requirements (Lines 1 though 5)	$384,165	$1,479,385	$2,228,761	$1,451,951	$1,735,319	$2,488,971	$9,768,552
7	Projected Revenue Requirements for the Period (Order No. PSC 13-0493-FOF-EI) (a)	$1,694,170	$1,357,082	$1,941,863	$1,665,592	$1,790,761	$2,045,964	$10,495,431
8	Final True-up Amount of (Over)/Under Recovery for the Period (Line 6 - Line 7)	($1,310,005)	$122,303	$286,898	($213,640)	($55,441)	$443,006	($726,879)
9	Actual/Estimated Revenue Requirements for the period (Order No. PSC-14-0617-FOF-EI)	$384,701	$1,479,721	$1,787,428	$1,454,124	$1,139,310	$1,581,899	$7,827,183
10	Final True-up Amount for the Period (Line 6 - Line 9)	($536)	($336)	$441,332	($2,173)	$596,009	$907,072	$1,941,369

11	(a) Total recovered in 2014 as approved in Order No. PSC-13-0493-FOF-EI in Docket No. 130009-EI:	January	February	March	April	May	June	6 Month Total
12	2012 Final True-Up (2012 T-1, Line 10)	($5,137)	($65)	($1,193,576)	$107,924	($2,045,915)	($293,584)	($3,430,352)
13	2013 (Over)/Under Recovery (AE-1, Line 8)	($1,320,718)	($1,916,213)	($952,611)	$58,354	$232,183	($1,187,448)	($5,086,454)
14	2014 Projected Cost / Carrying Cost (P-2, Line 7)	$1,159,902	$819,694	$1,401,006	$1,120,829	$1,242,343	$1,493,347	$7,237,120
15	2014 Projected DTA/DTL Carrying Cost (P-3A, Line 8)	$534,268	$537,388	$540,857	$544,763	$548,418	$552,617	$3,258,311
16	2014 Total (Over)/Under Recovery	$368,315	($559,196)	($204,324)	$1,831,870	($22,971)	$564,932	$1,978,625

*Totals may not add due to rounding

Turkey Point Units 6&7
Pre-Construction Costs and Carrying Costs
True-up Filing: Retail Revenue Requirements Summary

Schedule T-1(True-up) [Section(6)(c)1.a.]

FLORIDA PUBLIC SERVICE COMMISSION

EXPLANATION: Provide the calculation of the true-up of total retail revenue requirements based on actual expenditures for the prior year and previously filed expenditures.

COMPANY: FLORIDA POWER & LIGHT COMPANY

For the Year Ended 12/31/2014

DOCKET NO.: 150009-EI

Witness: Jennifer Grant-Keene

Line No.		(H) Actual July	(I) Actual August	(J) Actual September	(K) Actual October	(L) Actual November	(M) Actual December	(N) 12 Month Total
					Jurisdictional Dollars			
1	Pre-Construction Revenue Requirements (Schedule T-2, Line 7)	($326,506)	$487,158	$1,349,800	$1,134,085	$407,382	$379,120	$10,190,977
2	Construction Carrying Cost Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
3	Recoverable O&M Revenue Requirements	$0	$0	$0	$0	$0	$0	$0
4	DTA/(DTL) Carrying Cost (Schedule T-3A, Line 8)	$516,796	$517,832	$521,317	$525,765	$528,824	$530,748	$6,149,897
5	Other Adjustments	$0	$0	$0	$0	$0	$0	$0
6	Total Period Revenue Requirements (Lines 1 though 5)	$190,290	$1,004,990	$1,871,117	$1,659,851	$936,206	$909,868	$16,340,874
7	Projected Carrying Cost for the Period (Order No. PSC 13-0493-FOF-EI) (a)	$1,616,732	$1,578,331	$2,069,068	$1,652,534	$1,484,940	$4,252,860	$23,149,896
8	Actual (Over)/Under Recovery for the Period (Line 6 - Line 7)	($1,426,441)	($573,341)	($197,951)	$7,317	($548,734)	($3,342,992)	($6,809,022)
9	Actual/Estimated Revenue Requirements for the period (Order No. PSC-14-0617-FOF-EI)	$1,184,166	$1,115,039	$1,433,566	$1,019,064	$908,765	$3,544,603	$17,032,386
10	Final True-up Amount for the Period (Line 6 - Line 9)	($993,876)	($110,049)	$437,551	$640,787	$27,441	($2,634,734)	($691,512)

11	(a) Total being recovered in 2014 as approved in Order No. PSC-13-0493-FOF-EI in Docket No. 130009-EI:	July	August	September	October	November	December	12 Month Total
12	2012 Final True-Up (2012 T-1, Line 10)	$139,743	($77,716)	($909,817)	($738,602)	($1,343,584)	$757,529	($5,602,800)
13	2013 (Over)/Under Recovery (AE-1, Line 8)	$706,970	$1,494,077	$236,455	($140,818)	$242,404	$1,072,318	($1,475,048)
14	2014 Projected Cost / Carrying Cost (P-2, Line 7)	$1,060,202	$1,018,614	$1,505,510	$1,085,049	$914,429	$3,675,451	$16,496,375
15	2014 Projected DTA/DTL Carrying Cost (P-3A, Line 8)	$556,530	$559,717	$563,558	$567,485	$570,511	$577,410	$6,653,521
16	2014 Total Recovery	$2,463,444	$2,994,692$	1,395,706	$773,114	$383,759	$6,082,707	$16,072,048

Revised - WP-5, Column 10, Line 20, Dkt No. 130009-EI

*Totals may not add due to rounding

Review of Florida Power & Light Company's Project Management Internal Controls For Turkey Point 6 & 7 Construction

JUNE 2015

BY AUTHORITY OF

The Florida Public Service Commission
Office of Auditing and Performance Analysis

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 29
PARTY: STAFF RE: FPL
DESCRIPTION: David Rich DR-1

Review of Florida Power & Light Company's Project Management Internal Controls for Turkey Point 6 & 7 Construction

David F. Rich
Public Utility Analyst IV
Project Manager

June 2015

By Authority of
The State of Florida
Public Service Commission
Office of Auditing and Performance Analysis

PA-15-01-002

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1.0 Executive Summary

1.1 Turkey Point 6&7 Project At a Glance

- Project focus remains on licensing and licensing is the current critical path
- Revised NRC COLA review schedule and Section 366.93 FS impact project schedule
- Current Commercial Operation Date (COD) delayed five years to 2027 and 2028
- Estimated cost range - $13.7 billion to $20.0 billion, up 8.7 percent from a year ago
- State site certification is being appealed in court
- Construction contract(s) likely will not be signed before 2017
- COLA approval now estimated as March 2017
- New Nuclear Plant moved to Nuclear Division; reports to the Chief Nuclear Officer
- FPL asserts the project remains economically feasible

1.2 Audit Execution

1.2.1 Purpose and Objective

This audit addresses project internal controls and management oversight used by Florida Power & Light Company (FPL or the company) in managing the Turkey Point 6 & 7 (PTN6&7) project. The primary objective of this audit was to provide an independent account of project activities and to evaluate internal project controls. Information in this report may be used by the Commission to assess the reasonableness of FPL cost-recovery requests.

Commission audit staff published previous reports in 2008 through 2014, each entitled *Review of Florida Power & Light's Project Management Internal Controls for Nuclear Plant Uprate and Construction Projects.* These previous reports are available on the Commission website at www.floridapsc.com.

1.2.2 Scope

The period of this review is January 2014 to May 2015. Staff examined the adequacy of FPL project management and internal controls for the PTN6&7 project. The internal controls assessed were related to the following key areas of project activity:

- Planning
- Management and organization
- Cost and schedule controls
- Contractor selection and management
- Auditing and quality assurance

Comprehensive controls are essential for successful project management. However, adequate and comprehensive controls are ineffective if not actively emphasized by management, embraced by the organization, and subject to oversight, and revision. Proper internal controls minimize risk, enhance its mitigation and management, and aid efficient, reasoned decision making.

Risk must be timely and accurately identified. Sufficient safeguards created, vetted, and in place will help prevent and mitigate risk. Prudent decision making results from well-defined processes that address identified risks, expectations, and cost. Effective communication, adherence to clear procedures, and vigilant oversight are also essential to ensure prudent project decisions.

Commission audit staff's review places primary importance on internal controls found in the Institute of Internal Auditors' *Standards for the Professional Practice of Internal Auditing* and in the *Internal Control - Integrated Framework* developed by the Committee of Sponsoring Organizations of the Treadway Commission. The framework states that an internal control should consist of five interrelated components:

- Control environment
- Risk assessment
- Control activities
- Information and communication
- Monitoring

To maximize operational effectiveness and efficiency, reliability of financial reporting, and compliance with applicable laws and regulations, all five components must be present and functioning in concert to conclude that internal controls are effective.

1.2.3 Methodology

Initial planning, research, and data collection occurred from December 2014 through January 2015. Staff interviewed project management in April 2015.

Audit staff conducted additional data collection and analysis from January through May 2015. Staff also reviewed project internal audits and company testimony, discovery, and filings in Docket No. 150009-EI.

A large volume of information was collected and analyzed. Information collected from FPL included the following categories:

- Policies and procedures
- Organizational charts
- Project timelines
- Vendor and contract change orders and updates
- Vendor invoices
- Internal and external audit reports

1.3 Overview

1.3.1 Turkey Point 6&7 New Nuclear Project

During 2014, FPL continued to focus on licensing and characterizes its project management as deliberate and stepwise. The project critical path remains licensing, unchanged from a year ago.

FPL continues pursuing its Combined License Application (COLA) with the Nuclear Regulatory Commission (NRC) and, upon approval, an option to build two new AP1000 nuclear reactors, designated as Turkey Point Unit 6 and Turkey Point Unit 7.

Also in 2014, the NRC issued a revised COLA review schedule, delaying the anticipated date for COLA approval to March 2017. With the NRC revised schedule as its basis, FPL conducted a review of the PTN6&7 project schedule, developing a new construction timeline and cost estimate range. As a result of its schedule review, FPL also initiated new assessments of 18 critical project tasks with the intent of improving schedule detail, defining work scope, validating project assumptions, and supporting pre-construction work upon COLA receipt. The assessments are underway, scheduled to conclude in December 2016.

FPL believes that the NRC revised COLA review schedule, combined with changes to Florida statutes relevant to the project sequencing and construction, have combined to add five years and as much as $1.6 billion to project schedule and cost. The company states that pre-construction work previously anticipated to be accomplished concurrent with latter stages of the NRC review process (see **Exhibit 1**) is no longer possible and cannot begin now until receipt of the COLA (see **Exhibit 2**). Combined, these changes have added five years to the project timeline.

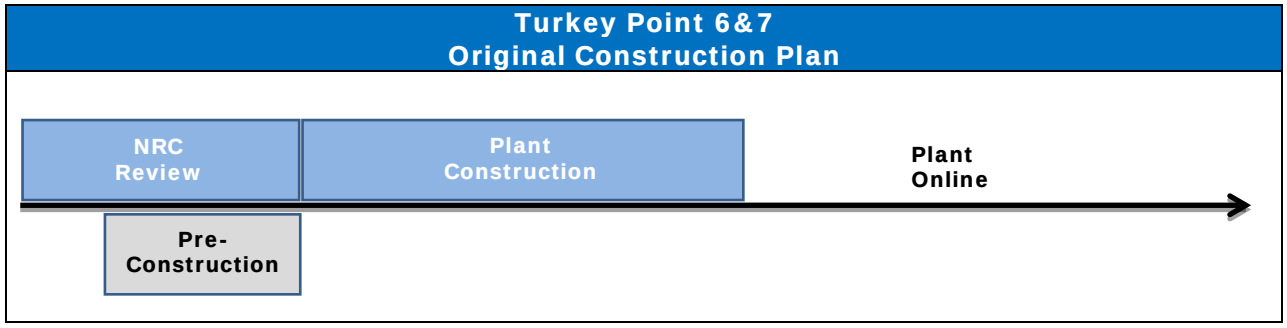


Exhibit 1 *Source: Document Request 4.1*

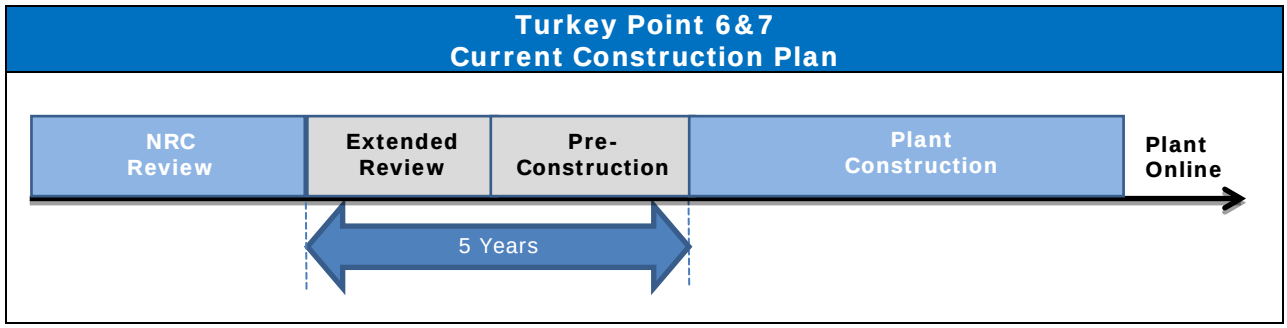


Exhibit 2 *Source: Document Request 4.1*

FPL completed an internal schedule review in the fall of 2014 and published a revised PTN6&7 project timeline in December. **Exhibit 3** shows the revised project timeline.

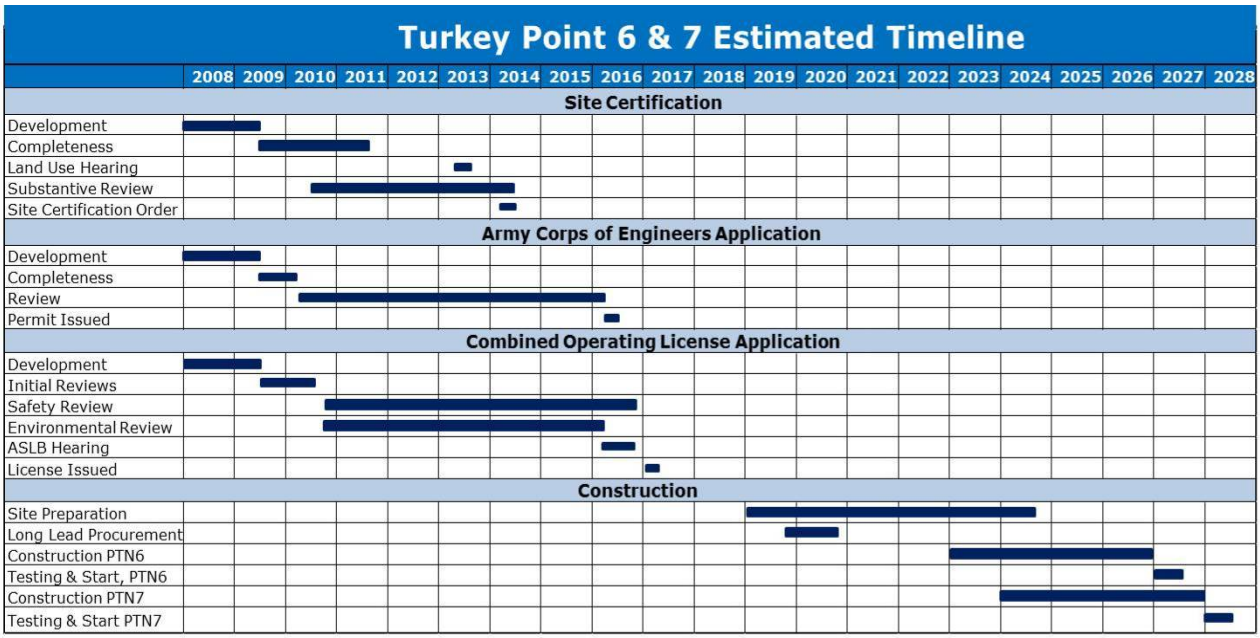


Exhibit 3 *Source: Document Request 1.13*

Licensing Schedule Changes

FPL received the Draft Environmental Impact Statement in February 2015 and receipt of the Final Environmental Impact Statement is now tentatively expected in February 2016.

In April 2014, FPL responded to NRC safety review concerns in the areas of geology, seismology, and geotechnical engineering and the NRC concluded that FPL's responses were sufficient to complete its safety review. **Exhibit 4** shows the revised safety review milestones:

Phase of Safety Review	Previous	Current
Phase A - Requests for Additional Information (RAIs) and Supplemental RAIs	02.2012	06.2015
Phase B - Advanced Final Safety Evaluation Report (SER) with no Open Items	01.2013	01.2016
Phase C - Advisory Cmte, Reactor Safeguards (ACRS) review, Advanced Final SER	07.2013	05.2016
Phase D - Final SER	11.2013	10.2016

Exhibit 4 *Source: Document Request 1.1*

Reallocation of NRC review resources to deal with the waste confidence issue directly impacted agency ability to complete the environmental portion of the COLA and contributed to project delay.

Project Cost Estimate

Project cost range has increased about 8.7 percent over last year's estimate. From a range of $12.62 billion to $18.42 billion in 2014, the estimated range is now $13.7 billion to $20.0 billion. **Exhibit 5** shows project cost estimates, 2007-2015.

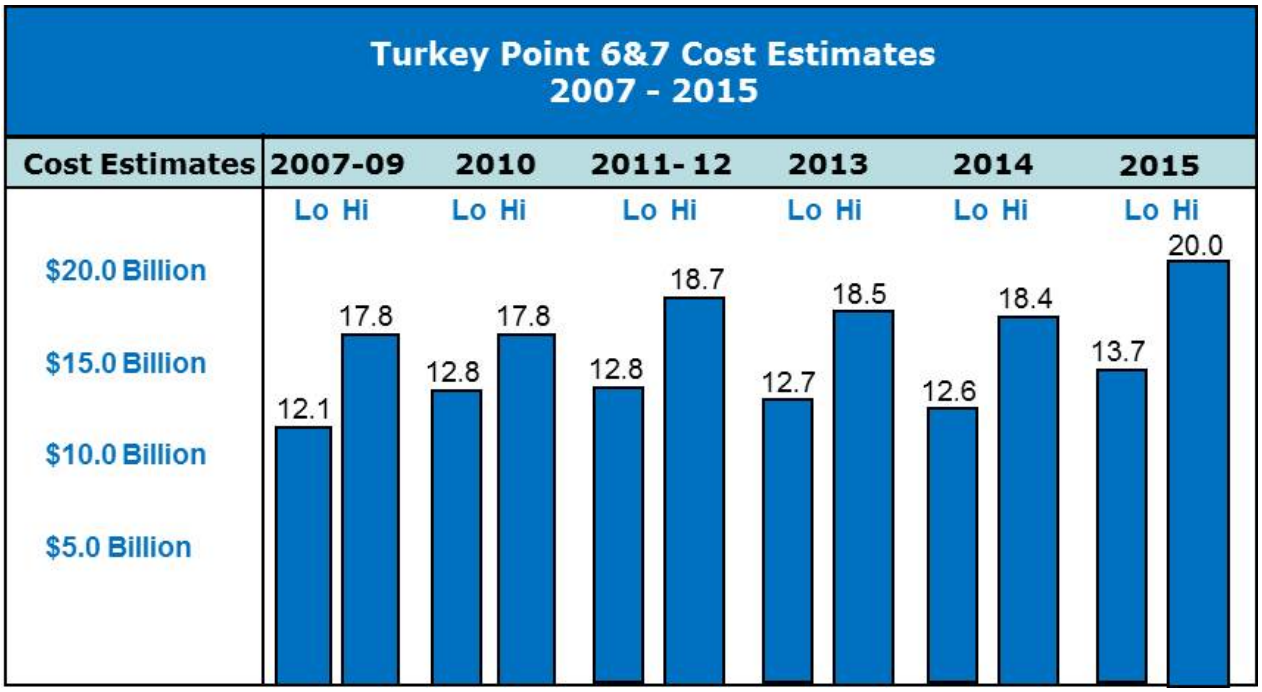


Exhibit 5 *Source: Document Request 2.1*

Federal Applications

There were no federal applications, approvals or certifications issued to or submitted by FPL in 2014. In January 2014, however, the Federal Aviation Administration did grant an extension through July 2015 of the permits relevant to the safe, efficient use and preservation of navigable airspace around the proposed containment structures. FPL plans to renew the permits.

State Level Applications

The FPL application to convert the exploratory injection well to an operating well was approved and operational testing successfully conducted in February 2014. Site Certification was approved in May 2014, effectively granting approval for the project and 88 miles of associated new transmission lines. Legal challenges continue; a decision is expected by the 3rd Circuit Court of Appeals by April 2016.

Construction Contract Structure and Timing

Whether a single EPC (engineering, procurement, construction) contract or separate EP and C contracts would be more advantageous when the project shifts to construction remains an open question. The company believes it best to defer the decision until closer to actual construction. Active pursuit of a contract is currently on hold.

Long Lead Forging Agreement

FPL's long lead forging agreement with Westinghouse remains in effect and unchanged from last year, when it was extended under the existing terms and conditions. The latest extension runs until October 2016. Also remaining in effect is the provision that should FPL cancel the project or forfeit the manufacturing slot, part or all of its $10.8 million reservation fee may be lost.

1.4 Commission Audit Staff Observations

Based upon its information gathering and analysis, Commission audit staff developed the following observations regarding the Turkey Point 6&7 project:

- Project internal controls, risk evaluation, and management oversight are adequate and responsive to current project requirements.
- Invoicing policies and procedures are adequate, universally understood and followed.
- Contracts and contract change orders (CO) adhered to FPL procedures and included all required justifications.

2.0 New Construction - Turkey Point 6&7

2.1 Key Project Developments

There were no federal applications submitted or approvals and/or certifications received in 2014. Site Certification was granted by the State of Florida in May 2014, effectively approving the project and 88 miles of associated transmission lines. A legal challenge is ongoing and a decision is expected in early 2016.

FPL states that the project critical path remains unchanged. That critical path is obtaining the licenses and approvals necessary to construct and operate Turkey Point 6&7. Specifically, that includes completing the licensing phase, obtaining FPSC approval for pre-construction activities (e.g. developing a site plan and execution plan, negotiating procurement and construction contracts), obtaining FPSC approval for construction activities, and conducting construction activities (i.e. building access roads and bridges, creating underground and civil infrastructure, building support facilities, and sequenced construction of the nuclear units).[1]

The FPL project schedule and cost estimate range review determined that a five-year delay is necessary and estimated project cost has increased approximately 8.7 percent. The estimated cost range is currently $13.7 billion to $20.0 billion.

2.1.1 Significant Events

Federal Applications, Approvals, or Certifications

No federal applications, approvals or certifications were issued to or submitted by FPL during 2014. However, in mid-2014 the Federal Aviation Administration did issue permit extensions for the proposed PTN6&7 containment structures. These permits are valid through July 2015 and relevant to the safe, efficient use and preservation of navigable airspace around the proposed containment facilities. FPL plans to renew the permits.

COLA Delay

Based on the revised NRC COLA review schedule of mid-2014, FPL reviewed the PTN6&7 project timeline and cost estimate range. That review was completed in late 2014, producing a new project timeline and cost estimate range. The new schedule adds five years to the project and increases the project cost estimate.

In April 2014, the NRC announced delays in publication of three documents critical to the continuation of the project -- Draft Environmental Impact Statement to February 2015, Final Environmental Impact Statement to February 2016, and the Final Safety Evaluation Report to March 2017. The Draft Environmental Impact Statement was received on schedule and FPL believes the remaining two milestones will be met on the schedule announced by the NRC. As a consequence of these delays, FPL shifted its estimated date for COLA approval.

[1] FPL response to Staff Document Request 1.4

NRC Requests for Information (RAI)

In 2013, the `NRC asked FPL to readdress certain portions of the company's original Final Safety Analysis Review relating to seismology and geology. FPL engaged third party experts to review data and provide assistance in preparing responses. FPL completed the environmental RAIs in 1Q2014 and those regarding safety in mid-2014.

Approximately a dozen RAIs remain open. FPL states that all RAIs will be submitted timely, by June 2015.

State Site Certification Application

The Florida Power Plant Siting Board granted final Site Certification in May 2014, including 88 miles of associated transmission lines. Four communities opposed the transmission lines (Miami, South Miami, Pinecrest and Coral Gables). FPL reached a settlement with Coral Gables. Remaining parties submitted position briefs to the 3rd Circuit Court of Appeals in January 2015. Responses were due 2Q2015 but a 60-day extension was granted to Florida Department of Environmental Protection. FPL expects the Court to hear the challenge in 4Q2015, with a decision following in approximately 90 days.

FPL states that it is confident of a favorable outcome but that the appeal process has potential to challenge PTN6&7 project critical path if the appeal is:

- Not heard in a timely manner, extending beyond 2017
- Decided in the appellants' favor and modifications cannot be made by 1Q2017, or
- Dismissed but appealed to the Florida Supreme Court, extending the process beyond 1Q2017

Land Exchange

The Everglades National Park land exchange process continues and is expected to be successfully completed by the end of this year. The swap would allow FPL, at little or no cost, to exchange land it owns within the Everglades National Park for land on the eastern edge of the park, creating a continuous north-south transmission right-of-way in Miami-Dade County.

A Draft Environmental Impact Statement was published in January 2014. Supporting agreements with state and regional agencies are in place, the swap is authorized by federal legislation, and the National Parks Service is completing its final environmental review. The Final Environmental Impact Statement is expected in 3Q2015, with a decision anticipated in 4Q2015.

Transmission

The Site Certification Final Order of May 2014 approved FPL's proposed transmission corridors and directed maximum use of the Western Consensus Corridor, which is dependent on successful completion of the land exchange and obtaining land rights from federal or state agencies. It also requires additional negotiations between FPL and the parties. If the Western Consensus Corridor cannot be obtained timely and at reasonable cost, FPL would pursue development of the Western Preferred Corridor also subject to the proposed land exchange with the National Parks Service.

Project Construction Contract

FPL maintains that the company has not made a decision whether an EPC or EP&C contracts would be more advantageous. The company states that a decision at this early point would be unwise based on industry experience. FPL believes the best course of action is to defer pursuit of the construction contract, with intentions of signing an EPC or EP&C up to 18 months before construction would begin in 2019. The company acknowledges risk associated with waiting (e.g. craft availability and costs increases) but believes this course reduces total risk.

Project Long Lead Forging Reservation

The Forging Reservation agreement between FPL and Westinghouse (2008) reserves manufacturing capacity. Multiple extensions have been signed, the most recent in 2014, extending original terms and conditions until October 2016. FPL believes continued extension is in its best interest, reduces near term cost and risk, while preserving schedule flexibility. The company acknowledges risk. If the agreement is dissolved, FPL may forfeit some or all of its $10.8 million deposit.

Project - Joint Ownership

Required annual meetings continue between FPL and prospective joint owner utilities. FPL provides the Commission with status updates. The 2014 participants included Florida Municipal Energy Association, Florida Municipal Power Agency, Orlando Utilities Commission, and Seminole Electric Cooperative. The 2015 meeting is not yet scheduled.

2.1.2 Turkey Point 6&7 Project Cost Estimate

FPL's reexamination of the cost estimate range resulted in a new cost estimate range of $13.7 billion to $20.0 billion. This new estimate represents an increase of approximately 8.7 percent overall, $1.1 billion on the low end and $1.6 billion on the high end of the range. **Exhibit 6** provides a component breakdown of the increase 2014 to 2015. Previously, **Exhibit 5** provided a project cost estimate history. FPL attributes the 2015 higher cost estimate range to NRC review schedule delays and Florida legislative changes that make pre-construction in parallel with the COLA review impossible.

Turkey Point 6&7
In-Service Cost Estimate – 2014 and 2015

Category	2015 Low	Change from 2014	2015 High	Change from 2014
Site Selection	$6,118,105	$0	$6,118,105	$0
Pre-construction	$304,509,934	$114,746,694	$337,177,897	$111,414,657
Construction	$10,149,263,190	$1,087,930,415	$14,906,444,521	$1,602,527,589
AFUDC	$3,240,607,689	($84,827,220)	$4,744,320,802	($138,109,210)
TOTAL	**$13,700,498,918**	**$1,117,849,889**	**$19,994,061,325**	**$1,575,833,036**

EXHIBIT 6 *Source: Docket 140009-EI, TOR-2, May 2014 & Docket 150009-EI, Tor-2, May 2015*

2.1.3 FPL Project Feasibility Analyses

FPL conducted its 2015 annual PTN6&7 project feasibility analyses using updated assumptions and forecasts but in the same basic analytical approach as the Need Determination proceeding and six previous feasibility studies. Analyses examined fourteen different scenarios of varying fuel and environmental compliance cost forecasts for 40 and 60 year operational lifespans. The company believes these analyses confirm cost effectiveness of the project and the benefits associated with constructing the new plants.

2.2 Project Controls and Oversight

2.2.1 Project Controls

Project controls are built into the financial and accounting systems, department procedures, and desktop instructions. No project controls were revised during 2014. Those shown in **Exhibit 7** below are the project instructions created or deleted during the year.

Turkey Point 6&7 Revised or Deleted Project Instructions - 2014			
Number	**Title**	**Revised**	**Deleted**
NNP-PI-1-00	Project Schedule Configuration and Control		02.11.14
NNP-PI-1-1	Change Control for COL Application Information		11.13.14
NNP-PI-3-01	Review of WEC Design Change Proposals (DCPs)	11.07.14	
NNP-PI-3-02	Pre-COL Departure Process	11.07.14	
NNP-PI-3-03	Preparation of Interim Staff Guidance – 011 Screens / Evaluations	11.07.14	

EXHIBIT 7 *Source: Document Request 1.27*

These revisions were responsive to changing project requirements. No internal audits, quality assurance reviews, or external audits reviewed by staff cited any weaknesses in project instructions or management controls.

"White papers" represent a project management tool that has been used by FPL to record and document key decisions or actions. There were no white papers produced in 2014 and none to date in 2015. One project memo was issued in November 2014, discussing the project schedule review and making a recommendation on revised project target dates.

Controls and process instructions exist in the following areas of project management:

- Budgeting and reporting
- Schedule and activity reporting
- Contract management
- Internal and external oversight
- Executive management

- Subordinate managers
- FPL subject matter experts (SME) and team members
- Third party experts
- Regular updates and reports on risk, cost, and schedule

FPL's Project Controls Group provides management schedule, budget, costs, vendor performance, and risk reports on a regular, ongoing basis. Primavera-6 remains the scheduling software, capable of real time updating, active monitoring, tailored date sorting, and customized status reports.

2.2.2 Risk Management Reporting

Project risk management remains unchanged from last year, using ongoing, regular meetings and reports designed to identify, characterize, evaluate, and isolate or mitigate project risk. Weekly small team meetings track project activities, facilitate risk identification, discussion, and development of response strategies. A more senior level of management gets involved if a small team cannot mitigate risk. The item is further elevated to increasingly higher levels of management, until resolution is achieved.

Project schedule, progress, and cost metrics are monitored in real time. Results are reported using standardized reports, increasing subject matter familiarity and allowing for close scrutiny of contractor performance. FPL considers vendors as important stakeholders in risk management and requires them to provide weekly agendas and progress reports.

The PTN6&7 project team meets monthly to review project schedule, budget, project issues, and risks. Each identified project risk is tracked and reviewed until resolved and closed out. A Cost Report meeting also provides an opportunity to scrutinize project cost risk. Project management provides regular project updates to FPL executive management.

Commission audit staff reviewed all monthly project dashboards and quarterly risk analyses for 2014 and to date in 2015. These reports provide issue and risk clarity and detail, a probability of occurrence, and analysis of potential project impacts, cost, and schedule turbulence. Areas assessed included:

- NRC Licensing
- US Army Corps of Engineers Permitting
- Site Certification Application
- Underground Injection Control well
- Miami-Dade County
- Development
- Project Design
- Pre-Construction Planning
- Budget
- Schedule / Revised Schedule
- Procurement
- Safety

The quarterly risk analysis is a project management assessment tool of wider, more comprehensive scope. Its purpose is to identify key issues, characterize them, provide historical trending, and track attendant risk. An integral part of this assessment is determining a likelihood of occurrence for each risk (low, medium, or high) and the potential negative consequences to the project if it occurs (low, medium, high). A response is designed for each identified risk. Then, a mitigation owner is assigned, management strategies are developed, and progress is tracked until the risk is either mitigated or eliminated.

PTN6&7 project leadership also has the option of presenting information to and obtaining the advice of the FPL Risk Committee. No presentations were made to the FPL Risk Committee from January 2014 thru May 2015.

Commission audit staff believes that risk controls are adequate and responsive to the current stage of the PTN6&7 project. Monthly dashboard and quarterly assessments inform FPL management and executive leadership. However, staff believes that as the plan shifts from licensing to construction a reassessment of content will be required and restructuring may be necessary to meet the increased demands of the rapidly expanding project.

2.2.3 Management Oversight

The position of Construction Director was filled in early 2014 with an experienced manager from the FPL EPU project. No additional personnel changes occurred in the remainder of 2014.

A new position of Vice-President, Design and Execution was created in early 2015 to place all major project activity under one group. FPL stated that the impetus for this initiative is from other projects, not PTN6&7 in its current state of project development. No positions or responsibilities changed in the New Nuclear Projects organization in the last year. Project procedures other than those shown in **Exhibit 7** remain unchanged to preserve project continuity.

2.2.4 Audits

In 2014, FPL again selected Experis to conduct an audit of project expenditures for 2014, under the direction and supervision of FPL Internal Audit. The report was published and reviewed by Commission staff in March 2015.

Audit areas remained unchanged from a year ago -- [redacted] and [redacted] of annual NCRC filings. The audit examined approximately $[redacted] million of $20.2 million in expenditures, or approximately [redacted] percent of the total. No exceptions were noted.

Since 2008, Concentric Energy Advisors has performed an annual review of PTN6&7 project processes, procedures, and structure, focusing on internal controls. In 2015 testimony, Concentric concluded that FPL capably managed the project in 2014 and that project expenditures during the year were prudently incurred.

2.2.5 FPL Quality Assurance Reviews

The FPL Quality Assurance (QA) group holds vendors accountable for process and product quality while under contract to FPL. Oversight of production quality, manufacturing activities,

and control procedures is accomplished through inspections at the vendors' headquarters and manufacturing sites.

During 2014 and to date in 2015, FPL Quality Assurance assessors did not conduct any on-site manufacturer visits. For vendors working at FPL facilities, QA assessors conducted on-site spot visits. No areas of vendor non-compliance related to the project were identified by FPL.

Commission audit staff continues to believe the layers and methodologies of FPL QA oversight are adequate, properly focused for current project development and scope. However, as the project matures, regular FPL QA visits to vendor manufacturing sites and a reassessment of the FPL QA oversight plan, schedule, and structure will be warranted. Restructuring, or at least an increase in QA scope and frequency, is likely necessary to accommodate project expansion.

2.3 Contract Oversight and Management

The FPL system for contract management and oversight remains intact from a year ago. The company uses project management, technical representatives, and QA personnel to monitor vendor performance. Vendors are required to provide regular progress reports.

Integrated Supply Chain sourcing specialists and contract managers monitor change orders and invoicing for anomalies. Items outside established contractual norms are routinely reported up the chain of command. Schedule and cost risks are identified, prioritized, and quantified. This information is then used to formulate responsive solutions.

FPL continues to employ systems, policies, procedures, and processes to identify invoice mistakes or vendor overcharges. Invoicing specialists review invoices for accuracy in meeting contract provisions and prevailing labor rates. Billed hours are scrutinized and checked against job categories. Travel expense requests are checked for applicability, authorization, required justification, and linkage to an existing contract.

2.3.1 Contract Oversight

FPL's controls to communicate procedures and provide ongoing oversight are unchanged from a year ago. These include policies and instructions, authorization requirements, approval methodologies, invoicing and control procedures.

Audit staff's review reaffirmed that FPL invoicing policies and procedures are well understood and that FPL contract and invoicing personnel follow company policies, practices, and procedures. Evidence of challenges to invoiced amounts and an appropriate level of push back of questionable or unsupported charges was observed.

FPL opened one warranty claim against a vendor during this report period. The amount disputed was less than $40,000 and the vendor was required to rework tasks previously completed. The claim was satisfied and closed.

Processes for contract oversight are adequate. Required authorizations are present and in the configuration specified by procedures. Vendor invoices and supporting documentation (e.g.

employee receipts) are challenged appropriately. Payment is withheld until reconciliation of any dispute. FPL memos, emails, and spreadsheet entries document challenges to invoices and requests for supporting documentation from vendors.

2.3.2 Contracts Executed or Modified

In 2014, PTN6&7 project management signed two significant new contracts (see **Exhibit 8**). One was single sourced (CB&I Stone & Webster) and the other was competitively bid (HDR Engineering Inc.). Commission audit staff verified that required letters of justification were present and in compliance with FPL internal policies and procedures.

Turkey Point 6&7 New Contracts Greater than $100,000					
Vendor	**Description**	**Terms**	**Original Value**	**Issued**	**Expire Date**
HDR Engineering, Inc.	Develop Submittals for USACE Sect408 Authorization	T&M	[redacted]	08/13/14	11/26/14
CB&I Stone & Webster	Project Schedule Review & Assessment	Fixed Price		06/06/14	12/15/14

EXHIBIT 8

Source: Document Request 1.37

Change orders represent added or deleted contract scope, an increase or decrease of contract value, or an administrative adjustment without monetary impact. Commission audit staff determined FPL executed no change orders of more than $50,000 during 2014 or to date in 2015.

There are 17 contracts (see **Exhibit 9**) valued at more than $250,000, representing original contract value and any subsequent change order.

Commission audit staff reviewed all 2014 contract justifications and those to date in 2015; no discrepancies were noted. The Bechtel contract is the largest at nearly $[redacted] Signed in 2007, this contract now has 58 change orders that have altered scope and value. Due to the probability of project schedule extensions, it is likely that the Bechtel contract cost will continue to increase.

Turkey Point 6&7 Existing Contracts Greater than $250,000			
Vendor	**Description**	**Current Value**	**Type***
AMEC Environment & Infrastructure	RAI response review	[redacted]	S
AMEC Environment & Infrastructure	RAI response review / FSAR 2.5.4		S
Atkins North America	Expert scientific analysis		S
Bechtel Power Corporation	COLA / SCA prep & RAI support		C, S, P
Burns & McDonnell	Design of radial collector well		C, S

Vendor	Description	Current Value	Type*
Eco Metrics, Inc.	Environmental consulting services		S
Environmental Consulting & Technology	SCA & post-submittal support		S, P
EPRI - Electric Power Research Institute	Nuclear technology; membership		S
Golder & Associates Inc.	Post-SCA submittal support		S, P
HDR Engineering, Inc.	Conceptual engineering of cooling water supply / discharge		C, S
Layne Christensen Company	Injection well testing		C
McCallum Turner, Inc.	COLA site selection RAI support		S
McNabb Hydrogeologic Consulting	Post-SCA / UIC licensing support		S, P
Paul C. Rizzo Associates, Inc.	Field Investigation; FSAR 2.5 Revision		S
Power Engineers, Inc.	Prelim Analysis of Miami River crossing and Davis/Miami Line		S
TetraTechGeo	Collector well modeling support		S
Westinghouse Electric Co.	COLA prep & RAI support		C, S, P

*** C = Competitive Bid S = Single/Sole Source P = Predetermined Source**

EXHIBIT 9

Source: DR-1.36 and Exhibit SDS-7, Schedule P-7A, May 2015

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FPL's Responses to Staff's First Set of Interrogatories (Nos. 1-3 and revised 4)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 30
PARTY: STAFF RE: FPL
DESCRIPTION: Steven D. Scroggs

Q.

For purposes of this question please refer to:
http://www.world-nuclear.org/info/Country-Profiles/Countries-T-Z/USA--Nuclear-Power/.
The website, as updated March 13, 2015, states "[o]f the above, for the first four AP1000 units, construction is well under way at Vogtle, Georgia, with about $4 billion invested in the project to February 2012, before it was technically 'under construction'." Witness Scrogg's March 2, 2015 testimony, at pages 10-14 and 21-22, discusses monitoring industry milestones, current industry events, the Nuclear Cost Recovery Clause Statute, the combined affect to the overall project schedule and FPL's project decision process.

a. Please identify how monitoring industry milestones, events and the Nuclear Cost Recovery Clause Statute, impacted FPL's 2014 activities and costs filed March 2, 2015 compared to the estimated 2014 activities and costs FPL filed May 1, 2014, if at all.

b. Please explain FPL's understanding of the types of activities and level of costs associated with the construction being well under way before being considered technically 'under construction', as discussed above, in the context of each subsection of 366.93(3), F.S.

A.

a. There was no direct impact to FPL's costs filed March 2, 2015 compared to the estimated 2014 costs filed May 1, 2014 as a result of monitoring industry milestones and events, or the Nuclear Cost Recovery Clause Statute.

   Monitoring of industry milestones and events did inform FPL's 2014 activities. Specifically, following receipt of a revised NRC COLA Review schedule for Environmental and Safety areas, FPL conducted a project schedule review. The review included significant input by Chicago Bridge & Iron, Co. (CBI) (the constructor for the Vogtle and Summer AP1000 units) and FPL's monitoring efforts through its participation in industry groups such as the AP1000 Owners Group (APOG) and EPRI's Advanced Nuclear Technology (ANT). Observations and lessons learned in the first wave of U.S. AP1000 construction projects have been reviewed and incorporated as appropriate in the Turkey Point 6 & 7 project schedule. While these observations did not result in a net increase or decrease in schedule duration, they informed the sequence and duration of individual activities.

Similarly, as FPL conducted its review of the Turkey Point 6 & 7 project schedule, amendments to the Nuclear Cost Recovery Clause Statute were integrated into the sequence of events to be in compliance with the amended Statute. The net impact of the amended Statute was to increase the project schedule by approximately 2.5 years, as pre-construction work must await the receipt of COL and approval of the FPSC.

b. FPL does not have access to the line item detail utilized by the author of the subject article, and therefore cannot delineate which costs might align to each subsection of Fla. Stat. Section 366.93. It is assumed that reference to being "technically under construction" refers to the beginning of safety related construction. Safety related construction, beginning with the pouring of the first nuclear grade concrete of the basemat, is that portion of the construction that is directly under the jurisdiction of the Nuclear Regulatory Commission. Safety related construction can begin only after a significant amount of site clearing, excavation, backfill and the installation of underground facilities has been completed. Therefore, by the time safety related construction begins, an owner will have made considerable investment in Engineering Design, Procurement and civil construction activities. The expenditure of $4 billion by the start of safety related construction is consistent with FPL's revised project schedule and associated spend curve.

Q.
FPL witness Reed's March 2, 2015 testimony, at page 27, discusses mechanisms used to monitor Turkey Point Units 6 and 7 (TP 6&7) Project budget performance in 2014. On page 29, witness Reed states that "Concentric found that in 2014 the PTN 6 & 7 Project team acted prudently when developing its annual budget and in tracking its performance relative to the annual budget."

a. Please state whether any non-TP 6&7 Project events prior to 2014 trigger or contribute to any of the variances reported in 2015 compared to the estimates filed in 2014? If so, please identify each event prior to 2014 and the respective impacts on the TP 6&7 Project costs during 2014 that was not included in the estimates filed in 2014.

b. Please state whether any non-TP 6&7 Project events during 2014 trigger or contribute to any of the variances reported in 2015 compared to the estimates filed in 2014? If so, please identify each 2014 event and the respective impacts on the TP 6&7 Project costs during 2014.

A.
FPL understands that "non-TP 6&7 Project events" refers to events at other U.S. AP1000 construction projects.

a. No events at non-TP 6&7 Projects prior to 2014 trigger or contribute to any of the variances reported in 2015 compared to the estimates filed in 2014.

b. No events at non-TP 6&7 Projects during 2014 trigger or contribute to any of the variances reported in 2015 compared to the estimates filed in 2014.

Q.

FPL witness Diaz's March 2, 2015 testimony, at page 6, discusses NRC staff previously identifying issues affecting the completion of the NRC's safety review. On page 7, witness Diaz mentions design changes to the control room and the condensate return feature. NRC document ML15040A027 discusses a December closed meeting regarding an AP1000 condensate return design change. Witness Diaz, at page 8, asserts confidence that FPL will receive a COL license by March 2017.

a. What, if any, items or issues surfaced during the NRC's 2014 review of any AP1000 project that could affect the NRC's current estimated schedule for completing its safety review of FPL's COL application before March 2017?

b. What, if any, items or issues surfaced during 2014 that could affect NRC's estimated schedule for completing its environmental review of FPL's COL application before March 2017?

c. How, if at all, did any items or issues listed above impact FPL's reported activity and cost variances compared to its 2014 filings.

A.

a. In addition to the design changes associated with the condensate return and control room discussed in Witness Diaz's March 2, 2015, testimony, a Hydrogen Venting design issue was also identified in 2014. These issues are expected to be resolved by October 2015 and are not expected to impact the NRC's review schedule for FPL's COL.

b. FPL is not aware of any items or issues that surfaced in 2014 that could affect the NRC's estimated schedule for completing its environmental review of FPL's COL application before March 2017.

c. The design issue above did not impact 2014 actual costs. The issue does affect the 2015 actual/estimated costs for APOG in the 2015 filing by increasing those costs to $3,000,000. This value was projected to be $1,000,000 in 2015 in the 2014 filings, resulting in a variance of $2,000,000. This variance represents FPL's share of increased APOG costs to address items such as these design issues for the AP1000 standard plant.

Q.
Witness Scrogg's March 2, 2015 testimony, at page 27, identifies a $16,072,491 amount associated with its COL application activities. On the same page, a $510,188 amount is identified as COL application activity related. On pages 27 and 28, a $414,704 amount is associated with "various license and permit applications." Please state the total amount FPL incurred during 2014 due to the NRC's review of its COL application and reconcile that amount with the respective cost categories in FPL's March 2015 filings on a system and jurisdictional basis.

A.
Licensing Category

The costs in the Licensing category are primarily COL application activities, but also include costs associated with Site Certification, Army Corps, County and Land Exchange activities. The total costs incurred in 2014 for the Licensing category of costs was $16,072,491, as identified on page 27 and delineated in SDS-7, Table 2. These activities include the project personnel, contractors, consultants and other experts necessary to prepare and defend the COLA and the other permits and approvals associated with the project. Also on page 27, the $510,188 is the positive variance between the actual 2014 amount ($16,072,491) and the actual/estimated amount included in the May 2014 filing ($16,582,678) for the Licensing category.

Permitting Category

The total costs incurred in 2014 for the Permitting category of costs was $414,704, as identified on page 27 and delineated in SDS-7, Table 3. The costs in the Permitting category are for the same licenses, permits, and approvals identified in the Licensing category but are for different types of activities in support of those licenses, permits, and approvals. Permitting costs are primarily related to activities that support the project's license and permit application, such as communications, legal support, and Development payroll.

The majority of the costs in each of these categories is for COLA activities; however, FPL does not separately track costs by individual license/permit/approval. FPL's total 2014 Licensing costs were $15,281,575 (jurisdictional), $16,072,491 (system total). FPL's total 2014 Permitting costs were $394,297 (jurisdictional), $414,704 (system total).

AFFIDAVIT

Steven D Scroggs
(Signature of Sponsor)

STATE OF FLORIDA)

COUNTY OF Palm Beach

I hereby certify that on this 27th day of April, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Steven D. Scroggs, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory numbers 1-4, from Staff's first set of interrogatories to Florida Power & Light Company (Nos. 1-4) in Docket No. 150009-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 27th day of APRIL, 2015.

HEATHER P. MELIGONIS
MY COMMISSION # FF 042785
EXPIRES: December 6, 2017
Bonded Thru Notary Public Underwriters

Heather P. Meligonis
Notary Public
State of Florida, at Large

My Commission Expires:
12/6/17

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FPL's Responses to Staff's Second Set of Interrogatories (Nos. 5-9, 11-18, and 20-46) See Staff Exhibit CD for Excel files re: Nos. 13 and 43

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 31
PARTY: STAFF RE: FPL
DESCRIPTION: Steven D. ScroggsJennifer Grant-KeeneRichard O. Brown

Q.
Please refer to FPL's 2014 and 2015 TOR-2 Schedules for the Turkey Point Units 6 & 7 Project (TP Project).

a. Please describe FPL's 2015 assumptions for total pre-construction costs that resulted in an approximate 35 percent increase in the low estimate and a 49 percent increase in the high estimate relative to FPL's 2014 estimates of total pre-construction costs.

b. Please describe FPL's 2015 assumptions for total construction costs that resulted in an approximate 12 percent increase relative to FPL's 2014 estimates of total construction costs.

c. Please describe FPL's 2015 assumptions for total allowance for funds used during construction (AFUDC) that resulted in an approximate three percent decrease relative to FPL's 2014 estimates of total AFUDC.

d. In regard to the total project cost estimates shown in schedule TOR-2, please identify what, if any, cost contingencies have been applied in the estimation process, and why FPL believes its assumptions are reasonable.

A.
The overnight capital cost estimate range, which forms the basis for the overall project cost estimate range, did not change. Therefore, changes are either a re-allocation of costs between Pre-Construction and Construction periods, a result of the time related costs that increase due to the change in in-service dates, a change in a non-capital cost assumption, or a combination of these factors.

a. The increase in estimated pre-construction costs was a result of re-allocation of costs. Following the 2014 project schedule review, the completion of the Pre-construction Period was changed from 2017 to 2019, to reflect the sequencing required by the revised NCRC Statute. Please see Exhibit SDS-3. This change shifted costs that were previously expected to be incurred during the Construction Period into the Pre-construction Period.

b. The increase in the construction cost category of TOR-2 (12%) are a result of the time related costs that increase due to the change in in-service dates.

c. The three percent decrease in total AFUDC is attributed to the decrease in the AFUDC rate assumed from 2014 (11.04%) to 2015 (9.39%), which is offset by the time related costs that increase due to the change in in-service dates.

d. FPL's standard budgeting practice is to apply a 15% contingency to projects to account for potential unforeseen costs or cost increases. In addition, the base overnight capital cost estimate was constructed understanding the limitations of such estimate in advance of negotiated cost, schedule and implementation contracts. The construction of the overnight cost estimate range is fully described in witness Scroggs' October 16, 2007 testimony in the Site Certification process for Turkey Point Units 6 & 7.

Q.

Witness Scroggs' May 1, 2015 testimony, at page 25, states in part that "CODs of 2027 and 2028 are assumed." The Nuclear Regulatory Commission (NRC) publishes and updates its review schedule for the Turkey Point, Units 6 and 7 (TP 6&7) combined license application. (http://www.nrc.gov/reactors/new-reactors/col/turkey-point/review-schedule.html) On May 1, 2015, the NRC's website stated an update date of September 25, 2014. The following table provides the NRC's current and November 2, 2011 review schedules.

Key Milestones	November 2, 2011 NRC Update	September 25, 2014 NRC Update
Application	6/30/2009	6/30/2009
Docketing Decision Letter	9/04/2009	9/04/2009
Review Schedule Established	5/28/2010	5/28/2010
Safety Review: Phase A	3/- -/2012	6/30/2015
Safety Review: Phase B	1/- -/2013	1/29/2016
Safety Review: Phase C	7/- -/2013	5/30/2016
Safety Review: Phase D	11/- -/2013	10/31/2016
Environmental Review: Phase 1	12/- -/2010	12/- -/2010
Environmental Review: Phase 2	2/- -/2013	2/- -/2015
Environmental Review: Phase 3	2/- -/2014	2/- -/2016

a. Please explain why the timeline for the NRC's safety review was extended by approximately three years within the past three years and how FPL has addressed the potential for further extended NRC safety review in its estimate of a 2017 combined operating license (COL) and the assumed commercial operation dates (CODs) of 2026 and 2027.
b. Please explain why the timeline for the NRC's environmental review was extended by approximately two years within the past three years and how FPL has addressed the potential for further extended NRC safety review in its estimate of a 2017 COL and the assumed CODs of 2026 and 2027.
c. What site-specific factors, if any, are the NRC's schedule changes addressing?
d. What generic AP1000 technology factors, if any, are the NRC's schedule changes addressing?
e. What generic nuclear industry factors, if any, are the NRC's schedule changes addressing?

f. On page 38 of witness Scroggs' May 1, 2015 testimony is a discussion regarding "initial assessment" studies related to the planning of other preconstruction work. What affect, if any, would delay in undertaking the "initial assessment" studies have on the estimated COD if the Company did not begin the studies until after receipt of the combined operating license?

A.

a. Witness Scroggs' testimony for the past three years has chronicled the ongoing impacts to NRC human and budgetary resources created by project related and external (nuclear industry/ U.S. Government) events. The culmination of these impacts has been reflected in the revised schedule letters FPL received in 2014 and the revised project schedule estimating COD's of 2027 and 2028.

Project related factors included additional review in specific focus areas, some in response to the events of Fukushima. FPL received correspondence from NRC on May 4, 2012 that identified focus areas (geology, seismology, and geotechnical engineering) that affected the pace of the safety review. Additionally, the correspondence identified questions regarding alternative sites that impacted the environmental review. These issues were addressed in the 2013 NCRC proceedings.

External events include an emergent revision of the Waste Confidence Rule that reassigned resources that were being used for the environmental review for FPLs COLA. The NRC also responded to the events of Fukushima by conducting an immediate evaluation of the existing operating nuclear power plants. Safety review resources that were being used for the seismic review for FPLs COLA were reassigned to that work. Finally, during the course of these events, the Federal government shutdown twice resulting in a lack of funding requiring all work associated with the FPL COLA review to be stopped. This particularly impacted the Environmental review that was being conducted by contractors. When funding was restored, contracts were reinstituted and reviews resumed. These issues have been addressed in prior NCRC proceedings.

In summary, the timeline for NRC's review was extended by NRC for several reasons. These delays could not be foreseen and are primarily a result of external events. Recognizing that external factors beyond FPL's control could extend the regulatory review timelines, FPL has applied a stepwise approach to the Turkey Point 6 & 7 project during the pursuit of licenses and permits needed to construct and operate the units. This stepwise approach limits expenditures to those necessary to obtain approvals. Further, when constructing the estimated project schedule, FPL reviews typical timelines for completion of NRC reviews observed in recent COLs. It is these inputs, coupled with a full review of pre-construction work and construction period activities that has resulted in the assumed CODs of 2027 and 2028.

b. Please see the response to subpart (a) above.

c. Please see the response to subpart (a) above.

d. There are no generic AP1000 technology factors driving the NRC review schedule changes.

e. Generic nuclear industry factors driving the NRCs schedule changes include those mentioned in response a) as "external events".

f. FPL has provided the earliest practicable schedule for COD of Turkey Point Units 6 & 7. This means that, based on the best information available, and balancing regulatory, cost and execution risk factors 2027 and 2028 is the earliest these units could be brought online. The project schedule includes an assessment of integrating the requirements of the amended NCRC statute and rule. If initial assessments were deferred until after receipt of the COL, the consequent impact to the overall schedule would be two years retaining the current execution risk profile. The delay could be reduced by conducting some analyses in parallel or expediting analyses, however that decision would negatively impact the execution risk profile introducing more uncertainty in the cost or schedule basis for the feasibility analysis used to make the decision to proceed to "pre-construction work".

Q.

Witness Scroggs' May 1, 2015 testimony, at page 25, states in part that "CODs of 2027 and 2028 are assumed." On page 9, Witness Scroggs mentions a nine-year construction schedule. The State of Florida Division of Administrative Hearing, in Case No. 09-003575EPP, issued a recommended order on December 5, 2013, that stated at paragraph 246, "[p]roject construction will take approximately 123 months."

a. Does FPL currently estimate "project construction" will take 123 months and if not why not?

b. Please explain the activities FPL includes in "project construction" for purposes of the 123 months identified in site certification process.

c. Please explain the activities FPL includes in "project construction" for purposes of assessing the "construction" costs estimates FPL provided in its TOR-2 schedule and the current estimate of the months required to complete such activities.

d. Please explain the activities FPL includes in the "nine-year construction schedule" referenced by witness Scroggs.

A.

a. No. The current "project construction" shown in the Project Baseline Schedule is 114 months. This was based on a schedule assessment completed in November 2014 which resulted in redefining the critical path of the overall project schedule. This revised schedule estimate is based on information from current US AP1000 projects and FPL/NextEra Energy's most current construction experience.

b. "Project construction" as identified in the site certification process is a broad term dating back to the beginning of the SCA process that includes pre-construction activities (clearing, site work, facilities, etc.), construction activities (48 months standard plant plus activities under NRC authority, i.e. slurry wall), fuel load/startup activities, and through commercial operation of both units.

c. The activities in "project construction" are activities starting with "construct island access" in January 2019, site civil work, nuclear island construction, startup and testing, and through commercial operation of both units. The activities are essentially the same activities identified in the Site Certification process, revised and refined through additional analysis and lessons learned from other AP1000 construction projects in the U.S.

d. Please refer to subpart (c) above.

Q.
Beginning on page 8 of Witness Brown's May 1, 2015 prefiled testimony is a discussion of the basic analytical approach for the Turkey Point 6 & 7 Project. Please describe the events and timing of those events that FPL foresees would prompt emergence of another analytical approach, and what that approach might be.

A.
After the project completes the Licensing phase and begins to develop a detailed construction execution plan, the projected capital costs for Turkey Point 6 & 7 will become better defined. Engineering, construction, etc. contracts will need to be developed along with detailed construction schedules. Once the project's costs and schedules are sufficiently firm, FPL may consider moving from its $/kW breakeven cost analysis approach currently used to analyze the Turkey Point 6 & 7 project to an approach in which capital cost projections for the project are directly accounted for in a CPVRR cost comparison of resource plans with and without the project.

Q.

Please refer to Schedule 7A and 7B filed May 1, 2015. Please identify which contract or contracts, if any, are being utilized for purposes of the "initial assessment" studies discussed on page 38 of witness Scroggs' May 1, 2015 testimony.

A.

None of the contracts listed on the 7A and 7B schedules include work for the "initial assessment" studies.

Q.
Please refer to page 17, lines 1-12. Please comment whether the new nuclear construction projects' delays, primarily related to the fabrication and delivery of modules, affects FPL's consideration of the AP1000 design for the TP Project. If so, how?

A.
FPL conducted a detailed technology review, including the analysis of siting and constructability issues, prior to selecting the AP1000 design. The NRC COL licensing process is such that an applicant must select a specific technology for the application, and the subsequent COL is restricted to that technology. Therefore, the consideration of shifting technologies at this stage is significant, essentially requiring a restart of the licensing process.

As described in the testimony, FPL maintains a close review of the design, construction and operational preparations for the AP1000 in the U.S. It was anticipated that the first wave of AP1000 construction in the U.S. would provide considerable opportunities for the next units to incorporate lessons learned. Observations related to fabrication and delivery of modules, quality control and overall supply chain performance is of utmost interest and will help inform FPL in the development of further project cost, schedule and implementation plans. In this way, FPL's "consideration" is affected by placing importance on identifying improvement opportunities in first wave AP1000 deployment.

Q.
Please refer to page 20, lines 3-6, and page 22, line 20 through page 23, line 21.

a. Has the FPL committed sufficient, meaningful, and available resources to enable the Company to mitigate the potential outcome of the site certification application (SCA) Appeal.

b. Please discuss the potential impacts to the project cost, scope of maintenance activities, and project timeline.

A.

a. Yes. FPL invested significant resources in the preparation and defense of the Site Certification Application resulting in the favorable Final Order of Certification. The strength of this record is evidence of FPL's commitment of sufficient, meaningful and available resources. In the appeal process, FPL has engaged a legal firm with significant experience in Florida's PPSA process, and a firm with specific experience in the Third District Court of Appeals.

b. It is assumed that this question asks about the potential project impacts of a negative outcome of the Appeal of the Final Order of Certification. The results of the appeal process can include 1) affirming the Final Order, 2) identifying a flaw, and requiring a new, limited SCA hearing, or 3) nullifying the Final Order. Therefore the impacts could be none, require a limited administrative hearing to address a specific issue(s), or require an additional hearing. Given that the issues objected to in the SCA hearing were primarily focused on the western or eastern transmission corridors, it is unlikely that further proceedings directed by the appellate court would require a complete review of the full SCA. A limited hearing revisiting the transmission line siting aspect of the project could require an additional year, and associated legal and expert witness support at a fraction of the cost of the full SCA process.

Q.

In Exhibit ROB-1 of Witness Brown's testimony, he shows approximate nominal fuel saving of $47 billion and $101 billion over the operational life of Turkey Point Units 6 & 7.

a. Please provide a spreadsheet and graph (in Excel format) showing the annual values and when the fuel saving begins to exceed the low range of the total estimated costs of the units in using nominal and cumulative present value of revenue requirement (CPVRR) calculations.

b. Please provide a spreadsheet and graph (in Excel format) showing the annual values and when the fuel saving begins to exceed the high range of the total estimated costs of the units in using nominal and CPVRR calculations.

A.

a. Table and Graph Staff-13a1, contained in Attachment No. 1, present the annual nominal net cost projections and Table and Graph Staff-13a2, contained in Attachment No. 2, present the annual CPVRR net cost projections for Turkey Point 6 & 7, assuming the low-end of the non-binding cost estimate range. The tables and graphs are projections of total cost impacts; i.e., capital, O&M, fuel, transmission, etc.

b. Table and Graph Staff-13b1, contained in Attachment No. 3, present the annual nominal net cost projections and Table and Graph Staff-13b2, contained in Attachment No. 4, present the annual CPVRR net cost projections for Turkey Point 6 & 7, assuming the high-end of the non-binding cost estimate range. The tables and graphs are projections of total cost impacts; i.e., capital, O&M, fuel, transmission, etc.

Q.

Please explain the process for developing the updated 2015 fuel cost forecasts, including the sources used for cost data, how the high and low fuel costs were derived, and how, if at all, U.S. Energy Information Administration (EIA) data was used.

A.

FPL's Medium price forecast methodology is consistent for oil and natural gas. For oil and natural gas commodity prices, FPL's Medium price forecast applies the following methodology:

- For 2015 through 2016, the methodology used the November 3, 2014 forward curve for New York Harbor 0.7% sulfur heavy oil, ultra-low sulfur diesel (ULSD) fuel oil, and Henry Hub natural gas commodity prices;
- For the next two years (2017 and 2018), FPL used a 50/50 blend of the November 3, 2014 forward curve and the most current projections at the time from the PIRA Energy Group (PIRA);
- For the 2019 through 2035 period, FPL used the annual projections from PIRA; and,
- For the period beyond 2035, FPL used the real rate of escalation from the EIA. In addition to the development of oil and natural gas commodity prices, nominal price forecasts also were prepared for oil and natural gas transportation costs. The addition of commodity and transportation forecasts resulted in delivered price forecasts.

FPL's Medium price forecast methodology is also consistent for coal prices. Coal prices were based upon the following approach:

- Delivered price forecasts for Central Appalachian (CAPP), Illinois Basin (IB), Powder River Basin (PRB), and South American coal were provided by JD Energy; and,
- The coal price forecast for St. Johns River Power Park (SJRPP) and Plant Scherer assumes the continuation of the existing mine-mouth and transportation contracts until expiration, along with the purchase of spot coal, to meet generation requirements.

The development of FPL's Low and High price forecasts for natural gas were based on the historical volatility of the 12-month forward price, one year ahead. FPL developed these forecasts to account for the uncertainty that exists for natural gas commodity prices. These forecasts reflect a range of reasonable forecast outcomes.

For nuclear fuel price projections, FPL subscribes to a number of publications such as reports published by Ux consulting, Energy Resources International and Trade Tech.

These firms represent a broad spectrum of companies and serves as indicators for spot and long term market behaviors. FPL's long term price projections are monitored and updated as necessary to be reasonably consistent with the best estimates/projections of these recognized independent companies. FPL expects that there will be times when uranium market prices will fluctuate about these projections, but the price used for uranium in FPL's forecasts provides a better representation of long terms trends.

Q.

Please explain the reasons for the change in forecasted fuel prices (2014 to 2015) shown in ROB-2, page 1.

A.

The 2014 forecasted prices shown in ROB-2, page 1 were developed on October 7, 2013. The 2015 forecasted prices shown in ROB-2, page 1 were developed on November 3, 2014. As discussed in the response to Staff's Second Set of Interrogatories, No. 14, FPL incorporates both annual forecast projections from the PIRA Energy Group (PIRA), as well as the real rate of escalation from the U.S. Energy Information Administration (EIA) when developing its fuel price forecasts. PIRA periodically revises its long term forecast projections. Similarly, the EIA periodically revises its published real rate of escalation. FPL includes these updates, as they become available, from both PIRA and the EIA in its fuel price forecasts. The change in forecasted fuel prices from 2014 to 2015 shown in ROB-2, page 1 is the result of updated information provided by PIRA and the lowering of the real rate of escalation by the EIA during the period between October 2013 and November 2014. These updates are consistent for both fuel oil and natural gas.

The change in the nuclear fuel forecast reflects the continued downward market pricing trends caused by a decrease in demand and an increase in supply.

The uranium price increased during the second half of 2010 due primarily to the news of a significant increase in the future uranium demand to feed an increase in the number of new reactors planned in China. The earthquake and tsunami that struck Japan in March 2011 reversed that trend when all of the reactors in Japan were shut down and several other countries initiated abandonment of their nuclear programs. The market has drifted down since then and returned during the summer of 2013 to the levels that existed prior to the late 2010 uranium price increase. That downward drift was aided by the decision by the Department of Energy to sell some of its excess uranium inventories to fund the decontamination and decommissioning activities of old uranium enrichment plants. At this time the market has stabilized even though supply still exceeds current demand. FPL expects less volatility in uranium prices in the next few years, with price behavior to be more consistent with market fundamentals.

The events in Japan have also had a significant impact on the enrichment services market. To date that market has declined by about 30% and further small declines are possible before the market stabilizes again. The timing of the return of the nuclear reactors in Japan, if they return at all, will play an important role in the future enrichment price.

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

Q.
Please explain any differences in FPL's medium case fuel price forecasts and alternative fuel price forecasts provided by 3rd parties.

A.
As discussed in more detail in response to Staff's Second Set of Interrogatories No. 14, FPL's medium fossil fuel price forecast methodology utilizes projections from The PIRA Energy Group (PIRA), rates of escalation from the Department of Energy's (DOE) Energy Information Administration (EIA), forward commodity price curves for fuel oil and natural gas, and projections from JD Energy, Inc. PIRA, a world-recognized consulting firm with expertise in all aspects of the fuel oil and natural gas industry, supplies FPL with an extensive database to support its short and long-term projections of future fuel oil and natural gas prices. FPL utilizes forward commodity price curves for fuel oil and natural gas to project the short-term forecast (current year, current year plus 1 and current year plus 2), creates a blend of forward curves and PIRA curves for the medium term (current year plus 3 and current year plus 4) and finally, applies escalation rates, provided by the EIA, to the long-term fuel oil and natural gas projections provided by PIRA. JD Energy, a consulting firm retained by many utilities and coal suppliers, has expertise in all aspects of the coal and petroleum coke industry. The firm supplies FPL with an extensive database to support its short and long-term projections of future coal and petroleum coke prices. FPL's forecasts reflect these authoritative and independent sources. Consequently, FPL believes the Company's projections are reasonable and comparisons to other forecasts are not necessary.

Q.
What is the Docket No., name, and date of each previous FPSC filing containing FPL's fuel price forecasts referenced in Witness Brown's testimony, Page 13 lines 16-17?

A.
The fuel price forecast referenced in Witness Brown's testimony has also been utilized in the following FPSC filings:

1) Docket No. 150000-EI – Florida Power & Light Company's 2015 Ten Year Power Plant Site Plan, Filed April 1, 2015;
2) Docket No. 150075-EI – Petition for Approval of Arrangement to Mitigate Impact of Unfavorable Cedar Bay Power Purchase Obligation, by Florida Power & Light Company, Filed March 6, 2015

Q.

Please refer to Witness Brown's Exhibit ROB-2, Page 2 of 4 which provides Projected Environmental Compliance Costs for the ENV II Forecast:

a. Please provide tables, similar to Witness Brown's Exhibit ROB-2, Page 2 of 4, which show the ENV I and ENV III cost forecasts used in developing the data shown in Exhibits ROB-5 and ROB-6 in FPL's economic analysis of the long-term feasibility of completing the TP Project.

b. Please explain the dramatic change in the projected environmental compliance cost for SO2 and NOx between 2014 and 2015.

A.

a. Table Staff 18a-ENV I, see Attachment No. 1, presents the requested information for the environmental cost forecast for ENV I, and Table Staff 18a-ENV III, see Attachment No. 2, presents the requested information for the environmental cost forecast for ENV III.

b. Since 2007 FPL has used environmental compliance cost projections for SO2, NOx, and CO2 in its resource planning work, including the nuclear feasibility analyses, based on values provided by the consulting firm ICF International (ICF). The changes in the SO2 and NOx costs were due to the Supreme Court's ruling in 2014 that countermanded a late 2011 District Court of Appeals in D.C. decision to stay the EPA's Cross-State Air Pollution Rule. This more recent court decision has resulted in changes in ICF's compliance cost projections for both SO2 and NOx. After discussions with ICF, FPL has incorporated new compliance cost projections into its resource planning work, including the current nuclear feasibility analyses.

Table Staff 18a-ENV I

Comparison of Key Assumptions Utilized in the 2014 and 2015 Feasibility Analyses of the Turkey Point 6 & 7 Project: Projected Environmental Compliance Costs (Env I Forecast)
(all $ values shown are in Nominal $)

	(1)	(2)	(3) = (2) - (1)
	Forecasted SO_2 Compliance Cost ($/ton)		
Selected Years	2014 Feasibility Analysis	2015 Feasibility Analysis	Change in 2015 Forecast
2027	$76	$0	($76)
2030	$82	$0	($82)
2040	$105	$0	($105)
2050	$134	$0	($134)
2060	$172	$0	($172)
2070	$220	$0	($220)
2080	$282	$0	($282)

	(1)	(2)	(3) = (2) - (1)
	Forecasted NO_x Compliance Cost ($/ton)		
Selected Years	2014 Feasibility Analysis	2015 Feasibility Analysis	Change in 2015 Forecast
2027	$685	$0	($685)
2030	$737	$0	($737)
2040	$944	$0	($944)
2050	$1,208	$0	($1,208)
2060	$1,547	$0	($1,547)
2070	$1,980	$0	($1,980)
2080	$2,534	$0	($2,534)

	(1)	(2)	(3) = (2) - (1)
	Forecasted CO_2 Compliance Cost ($/ton)		
Selected Years	2014 Feasibility Analysis	2015 Feasibility Analysis	Change in 2015 Forecast
2027	$15	$17	$3
2030	$21	$25	$3
2040	$64	$68	$4
2050	$154	$156	$1
2060	$321	$301	($20)
2070	$448	$386	($62)
2080	$573	$494	($79)

Table Staff 18a-ENV III

Comparison of Key Assumptions Utilized in the 2014 and 2015 Feasibility Analyses of the Turkey Point 6 & 7 Project: Projected Environmental Compliance Costs (Env III Forecast)
(all $ values shown are in Nominal $)

	(1)	(2)	(3) = (2) - (1)
	Forecasted SO_2 Compliance Cost ($/ton)		
Selected Years	2014 Feasibility Analysis	2015 Feasibility Analysis	Change in 2015 Forecast
2027	$76	$0	($76)
2030	$82	$0	($82)
2040	$105	$0	($105)
2050	$134	$0	($134)
2060	$172	$0	($172)
2070	$220	$0	($220)
2080	$282	$0	($282)

	(1)	(2)	(3) = (2) - (1)
	Forecasted NO_x Compliance Cost ($/ton)		
Selected Years	2014 Feasibility Analysis	2015 Feasibility Analysis	Change in 2015 Forecast
2027	$685	$400	($285)
2030	$737	$400	($337)
2040	$944	$400	($544)
2050	$1,208	$400	($808)
2060	$1,547	$400	($1,147)
2070	$1,980	$400	($1,580)
2080	$2,534	$400	($2,134)

	(1)	(2)	(3) = (2) - (1)
	Forecasted CO_2 Compliance Cost ($/ton)		
Selected Years	2014 Feasibility Analysis	2015 Feasibility Analysis	Change in 2015 Forecast
2027	$15	$26	$11
2030	$21	$37	$15
2040	$64	$102	$38
2050	$154	$234	$79
2060	$321	$452	$131
2070	$448	$578	$131
2080	$573	$741	$167

Q.
For purposes of its 2014 economic analysis of the long-term feasibility of completing the TP Project, how, if at all, did FPL test the reasonableness and biases of the fuel and environmental costs forecasts that it relies on? Include in your response an explanation of whether the fuel cost forecasts reflect cost effects that are also captured in the environmental cost forecasts and, if so, how FPL addressed the possibility of overestimating or underestimate a particular change in environmental regulation.

A.
The fuel cost forecasts and environmental compliance cost forecasts used in FPL's 2015 feasibility analyses are two of many types of assumptions/forecasts that FPL typically updates each year in preparation for resource planning analyses that will be conducted throughout the remainder of the year. For example, the combined cycle assumptions used in the feasibility analysis (and reflected on Exhibit ROB-2 Page 4 of 4) reflect current/ongoing information exchanges with vendors. The resource planning analyses that utilize these assumptions address the projected economic and non-economic impacts to the FPL system of many types of resource options including, but not necessarily limited to, the following: steam generating units, combined cycle generating units, nuclear generating units, demand side management programs, renewable energy facilities, and purchased power options. In addition, many of these assumptions are also used in system reliability analyses, power plant maintenance planning and analyses, etc.

The fact that these assumptions are relied upon for a variety of system analyses throughout the year demonstrate the lack of any bias with respect to the analysis of Turkey Point 6 & 7. FPL seeks each year to develop a set of assumptions that reflect updated current information and which are deemed to be both reasonable and unbiased in regard to any resource option that is being analyzed. For this reason, the process of developing the key assumptions typically includes review by many of FPL's departments and business units.

Specifically in regard to the fuel cost forecast and the environmental cost forecasts, these forecasts are developed based on forecasts from outside parties. For example, the fuel cost forecasts for oil and natural gas use a combination of recent forward curves, projections from PIRA, and escalation rates from EIA. The environmental cost forecast utilizes information from ICF International. The use of third-party forecasts is reasonable and also demonstrates a lack of bias. Neither the fuel cost forecast nor the environmental compliance cost forecast accounts for costs included in the other forecast. FPL's use of a range of environmental cost forecasts (i.e., ENV I, ENV II, and ENV III) addresses the possibility of overestimating or underestimating a particular change in environmental regulation.

Q.

Please provide tables, similar to Witness Brown's Exhibit ROB-5 and ROB-6, for each fuel cost scenario with a $0/ton (zero) carbon dioxide emission cost assumption in lieu of the assumptions for the cost of carbon dioxide emission included in FPL's ENV I, II and ENV III cost forecasts. For purposes of this request, please identify the resultant scenario calculations as ENV 0-I, 0-II and ENV 0-III in lieu of ENV I, II and ENV III.

A.

Attachment No. 1, for the 40 year analysis, and Attachment No. 2, for the 60 year analysis, present the results of the requested sensitivity analyses for all 7 scenarios of fuel cost forecasts and environmental compliance cost forecasts in which the CO2 compliance costs is assumed to be $0/ton for all years of the analysis. Please refer to these tables for the requested information. However, FPL does not believe that this sensitivity assumption represents a reasonable projection.

Florida Power & Light Company
Docket No. 150009-EI
Staff's Second Set of Interrogatories
Interrogatory No. 21
Attachment No. 1
Tab 1 of 1

Table Staff-21a

Sensitivity Analyses: Assuming Zero CO_2 Compliance Costs

2015 Feasibility Analyses Results for the Turkey Point 6 & 7 Project:
Case # 1 Analysis - 40-Year Operating Life; Total Costs,
Total Cost Differentials, and Breakeven Costs for All Fuel
and Environmental Compliance Cost Scenarios in 2015$
(millions, CPVRR, 2015 - 2068)

(1)	(2)	(3)	(4)	(5) = (3) - (4)	(6)
Fuel Cost Forecast	Environmental Compliance Cost Forecast **	Total Costs for Plans		Total Cost Difference Plan with TP 6 & 7 minus Plan without TP 6 & 7 *	Breakeven Nuclear Capital Costs ($/kW in 2015$)
		Resource Plan w/ TP 6 & 7	Resource Plan w/o TP 6 & 7		
High Fuel Cost	Env 0- I	112,092	119,660	(7,568)	3,692
High Fuel Cost	Env 0-II	112,163	119,741	(7,578)	3,696
High Fuel Cost	Env 0-III	112,217	119,809	(7,592)	3,703
Medium Fuel Cost	Env 0-I	97,328	103,695	(6,367)	3,104
Medium Fuel Cost	Env 0-II	97,354	103,717	(6,363)	3,102
Medium Fuel Cost	Env 0-III	97,373	103,734	(6,362)	3,101
Low Fuel Cost	Env 0-I	82,313	87,436	(5,123)	2,495

* The TP 6 & 7 savings values in Column (5) also represent CPVRR breakeven capital costs for each scenario.

** CO_2 compliance costs are assumed to be $0/ton for all years of the analyses for all three environmental scenarios.

Note: The TP 6 & 7 non-binding cost estimate range to which the breakeven cost is compared is $3,844/kW to $5,589/kW in 2015$.

Florida Power & Light Company
Docket No. 150009-EI
Staff's Second Set of Interrogatories
Interrogatory No. 21
Attachment No. 2
Tab 1 of 1

Table Staff-21b

Sensitivity Analyses: Assuming Zero CO_2 Compliance Costs

2015 Feasibility Analyses Results for the Turkey Point 6 & 7 Project:
Case # 2 Analysis - 60-Year Operating Life; Total Costs,
Total Cost Differentials, and Breakeven Costs for All Fuel
and Environmental Compliance Cost Scenarios in 2015$
(millions, CPVRR, 2015 - 2088)

(1)	(2)	(3)	(4)	(5) = (3) - (4)	(6)
Fuel Cost Forecast	Environmental Compliance Cost Forecast **	Total Costs for Plans		Total Cost Difference Plan with TP 6 & 7 minus Plan without TP 6 & 7 *	Breakeven Nuclear Capital Costs ($/kW in 2015$)
		Resource Plan w/ TP 6 & 7	Resource Plan w/o TP 6 & 7		
High Fuel Cost	Env 0- I	120,362	128,403	(8,041)	3,923
High Fuel Cost	Env 0-II	120,437	128,484	(8,047)	3,926
High Fuel Cost	Env 0-III	120,494	128,555	(8,061)	3,933
Medium Fuel Cost	Env 0-I	104,373	111,062	(6,688)	3,261
Medium Fuel Cost	Env 0-II	104,401	111,082	(6,681)	3,258
Medium Fuel Cost	Env 0-III	104,421	111,099	(6,679)	3,256
Low Fuel Cost	Env 0-I	88,129	93,424	(5,294)	2,579

* The TP 6 & 7 savings values in Column (5) also represent CPVRR breakeven capital costs for each scenario.

** CO_2 compliance costs are assumed to be $0/ton for all years of the analyses for all three environmental scenarios.

Note: The TP 6 & 7 non-binding cost estimate range to which the breakeven cost is compared is $3,844/kW to $5,589/kW in 2015$.

Q.

Please provide charts, in hard copy and electronic (Excel format), with projections of the nominal annual residential rate impact over the period from 2015 to 2084, assuming 1,000 kWh and 1,200 kWh monthly consumption consistent with the planning assumptions shown in Exhibit ROB-4. The charts should show the estimated impacts of completing the TP Project, the estimated impacts of terminating the TP Project by December 31, 2015, and differences between these two cases. Please include notations addressing how FPL addressed factors such as the estimated ranges in capital costs, fuel costs, recovery of existing unrecovered TP Project costs, and base rate effects for the TP Project replacement alternative(s), and whether the replacement plan included the equivalent base-load capacity and energy as from the TP Project.

A.

Attachment Nos. 1 & 2, present a comparison of system average electric rate and bill impacts for the years 2015 through 2084 for the Resource Plan with Turkey Point 6 & 7 and for a modified version of the Resource Plan without Turkey Point 6 & 7. The projected costs for the Resource Plan without Turkey Point 6 & 7 that were used in FPL's 2015 feasibility analyses have been modified for this analysis to include recovery of approximately $873,000 in costs that would be incurred in 2015 in order to terminate the project at the end of 2015. Table Staff-22a, contained in Attachment No. 1, assumes the high-end of the non-binding capital cost estimate for Turkey Point 6 & 7. Table Staff-22b, contained in Attachment No. 2, assumes the low-end of the non-binding capital cost estimate for Turkey Point 6 & 7. Both tables present results based on the Medium Fuel Cost, Environmental II scenario.

The rate impacts shown in this response are based on system average total electric rates (base rates plus clauses) developed by dividing total projected system costs by total projected GWh served.

The Resource Plan without Turkey Point 6 & 7 replaces the baseload capacity and energy of these two nuclear units with a comparable amount of baseload capacity and energy from two combined cycle units.

Table Staff-22a

Turkey Point 6&7 Project

Scenario: Medium Fuel Cost Forecast, Env II Environmental Compliance Cost Forecast

Projected System Average Electric Rate and Bill Impact: assuming High End of the Non-Binding Capital Cost Range

	(1)	(2)	(3) – (1)-(2)	(4)	(5) = ((3)x1,000,000x100) / ((4)x1,000,000)	(6) = (5) * 1,000)/100	(7) = ((5) * 1,200)/100
Year	Resource Plan with TP 6&7 Annual Revenue Requirements ($millions, Nominal $)	Resource Plan without TP 6 & 7 Annual Revenue Requirements ($millions, Nominal $)	Differential in Annual Revenue Requirements ($millions, Nominal $)	Projected Total Sales (GWh)	Differential in System Average Electric Rates (cents/kwh)	Bill Impact Based on 1,000 kWh ($)	Bill Impact Based on 1,200 kWh ($)
2015	2,865	2,838	27	112,977	0.02	0.24	0.29
2016	3,006	2,987	19	115,537	0.02	0.16	0.19
2017	2,774	2,741	33	117,012	0.03	0.28	0.34
2018	3,023	2,948	74	118,432	0.06	0.63	0.75
2019	3,610	3,596	14	119,968	0.01	0.12	0.14
2020	4,421	4,376	44	121,660	0.04	0.36	0.44
2021	4,838	4,707	130	122,065	0.11	1.07	1.28
2022	5,338	5,062	276	122,811	0.22	2.25	2.70
2023	5,980	5,510	470	124,143	0.38	3.78	4.54
2024	6,590	5,901	689	125,817	0.55	5.48	6.57
2025	7,197	6,290	906	126,960	0.71	7.14	8.57
2026	7,884	6,778	1,106	128,621	0.86	8.60	10.32
2027	8,626	7,255	1,371	130,639	1.05	10.49	12.59
2028	9,386	8,039	1,347	133,059	1.01	10.12	12.15
2029	9,804	8,571	1,233	134,917	0.91	9.14	10.97
2030	10,122	9,096	1,026	137,231	0.75	7.48	8.98
2031	10,635	9,641	993	139,266	0.71	7.13	8.56
2032	11,446	10,862	584	141,732	0.41	4.12	4.94
2033	12,872	12,390	482	143,216	0.34	3.36	4.03
2034	13,549	13,166	383	144,926	0.26	2.64	3.17
2035	14,097	14,060	37	146,643	0.03	0.25	0.31
2036	15,349	15,464	(115)	148,810	(0.08)	(0.77)	(0.93)
2037	16,419	16,299	120	150,198	0.08	0.80	0.96
2038	17,110	17,184	(74)	151,994	(0.05)	(0.49)	(0.59)
2039	17,868	18,097	(229)	153,792	(0.15)	(1.49)	(1.79)
2040	18,766	19,321	(555)	156,009	(0.36)	(3.56)	(4.27)
2041	19,607	20,321	(714)	157,558	(0.45)	(4.53)	(5.44)
2042	20,794	21,345	(551)	159,105	(0.35)	(3.46)	(4.16)
2043	22,421	22,997	(576)	160,666	(0.36)	(3.59)	(4.30)
2044	23,662	24,417	(754)	162,243	(0.46)	(4.65)	(5.58)
2045	24,605	25,465	(860)	163,836	(0.52)	(5.25)	(6.30)
2046	25,515	26,772	(1,257)	165,444	(0.76)	(7.60)	(9.12)
2047	26,416	27,803	(1,388)	167,069	(0.83)	(8.31)	(9.97)
2048	27,435	28,913	(1,478)	168,709	(0.88)	(8.76)	(10.51)
2049	28,782	30,095	(1,313)	170,366	(0.77)	(7.70)	(9.25)
2050	29,911	31,369	(1,458)	172,039	(0.85)	(8.47)	(10.17)
2051	31,122	32,672	(1,549)	173,729	(0.89)	(8.92)	(10.70)
2052	32,493	34,547	(2,054)	175,436	(1.17)	(11.71)	(14.05)
2053	33,890	36,043	(2,152)	177,055	(1.22)	(12.16)	(14.59)
2054	35,352	37,677	(2,326)	178,792	(1.30)	(13.01)	(15.61)
2055	37,378	39,516	(2,138)	180,550	(1.18)	(11.84)	(14.21)
2056	39,016	41,353	(2,337)	182,325	(1.28)	(12.82)	(15.38)
2057	40,773	43,310	(2,537)	184,118	(1.38)	(13.78)	(16.53)
2058	42,671	45,377	(2,706)	185,929	(1.46)	(14.55)	(17.46)
2059	44,776	48,087	(3,311)	187,757	(1.76)	(17.64)	(21.16)
2060	46,976	50,474	(3,498)	189,604	(1.85)	(18.45)	(22.14)
2061	49,745	53,091	(3,346)	191,469	(1.75)	(17.47)	(20.97)
2062	52,217	55,855	(3,638)	193,352	(1.88)	(18.82)	(22.58)
2063	54,893	58,851	(3,958)	195,254	(2.03)	(20.27)	(24.32)
2064	57,746	62,462	(4,716)	197,012	(2.39)	(23.94)	(28.73)
2065	60,796	65,865	(5,069)	198,785	(2.55)	(25.50)	(30.60)
2066	64,192	69,635	(5,444)	200,574	(2.71)	(27.14)	(32.57)
2067	68,062	73,553	(5,491)	202,379	(2.71)	(27.13)	(32.56)
2068	71,704	77,811	(6,108)	204,201	(2.99)	(29.91)	(35.89)
2069	75,821	82,452	(6,631)	206,038	(3.22)	(32.18)	(38.62)
2070	80,354	87,955	(7,601)	207,893	(3.66)	(36.56)	(43.87)
2071	85,205	93,302	(8,097)	209,764	(3.86)	(38.60)	(46.32)
2072	90,934	99,065	(8,131)	211,652	(3.84)	(38.42)	(46.10)
2073	96,578	105,309	(8,731)	213,556	(4.09)	(40.88)	(49.06)
2074	102,583	111,964	(9,381)	215,478	(4.35)	(43.53)	(52.24)
2075	109,061	119,682	(10,621)	217,418	(4.89)	(48.85)	(58.62)
2076	116,093	127,454	(11,361)	219,375	(5.18)	(51.79)	(62.14)
2077	124,248	135,841	(11,594)	221,349	(5.24)	(52.38)	(62.85)
2078	132,377	144,843	(12,466)	223,341	(5.58)	(55.82)	(66.98)
2079	141,132	154,542	(13,411)	225,351	(5.95)	(59.51)	(71.41)
2080	150,564	165,591	(15,027)	227,379	(6.61)	(66.09)	(79.30)
2081	160,713	176,824	(16,111)	229,426	(7.02)	(70.22)	(84.27)
2082	172,255	188,911	(16,656)	231,491	(7.20)	(71.95)	(86.34)
2083	183,992	201,922	(17,929)	233,574	(7.68)	(76.76)	(92.11)
2084	196,627	216,575	(19,948)	235,676	(8.46)	(84.64)	(101.57)

*** Both new nuclear units are in-service for full-year operation starting in 2029.**

(1) This projection assumes instantaneous adjustment to electric rates and is for illustrative purposes only

(2) The cost values presented are system revenue requirements (capital, system fuel, etc.) directly associated with a resource plan

(3) For purposes of this analysis, the highest end of the non-binding capital cost estimate, $5,589/kW (2015$) is assumed for both new nuclear units

(4) An estimated termination cost of approximately $873 thousand is included in 2016 for the Resource Plan without Turkey Point 6&7 based on an assumption that the project is terminated on 12/31/2015

Table Staff-22b

Turkey Point 6&7 Project

Scenario: Medium Fuel Cost Forecast, Env II Environmental Compliance Cost Forecast

Projected System Average Electric Rate and Bill Impact: assuming Low End of the Non-Binding Capital Cost Range

	(1)	(2)	(3) = (1)-(2)	(4)	(5) = ((3)x1,000,000x100) / ((4)x1,000,000)	(6) = ((5) * 1,000)/100	(7) = ((5) * 1,200)/100
Year	Resource Plan with TP 6&7 Annual Revenue Requirements ($millions, Nominal $)	Resource Plan without TP 6 & 7 Annual Revenue Requirements ($millions, Nominal $)	Differential in Annual Revenue Requirements ($millions Nominal $)	Projected Total Sales (GWh)	Differential in System Average Electric Rates (cents/kwh)	Bill Impact Based on 1,000 kWh ($)	Bill Impact Based on 1,200 kWh ($)
2015	2,865	2,838	27	112,977	0.02	0.24	0.29
2016	3,002	2,987	15	115,537	0.01	0.13	0.15
2017	2,766	2,741	25	117,012	0.02	0.21	0.25
2018	3,001	2,948	53	118,432	0.04	0.45	0.54
2019	3,608	3,596	12	119,968	0.01	0.10	0.12
2020	4,409	4,376	33	121,660	0.03	0.27	0.32
2021	4,798	4,707	91	122,065	0.07	0.75	0.89
2022	5,253	5,062	191	122,811	0.16	1.55	1.86
2023	5,832	5,510	322	124,143	0.26	2.60	3.11
2024	6,373	5,901	472	125,817	0.37	3.75	4.50
2025	6,910	6,290	620	126,960	0.49	4.88	5.86
2026	7,533	6,778	755	128,621	0.59	5.87	7.05
2027	8,112	7,255	856	130,639	0.66	6.56	7.87
2028	8,684	8,039	645	133,059	0.49	4.85	5.82
2029	9,059	8,571	488	134,917	0.36	3.62	4.34
2030	9,408	9,096	312	137,231	0.23	2.27	2.73
2031	9,949	9,641	308	139,266	0.22	2.21	2.65
2032	10,787	10,862	(75)	141,732	(0.05)	(0.53)	(0.63)
2033	12,238	12,390	(152)	143,216	(0.11)	(1.06)	(1.27)
2034	12,940	13,166	(226)	144,926	(0.16)	(1.56)	(1.87)
2035	13,513	14,060	(547)	146,643	(0.37)	(3.73)	(4.47)
2036	14,789	15,464	(675)	148,810	(0.45)	(4.53)	(5.44)
2037	15,884	16,299	(416)	150,198	(0.28)	(2.77)	(3.32)
2038	16,599	17,184	(585)	151,994	(0.38)	(3.85)	(4.62)
2039	17,382	18,097	(715)	153,792	(0.46)	(4.65)	(5.58)
2040	18,304	19,321	(1,017)	156,009	(0.65)	(6.52)	(7.82)
2041	19,170	20,321	(1,151)	157,558	(0.73)	(7.31)	(8.77)
2042	20,380	21,345	(965)	159,105	(0.61)	(6.07)	(7.28)
2043	22,025	22,997	(972)	160,666	(0.61)	(6.05)	(7.26)
2044	23,279	24,417	(1,138)	162,243	(0.70)	(7.01)	(8.42)
2045	24,233	25,465	(1,232)	163,836	(0.75)	(7.52)	(9.03)
2046	25,154	26,772	(1,618)	165,444	(0.98)	(9.78)	(11.74)
2047	26,066	27,803	(1,738)	167,069	(1.04)	(10.40)	(12.48)
2048	27,096	28,913	(1,816)	168,709	(1.08)	(10.77)	(12.92)
2049	28,455	30,095	(1,640)	170,366	(0.96)	(9.63)	(11.55)
2050	29,595	31,369	(1,774)	172,039	(1.03)	(10.31)	(12.38)
2051	30,817	32,672	(1,854)	173,729	(1.07)	(10.67)	(12.81)
2052	32,199	34,547	(2,348)	175,436	(1.34)	(13.38)	(16.06)
2053	33,607	36,043	(2,435)	177,055	(1.38)	(13.75)	(16.50)
2054	35,080	37,677	(2,597)	178,792	(1.45)	(14.53)	(17.43)
2055	37,117	39,516	(2,399)	180,550	(1.33)	(13.29)	(15.94)
2056	38,766	41,353	(2,587)	182,325	(1.42)	(14.19)	(17.02)
2057	40,535	43,310	(2,775)	184,118	(1.51)	(15.07)	(18.09)
2058	42,444	45,377	(2,933)	185,929	(1.58)	(15.78)	(18.93)
2059	44,560	48,087	(3,527)	187,757	(1.88)	(18.79)	(22.54)
2060	46,771	50,474	(3,703)	189,604	(1.95)	(19.53)	(23.44)
2061	49,552	53,091	(3,539)	191,469	(1.85)	(18.48)	(22.18)
2062	52,035	55,855	(3,820)	193,352	(1.98)	(19.76)	(23.71)
2063	54,722	58,851	(4,129)	195,254	(2.11)	(21.15)	(25.38)
2064	57,586	62,462	(4,876)	197,012	(2.48)	(24.75)	(29.70)
2065	60,647	65,865	(5,218)	198,785	(2.62)	(26.25)	(31.50)
2066	64,054	69,635	(5,581)	200,574	(2.78)	(27.83)	(33.39)
2067	67,971	73,553	(5,583)	202,379	(2.76)	(27.59)	(33.10)
2068	71,678	77,811	(6,134)	204,201	(3.00)	(30.04)	(36.04)
2069	75,821	82,452	(6,631)	206,038	(3.22)	(32.18)	(38.62)
2070	80,354	87,955	(7,601)	207,893	(3.66)	(36.56)	(43.87)
2071	85,205	93,302	(8,097)	209,764	(3.86)	(38.60)	(46.32)
2072	90,934	99,065	(8,131)	211,652	(3.84)	(38.42)	(46.10)
2073	96,578	105,309	(8,731)	213,556	(4.09)	(40.86)	(49.06)
2074	102,583	111,964	(9,381)	215,478	(4.35)	(43.53)	(52.24)
2075	109,061	119,682	(10,621)	217,418	(4.89)	(48.85)	(58.62)
2076	116,093	127,454	(11,361)	219,375	(5.18)	(51.79)	(62.14)
2077	124,248	135,841	(11,594)	221,349	(5.24)	(52.38)	(62.85)
2078	132,377	144,843	(12,466)	223,341	(5.58)	(55.82)	(66.98)
2079	141,132	154,542	(13,411)	225,351	(5.95)	(59.51)	(71.41)
2080	150,564	165,591	(15,027)	227,379	(6.61)	(66.09)	(79.30)
2081	160,713	176,824	(16,111)	229,426	(7.02)	(70.22)	(84.27)
2082	172,255	188,911	(16,656)	231,491	(7.20)	(71.95)	(86.34)
2083	183,992	201,922	(17,929)	233,574	(7.68)	(76.76)	(92.11)
2084	196,627	216,575	(19,948)	235,676	(8.46)	(84.64)	(101.57)

*** Both new nuclear units are in-service for full-year operation starting in 2029.**

(1) This projection assumes instantaneous adjustment to electric rates and is for illustrative purposes only.

(2) The cost values presented are system revenue requirements (capital, system fuel, etc.) directly associated with a resource plan.

(3) For purposes of this analysis, the lowest end of the non-binding capital cost estimate, $3,844/kW (2015$) is assumed for both new nuclear units.

(4) An estimated termination cost of approximately $873 thousand is included in 2016 for the Resource Plan without Turkey Point 6&7 based on an assumption that the project is terminated on 12/31/2015.

Q.
Please provide the status of efforts to identify potential joint owners for the TP Project, including specific actions FPL has taken and results achieved toward joint ownership since March 2014.

A.
FPL has continued good faith discussions with the Florida Municipal Energy Association ("FMEA"), Florida Municipal Power Agency ("FMPA"), Orlando Utilities Commission ("OUC"), JEA, and Seminole Electric Cooperative, Inc. ("Seminole") through annual updates. The most recent annual update was provided on June 6, 2014. No significant developments have occurred during this time period. FPL views that entering into any joint ownership agreements in advance of completing the COL would be premature and, perhaps detrimental to the overall licensing timeline. Please also see Docket No. 080271-EI for quarterly updates regarding the status of discussions with various potential partners.

Q.
Please provide tables showing the calculation of the CPVRR corresponding to a $1/kW overnight construction cost for the TP Project as used to calculate the "Breakeven Nuclear Capital Costs" (Column 6) from the "Total Cost Difference Plan with TP 6 & 7 minus Plan without TP 6 & 7" (Column 5) in Witness Brown's Exhibits ROB-5 and ROB-6.

A.
Attachment No. 1 shows that the 2015$ CPVRR cost corresponding to a $1/kW overnight construction cost is approximately $2.048 million CPVRR.

The fact that a $1/kW overnight construction cost equates to approximately $2.048 million CPVRR can be used to convert the CPVRR differences between the Resource Plan with Turkey Point 6 & 7 and the Resource Plan without Turkey Point 6 & 7 into $/kW breakeven costs. For example, as shown in Column (5) of Exhibit ROB-5, the CPVRR difference between the two resource plans for the High Fuel Cost/Env I scenario is $10,762 million CPVRR. Dividing this value by $2.048 million CPVRR per $1/kW yields a projected breakeven overnight construction cost of $5,254/kW that matches the value shown in Column (6) in Exhibit ROB-5 for this scenario.

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Discount Rate = 7.51%

Overnight Cost ($/kW) = 1

Year	[1] Revenue requirement on site selection and pre-construction ($ 000)	[2] Construction CCC ($ 000)	[3] In-service Revenue Requirements ($ 000)	[4] = [1]+[2]+[3] Total Revenue Requirements ($ 000)
2007	0	0	0	0
2008	0	0	0	0
2009	15	0	0	15
2010	4	0	0	4
2011	4	0	0	4
2012	5	0	0	5
2013	5	0	0	5
2014	4	0	0	4
2015	4	0	0	4
2016	3	0	0	3
2017	6	0	0	6
2018	13	0	0	13
2019	2	0	0	2
2020	2	4	0	6
2021	2	13	0	15
2022	2	28	0	29
2023	2	47	0	49
2024	2	69	0	70
2025	2	88	0	90
2026	2	106	0	108
2027	2	50	133	185
2028	1	0	220	221
2029	0	0	211	211
2030	0	0	203	203
2031	0	0	194	194
2032	0	0	187	187
2033	0	0	180	180
2034	0	0	172	172
2035	0	0	165	165
2036	0	0	158	158
2037	0	0	151	151
2038	0	0	144	144
2039	0	0	137	137
2040	0	0	129	129
2041	0	0	122	122
2042	0	0	116	116
2043	0	0	112	112
2044	0	0	109	109
2045	0	0	105	105
2046	0	0	102	102
2047	0	0	99	99
2048	0	0	95	95
2049	0	0	92	92
2050	0	0	89	89
2051	0	0	86	86
2052	0	0	82	82
2053	0	0	79	79
2054	0	0	76	76
2055	0	0	73	73
2056	0	0	69	69
2057	0	0	66	66
2058	0	0	63	63
2059	0	0	60	60
2060	0	0	56	56
2061	0	0	53	53
2062	0	0	50	50
2063	0	0	46	46
2064	0	0	43	43
2065	0	0	40	40
2066	0	0	37	37
2067	0	0	14	14
2068	0	0	0	0

Total CPVRR TP6 = 631

Year	[1] Revenue requirement on site selection and pre-construction ($ 000)	[2] Construction CCC ($ 000)	[3] In-service Revenue Requirements ($ 000)	[4] = [1]+[2]+[3] Total Revenue Requirements ($ 000)
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
2013	0	0	0	0
2014	0	0	0	0
2015	0	0	0	0
2016	0	0	0	0
2017	0	0	0	0
2018	0	0	0	0
2019	0	0	0	0
2020	0	2	0	2
2021	0	8	0	8
2022	0	20	0	20
2023	0	35	0	35
2024	0	53	0	53
2025	0	72	0	72
2026	0	90	0	90
2027	0	108	0	108
2028	0	51	128	178
2029	0	0	212	212
2030	0	0	203	203
2031	0	0	195	195
2032	0	0	187	187
2033	0	0	180	180
2034	0	0	173	173
2035	0	0	166	166
2036	0	0	159	159
2037	0	0	153	153
2038	0	0	146	146
2039	0	0	139	139
2040	0	0	132	132
2041	0	0	125	125
2042	0	0	119	119
2043	0	0	113	113
2044	0	0	109	109
2045	0	0	105	105
2046	0	0	102	102
2047	0	0	99	99
2048	0	0	96	96
2049	0	0	93	93
2050	0	0	90	90
2051	0	0	87	87
2052	0	0	84	84
2053	0	0	81	81
2054	0	0	78	78
2055	0	0	74	74
2056	0	0	71	71
2057	0	0	68	68
2058	0	0	65	65
2059	0	0	62	62
2060	0	0	59	59
2061	0	0	56	56
2062	0	0	53	53
2063	0	0	50	50
2064	0	0	46	46
2065	0	0	43	43
2066	0	0	40	40
2067	0	0	37	37
2068	0	0	14	14

Total CPVRR TP7 = 538

2007$ **Total CPVRR - both units =** 1,169

2015$ **Total CPVRR - both units * =** 2,048

* The previously spent (or sunk) capital costs have been excluded in the calculation of the $2,048 ($000) CPVRR value.

Q.

On page 6 of his pre-filed testimony FPL witness Brown discussed steps being taken to minimize the risk of in having a high reliance on natural gas. Among those steps he mentions diversifying the fuel mix by adding renewable energy. In Exhibit ROB-4, 223 MW of solar generation is shown being added only in 2017, with or without the TP Project.

a. Please discuss FPL's rationale for limiting investment in renewable generation to 223 MW in 2017 and no more through 2030.

b. How, if at all, did FPL's analysis of the long-term feasibility of completing the TP Project include explicit consideration and addition of various forms of renewable energy alternatives?

c. How, if at all, did FPL's analysis of the long-term feasibility of completing the TP Project include implicit consideration and addition of various forms of renewable energy alternatives?

d. Did FPL consider base-loaded wind technology and if so how? If not explain why.

e. Did FPL consider additional base-loaded solar technology and if so how? If not explain why.

f. Did FPL consider base-loaded biomass technology and if so how? If not explain why.

g. What other forms of renewable base-loaded generation technology, if any, were considered and if so how? If not explain why.

A.

a. FPL disagrees with the premise of the question. FPL is not "limiting investment in renewable generation." Rather, the 223 MW included in ROB-4 reflects specific solar projects discussed in FPL's 2015 Ten Year Power Plant Site Plan (see page 7 of FPL's 2015 TYSP). FPL expects to identify additional PV facilities that will be projected to be cost-effective. When this occurs, FPL will incorporate those PV facilities into FPL's resource plans and discuss those facilities in future Site Plans. In addition, FPL does not view new nuclear and new renewable projects as mutually exclusive. Both types of generation can be valuable additions for FPL's customers both in terms of system economics and fuel diversity. Consequently, FPL is pursuing both of these (as well as other) resource options.

b. In general, FPL views renewable energy resources as complementary to base load capacity resource options, such as Turkey Point 6 & 7. In order for a renewable energy resource option to be considered as a viable potential alternative to Turkey Point 6 & 7, the resource option would need to have several characteristics. Among these would be: (i) the ability to provide 2,200 MW of firm capacity, and (ii) be considered base loaded. In Florida, most renewable energy options, including solar and wind, are not based loaded in nature and have limited if any firm capacity value. Therefore, these types of renewable energy options are not currently considered as viable alternatives to Turkey Point 6 & 7.

   In regard to biomass, it is one renewable energy resource in Florida that can be considered to be a firm capacity resource option. However, FPL does not believe there is 2,200 MW of untapped biomass potential in FPL's service territory. Therefore, FPL does not consider incremental biomass to be a viable potential alternative to Turkey Point 6 & 7.

   In addition, the location of Turkey Point 6 & 7, in Miami-Dade County, results in Turkey Point 6 & 7 being projected to provide significant transmission-related benefits for FPL's customers. FPL does not believe that by 2027 and 2028 it can develop up to 2,200 MW of firm renewable resources in Southeastern Florida (specifically Miami-Dade and Broward Counties).

c. Please refer to response to subpart b.

d. Please refer to response to subpart b.

e. Please refer to responses to subparts a and b.

f. Please refer to response to subpart b.

g. Please refer to response in subpart b.

Q.
Please describe what FPL has done since March 2014 to identify additional conservation measures that could be adopted as an alternative to completing the TP Project.

A.
FPL's practice is to regularly examine potential new DSM measures to determine if they are applicable for FPL's service territory and our customers' patterns of electrical usage. If a potential new measure appears promising, it is then typically examined through preliminary cost-effectiveness screening. Such a screening would be against a self-build unit that could address FPL's next resource need. Once the results of FPL's capacity RFP analyses are determined, FPL's next resource need would be expected to be shortly after 2019 (and well before the 2027 and 2028 in-service dates for Turkey Point 6 & 7 utilized in the nuclear feasibility analyses).

FPL does not currently view DSM as a logical alternative to Turkey Point 6 & 7 for several reasons. First, as mentioned above, FPL will have resource needs earlier than 2027 and 2028 that DSM could address. Second, DSM sign-ups now would fare poorly in cost-effectiveness tests examining the potential avoidance of generation in 2027 and 2028 because the present value of the near term costs would be compared to more heavily discounted benefits that would begin 12 or 13 years in the future. Third, Turkey Point 6 & 7 will provide 2,200 MW of capacity. Consideration of FPL's 20% total reserve margin reliability criterion would show that 1,833 MW of DSM (2,200/1.20 = 1,833) would be needed to result in the same total reserve margin that would be achieved with Turkey Point 6 & 7. The just concluded DSM Goals docket resulted in 522 MW of DSM being deemed achievable over a 10-year period through 2024. Accordingly, FPL views the identification of 1,833 MW of achievable DSM in the next 13 years as highly unlikely.

Q.

How has FPL accounted for the newly established demand side management (DSM) goals per Order No. PSC-14-0696-FOF-EU for the years 2015-2024 in its determination of the utility's system-wide available conservation for the instant proceeding?

A.

FPL assumed that the DSM amounts established in the recent DSM Goals docket were implemented in its 2015 feasibility analyses.

Q.
Do Exhibits ROB-5 and ROB-6 include the capital costs, operational costs, and impacts on performance associated with implementing carbon capture technology on natural gas combined cycle facilities? If yes, please provide FPL's estimates for carbon capture technology on natural gas combined cycle facilities. If not, please explain how, if at all, FPL's analysis implicitly or explicitly addresses the potential for such costs.

A.
In its 2015 feasibility analyses, FPL did not analyze the cost and impact on performance associated with placing carbon capture technology on CC units. There are several reasons why this scenario was not analyzed in the current feasibility analyses. First, there is no carbon capture technology that is commercially available for the size (1,300 MW) of CC units that FPL assumed would be added in the Resource Plan without Turkey Point 6 & 7. Thus any cost and performance impacts for this technology would be theoretical at this time.

Second, it would be meaningless to install carbon capture technology unless carbon sequestration was also implemented. No large-scale carbon sequestration sites are currently known to exist in FPL's service territory. Therefore, the cost of transporting the captured carbon to a suitable site (if one could be found) would involve considerable cost and difficulty. In addition, carbon sequestration technology of a scale needed to handle the carbon captured from two 1,300 MW CC units has not yet been in operation so both the technical feasibility and cost are uncertain at this point in time.

Third, FPL previously analyzed carbon capture and sequestration (CCS) in its 2007 need filing for Turkey Point 6 & 7. In that filing, the two new nuclear units were analyzed versus CC and integrated gasification combined cycle (IGCC) capacity. In one scenario, FPL looked at how the overnight breakeven cost of Turkey Point 6 & 7 versus IGCC capacity would change if the IGCC units were assumed to be using CCS technology. Due to the additional capital and operating costs associated with CCS, plus the various other operating impacts (such as unit availability) of CCS technology, the results of the analysis of this scenario were that the breakeven overnight costs for Turkey Point 6 & 7 were projected to increase from approximately $430/kw to approximately $2,900/kw over the various fuel cost and environmental cost scenarios. FPL believes that if a similar analysis of CCS technology applied to CC capacity were attempted, the results would be that the projected breakeven costs for Turkey Point 6 & 7 would also be significantly increased, further supporting the cost-effectiveness of Turkey Point 6 & 7.

Q.
Please provide a levelized cost (in $/kWh) for various capacity factors comparing nuclear, natural gas combined cycle, wind, biomass, and roof top photovoltaic technology based on FPL's long-term planning assumptions for each of these options. Please show levelized capital costs and operation and maintenance (O&M)/Fuel costs separately. Also, please provide the raw data and a chart depicting this information.

A.
FPL would like to first point out, as it has done several times in previous NCRC dockets, that a comparison of the costs of resource options on a $/kWh basis (or a $/kW basis) should never be used to make a final decision regarding the competing resource options. The reason for this is that these calculations do not – and cannot – account for numerous impacts to the utility system that different resource options will have. Thus, such overly simplistic calculations cannot provide complete information regarding all of the system cost impacts associated with resource options. Therefore, unless the resource options in question are identical, or nearly identical, in regard to all of (at least) the characteristics listed below, these types of calculations are meaningless if the intent is to make a final decision regarding which of competing resource options would be most beneficial to customers.

The characteristics that must <u>all</u> be identical, or nearly identical, in order for these types of calculations to even approach being meaningful include at least the following four characteristics: (i) size (MW); (ii) capacity factor; (iii) the percentage of the resource option's capacity that can be considered firm capacity; and (iv) life of the resource option. FPL notes that no two of the resource options included in the interrogatory (Turkey Point 6 & 7, a CC unit, a wind unit, a biomass unit, and a rooftop PV unit) are identical, or nearly identical, in regard to these four characteristics. Therefore, a comparison of these very different resource options using a $/kWh calculation cannot provide meaningful results in regard to making a final decision about these resource options. For this reason, neither FPL nor the FPSC utilize such calculations to make resource decisions.

With that explanation, the requested information is presented in Table Staff-29a - Table Staff-29e (Attachment Nos. 1 - 5 respectively), in the "Levelized Cost" tab. These tables present standard levelized $/MWh results in the shaded column on the left side of the page. (The $/MWh values are easily converted to cents/kWh by dividing the $/MWh values by 10.) In this analysis, the high-end of FPL's non-binding capital cost estimated range was used. As discussed above, these type of analyses do not account for system impacts and, therefore, can only provide incomplete information regarding the full impact resource options will have on a utility system.

In order to demonstrate how incomplete the information such analyses provide is, FPL is also providing Table Staff-29f (Attachment No. 6). In this table, FPL has started with Table Staff-29a, which looks at unit cost only for Turkey Point 6 & 7. Table Staff-29a projected a levelized cost of $168/MWh, or 16.8 cents/kWh, assuming a 90% capacity factor. However, Table Staff-29f shows how significantly that projection can change if only a few system cost impacts are accounted for. In Table Staff-29f, just three system cost impacts are accounted for: system fuel savings, system environmental compliance cost savings, and transmission cost savings for regional transmission that would otherwise be needed in regard to the Southeastern Florida region. Typical levelized cost calculations do not account for such system impacts.

By accounting for only these three system cost impacts, the projected levelized costs shown in Table Staff-29a of 16.8 cents/kWh for a 90% capacity factor drop significantly to 5.5 cents/kWh. In addition, this much lower value still does not account for other system benefits (such as generating capacity cost avoidance, firm gas transportation cost avoidance, etc.). However, FPL's 2015 feasibility analyses, like all of FPL's previous feasibility analyses, do account for all system cost impacts and, therefore, presents a complete picture of the full cost impacts of Turkey Point 6 & 7.

Table Staff-29a

Unit Operating and Cost Data

	Turkey Point 6&7
Operating and Cost Data	
Technology	Nuclear
Fuel	Nuclear
Fuel Type Number (see fuel price pages)	1
Gas MMBTU/day (e.g 200,000 per 3x1 CC)	0
Gas Transportation Cost $/MMBTU	0.00
Transportation Cost $/KW	0.00
Base Operation (MW) annual average rating	2,200
Base Op 'Heat Rate, 75 deg. F (BTU/KWH)	10,437
Capacity payment ($/kw month)	N
Fixed O&M ($/KW-yr) see note	120.00
Capital Replace ($/kW-Yr)	15.10
VOM ($/MWh)	0.00
Nox emission rate (lb/mmbtu)	0.000
SO2 emission rate (lb/mmbtu)	0.000
CO2 emission rate (lb/mmbtu)	0
Hg emission rate (lb/ trillion btu)	0.0
Financial Data	
Discount rate	7.51%
I/S Year of Units for comparison	**2027**
Book Life (from EDM) or length of proposal	42
Costs entered in year $ (FOM and Cap. Repl.)	**2018**

Note: The costs in this page for units can be input in diffe
the i/s year of the analysis.

Table Staff-29b

Unit Operating and Cost Data

	Natural Gas Combined Cycle
Operating and Cost Data	
Technology	Combined Cycle
Fuel	Natural Gas
Fuel Type Number (see fuel price pages)	1
Gas MMBTU/day (e.g 200,000 per 3x1 CC)	0
Gas Transportation Cost $/MMBTU	0.00
Transportation Cost $/KW	0.00
Base Operation (MW) annual average rating	1,317
Base Op 'Heat Rate, 75 deg. F (BTU/KWH)	6,307
Capacity payment ($/kw month)	N
Fixed O&M ($/KW-yr) see note	0.00
Capital Replace ($/kW-Yr)	0.00
VOM ($/MWh)	0.00
Nox emission rate (lb/mmbtu)	0.010
SO2 emission rate (lb/mmbtu)	0.006
CO2 emission rate (lb/mmbtu)	119
Hg emission rate (lb/ trillion btu)	0.0
Financial Data	
Discount rate	7.51%
I/S Year of Units for comparison	**2027**
Book Life (from EDM) or length of proposal	31
Costs entered in year $ (FOM and Cap. Repl.)	**2027**

Note: The costs in this page for units can be input in different yea
the i/s year of the analysis.

Table Staff-29c

Unit Operating and Cost Data

	Wind Unit
Operating and Cost Data	
Technology	Wind
Fuel	
Fuel Type Number (see fuel price pages)	1
Gas MMBTU/day (e.g 200,000 per 3x1 CC)	0
Gas Transportation Cost $/MMBTU	0.00
Transportation Cost $/KW	0.00
Base Operation (MW) annual average rating	100
Base Op 'Heat Rate, 75 deg. F (BTU/KWH)	0
Capacity payment ($/kw month)	N
Fixed O&M ($/KW-yr) see note	27.34
Capital Replace ($/kW-Yr)	0
VOM ($/MWh)	0.00
Nox emission rate (lb/mmbtu)	0.000
SO2 emission rate (lb/mmbtu)	0.000
CO2 emission rate (lb/mmbtu)	0
Hg emission rate (lb/ trillion btu)	0.0
Financial Data	
Discount rate	7.51%
I/S Year of Units for comparison	**2027**
Book Life (from EDM) or length of proposal	31
Costs entered in year $ (FOM and Cap. Repl.)	**2015**

Note: The costs in this page for units can be input in different years and the costs will be automatically adjusted to the i/s year of the analysis.

Table Staff-29d

Unit Operating and Cost Data

	Biomass (wood burning plant)
Operating and Cost Data	
Technology	Biomass
Fuel	Wood
Fuel Type Number (see fuel price pages)	1
Gas MMBTU/day (e.g 200,000 per 3x1 CC)	0
Gas Transportation Cost $/MMBTU	0.00
Transportation Cost $/KW	0.00
Base Operation (MW) annual average rating	63
Base Op 'Heat Rate, 75 deg. F (BTU/KWH)	11,746
Capacity payment ($/kw month)	N
Fixed O&M ($/KW-yr) see note	587.21
Capital Replace ($/kW-Yr)	0
VOM ($/MWh)	0.00
Nox emission rate (lb/mmbtu)	0.009
SO2 emission rate (lb/mmbtu)	0.000
CO2 emission rate (lb/mmbtu)	211.15
Hg emission rate (lb/ trillion btu)	0.0
Financial Data	
Discount rate	7.51%
I/S Year of Units for comparison	**2027**
Book Life (from EDM) or length of proposal	42
Costs entered in year $ (FOM and Cap. Repl.)	**2019**

Note: The costs in this page for units can be input in different years and the costs will be automatically adjusted to the i/s year of the analysis.

Table Staff-29e

Unit Operating and Cost Data

	Roof Top Solar C/I
Operating and Cost Data	
Technology	PV
Fuel	Solar
Fuel Type Number (see fuel price pages)	1
Gas MMBTU/day (e.g 200,000 per 3x1 CC)	0
Gas Transportation Cost $/MMBTU	0.00
Transportation Cost $/KW	0.00
Base Operation (MW) annual average rating	0.0283
Base Op 'Heat Rate, 75 deg. F (BTU/KWH)	0
Capacity payment ($/kw month)	N
Fixed O&M ($/KW-yr) see note	0
Capital Replace ($/kW-Yr)	48.65
VOM ($/MWh)	0.00
Nox emission rate (lb/mmbtu)	0.000
SO2 emission rate (lb/mmbtu)	0.000
CO2 emission rate (lb/mmbtu)	0
Hg emission rate (lb/ trillion btu)	0.0
Financial Data	
Discount rate	7.51%
I/S Year of Units for comparison	**2027**
Book Life (from EDM) or length of proposal	31
Costs entered in year $ (FOM and Cap. Repl.)	**2015**

Note: The costs in this page for units can be input in different years and the costs will be automatically adjusted to the i/s year of the analysis.

Table Staff-29f

Unit Operating and Cost Data

	Turkey Point 6&7
Operating and Cost Data	
Technology	Nuclear
Fuel	Nuclear
Fuel Type Number (see fuel price pages)	1
Gas MMBTU/day (e.g 200,000 per 3x1 CC)	0
Gas Transportation Cost $/MMBTU	0.00
Transportation Cost $/KW	0.00
Base Operation (MW) annual average rating	2,200
Base Op 'Heat Rate, 75 deg. F (BTU/KWH)	10,437
Capacity payment ($/kw month)	N
Fixed O&M ($/KW-yr) see note	120.00
Capital Replace ($/kW-Yr)	15.10
VOM ($/MWh)	0.00
Nox emission rate (lb/mmbtu)	0.000
SO2 emission rate (lb/mmbtu)	0.000
CO2 emission rate (lb/mmbtu)	0
Hg emission rate (lb/ trillion btu)	0.0
Financial Data	
Discount rate	7.51%
I/S Year of Units for comparison	**2027**
Book Life (from EDM) or length of proposal	42
Costs entered in year $ (FOM and Cap. Repl.)	**2018**

Note: The costs in this page for units can be input in diffe
the i/s year of the analysis.

Q.
Please complete the table below assuming an FPL owned base-loaded solar photovoltaic facility with the capacity capabilities of the TP Project.

	FPL Solar	TP Project	Difference
Capacity (MW)			
Total Site Area (Acres)			
Total Installed Costs ($/kw)			
Net Annual Generation (MWh)			
Resulting Capacity Factor (%)			

A.
Attachment No. 1 presents the requested information.

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Table Staff-30

	FPL Solar	TP Project	Difference
Capacity (MW AC)	4,400 (1)	2,200	2,200
Total Site Area (Acres)	35,200	422	34,778
Total Installed Costs ($1,000s) (2)	$8,074,000	$12,295,800	($4,221,800)
Total Installed Costs ($/kW) (2)	$1,835	$5,589	($3,754)
Net Annual Generation (MWh)	10,021,440	17,707,280	(7,685,840)
Resulting Capacity Factor (%)	26%	90%	-64%

Solar PV Assumptions:
- Fixed tilt, crystalline panels
- 26% Average Annual Capacity Factor (kWh/kWac)
- 50% expected nameplate generation available at system summer peak hour
- 8 acres required per MW installed

Notes:

(1) FPL does not consider PV as a baseload resource. Solar power is non-firm capacity, unlike Turkey Point 6 & 7. Though non-firm, FPL assigns a capacity value to solar projects based on the modeled P50 output of the project at the time of system peak. This can vary from 0 to 50% depending on project characteristics, solar resource, amount of existing solar assets on the grid, and time of system peak. For this analysis, 50% of solar nameplate capacity is assumed to be available on average during the system summer peak hour. Additionally, solar panel output is projected to decline at a rate of 0.3% per year.

(2) Solar project costs are estimated on a the estimated construction cost of FPL's three proposed 74.5 MW solar projects to be placed in service in November 2016. Pricing is in nominal future dollars with construction expenses occuring primarily in 2016. Assumes the high end of the overnight cost estimate range for the Turkey Point 6 & 7 Project.

Q.
Please complete the table below assuming an FPL owned base-loaded solar photovoltaic facility with the generation capabilities of the TP Project.

	FPL Solar	TP Project	Difference
Capacity (MW)			
Total Site Area (Acres)			
Total Installed Costs ($/kw)			
Net Annual Generation (MWh)			
Resulting Capacity Factor (%)			

A.
Attachment No. 1 presents the requested information.

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Interrogatory No. 31
Attachment No. 1
Tab 1 of 1

	FPL Solar	TP Project	Difference
Capacity (MW AC)	7,775 [1]	2,200	5,575
Total Site Area (Acres)	62,200	422	61,778
Total Installed Costs ($1,000s) [2]	$14,267,125	$12,295,800	$1,971,325
Total Installed Costs ($/kW) [2]	$1,835	$5,589	($3,754)
Net Annual Generation (MWh)	17,707,280	17,707,280	0
Resulting Capacity Factor (%)	26%	90%	-64%

Solar PV Assumptions:
- Fixed tilt, crystalline panels
- 26% Average Annual Capacity Factor (kWh/kWac)
- 50% expected nameplate generation available at system summer peak hour
- 8 acres required per MW installed

Notes:

(1) FPL does not consider PV as a baseload resource. Solar power is non-firm capacity, unlike Turkey Point 6 & 7. Though non-firm, FPL assigns a capacity value to solar projects based on the modeled P50 output of the project at the time of system peak. This can vary from 0 to 50% depending on project characteristics, solar resource, amount of existing solar assets on the grid, and time of system peak. For this analysis, 50% of solar nameplate capacity is assumed to be available on average during the system summer peak hour. Additionally, solar panel output is projected to decline at a rate of 0.3% per year.

(2) Solar project costs are estimated on a the estimated construction cost of FPL's three proposed 74.5 MW solar projects to be placed in service in November 2016. Pricing is in nominal future dollars with construction expenses occuring primarily in 2016. Assumes the high end of the overnight cost estimate range for the Turkey Point 6 & 7 Project.

Q.

Please complete the table below assuming an FPL owned base-loaded wind facility with the capacity capabilities of the TP Project.

	FPL Solar	TP Project	Difference
Capacity (MW)			
Total Site Area (Acres)			
Total Installed Costs ($/kw)			
Net Annual Generation (MWh)			
Resulting Capacity Factor (%)			

A.

Attachment No. 1 presents the requested information.

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Interrogatory No. 32
Attachment No. 1
Tab 1 of 1

Table Staff-32

	FPL Wind	TP Project	Difference
Capacity (MW)	2200 [1]	2,200	0
Total Site Area (Acres)	165,000	422	164,578
Total Installed Costs ($/kW) [2]	$2,450	$5,589	($3,139)
Net Annual Generation (MWh)	3,661,680	17,707,280	(14,045,600)
Resulting Capacity Factor (%)	19%	90%	-71%

Wind Assumptions:
- GE 1.7 MW turbines (80M hub Height)
- 19% Average Annual Capacity Factor
- 75 Acres per MW assumed, which is a conservative representation based on a contiguous piece of land
- All pricing in 2015 $'s

Notes:

(1) FPL does not consider wind facilities as a baseload resource. Wind is non-firm capacity, unlike Turkey Point 6 & 7. At this time, FPL has not determined what portion of a Wind turbine's output can be projected as firm capacity at FPL's peak hour (summer and winter).

(2) Cost estimate, acreage requirement, and capacity factor based upon a hypothetical project built in Florida at an inland site. Assumes the high end of the overnight cost estimate range for the Turkey Point 6 & 7 Project.

Q.

Please complete the table below assuming an FPL owned base-loaded wind facility with the generation capabilities of the TP Project.

	FPL Solar	TP Project	Difference
Capacity (MW)			
Total Site Area (Acres)			
Total Installed Costs ($/kw)			
Net Annual Generation (MWh)			
Resulting Capacity Factor (%)			

A.

Attachment No. 1 presents the requested information.

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Attachment No. 1
Tab 1 of 1

Table Staff-33

	FPL Wind	TP Project	Difference
Capacity (MW)	10,639 (1)	2,200	8,439
Total Site Area (Acres)	797,925	422	797,503
Total Installed Costs ($/kW) (2)	$2,450	$5,589	($3,139)
Net Annual Generation (MWh)	17,707,280	17,707,280	0
Resulting Capacity Factor (%)	19%	90%	-71%

Wind Assumptions:
- GE 1.7 MW turbines (80M hub Height)
- 19% Average Annual Capacity Factor
- 75 Acres per MW assumed, which is a conservative representation based on a contiguous piece of land
- All pricing in 2015 $'s

Notes:

(1) FPL does not consider wind facilities as a baseload resource. Wind is non-firm capacity, unlike Turkey Point 6 & 7. At this time, FPL has not determined what portion of a Wind turbine's output can be projected as firm capacity at FPL's peak hour (summer and winter).

(2) Cost estimate, acreage requirement, and capacity factor based upon a hypothetical project built in Florida at an inland site. Assumes the high end of the overnight cost estimate range for the Turkey Point 6 & 7 Project.

Q.
Please complete the table below assuming an FPL owned base-loaded biomass facility with the capacity capabilities of the TP Project.

	FPL Biomass	TP Project	Difference
Capacity (MW)			
Total Site Area (Acres)			
Biomass Fuel Req. (Acres)			
Biomass Fuel req. (Tons)			
Total Installed Costs ($/kw)			
Net Annual Generation (MWh)			
Resulting Capacity Factor (%)			

A.
Attachment No. 1 presents the requested information.

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Attachment No. 1
Tab 1 of 1

	FPL Biomass	TP Project	Difference
Capacity (MW)	2,200	2,200	0
Total Site Area (Acres)	1,540	422	1,118
Biomass Fuel Req. (Acres)	1,018,550	0	1,018,550
Biomass Fuel Req. (Tons)	16,296,794	0	16,296,794
Total Installed Costs ($/kW)	4,500	5,589	(1,089)
Net Annual Generation (MWh)	17,707,280	17,707,280	0
Resulting Capacity Factor (%)	90%	90%	0

Notes:
(1) The Biomass Fuel is an annual fuel requirement.
(2) The Biomass Fuel Req. (Acres) equates to 1592 square miles.
(3) Assumes the high end of the overnight cost estimate range for the Turkey Point 6 & 7 Project.

Q.
Please complete the table below assuming an FPL owned base-loaded biomass facility with the generation capabilities of the TP Project.

	FPL Biomass	TP Project	Difference
Capacity (MW)			
Total Site Area (Acres)			
Biomass Fuel Req. (Acres)			
Biomass Fuel req. (Tons)			
Total Installed Costs ($/kw)			
Net Annual Generation (MWh)			
Resulting Capacity Factor (%)			

A.
Please see FPL's Response to Staff's Second Set of Interrogatories No. 34.

Q.

Please complete the table below for a typical roof top photovoltaic array installed within FPL's service area.

	Roof-Top PV
Capacity (MW)	
Total Installed Costs ($/kw)	
Roof Space (Sq. Feet)	
Net Annual Generation (MWh)	
Resulting Capacity Factor (%)	

A.

Please see Attachment No. 1.

	Residential PV (Roof Top)	Business PV (Roof Top)	Assumptions
Capacity (kW)	7.5	28.3	2014 Installations - Average Nameplate kW_{DC}
Total Installed Costs ($/kw)	$3,850	$3,969	
Roof Space (Sq. Feet)	750	2,830	FPL does not collect this data from customers Assumes 10 watts/square foot
Net Annual Generation (kWh)	8,370	38,969	
Resulting Capacity Factor (%)	17%	20%	DC to AC Derate Factor = 0.77

Q.

Please list and discuss the status of all FPL negotiated Capacity and/or Power Purchase Agreements or contracts that have been approved by the Commission since January 1, 2009. Please include in the response, the term, the capacity, capacity factor, and energy associated with each contract. For any contract that is no longer active, please explain why the contract is no longer active.

A.

Please see Attachment No. 1.

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Purchased Power Agreements (2009 - 2015)					
Seller	Contract Term		Capacity	Capacity Factor *	Contract Status
	Begins	Ends	(MW)	(%)	
Southern Company - Harris	6/1/2010	12/31/2015	584	28%	Contract is Active.
Southern Company - Franklin	6/1/2010	12/31/2015	185	32%	Contract is Active.
Southern Company - Scherer 3	6/1/2010	12/31/2015	159	63%	Contract is Active.
SJRPP **	4/2/1982	4/1/2019	375	62%	Contract is Active.
Wheelabrator Technologies	1/1/1993	12/31/2026	11	90%	Contract is Active.
Wheelabrator Technologies	1/1/1993	12/31/2026	3.5	99%	Contract is Active.
Cedar Bay Generating Co.	1/25/1994	12/31/2024	250	36%	Contract is Active.
Indiantown Cogen, LP	12/22/1995	12/1/2025	330	22%	Contract is Active.
Solid Waste Authority of Palm Beach	1/1/2012	4/1/2032	40	97%	Contract is Active.
Solid Waste Authority of Palm Beach	7/1/2015	6/1/2034	70	85%	Contract has been approved by the Commission.
U.S. EcoGen - Clay	6/1/2019	12/31/2049	60	90%	Contract has been approved by the Commission.
U.S. EcoGen - Okeechobee	6/1/2019	12/31/2049	60	90%	Contract has been approved by the Commission.
U.S. EcoGen - Martin	6/1/2019	12/31/2049	60	90%	Contract has been approved by the Commission.
Southern Company	7/20/1988	5/31/2010	931	85%	Replaced with 6/1/2010 agreements.
Solid Waste Authority of Palm Beach	4/1/1992	3/31/2010	50	85%	Replaced with 1/1/2012 agreement.
Reliant Energy Services	1/1/2006	12/31/2009	250	10%	Generation unit was no longer being marketed by the owner.
Oleander Power Project	6/1/2002	9/30/2012	156	15%	Contract was not renewed as FPL no longer had a need for this capacity to meet temporary system needs.
JP Morgan/Williams/Bear Energy	3/3/2006	12/31/2009	106	24%	Transmission capacity constraints prevented feasability of contract renewal.
Progress Energy Ventures/Constellation	5/1/2006	4/30/2009	0-93	18%	Transmission capacity constraints prevented feasability of contract renewal.
DeSoto	1/1/2012	12/31/2012	305	22%	Contract was not renewed as FPL no longer had a need for this capacity to meet temporary system needs.
Tampa Electric Company	1/1/2012	12/31/2012	75-125	22%	Contract was not renewed as FPL no longer had a need for this capacity to meet temporary system needs.
Seminole Electric Cooperative Inc.	4/1/2012	9/30/2012	150	22%	Contract was not renewed as FPL no longer had a need for this capacity to meet temporary system needs.

* Where historical data is available, values reflect purchases for the calendar year as reported in the A-Schedules.

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

Q.
Please complete the table below for each FPL negotiated contract involving a biomass facility.

Capacity (MW)	
Timber (Tons/day)	
Total Site Area Including Timber (Acres)	
Net Annual Generation (MWh)	
Resulting Capacity Factor (%)	

A.
The table below is applicable for each of USEcoGen Clay, USEcoGen Martin, and USEcoGen Okeechobee facilities.

Capacity (MW)	60
Timber (Tons/day)*	790
Total Site Area Including Timber (Acres)*	16,000
Net Annual Generation (MWh)**	452,000
Resulting Capacity Factor (%)	86

* FPL estimate, using publicly available information
** Based upon two weeks of scheduled outages per year

Q.
Please explain how any of the information or assumptions contained in FPL witness Brown's Exhibits ROB-5 and ROB-6 differ from that contained in FPL's 2015 Ten-Year Site Plan and the reason for any differences.

A.
FPL's 2015 Ten-Year Site Plan (Site Plan) addressed the years 2015 through 2024. The resource plan presented in the 2015 feasibility analyses assumed that Turkey Point 6 is added in 2027 and Turkey Point 7 is added in 2028. The 2015 Site Plan also utilized one fuel cost and one environmental compliance cost forecast. These are the same Medium Fuel Cost forecast, and Env II cost forecast, that are used in FPL's 2015 feasibility analyses.

The only differences in information and/or assumptions between those used in the 2015 Site Plan and the 2015 feasibility analyses are: (i) the feasibility analyses addressed years 2015 through 2068 and 2015 through 2088 while the Site Plan addressed years 2015 through 2024; (ii) the feasibility analyses included an additional resource plan (the Resource Plan Without Turkey Point 6 & 7) that assumed Turkey Point 6 & 7 were not added in 2027 and 2028; and, (iii) the feasibility analyses utilized six additional scenarios of fuel cost forecasts and environmental compliance cost forecasts.

Q.
Please perform the analyses shown in witness Brown's Exhibit ROB-5 and ROB-6 for two additional scenarios: (1) a 5-year delay in the construction start and in-service dates, and (2) a 10-year delay in the construction start and in-service dates. In each scenario, please identify any assumptions that were changed to conduct the analyses of delays compared to FPL's current estimate of 2027/2028 in-service dates.

A.
The projected breakeven cost results in 2015$/kW for the requested analyses are presented in Table Staff-40a, Table Staff-40b, Table Staff-40c, and Table Staff-40d (Attachment Nos. 1 - 4 respectively). Table Staff-40a presents the projected results assuming a 5-year delay in the in-service dates of Turkey Point 6 & 7 to 2032 and 2033, respectively and a 40-year operating life. Table Staff-40b presents the projected results assuming a 5-year delay in the in-service dates of Turkey Point 6 & 7 to 2032 and 2033, respectively and a 60-year operating life. Table Staff-40c presents the projected results assuming a 10-year delay in the in-service dates of Turkey Point 6 & 7 to 2037 and 2038, respectively and a 40-year operating life. Table Staff-40d presents the projected results assuming a 10-year delay in the in-service dates of Turkey Point 6 & 7 to 2037 and 2038, respectively and a 60-year operating life.

These analyses used identical assumptions to those used in FPL's 2015 feasibility analyses in the Resource Plan With Turkey Point 6 & 7 except for: (i) the later in-service dates for the two new nuclear units, and (ii) earlier combined cycle capacity that is assumed to be added to meet reserve margin requirements between 2027/2028 and either 2032/2033 or 2037/3038 due to the assumed delay in the in-service dates of Turkey Point 6 & 7. Note also that the results for the Resource Plan Without Turkey Point 6 & 7 are identical to the results for this resource plan as presented in FPL's 2015 feasibility analyses through the year 2068 for the 40-year operation life and through the year 2088 for the 60-year operating life because there is no change in that resource plan except for an extension of either 5 or 10 years in the analyses. The projected economic results for an additional 5 years, and for an additional 10 years, have been added onto the 2015 through 2068 and 2015 through 2088 results from the 2015 feasibility analyses for the Resource Plan without Turkey Point 6 & 7.

Because FPL has not determined what the appropriate non-binding overnight construction cost ($/kW in 2015$) for Turkey Point 6 & 7 would be assuming either a 5-year delay or a 10-year delay, for purposes of performing the requested analysis, FPL used the high-end ($5,589/kW) of the non-binding overnight construction costs that was used to analyze the original in-service dates of 2027/2028 for Turkey Point 6 & 7.

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Attachment No. 1
Tab 1 of 1

Table Staff-40a

Staff Requested Analyses: Assuming the construction start and in-service dates are delayed by 5 years

2015 Feasibility Analyses Results for the Turkey Point 6 & 7 Project:
Case # 1 Analysis - 40-Year Operating Life; Total Costs,
Total Cost Differentials, and Breakeven Costs for All Fuel
and Environmental Compliance Cost Scenarios in 2015$
(millions, CPVRR, 2015 - 2073)

(1)	(2)	(3)	(4)	(5) = (3) - (4)	(6)
Fuel Cost Forecast	Environmental Compliance Cost Forecast	Total Costs for Plans		Total Cost Difference Plan with TP 6 & 7 minus Plan without TP 6 & 7 *	Breakeven Nuclear Capital Costs ($/kW in 2015$)
		Resource Plan w/ TP 6 & 7	Resource Plan w/o TP 6 & 7		
High Fuel Cost	Env I	150,654	159,002	(8,348)	5,780
High Fuel Cost	Env II	158,962	168,142	(9,180)	6,362
High Fuel Cost	Env III	167,274	177,310	(10,037)	6,962
Medium Fuel Cost	Env I	135,102	142,495	(7,393)	5,113
Medium Fuel Cost	Env II	143,377	151,582	(8,204)	5,680
Medium Fuel Cost	Env III	151,652	160,695	(9,043)	6,267
Low Fuel Cost	Env I	119,336	125,756	(6,420)	4,432

*The TP 6 & 7 savings values in Column (5) also represent CPVRR breakeven capital costs for each scenario.

Note: The TP 6 & 7 non-binding cost estimate range to which the breakeven cost is compared is $3,844/kW to $5,589/kW in 2015$.

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Attachment No. 2
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Table Staff-40b

Staff Requested Analyses: Assuming the construction start and in-service dates are delayed by 5 years

2015 Feasibility Analyses Results for the Turkey Point 6 & 7 Project:
Case # 2 Analysis - 60-Year Operating Life; Total Costs,
Total Cost Differentials, and Breakeven Costs for All Fuel
and Environmental Compliance Cost Scenarios in 2015$
(millions, CPVRR, 2015 - 2093)

(1)	(2)	(3)	(4)	(5) = (3) - (4)	(6)
Fuel Cost Forecast	Environmental Compliance Cost Forecast	Total Costs for Plans		Total Cost Difference Plan with TP 6 & 7 minus Plan without TP 6 & 7 *	Breakeven Nuclear Capital Costs ($/kW in 2015$)
		Resource Plan w/ TP 6 & 7	Resource Plan w/o TP 6 & 7		
High Fuel Cost	Env I	174,301	184,901	(10,600)	7,355
High Fuel Cost	Env II	186,857	198,766	(11,908)	8,271
High Fuel Cost	Env III	199,417	212,671	(13,254)	9,212
Medium Fuel Cost	Env I	157,759	167,289	(9,529)	6,607
Medium Fuel Cost	Env II	170,279	181,092	(10,813)	7,504
Medium Fuel Cost	Env III	182,792	194,928	(12,135)	8,429
Low Fuel Cost	Env I	140,994	149,434	(8,440)	5,845

*The TP 6 & 7 savings values in Column (5) also represent CPVRR breakeven capital costs for each scenario.

Note: The TP 6 & 7 non-binding cost estimate range to which the breakeven cost is compared is $3,844/kW to $5,589/kW in 2015$.

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Interrogatory No. 40
Attachment No. 3
Tab 1 of 1

Table Staff-40c

Staff Requested Analyses: Assuming the construction start and in-service dates are delayed by 10 years

2015 Feasibility Analyses Results for the Turkey Point 6 & 7 Project:
Case # 1 Analysis - 40-Year Operating Life; Total Costs,
Total Cost Differentials, and Breakeven Costs for All Fuel
and Environmental Compliance Cost Scenarios in 2015$
(millions, CPVRR, 2015 - 2078)

(1)	(2)	(3)	(4)	(5) = (3) - (4)	(6)
Fuel Cost Forecast	Environmental Compliance Cost Forecast	Total Costs for Plans		Total Cost Difference Plan with TP 6 & 7 minus Plan without TP 6 & 7 *	Breakeven Nuclear Capital Costs ($/kW in 2015$)
		Resource Plan w/ TP 6 & 7	Resource Plan w/o TP 6 & 7		
High Fuel Cost	Env I	159,052	165,923	(6,871)	6,730
High Fuel Cost	Env II	168,443	176,204	(7,761)	7,618
High Fuel Cost	Env III	177,862	186,517	(8,655)	8,510
Medium Fuel Cost	Env I	142,944	149,046	(6,102)	5,963
Medium Fuel Cost	Env II	152,298	159,271	(6,973)	6,832
Medium Fuel Cost	Env III	161,662	169,525	(7,863)	7,720
Low Fuel Cost	Env I	126,601	131,933	(5,332)	5,195

*The TP 6 & 7 savings values in Column (5) also represent CPVRR breakeven capital costs for each scenario.

Note: The TP 6 & 7 non-binding cost estimate range to which the breakeven cost is compared is $3,844/kW to $5,589/kW in 2015$.

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Interrogatory No. 40
Attachment No. 4
Tab 1 of 1

Table Staff-40d

Staff Requested Analyses: Assuming the construction start and in-service dates are delayed by 10 years

2015 Feasibility Analyses Results for the Turkey Point 6 & 7 Project:
Case # 2 Analysis - 60-Year Operating Life; Total Costs,
Total Cost Differentials, and Breakeven Costs for All Fuel
and Environmental Compliance Cost Scenarios in 2015$
(millions, CPVRR, 2015 - 2098)

(1)	(2)	(3)	(4)	(5) = (3) - (4)	(6)
Fuel Cost Forecast	Environmental Compliance Cost Forecast	Total Costs for Plans		Total Cost Difference Plan with TP 6 & 7 minus Plan without TP 6 & 7 *	Breakeven Nuclear Capital Costs ($/kW in 2015$)
		Resource Plan w/ TP 6 & 7	Resource Plan w/o TP 6 & 7		
High Fuel Cost	Env I	181,709	190,891	(9,182)	9,036
High Fuel Cost	Env II	195,433	206,006	(10,573)	10,423
High Fuel Cost	Env III	209,192	221,164	(11,972)	11,818
Medium Fuel Cost	Env I	164,807	173,122	(8,315)	8,171
Medium Fuel Cost	Env II	178,490	188,174	(9,684)	9,536
Medium Fuel Cost	Env III	192,178	203,258	(11,081)	10,929
Low Fuel Cost	Env I	147,656	155,109	(7,453)	7,311

*The TP 6 & 7 savings values in Column (5) also represent CPVRR breakeven capital costs for each scenario.

Note: The TP 6 & 7 non-binding cost estimate range to which the breakeven cost is compared is $3,844/kW to $5,589/kW in 2015$.

Q.
Please complete the table below describing the energy production and projected capacity factor of Turkey Point Unit 6.

	Net Annual Generation (MWh)	Resulting Capacity Factor (%)
2027		
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
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2077		
2078		
2079		
2080		
2081		

2082		
2083		
2084		
2085		
2086		
2087		

A.
The projected annual energy (MWh) output and associated capacity factors for Turkey Point 6 from 2027 through 2087 are presented in Attachment No. 1.

Florida Power & Light Company
Docket No. 150009-EI
Staff's Second Set of Interrogatories
Interrogatory No. 41
Attachment No. 1
Tab 1 of 1

Table Staff-41

Energy Production and Projected Capacity Factor of Turkey Point Unit 6

Year	Net Annual Generation (MWh)	Resulting Capacity Factor (%)
2027	5,705,200	58.4 *
2028	8,869,110	90.5
2029	9,396,880	96.1
2030	9,030,590	92.4
2031	8,842,490	90.5
2032	9,423,510	96.2
2033	9,030,590	92.4
2034	9,396,880	96.1
2035	9,396,880	96.1
2036	9,423,510	96.2
2037	8,842,490	90.5
2038	9,396,880	96.1
2039	9,396,880	96.1
2040	8,869,110	90.5
2041	9,396,880	96.1
2042	9,030,590	92.4
2043	8,842,490	90.5
2044	9,423,510	96.2
2045	8,869,110	90.5
2046	9,396,880	96.1
2047	9,030,590	92.4
2048	8,842,490	90.5
2049	9,423,510	96.2
2050	9,030,590	92.4
2051	9,396,880	96.1
2052	9,396,880	96.1
2053	9,423,510	96.2
2054	8,842,490	90.5
2055	9,396,880	96.1
2056	9,396,880	96.1
2057	8,869,110	90.5
2058	9,396,880	96.1
2059	9,030,590	92.4
2060	8,842,490	90.5
2061	9,423,510	96.2
2062	8,869,110	90.5
2063	9,396,880	96.1
2064	9,030,590	92.4
2065	8,842,490	90.5
2066	9,423,510	96.2
2067	9,030,590	92.4
2068	9,396,880	96.1
2069	9,396,880	96.1
2070	9,423,510	96.2
2071	8,842,490	90.5
2072	9,396,880	96.1
2073	9,396,880	96.1
2074	8,869,110	90.5
2075	9,396,880	96.1
2076	9,030,590	92.4
2077	8,842,490	90.5
2078	9,423,510	96.2
2079	8,869,110	90.5
2080	9,396,880	96.1
2081	9,030,590	92.4
2082	8,842,490	90.5
2083	9,423,510	96.2
2084	9,030,590	92.4
2085	9,396,880	96.1
2086	9,396,880	96.1
2087	9,423,510	96.2

Note:
*
Turkey Point 6 is assumed to start operation June 1st of the year 2027.

Q.
Please complete the table below describing the energy production and projected capacity factor of Turkey Point Unit 7.

	Net Annual Generation (MWh)	Resulting Capacity Factor (%)
2028		
2029		
2030		
2031		
2032		
2033		
2034		
2035		
2036		
2037		
2038		
2039		
2040		
2041		
2042		
2043		
2044		
2045		
2046		
2047		
2048		
2049		
2050		

2051		
2052		
2053		
2054		
2055		
2056		
2057		
2058		
2059		
2060		
2061		
2062		
2063		
2064		
2065		
2066		
2067		
2068		
2069		
2070		
2071		
2074		
2075		
2076		
2077		
2078		
2079		
2080		
2081		

2082		
2083		
2084		
2085		
2086		
2087		
2088		

A.
The projected annual energy (MWh) output and associated capacity factors for Turkey Point 7 from 2028 through 2088 are presented in Attachment No. 1.

Florida Power & Light Company
Docket No. 150009-EI
Staff's Second Set of Interrogatories
Interrogatory No. 42
Attachment No. 1
Tab 1 of 1

Table Staff-42

Energy Production and Projected Capacity Factor of Turkey Point Unit 7

Year	Net Annual Generation (MWh)	Resulting Capacity Factor (%)
2028	5,520,400	56.3 *
2029	9,006,970	92.2
2030	9,404,070	96.2
2031	8,876,070	90.8
2032	9,027,680	92.1
2033	9,404,070	96.2
2034	8,876,070	90.8
2035	9,006,970	92.2
2036	9,431,380	96.2
2037	8,876,070	90.8
2038	9,006,970	92.2
2039	9,404,070	96.2
2040	8,903,380	90.8
2041	9,006,970	92.2
2042	9,404,070	96.2
2043	8,876,070	90.8
2044	9,027,680	92.1
2045	9,006,970	92.2
2046	9,404,070	96.2
2047	8,876,070	90.8
2048	9,027,680	92.1
2049	9,404,070	96.2
2050	8,876,070	90.8
2051	9,006,970	92.2
2052	9,431,380	96.2
2053	8,876,070	90.8
2054	9,006,970	92.2
2055	9,404,070	96.2
2056	8,903,380	90.8
2057	9,006,970	92.2
2058	9,404,070	96.2
2059	8,876,070	90.8
2060	9,027,680	92.1
2061	9,006,970	92.2
2062	9,404,070	96.2
2063	8,876,070	90.8
2064	9,027,680	92.1
2065	9,404,070	96.2
2066	8,876,070	90.8
2067	9,006,970	92.2
2068	9,431,380	96.2
2069	8,876,070	90.8
2070	9,006,970	92.2
2071	9,404,070	96.2
2072	8,903,380	90.8
2073	9,006,970	92.2
2074	9,404,070	96.2
2075	8,876,070	90.8
2076	9,027,680	92.1
2077	9,006,970	92.2
2078	9,404,070	96.2
2079	8,876,070	90.8
2080	9,027,680	92.1
2081	9,404,070	96.2
2082	8,876,070	90.8
2083	9,006,970	92.2
2084	9,431,380	96.2
2085	8,876,070	90.8
2086	9,006,970	92.2
2087	9,404,070	96.2
2088	8,903,380	90.8

Note:
*
Turkey Point 7 is assumed to start operation June 1st of the year 2028.

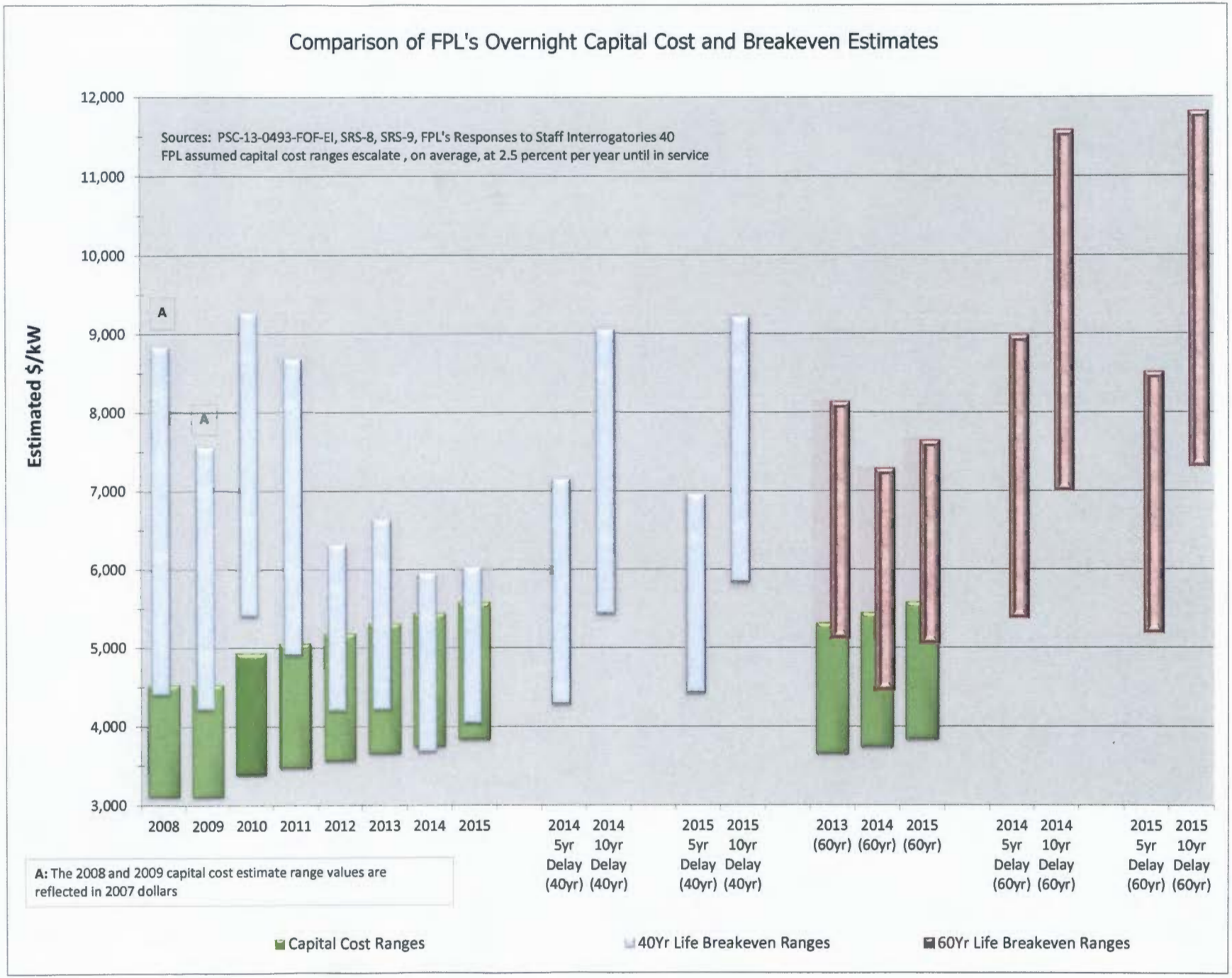
Q.
Please refer to the FPL response to Staff's Fourth Set of Interrogatories, Interrogatory No. 33 in Docket No. 140009-EI (EXH 91, Bates No. 67). Please update the chart FPL provided in its 2014 response so that the new chart reflects FPL's NCRC testimony, analysis, and views concerning the economic feasibility of completing the Turkey Point 6 & 7 Projects.

A.
Please see the Table and Chart Staff-43, contained in Attachment No. 1, in response to the above question. Please note FPL has not conducted the analysis to determine the non-binding overnight construction cost ($/kW in 2015$) for Turkey Point 6 & 7 assuming either a 5-year delay or a 10-year delay. Therefore, for purposes of responding to this interrogatory, FPL used the high-end ($5,589/kW) of the non-binding overnight construction costs that was used to analyze the original in-service dates of 2027/2028 for Turkey Point 6 & 7.

The chart, when taken in combination with other qualitative factors and observations, is consistent with FPL's view of the economic feasibility of completing the Turkey Point 6 & 7 project. These factors include, but are not limited to, natural gas price trends, projections of CO2 compliance costs, the expectation that cost predictability will increase as additional studies and negotiations are undertaken, and the actual experience of similar U.S. projects in construction.

Each year, the Turkey Point 6 & 7 project is compared against a continually improving competitive alternative. It is further noted that the period of time reflected in the chart has been characterized by major investments in the FPL system that have increased efficiency and decreased costs for FPL's customers, and in this way has raised the bar against which the project is evaluated.

The major takeaway from this chart is that the project economics continue to exhibit robustness and resiliency.


Comparison of FPL's Overnight Capital Cost and Breakeven Estimates
Sources: PSC-13-0493-FOF-EI, SRS-8, SRS-9, FPL's Responses to Staff Interrogatories 40
FPL assumed capital cost ranges escalate , on average, at 2.5 percent per year until in service
Estimated $/kW
12,000
11,000
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
A
A
2008
2009
2010
2011
2012
2013
2014
2015
2014 5yr Delay (40yr)
2014 10yr Delay (40yr)
2015 5yr Delay (40yr)
2015 10yr Delay (40yr)
2013 (60yr)
2014 (60yr)
2015 (60yr)
2014 5yr Delay (60yr)
2014 10yr Delay (60yr)
2015 5yr Delay (60yr)
2015 10yr Delay (60yr)
A: The 2008 and 2009 capital cost estimate range values are reflected in 2007 dollars
Capital Cost Ranges
40Yr Life Breakeven Ranges
60Yr Life Breakeven Ranges

Q.
Does FPL consider the "initial assessments" to be associated with separate and individual activities or work? If so, please provide a table listing each individual activity and work, a general description of the scope of work, whether FPL anticipates the materials and equipment purchases are likely to exceed one percent of the estimated total project cost (inclusive of sunk costs), whether FPL anticipates the costs for the scope of work, including services, are likely to exceed one percent of the estimated total project cost (inclusive of sunk costs).

A.
FPL does not consider the initial assessments to be associated with separate and individual activities or work. Please see FPL's response to Staff's Second Set of Interrogatories No. 45.

Q.

Does FPL consider the "initial assessments" to be one singe activity and work? If so, please provide a general description of the scope of work, whether FPL anticipates the materials and equipment purchases are likely to exceed one percent of the estimated total project cost (inclusive of sunk costs), whether FPL anticipates the costs for the scope of work, including services, are likely to exceed one percent of the estimated total project cost(inclusive of sunk costs).

A.

FPL considers the initial assessments to be one single activity and work. The scope of work (SOW) of the initial assessments is to validate the schedule activities with respect to scope, schedule, and assumptions. Collectively these studies will provide greater schedule fidelity in support of FPL's 2016 feasibility analysis.

FPL does not anticipate the materials and equipment purchases are likely to exceed one percent of the estimated total project costs (inclusive of sunk costs). FPL does not anticipate the costs for the scope of work, including services, are likely to exceed one percent of the estimated total project costs (inclusive of sunk costs). The estimated costs for this work in 2015 and 2016 is approximately $5,000,000.

Q.
For projects that do not qualify under 366.93, Florida Statutes, please describe FPL's general accounting practice and treatment for the costs incurred for initial assessment studies prior to FPL determining that it will actually pursue the project or scope of work addressed by the initial assessment studies. Please identify all documents, rules, and procedures that FPL relies on in its response.

A.
FPL's Initial Assessment studies are an undertaking specific to the Turkey Point 6 & 7 project. FPL's treatment of Initial Assessment costs are consistent with FPL's treatment of preliminary studies conducted prior to a determination to pursue a project, but slightly modified to reflect specific considerations of the Nuclear Cost Recovery process.

FPL defers costs incurred for preliminary studies and records them in FERC Account 183, Preliminary Survey and Investigation Charges, if it is probable that construction of the project will ultimately occur. This treatment is consistent with the Uniform System of Accounts (18 C.F.R. 101), in that amounts charged to this account represent preliminary costs incurred for the purpose of determining the feasibility of utility projects. Costs deferred in FERC Account 183 are presented as other non-current assets on FPL's balance sheet. Once construction begins, FPL transfers costs deferred in FERC Account 183 to FERC Account 107, Construction Work in Process (CWIP).

In this instance, FPL has already decided to pursue the Turkey Point 6 & 7 project. Additionally, in 2007, FPL concluded that the pre-construction costs for Turkey Point 6 & 7 can be recorded to CWIP upon receipt of an affirmative need determination from the Commission because of the assurance of recovery of all prudently incurred costs provided by Section 366.96 and Section 403.519, Florida Statutes. Accordingly, the Initial Assessment costs are recorded in CWIP.

AFFIDAVIT

Jennifer Grant-Keene

STATE OF FLORIDA)

COUNTY OF Palm Beach)

I hereby certify that on this 2nd day of June, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Jennifer Grant-Keene, who is personally known to me, and she acknowledged before me that she provided the answer to interrogatory number 46 and co-sponsored number 5 from Staff's Second Set of Interrogatories to Florida Power & Light Company (Nos. 5-46) in Docket No. 150009-EI, and that the response is true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 2nd day of June, 2015.

Notary Public
State of Florida, at Large

My Commission Expires:

CAROLYN J SMITH
Notary Public - State of Florida
My Comm. Expires Sep 11, 2018
Commission # FF 122975

AFFIDAVIT

Steven D. Scroggs

STATE OF FLORIDA)

COUNTY OF Palm Beach)

I hereby certify that on this 3rd day of June, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Steven D. Scroggs, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory numbers 6, 7, 9-12, 23, 44, 45 and co-sponsored numbers 5 and 43 from Staff's Second Set of Interrogatories to Florida Power & Light Company (Nos. 5-46) in Docket No. 150009-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 3rd day of June, 2015.

HEATHER P. MELIGONIS
MY COMMISSION # FF 042765
EXPIRES: December 6, 2017
Bonded Thru Notary Public Underwriters

Heather P. Meligonis
Notary Public
State of Florida, at Large

My Commission Expires:
12/6/17

AFFIDAVIT

Richard O. Brown

STATE OF FLORIDA)

COUNTY OF Miami Dade)

I hereby certify that on this 1st day of June, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Richard O. Brown, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory numbers 8, 13-22, 24-42 and co-sponsored number 43 from Staff's Second Set of Interrogatories to Florida Power & Light Company (Nos. 5-46) in Docket No. 150009-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 1st day of June, 2015.

Notary Public
State of Florida, at Large

My Commission Expires:

Notary Public State of Florida
Lily A Rodriguez
My Commission EE 875512
Expires 02/17/2017

150009 - Miami's response to Staff INT No. 1 - co2iMPACTROG

150009 - Staff's 1st POD No. 6 - Table Staff - 6a

150009 - Staff's 1st POD No. 6 - Table Staff - 6b

150009 - Staff's 2nd INTs No. 13 - Attachment No. 1

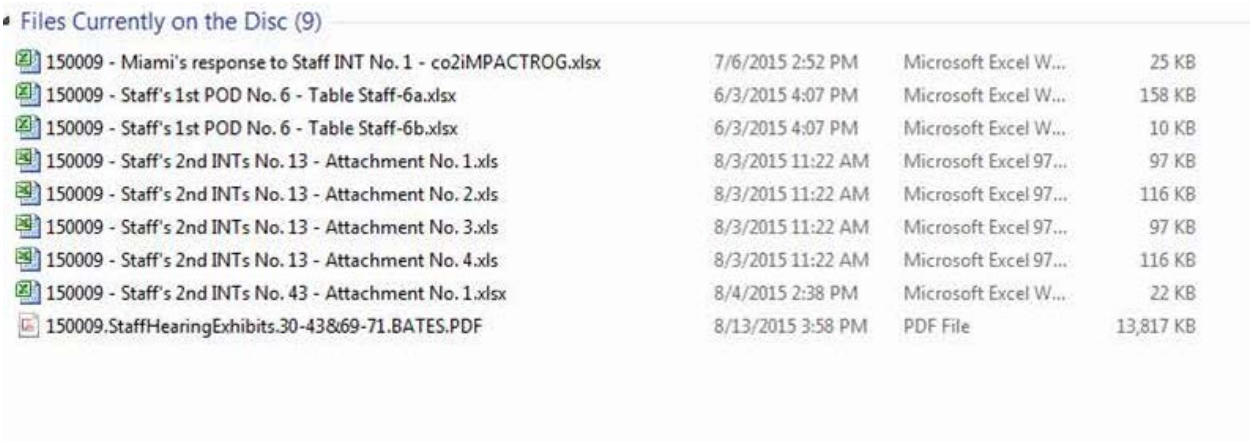
150009 - Staff's 2nd INTs No. 13 - Attachment No. 2

150009 - Staff's 2nd INTs No. 13 - Attachment No. 3

150009 - Staff's 2nd INTs No. 13 - Attachment No. 4

150009 - Staff's 2nd INTs No. 43 - Attachment No. 1

150009.StaffHearingExhibitss.30-43&69-71.BATES



32

FPL's Responses to Staff's Third Set of Interrogatories (Nos. 47-49)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 32
PARTY: STAFF RE: FPL
DESCRIPTION: Steven R. Sim

Q.
Did the Company make any adjustments to the ICF International (ICF) price forecast of Carbon Dioxide (CO2) for its 2015 TP Project's Feasibility Analysis? If so, please specify the adjustments and reasons for modifications.

A.
In 2015 FPL updated its CO_2 forecast as a result of the issuance of the CPP draft rule. FPL started with the ENV II forecast used from 2012 to 2014, which reflected ICF's 2012 forecast. Then, FPL moved the CO_2 emission costs forward so they started in 2020. This year was chosen as it is the first year that the Clean Power Plant draft rules are projected to start. No adjustments were made to the prices in this process. This created the new ENV II (Mid) CO_2 price forecast used in the 2015 NCRC analysis.

To create the ENV I (Low) CO2 price forecast, FPL reduced the CO2 prices in the ENV II (Mid) forecast by multiplying them by 0.80. To create the ENV III (High) CO2 price forecast, FPL increased the CO2 prices in the ENV II (Mid) forecast by multiplying them by 1.20.

In order to continue the analysis thru the year 2088, FPL extrapolated CO2 cost projections by 8% per year starting in 2045.

Q.
Did the Company compare the ICF price forecast of CO2 (used for its 2015 TP Project's Feasibility Analysis) to any other industry-recognized forecasted CO2 pricing schedules? If so, please detail.

A.
FPL believes that ICF is a respected source in the industry for this type of forecast. For example, ICF's model and practices have been and continue to be used by the EPA in development of the air emission regulations such as the Clean Power Plan. As a result, FPL did not compare the ICF CO_2 price forecast to forecasts from other sources.

Q.

For the purposes of the following request, please refer to FPL's Responses to Staff's Second Set of ROGs, No. 18(b.). Please elaborate on how "the Supreme Court's ruling in 2014 that countermanded a late 2011 District Court of Appeals in D.C. decision to stay the EPA's Cross-State Air Pollution Rule" reduced the estimated/forecasted costs ($/ton) of Sulfur Dioxide (SO2), and Nitrogen Oxide (NOx), from 2014 to zero in the 2015 Feasibility Analysis (ENV I).

A.

At the end of 2011, the District Court of Appeals for D.C. had stayed EPA's Cross-State Air Pollution Rule (CSAPR) and subsequently vacated it in August 2012, leaving the Clean Air Interstate Rule (CAIR) to control SO_2 and NO_x emissions in its place. That change was adopted for FPL's 2012 forecast, assuming that CAIR would remain in place to control NO_x and SO_2 emissions while EPA developed a replacement for CSAPR. CAIR included a cap for SO_2 emissions in FL, resulting in the SO_2 $/ton allowance price trajectory that was provided in 2012. In 2014, the Supreme Court reversed the lower court's decision on CSAPR, which allowed EPA to implement the program in 2015. The recent forecast therefore assumes that CSAPR is in place. CSAPR does not include an SO_2 cap for FL, however. As a result, FL generators face only the original Title IV Acid Rain program requirements for SO_2. Actual emissions by affected sources under the Acid Rain program are well below the cap for the program, so the assumption for the cost of SO_2 under that program is $0/ton.

While the Supreme Court upheld CSAPR in April 2014, the D.C. Circuit's stay of CSAPR remained in effect. As a result the case went back to the D.C. Circuit to address substantive issues left open by the Supreme Court (e.g., potential "over control" issues). For instance, in February 2012 the Florida Electric Power Coordinating Group had petitioned EPA to reconsider and stay the CSAPR stating that the agency's use of outdated data, modeling and methodology were flawed and Florida should not be included in the rule. It was not until October of 2014 that the stay of CSAPR was lifted by the D.C. Circuit Court. Since the initial compliance deadlines of CSAPR had long passed it was anticipated that EPA would initiate new rulemaking under a remand by the D.C. Circuit court using updated emissions data and new modeling. Because Florida was considered a minor contributor of NO_x to downwind states only in the ozone season and many facilities in Florida had added NOx reduction controls in response to the Clean Air Interstate Rule (CAIR), a new rulemaking effort would likely have shown that Florida was no longer a significant contributor to downwind states in the ozone season. In this possible outcome Florida would not have had a NOx allowance obligation during the ozone season when CSAPR was reinstated in 2015. Thus ENV I was intended to evaluate the impacts of the possible "no impact by CSAPR" outcome. However, as applied the CSAPR does impact Florida in the ozone season making scenarios ENV II and III more applicable today.

AFFIDAVIT

Steven R. Sim

Steven R. Sim

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 13th day of July, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Steven R. Sim, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 47-50 from Staff's Third Set of Interrogatories to Florida Power & Light Company (Nos. 47-50) in Docket No. 150009-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 13th day of July, 2015.

Traci D. Goldwire

Notary Public
State of Florida, at Large

TRACI D. GOLDWIRE
Notary Public - State of Florida
My Comm. Expires Jul 31, 2015
Commission # EE 117539

My Commission Expires:
July 31, 2015

33

FPL's Responses to Staff's Fourth Set of Interrogatories (No. 51)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 33
PARTY: STAFF RE: FPL
DESCRIPTION: Steven R. Sim

Q.

For the purposes of the following request, please refer to the rebuttal testimony of FPL Witness Sim, Page 7, lines 12-21. Please provide, both on a nominal and Cumulative Present Value basis of Revenue Requirements the CO2 costs associated with the TP Project's Feasibility Analysis for 2015.

A.

FPL interprets this request to ask for the total nominal CO2 costs, and the total CPVRR CO2 costs, for each resource plan for each scenario of fuel cost, environmental compliance cost, and operating life that was analyzed in FPL's 2015 feasibility analyses. That information is provided in the table in Attachment No. 1 to this response.

Florida Power & Light Company
Docket No. 150009-EI
Staff's Fourth Set of Interrogatories
Interrogatory No. 51
Attachment No. 1

Table Staff-51

2015 Feasibility Analyses of the Turkey Point 6 & 7 Project:
CO_2 Revenue Requirements (Total Nominal and Total CPVRR) - 40-Year Operating Life
(Millions, 2015-2068)

Fuel Cost Forecast	Environmental Compliance Cost Forecast	Total Nominal		Total CPVRR	
		Resource Plan w/ TP 6 & 7	Resource Plan w/o TP 6 & 7	Resource Plan w/ TP 6 & 7	Resource Plan w/o TP 6 & 7
High Fuel Cost	Env I	466,917	520,144	28,718	31,911
High Fuel Cost	Env II	583,733	650,044	35,884	39,854
High Fuel Cost	Env III	700,682	780,265	43,081	47,836
Medium Fuel Cost	Env I	466,831	519,999	28,661	31,830
Medium Fuel Cost	Env II	583,503	649,805	35,832	39,781
Medium Fuel Cost	Env III	700,129	779,771	43,020	47,762
Low Fuel Cost	Env I	466,606	519,923	28,637	31,812

2015 Feasibility Analyses of the Turkey Point 6 & 7 Project:
CO_2 Revenue Requirements (Total Nominal and Total CPVRR) - 60-Year Operating Life
(Millions, 2015-2088)

Fuel Cost Forecast	Environmental Compliance Cost Forecast	Total Nominal		Total CPVRR	
		Resource Plan w/ TP 6 & 7	Resource Plan w/o TP 6 & 7	Resource Plan w/ TP 6 & 7	Resource Plan w/o TP 6 & 7
High Fuel Cost	Env I	2,280,570	2,539,798	45,304	50,382
High Fuel Cost	Env II	2,851,521	3,174,707	56,624	62,943
High Fuel Cost	Env III	3,422,909	3,811,009	67,976	75,553
Medium Fuel Cost	Env I	2,280,838	2,540,179	45,251	50,305
Medium Fuel Cost	Env II	2,850,846	3,174,299	56,567	62,868
Medium Fuel Cost	Env III	3,420,438	3,809,039	67,898	75,465
Low Fuel Cost	Env I	2,279,871	2,539,915	45,220	50,285

AFFIDAVIT

Steven R. Sim

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 13th day of July, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Steven R. Sim, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory number 51 from Staff's Fourth Set of Interrogatories to Florida Power & Light Company (No. 51) in Docket No. 150009-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 13th day of July, 2015.

TRACI D. GOLDWIRE
Notary Public - State of Florida
My Comm. Expires Jul 31, 2015
Commission # EE 117539

Traci D. Goldwire
Notary Public
State of Florida, at Large

My Commission Expires:
July 31, 2015

34

FPL's Responses to Staff's Fifth Set of Interrogatories (No. 52)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 34
PARTY: STAFF RE: FPL
DESCRIPTION: Steven R. Sim

Q.

For the purposes of the following Interrogatory (ROG), please refer to Florida Power & Light Company's (FPL) response to Staff's Third Set of ROGs, No. 47, FPL's response to Staff's Second Production of Documents (POD), No. 8, and FPL's response to City of Miami's (Miami) Third Set of ROGs, No. 20.

a. It is stated in FPL's response to Miami's ROG No. 20 that "The annual escalation rate for the projected compliance costs for CO2 exceeds 7.51% in all years from 2021 – on." Also, stated in FPL's response to Staff ROG No. 47, "In order to continue the analysis thru the year 2088, FPL extrapolated CO2 cost projections by 8% per year starting in 2045." Please detail how the escalation of CO2 costs (7.51%-8%) are reflected, if at all, by the ENV II CO2 prices shown on FPL's response to Staff's Second PODs, No. 8. For example, please explain how CO2 costs are escalated by 7.51% to 8% for every year 2045 and beyond, but CO2 prices, as shown on FPL's response to Staff's Second PODs, No. 8 are not.

b. If CO2 emissions prices are a subcomponent of CO2 costs that are being escalated by 7.51% to 8%, in 2045 and beyond, please detail the other factors/items accounted for in Company's CO2 cost analysis.

c. How did FPL determine the CO2 cost escalation rate of approximately 8% (for 2045 and beyond) and what were the factors of the Company's analysis that led it to this 8% escalation level?

d. Please specify what other system planning reviews/Dockets filed with the FPSC, if any, also used and/or relied on the same ICF air emissions forecasts.

A.

a. There are two types of CO2 cost values that are referred to in this question. One type is the ENV I, II, and III ($/ton) cost values that are based on ICF's forecasts. These values are used as inputs in FPL's analyses. The other type of CO2 cost is the projected annual total system CO2 costs ($ millions) for each resource plan. These values are an output of the analyses. The following explanation is intended to explain the development of both the inputs and the outputs using the ENV II scenario.

- In its 2012 forecast of CO2 $/ton costs, ICF projected non-zero costs that began in 2023. Their cost projection addressed the years 2023 through 2030. These projected values were in real 2010 dollars. Based on discussions with ICF, FPL both converted those 2010 real dollar values to nominal dollars for this same time period and extrapolated the values out into the future. (FPL typically extrapolates these values out to approximately 2060.) Please note that in FPL's response to Staff's Second Request for Production of Documents No. 8 the CO2 values directly supplied by ICF, and the SO2 and NOx values that were jointly developed by ICF and FPL, in nominal terms, are reflected in the "mid" column through the year 2030.
- For the 2015 feasibility analyses, after further discussions with ICF, FPL advanced the start date of the non-zero cost values from 2023 to 2020 to match the projected start year in the draft rules for EPA's Clean Power Plan.
- FPL used the resulting forecasted $/ton values as inputs in its production costing model, UPLAN, for the years 2015 through 2044. The resulting UPLAN output provided the annual total system CO2 costs ($ million) for each resource plan for each of these years.
- The UPLAN model is capable of addressing a 30-year time period. Although this time period is sufficient for analyzing most resource options, additional steps must be taken when analyzing resource options, such as new nuclear units, with 40-year to 60-year lives.
- In regard to developing the projected CO2 total system costs for the years 2045-on that is required in the feasibility analyses, FPL used its extrapolation of the $/ton CO2 costs. The annual escalation rate for the years 2045 through 2059 was approximately 8%. That escalation value was then used to project annual total CO2 costs for years after 2045 for each resource plan.

b. When deriving the annual total system CO2 cost projections for a nuclear analysis, the driving factors are the projected annual $/ton CO2 cost values and the projected annual output of the nuclear units.

c. Please see FPL's response to subpart (a) of this interrogatory.

d. FPL's resource planning-related filings with the FPSC beginning in 2012 to the present have used the same ICF 2012 CO2 cost forecast that was the basis for the $/ton input values used in the 2015 feasibility analysis. These include the annual Site Plan filings since 2012, the annual standard offer contract filings since 2012, and the annual NCR filings in the years 2012 through 2014.

In FPL's 2014 DSM Goals docket, the FPSC Staff requested that all utilities that wanted to include a projection of CO2 costs impacts use a common projection of CO2 costs. FPL and DEF wanted to include a scenario that included CO2 costs. In order to respond to Staff's request, the two companies developed a composite CO2 forecast of their then current CO2 $/ton forecasts. FPL's forecast was based on the ICF 2012 forecast. The resulting composite forecast projected higher $/ton CO2 costs, that were then used in FPL's DSM analyses, than if FPL's own CO2 cost forecast had been used.

In 2015, FPL adjusted the forecast, as explained in FPL's rebuttal testimony, so that the starting year for the $/ton costs was 2020. The revised ENV II forecast has been used in both this docket and in the Cedar Bay filing (Docket No. 150075-EI). In addition, this revised forecast is being used in all of FPL's current resource planning work.

AFFIDAVIT

Steven R. Sim

Steven R. Sim

STATE OF FLORIDA)

COUNTY OF Palm Beach)

I hereby certify that on this 30th day of July, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Steven R. Sim, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory number 52 from Staff's Fifth Set of Interrogatories to Florida Power & Light Company (No. 52) in Docket No. 150009-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 30th day of July, 2015.

TRACI D. GOLDWIRE
Notary Public - State of Florida
My Comm. Expires Jul 31, 2015
Commission # EE 117539

Traci D. Goldwire

Notary Public
State of Florida, at Large

My Commission Expires:
July 31, 2015

35

FPL's Responses to Staff's First Request for Production of Documents (Nos. 2 and 6) See Staff Exhibit CD for Excel files Re: Nos. 6a and 6b

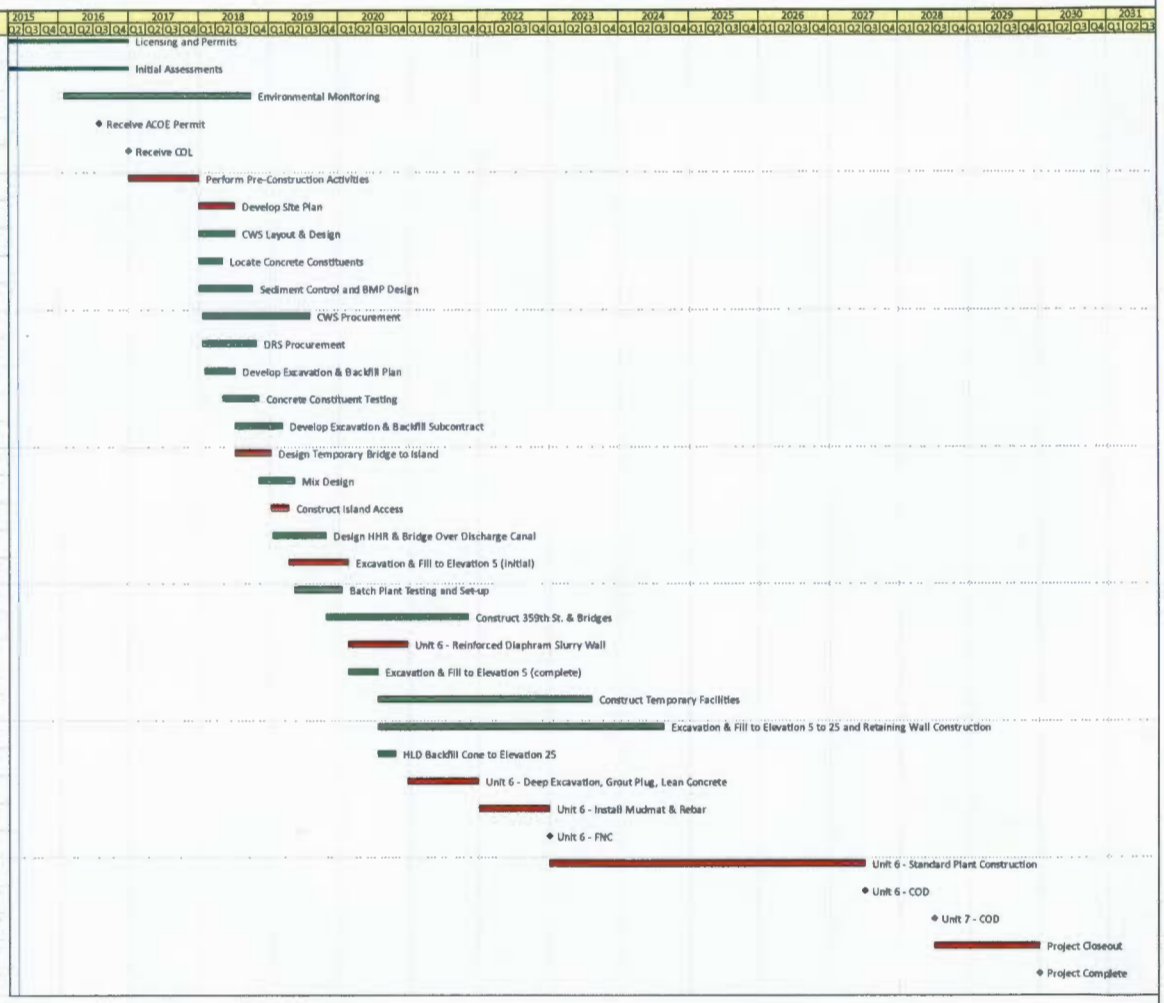
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 35
PARTY: STAFF RE: FPL
DESCRIPTION: FPL's Responses to Staff's First Request for Production of Documents

DOCUMENTS REQUESTED

2. TP Project Critical Path: Please provide a copy of FPL's estimate of the TP Project critical path timeline that shows FPL's estimated major milestone completion dates for permitting, licensing, beginning other pre-construction work, issuance of a full notice to proceed with construction, first nuclear construction work, and transmission and associated facilities activities relied on by FPL witness Steven D. Scroggs in development of the projected commercial operation dates of 2027/28 (see May 1, 2015 testimony, at page 25).

PTN Units 6 & 7 Level 1 Baseline Project Schedule

Activity ID	Activity Name	Original Duration	Start	Finish
TPN541035	Licensing and Permits	699	09/01/2007 A	12/30/2016
TPN541025	Initial Assessments	678	02/02/2015 A	12/31/2016
TPN540120	Environmental Monitoring	975	02/01/2016*	10/02/2018
TPN540184	Receive ACOE Permit	0	08/01/2016*	
TPN540194	Receive CDL	0	12/31/2016*	
TPNMG0110	Perform Pre-Construction Activities	365	01/01/2017	12/31/2017
TPN540117	Develop Site Plan	187	01/01/2018	07/06/2018
TPN540123	CWS Layout & Design	187	01/01/2018	07/06/2018
TPN540125	Locate Concrete Constituents	124	01/01/2018	05/04/2018
TPN540129	Sediment Control and BMP Design	280	01/01/2018	10/07/2018
TPN540124	CWS Procurement	559	01/21/2018	08/02/2019
TPN540130	DRS Procurement	280	01/21/2018	10/27/2018
TPN540131	Develop Excavation & Backfill Plan	156	01/31/2018	07/05/2018
TPN540126	Concrete Constituent Testing	186	05/05/2018	11/06/2018
TPN540132	Develop Excavation & Backfill Subcontract	249	07/06/2018	03/11/2019
TPN540118	Design Temporary Bridge to Island	186	07/07/2018	01/08/2019
TPN540127	Mix Design	186	11/07/2018	05/11/2019
TPN540119	Construct Island Access	94	01/09/2019	04/12/2019
TPN540121	Design HHR & Bridge Over Discharge Canal	280	01/18/2019	10/24/2019
TPN540133	Excavation & Fill to Elevation 5 (initial)	310	04/13/2019	02/16/2020
TPN540128	Batch Plant Testing and Set-up	247	05/12/2019	01/13/2020
TPN540122	Construct 359th St. & Bridges	744	10/25/2019	11/06/2021
TPN540137	Unit 6 - Reinforced Diaphram Slurry Wall	310	02/17/2020	12/22/2020
TPN540136	Excavation & Fill to Elevation 5 (complete)	154	02/17/2020	07/19/2020
TPN540138	Construct Temporary Facilities	1118	07/20/2020	08/11/2023
TPN540135	Excavation & Fill to Elevation 5 to 25 and Retaining Wall Construction	1490	07/20/2020	08/17/2024
TPN540134	HLD Backfill Cone to Elevation 25	94	07/20/2020	10/21/2020
TPN540139	Unit 6 - Deep Excavation, Grout Plug, Lean Concrete	372	12/23/2020	12/29/2021
TPN540140	Unit 6 - Install Mudmat & Rebar	366	12/30/2021	12/30/2022
TPN540141	Unit 6 - FNC	0		12/30/2022
TPN540142	Unit 6 - Standard Plant Construction	1643	12/31/2022	06/30/2027
TPN540143	Unit 6 - COD	0		06/30/2027*
TPN540144	Unit 7 - COD	0		06/30/2028*
TPN541170	Project Closeout	549	07/01/2028	12/31/2029
PRJ-FM	Project Complete	0		01/01/2030*



Remaining Level of Effort | Actual Work | Critical Remaining Work
Actual Level of Effort | Remaining Work | Milestone

Page 1 of 1

DRAFT

Date	Revision	Checked	Approved
01/28/2015	Level 1 Baseline		

FPL 000090
NCR-15

Q.

Please provide FPL's commodity, transportation, and delivered fuel price forecasts in electronic format (Excel, intact and unlocked) for uranium, oil, and natural gas (for low, medium, and high cases) used in support of the TP Project's 2015 Feasibility Analysis (nominal $/mmBtu). Please also provide any alternative fuel forecasts the Company may have reviewed for evaluating the forecast utilized for the 2015 Feasibility Analysis, including sources and dates.

A.

Table Staff-6a, provided, presents the delivered prices for natural gas, oil, and uranium. These costs are used in both the with and without Turkey Point 6 & 7 resource plans.

In Table Staff-6b, provided, FPL has provided the transportation costs associated with natural gas additions, including those that would change between the resource plan that includes Turkey Point 6 and 7 and the resource plan that does not include these proposed nuclear units, instead replacing them with gas-fired combined cycle units. These transportation costs, as shown in Table Staff-6b, were used for all fuel cost scenarios. FPL did not review any alternative fuel forecasts in the 2015 feasibility analysis.

150009 - Miami's response to Staff INT No. 1 - co2iMPACTROG

150009 - Staff's 1st POD No. 6 - Table Staff - 6a

150009 - Staff's 1st POD No. 6 - Table Staff - 6b

150009 - Staff's 2nd INTs No. 13 - Attachment No. 1

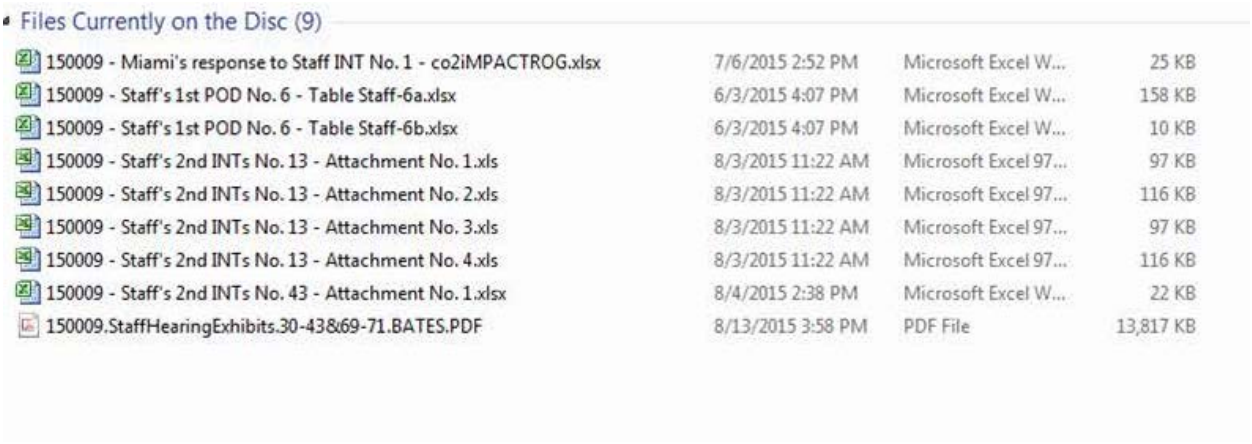
150009 - Staff's 2nd INTs No. 13 - Attachment No. 2

150009 - Staff's 2nd INTs No. 13 - Attachment No. 3

150009 - Staff's 2nd INTs No. 13 - Attachment No. 4

150009 - Staff's 2nd INTs No. 43 - Attachment No. 1

150009.StaffHearingExhibitss.30-43&69-71.BATES



36

FPL's Responses to Staff's Second Request for Production of Documents (Nos. 8 and 9)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 36
PARTY: STAFF RE: FPL
DESCRIPTION: FPL's Responses to Staff's Second Request for Production of Documents

Q.

For the purposes of the following request, please refer to FPL's Responses to Staff's Second Set of ROGs, No. 18(b.). Please provide a copy of the ICF International (ICF) forecasted pricing schedules for Carbon Dioxide (CO2), Sulfur Dioxide (SO2), and Nitrogen Oxide (NOx).

A.

ICF did not provide an updated projection for 2015. In order to address the uncertainty regarding the Clean Power Plan (CPP) draft rule and how there may be changes in the final rules, FPL discussed an approach with ICF. The resulting forecast was used in the 2015 analysis and is also provided along with this response. Please see FPL's response to the City of Miami's Second Request for Production of Documents No. 11 for the most recent forecast provided by ICF (2012).

FPL 001178
NCR-15

Emission Price Projections used in the 2015 NCR Feasibility Analysis

	CO_2 Emissions Price Forecast $/ton			SO_2 Emissions Price Forecast $/ton			NOx Emissions Price Forecast $/ton		
Year	Low	Mid (base)	High	Low	Mid (base)	High	Low	Mid (base)	High
2015	0	0	0	0	0	0	0	125	400
2016	0	0	0	0	0	0	0	125	400
2017	0	0	0	0	0	0	0	125	400
2018	0	0	0	0	0	0	0	125	400
2019	0	0	0	0	0	0	0	125	400
2020	7	9	10	0	0	0	0	125	400
2021	8	10	12	0	0	0	0	125	400
2022	9	11	13	0	0	0	0	125	400
2023	10	13	15	0	0	0	0	125	400
2024	12	15	17	0	0	0	0	125	400
2025	13	16	20	0	0	0	0	125	400
2026	15	19	23	0	0	0	0	125	400
2027	17	21	26	0	0	0	0	125	400
2028	19	24	29	0	0	0	0	125	400
2029	22	27	33	0	0	0	0	125	400
2030	25	31	37	0	0	0	0	125	400
2031	27	34	41	0	0	0	0	125	400
2032	31	38	46	0	0	0	0	125	400
2033	34	43	51	0	0	0	0	125	400
2034	38	48	57	0	0	0	0	125	400
2035	42	53	63	0	0	0	0	125	400
2036	47	58	70	0	0	0	0	125	400
2037	51	64	77	0	0	0	0	125	400
2038	57	71	85	0	0	0	0	125	400
2039	62	78	93	0	0	0	0	125	400
2040	68	85	102	0	0	0	0	125	400
2041	75	93	112	0	0	0	0	125	400
2042	82	102	122	0	0	0	0	125	400
2043	89	111	133	0	0	0	0	125	400
2044	97	121	145	0	0	0	0	125	400
2045	105	131	158	0	0	0	0	125	400
2046	114	142	171	0	0	0	0	125	400
2047	123	154	185	0	0	0	0	125	400
2048	134	167	200	0	0	0	0	125	400
2049	144	180	216	0	0	0	0	125	400
2050	156	195	234	0	0	0	0	125	400
2051	168	210	252	0	0	0	0	125	400
2052	181	226	271	0	0	0	0	125	400
2053	194	243	291	0	0	0	0	125	400
2054	209	261	313	0	0	0	0	125	400
2055	224	280	336	0	0	0	0	125	400
2056	240	300	360	0	0	0	0	125	400
2057	257	321	385	0	0	0	0	125	400
2058	275	344	412	0	0	0	0	125	400
2059	294	367	441	0	0	0	0	125	400
2060	301	377	452	0	0	0	0	125	400
2061	309	386	463	0	0	0	0	125	400
2062	317	396	475	0	0	0	0	125	400
2063	324	406	487	0	0	0	0	125	400
2064	333	416	499	0	0	0	0	125	400
2065	341	426	511	0	0	0	0	125	400
2066	349	437	524	0	0	0	0	125	400
2067	358	448	537	0	0	0	0	125	400
2068	367	459	551	0	0	0	0	125	400
2069	376	470	564	0	0	0	0	125	400
2070	386	482	578	0	0	0	0	125	400
2071	395	494	593	0	0	0	0	125	400
2072	405	506	608	0	0	0	0	125	400
2073	415	519	623	0	0	0	0	125	400
2074	426	532	639	0	0	0	0	125	400
2075	436	545	655	0	0	0	0	125	400
2076	447	559	671	0	0	0	0	125	400
2077	458	573	688	0	0	0	0	125	400
2078	470	587	705	0	0	0	0	125	400
2079	482	602	722	0	0	0	0	125	400
2080	494	617	741	0	0	0	0	125	400
2081	506	633	759	0	0	0	0	125	400
2082	519	648	778	0	0	0	0	125	400
2083	532	665	797	0	0	0	0	125	400
2084	545	681	817	0	0	0	0	125	400
2085	559	698	838	0	0	0	0	125	400
2086	573	716	859	0	0	0	0	125	400
2087	587	734	880	0	0	0	0	125	400
2088	601	752	902	0	0	0	0	125	400

Q.
Please provide any documentation that supports FPL's response to Staff's Second Set of Interrogatories, No. 48.

A.
FPL does not have any supporting documents for Staff's Third Set of Interrogatories No. 48.

37

FPL's Responses to OPC's First Set of Interrogatories (Nos. 4 and 5)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 37
PARTY: STAFF RE: FPL
DESCRIPTION: Steven D. Scroggs

Q.
Referring to Exhibit SDS-9, page 3 of 3 of Mr. Scroggs May 1, 2015 testimony, Table 5. 2015 Initial Assessment Costs, please provide a detailed description of costs included as Initial Assessment costs. Also, please identify which Initial Assessment costs are specifically required to obtain the COL for Turkey Point Units 6 and 7. Please provide the date these costs were incurred.

A.
Initial assessments are specific analyses that are either currently under contract (Category A) or are being planned (Categories B, C, and D).

The Category A Initial Assessment contract was awarded 4/15/15 with a time and material estimated value of $905,635, to be completed by 9/15/15. The descriptions and costs of each task included in Category A of initial assessments is shown below. Category B/C activities are anticipated to be awarded later this year and make up the balance of the $1,842,105 identified for 2015 in SDS-9.

Category A Initial Assessment Task Item estimated cost:

· Task 1 – Site Development Plan	$354,696
· Task 2 – Offsite Facilities needed	$ 74,664
· Task 3 – Module Assembly Facility	$ 63,973
· Task 4 – Module Delivery/Transport	$102,589
· Task 5 – Heavy Lift	$103,481
· Task 6 – Review of Schedule	$117,689
· Meetings	$ 88,543
Total	$905,635

Category A Initial Assessment Task Item description:

- Task 1 – Prepare a Site Development Plan showing all permanent and temporary features in a time-phased sequence approach, from Start of Construction through Commercial Operation.
- Task 2 – Determine the requirements for Off-Site Facilities based on evaluation of the available areas on site for laydown, storage, parking, etc.
- Task 3 – Determine the need, type of structure, and design requirements for the Module Assembly Facility.
- Task 4 – Develop a plan for module fabrication, delivery, transportation and assembly.
- Task 5 – Determine the appropriate type of Heavy Lift Crane and location to meet the requirements of the project.
- Task 6 – Review Level 1 Baseline Schedule to ensure that the results of Tasks 1-5 meet the requirements of the schedule.

The estimated contract value of Category B is $700,000; Category C is $400,000; Category D is $3,000,000. Detailed scope development for Category B, C and D has not been completed at this time. Costs for Category C and D are predominantly incurred in 2016.

Category B / Category C Excavation, Fill and Sub Foundation Initial Assessment:

- Island Retaining Wall conceptual development
- Island backfill sequence, evaluate fill supply, delivery methods and rates
- Update level 2 pre FNC-6 schedule
- Dewatering plan development
- Slurry Wall execution plan
- Concrete- aggregate supply, transportation, storage
- Retaining wall material, batch plant location/design study

Category D Miscellaneous:

- Evaluate non-critical path work on FNC-6 schedule
- Site Surveying specification
- Cooling towers, circulating water system design layout
- Road, Bridges, Potable water pipeline, transmission construction plan for 359th street access
- Reclaimed Water Treatment Plant construction plan
- Underground Injection Control construction plan
- Radial Collector Wells construction plan
- Reclaimed Water pipeline construction plan

Initial Assessment analyses are required to inform the project schedule and cost estimates that will be relied upon in the 2016 feasibility analysis that will support FPL's anticipated request to proceed from the licensing phase to the initiation of "pre-construction work," upon receipt of the COL.

Q.
Referring to Page 25, lines 7-9 of Mr. Scroggs May 1, 2015 testimony, please describe in detail the Company's plans to request recovery of pre-construction costs not related to obtaining the COL, including, but not limited to, the initial assessments discussed by Mr. Scroggs, and non-COLA related licensing, engineering, and permitting costs.

A.
At this time, FPL plans to request recovery of pre-construction costs not related to or necessary for obtaining the COL in time to begin recovering those costs concurrently with when FPL expects to incur them, which would begin in early 2017 upon receipt of the COL. That means such costs will be included in FPL's 2016 NCR projection of 2017 costs, for recovery in 2017, assuming the Commission approves the initiation of such pre-construction work.

The initial assessment costs, on the other hand, provide important base information to complete the feasibility analysis that is required to support FPL's request to begin pre-construction work, following the end of the licensing phase once the COL is obtained (in early 2017). FPL's revised project schedule requires this request to be made in the 2016 NCR filing. FPL has chosen to seek recovery of these costs concurrent with its request to begin pre-construction work and approve the feasibility analysis that those initial assessments support in 2016.

AFFIDAVIT

(Steven D Scroggs)

STATE OF FLORIDA)

COUNTY OF LEON)

I hereby certify that on this 26th day of MAY, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Steven D. Scroggs, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatories numbers 1-8 from OPC's first set of interrogatories to Florida Power & Light Company (Nos. 1-8) in Docket No. 150009-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 26th day of MAY, 2015.

Notary Public
State of Florida, at Large

JENNIFER MELCHIOR
MY COMMISSION EXPIRES
November 17, 2017
NOTARY PUBLIC STATE OF FLORIDA

My Commission Expires:
11/17/2017

38

FPL's Responses to OPC's Third Set of Interrogatories (Nos. 15, 19, 21, 22, 33, 34, and 35)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 38
PARTY: STAFF RE: FPL
DESCRIPTION: Steven D. ScroggsJohn J. Reed

Q.

On page 5, line 21, Witness Scroggs uses the term "preconstruction work." Please define the term "preconstruction work" as used in his testimony.

A.

As indicated at page 5, line 22, the term "preconstruction work" has the meaning "as that term is used in F.S. 366.93 (3)(c)." FPL's understands "preconstruction work" to include the Front End Engineering and Design (FEED) studies, bid specification development and project implementation planning necessary to begin physical construction. Note that in F.S. 366.93(3)(c)2.a., the statute links approval for "preconstruction work" following receipt of a COL to a demonstration that the project remains feasible.

Q.
Please refer to Page 9, lines 1-7:

a. Please list the "lessons learned" that have provided "very real impact" to reduce the costs of Turkey Point Units 6 and 7.

b. Quantify the specific "very real impact" of each lesson learned on the Turkey Point Units 6 and 7 project estimate.

A.

a. The cited section of testimony clearly discusses the expected impact from lessons learned, not historical cost impacts as the question indicates. FPL's current project schedule incorporates the following specific lessons learned.

1) Contracting Lessons. Georgia Power and the Consortium partners (Westinghouse and CB&I) are currently in litigation regarding cost responsibility for schedule delays that resulted from design changes occurring after EPC contract execution. Incorporation of language to more effectively mitigate and manage potential engineering design changes after contract execution would be anticipated to avoid a majority of this type of cost exposure.

2) Construction Lessons (examples).

(a) Nuclear Island Basemat Placement. Interpretation of code and subsequent NRC inspections resulted in an estimated delay of 2 or 3 months.
(b) Batch plant construction and startup resulting in delay of several months. Additionally, procurement of the high dry unit weight aggregate to meet the AP1000 design standard required additional lead time to procure and deliver to site.
(c) Quality control in module fabrication, assembly and erection have created ongoing delays at the Vogtle and Summer projects. Unconfirmed estimates range from 12 to 18 months. While quality of the current providers is improving, additional mitigation may be available through development of additional sources or procurement strategies.

3) Regulatory lessons. The NRC has identified many lessons learned as they have taken on COLA review and construction monitoring under Part 52 as a first of a kind regulatory effort. Specifically, examples of the NRC's findings regarding construction monitoring (March 7, 2014 Memo; ADAMS Accession No.: ML13357A259) include:

(a) Clear and timely regulatory decision making in the construction environment can be enhanced through better communications. Second wave projects will be able to adopt the best practices developed in first wave projects.

(b) Clarity of design control document (DCD) Tier 2* information (i.e. information for which prior Nuclear Regulatory Commission (NRC) review and approval is needed before changes can be implemented) could be enhanced. This issue will be clarified for second wave projects.

(c) NRC staff acceptance of submitted Inspections, Tests, Analyses, and Acceptance Criteria (ITAAC) closure notifications (ICN) will require continued, effective interface with licensees. Second wave projects will be able to adopt the form and content of ICN's from first wave projects.

b. Lessons learned are expected to provide cost savings for the Turkey Point Units 6&7 project by mitigating project schedule delays and/or avoiding rework. Cost savings will be realized by more accurately defining scope and responsibilities to avoid or minimize future litigation exposure, enhancing planning and scheduling to accommodate observed logistical conflicts or execution durations, reducing additional engineering, labor and material costs associated with redesign or rework of construction methods, improved quality control by material providers, manufacturers and constructors, and improved process controls and communication protocols between all parties involved in construction. As these lessons have not been applied, no specific quantification is possible. Further, as many of these lessons avoid delays, they avoid cost overruns, not necessarily providing savings that would be deducted from the current project cost estimate.

In the case of the contract dispute under litigation, the costs of those issues have been estimated up to $900 million.

Q.
What are the owner's costs included in the Turkey Point Units 6 and 7 cost estimates?

A.
Exhibit SDS-6 to Witness Scroggs' Need Determination testimony (Docket 070650-EI) provides a description of Owners Costs, see Attachment No. 1.

Florida Power & Light Company
Docket No. 150009-EI
OPC's Third Set of Interrogatories
Interrogatory No. 21
Attachment No. 1
Page 1 of 1

Overnight Cost Estimate Range ($/kW, 2007$)

Construction Unit Cost Estimate Range Based on TVA Study - Two Unit ABWR Project, at 1,371 MW per unit	CASE A: TVA Study Adjusted to 2007$ (Index 206/238) and Modified for FPL Owners Scope and PTN Site Cost Estimates		CASE B: Reduced Material Escalation (Index 170/192), Reduced Owner Scope, 10% lower Owners Costs, Low Transmission Estimate		CASE C: Increased Material Escalation (Index 242/284), Added Owner Scope, 10% higher Owner's Costs, High Labor & Transmission Estimate	
	2007 $	$/kWe	2007 $	$/kWe	2007 $	$/kWe
Power Plant Island and Supporting Construction						
Structure & Improvements	$792,000,000	$289	$654,000,000	$239	$931,000,000	$340
Reactor Plant Equipment	$1,399,000,000	$510	$1,155,000,000	$421	$1,644,000,000	$600
Turbine Plant Equipment	$934,000,000	$341	$771,000,000	$281	$1,097,000,000	$400
Electric Plant Equipment	$413,000,000	$151	$333,000,000	$121	$493,000,000	$180
Misc. Plant Equipment	$146,000,000	$53	$118,000,000	$43	$174,000,000	$63
Main Cond. Heat Reject Sys	$84,000,000	$31	$84,000,000	$31	$84,000,000	$31
Circ. Water Pumps & Pipe	$26,000,000	$9	$26,000,000	$9	$26,000,000	$9
Construction Labor, Manual	$1,422,000,000	$519	$1,422,000,000	$519	$1,848,600,000	$674
Construction Services	$534,000,000	$195	$431,000,000	$157	$694,200,000	$253
Engineers Home Office Services	$834,000,000	$304	$834,000,000	$304	$1,084,200,000	$395
Additional Required Scope	$98,000,000	$36	$0	$0	$107,800,000	$39
Allowance for Cost Risk	$1,002,300,000	$366	$874,200,000	$319	$1,636,760,000	$597
Subtotal	$7,684,300,000	$2,802	$6,702,200,000	$2,444	$9,820,560,000	$3,582
Owners Costs						
Security infrastructure	$109,000,000	$40	$98,100,000	$36	$119,900,000	$44
Cooling Towers	$131,000,000	$48	$0	$0	$144,100,000	$53
Aux Boilers	$16,000,000	$6	$0	$0	$17,600,000	$6
Switch Yard	$93,000,000	$34	$83,700,000	$31	$102,300,000	$37
Site work	$257,000,000	$94	$231,300,000	$84	$282,700,000	$103
EPC startup costs	$139,000,000	$51	$125,100,000	$46	$152,900,000	$56
Fuel	$45,000,000	$16	$40,500,000	$15	$49,500,000	$18
Site Security	$91,000,000	$33	$81,900,000	$30	$100,100,000	$37
Permits/Licensing	$104,000,000	$38	$93,600,000	$34	$114,400,000	$42
Other Owner costs	$38,000,000	$14	$34,200,000	$12	$41,800,000	$15
Owner Project Management	$166,000,000	$61	$149,400,000	$54	$237,380,000	$87
Owner Transition	$192,000,000	$70	$172,800,000	$63	$274,560,000	$100
Land Costs - Site	$0	$0	$0	$0	$0	$0
Land Costs - Offsite	$0	$0	$0	$0	$0	$0
Allowance for Cost Risk	$207,150,000	$76	$166,590,000	$61	$327,448,000	$119
Subtotal	$1,588,150,000	$579	$1,277,190,000	$466	$1,964,688,000	$717
Additional Project Related Costs						
Transmission Integration	$512,000,000	$187	$471,000,000	$172	$553,000,000	$202
Allowance for Cost Risk	$76,800,000	$28	$70,650,000	$26	$110,600,000	$40
Subtotal	$588,800,000	$215	$541,650,000	$198	$663,600,000	$242
Grand Total	**$9,861,250,000**	**$3,596**	**$8,521,040,000**	**$3,108**	**$12,448,848,000**	**$4,540**

Docket No. 07_____-EI
Overnight Cost Estimate Range
(2007$)
Exhibit SDS-6, Page 1 of 1

Q.
Please refer to page 12, lines 20-22. What are the costs associated with obtaining binding bids? How does this compare to total project costs?

A.
No specific cost estimate for this work has been prepared. However, based on FPL's experience and the magnitude of the undertaking, a preliminary order of magnitude estimate for the costs could range up to $100 million. That cost would be approximately 0.5% of the overall project cost.

Q.
Please explain the accounting treatment of FERC account 183 Preliminary survey and investigation costs incurred for an electric power plant project which is discontinued prior to being placed into service and does not get recovered through base rates.

A.
For purposes of this request, FPL assumes that the referenced electric power plant project is a non-nuclear project and construction has not begun.

As described in the CFR, if a project is abandoned after preliminary survey and investigation costs are incurred and recorded to FERC account 183, then the utility is required to record the costs to FERC account 426.5, Other Deductions, or to the appropriate operating expense account. If the project is mandated by regulators and does not proceed to construction, the CFR provides that all preliminary costs incurred up to the date the utility decides not to move forward with the project or is precluded from doing so, are transferred to FERC account 182.2, Unrecovered Plant and Regulatory Costs, or an appropriate operating expense account. Balances transferred to FERC account 182.2 are amortized to an operating expense account 407, Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs over a period specified by either the FPSC or FERC.

Q.

Please explain whether the Initial Assessment costs that FPL has identified in the nuclear cost recovery docket would be accounted as Preliminary Survey and Investigation charges under FERC account 183 if they are not recovered through the NCRC? If not accounted for in Account 183, please explain which in which FERC account FPL believes the Initial Assessment costs should be recorded.

A.

The Initial Assessment costs that have been identified in Docket No. 150009 should be recorded in CWIP (FERC account 107) as costs are incurred. These pre-construction costs, defined by FPSC Rule 25-6.0423, are appropriately recorded to CWIP consistent with all other Turkey Point 6 & 7 pre-construction costs incurred since the filing of FPL's need determination.

Q.

If FPL incurred Initial Assessment costs in constructing a gas power electric power plant please state whether those costs would be recorded in Account 183 (PS&I) or in Construction Work in Progress.

A.

FPL does not anticipate that it would incur Initial Assessment costs, as defined in the instant proceeding, for constructing a gas fired electric power plant and has not assessed how such costs would be recorded. Natural gas fired power plant projects are shorter in duration and better defined, so they do not require this type of additional analysis. However, FPL's policy, which is consistent with the CFR, is to record costs incurred for preliminary project feasibility studies and analysis under consideration that are anticipated to be capitalized to FERC account 183. For a large project, such as a gas power electric power plant, which is subject to the site certification act, all costs charged to FERC account 183 are transferred to CWIP upon receipt of site certification, which signals the project will move toward construction.

AFFIDAVIT

(John J. Reed)

STATE OF Ma)

COUNTY OF Middlesex)

I hereby certify that on this 22 day of July, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared John J. Reed, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatories numbers 23-30 from OPC's third set of interrogatories to Florida Power & Light Company (Nos. 13-35) in Docket No. 150009-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 22 day of July, 2015.

Notary Public
State of Ma. at Large

My Commission Expires:

WENDY L. PRESTON
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
April 22, 2022

AFFIDAVIT

(Steven D. Scroggs)

STATE OF FLORIDA)

COUNTY OF Pasco)

I hereby certify that on this 23rd day of July, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Steven D. Scroggs, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatories numbers 13-22 and co-sponsored number 35 from OPC's third set of interrogatories to Florida Power & Light Company (Nos. 13-35) in Docket No. 150009-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 23rd day of July, 2015.

Notary Public
State of Florida, at Large

My Commission Expires:
March 17, 2017

ANNETTE L. GIVENS
My Comm. Exp. Mar 17, 2017
NO. EE 834124
NOTARY PUBLIC
STATE OF FLORIDA

38A

FPL's Responses to OPC's Third Set of Interrogatories (No[redacted] 18)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 38A
PARTY: STAFF RE: FPL
DESCRIPTION: Steven D. Scroggs
John J. Reed

Q.
Please refer to page 6, lines 9-10 of Witness Scroggs rebuttal testimony:

a. At what "stage" would Witness Scroggs expect "actual, binding bids" could be obtained?

b. Does Witness Scroggs suggest that the Commission should approve proceeding to the next phase of "preconstruction" for the project before these bids are obtained?

A.
a. Upon receipt of a COL and Commission approval to proceed, FPL will begin preconstruction work, as that term is used in F.S. 366.93(3)(c). This preconstruction work is anticipated to include a series of engineering studies and plans that will support bid specifications or other relevant and detailed documentation. This documentation will describe the scope of work, firm schedule milestones and outline terms and conditions for the execution of the work. With this as a foundation, FPL will be able to obtain actionable bids for portions of the work which meet the requirements for competitive bidding.

b. Yes. As discussed on pages 6-8 of Witness Scroggs rebuttal testimony, meaningful bids cannot be obtained without the requisite defining information that will be produced following receipt of the COL. This is not meant to imply that the Commission is left in a position of making uninformed decisions. On the contrary, FPL expects that the Commission requires the best information available for each decision it makes. Accordingly, FPL is performing Initial Assessments to support approval to proceed to "the next phase of 'preconstruction'".

39

FPL's Responses to Miami's First Set of Interrogatories (No. 11)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 39
PARTY: STAFF RE: FPL
DESCRIPTION: Steven D. Scroggs

Q.

In the event that FPL were to conclude that proceeding with Turkey Point was not desirable, please explain and provide a numerical example of the annual recovery of investment to date that FPL would request. For the example please assume that the decision to not proceed is finalized, recovery was approved as of 12/31/20, and that recovery begins 1/1/21.

A.

The question does not appear to reflect the Nuclear Cost Recovery (NCR) process as it stands today. Per NCR Rule 25-6.0423, Section 7(a), "in the event the utility elects not to complete or is precluded from completing construction of the power plant, the utility shall be allowed to recover all prudent site selection costs, pre-construction costs and construction costs." The Rule further clarifies in Section 7(b), that the amount recovered pertains to unrecovered costs remaining at the time of "abandonment" (as well as future payment of all outstanding costs and any other prudent and reasonable exit costs). FPL has applied for and been granted contemporaneous recovery of costs associated with site selection and pre-construction of the Turkey Point Units 6 & 7 project in annual filings. So in the event that FPL were to conclude that it should not proceed with Turkey Point 6 & 7 in the near term, FPL expects there to be no balance of these costs subject to future recovery, regardless of when recovery is hypothesized to begin.

AFFIDAVIT

Steven D. Scroggs

STATE OF FLORIDA)

COUNTY OF Palm Beach)

I hereby certify that on this 9th day of June, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Steven D. Scroggs, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory numbers 4, 6, 7, 9-13, 17 from the City of Miami's First Set of Interrogatories to Florida Power & Light Company (Nos. 1-18) in Docket No. 150009-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 9th day of June, 2015.

HEATHER P. MELIGONIS
MY COMMISSION # FF 042785
EXPIRES: December 6, 2017
Bonded Thru Notary Public Underwriters

Heather P. Meligonis
Notary Public
State of Florida, at Large

My Commission Expires:
12/6/17

40

FPL's Responses to Miami's Second Request for Production of Documents (No. 11)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 40
PARTY: STAFF RE: FPL
DESCRIPTION: FPL's Responses to Miami's Second Request for Production of Documents

Q.

Please reference FPL rebuttal testimony of Steven R. Sim, page 9, lines 21-23, and page 10, lines 1-14. Please provide all material and communications provided by ICF with respect to carbon price forecasts and also escalation of carbon prices after the year 2030.

A.

FPL received projected environmental compliance cost forecasts from ICF in the years 2007, 2008, 2010, 2011, and 2012 which have been used in the Turkey Point 6 & 7 project determination of need and annual nuclear cost recovery dockets. These forecasts provide projected forecasted $/ton values in terms of both real and nominal dollars for various time periods ranging from 2030-2064. Those forecast documents are being provided. There were also discussions between FPL and ICF regarding ICF's view of how to extend the forecasts into later years. However, these discussions were verbal and there are no such ICF documents.

The forecast documents provided in response to this request are confidential and will be made available for inspection at FPL's Tallahassee Office at 215 South Monroe Street, Suite 810, Tallahassee, Florida, during regular business hours, 8 a.m. to 5 p.m., Monday through Friday, upon reasonable notice to FPL's counsel.

Q.

Please reference FPL rebuttal testimony of Steven R. Sim, page 9, lines 21-23, and page 10, lines 1-14. Please provide all material and communications provided by ICF with respect to carbon price forecasts and also escalation of carbon prices after the year 2030.

A.

Please note that the values provided by ICF are those reflected on tabs labeled as "ICF" (or on the tab labeled "CO2" in the 2010 Emission Prices file) through the year 2030.

41

Miami's Responses to Staff's First Set of Interrogatories (Nos. 1 and 2) See Staff Exhibit CD for Excel Files re: No. 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 41
PARTY: STAFF RE: FPL
DESCRIPTION: Eugene T. Meehan

Q.

Please refer to page 13, lines 6-8. Please provide a calculation (showing all steps) of the "$1400 per KW to over $ 2600 per KW" range presented in this section of Testimony.

A.

The attached EXCEL file, entitled CO2iMPACTROG.xlsx, contains the calculations. Columns G and L show the assumed pro-rated carbon reductions based upon the 290 million lifetime carbon reduction stated on page 1 of Exhibit ROB-1. Columns C, D, and E show the annual nominal carbon prices for scenarios ENV1, ENV 2 and ENV 3. Columns H,I, J and M,N,O multiply the carbon prices for each year by the annual carbon reduction and the discount rate from Column B which discounts to end of year 2015 dollars using FP&L's 7.51% discount rate. The values in those columns are summed over 40 or 60 years as appropriate. The result is for each scenario is a present value of revenue requirement impact for carbon costs in 2015 present value dollars shown rounded in Row 80. In row 82, the present value impacts are multiplied by .485 to convert to break even per KW costs. This factor of .485 is taken from Exhibits ROB-5 and ROB-6. This factor is the relationship between the present value of revenue requirement differences, with and without Turkey Point Units 6 and 7, and the per KW break even costs. It is consistent across all scenarios. While .485 was used in the calculations the actual ratio is closer to .488 which would increase the impact on break even cost. Also, note that in order to be conservative the annual carbon reductions were all based on the 290 million tons from the 40 year scenario. Exhibit ROB-1 shows a proportionally higher carbon reduction of 481 million tons for the 60 year scenario. This would increase the top end of the $2600 per KW range if it had been used.

Q.

Please refer to page 13, lines 19-21.

a. Which of FPL's ENV scenarios is the Witness referring for the "by a factor of over 20 times" figure presented in this section of testimony?

b. What rate of inflation is being referenced where the witness states "reaching up to eight times that which would result from inflation alone."

A.

a. All the scenarios show this same relationship because the scenarios are proportional over all years. The attached file CO2iMPACTROG.xlsx shows the annual carbon prices supplied by FP&L for each scenario and the calculation of the over 20 times factor in Row 5.

b. This statement is based on a 2.5% rate of inflation. The attached file CO2iMPACTROG.xlsx also shows this calculation in Row 10. The stated value of eight is rounded from 7.8. Note that FP&L has used inflation estimates of 2% and 2.5%. If 2% were used the increases would be reaching up to 9.5 times that which would result from inflation alone.

AFFIDAVIT

STATE OF UTAH)

COUNTY OF SUMMIT)

I hereby certify that on this 6th day of July, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Eugene T. Meehan, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory number(s) 1-2 from STAFF'S FIRST SET OF INTERROGATORIES TO CITY OF MIAMI (NOS. 1-2) in Docket No(s). 150009-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 6th day of July, 2015, by Eugene Thomas Meehan.

Eugene Thomas Meehan

Stefanie Bowen
Notary Public
State of Utah

My Commission Expires: 4/8/2019

STEFANIE BOWEN
NOTARY PUBLIC • STATE OF UTAH
My Commission Expires April 8, 2019
COMMISSION NUMBER 682789

150009 - Miami's response to Staff INT No. 1 - co2iMPACTROG

150009 - Staff's 1st POD No. 6 - Table Staff - 6a

150009 - Staff's 1st POD No. 6 - Table Staff - 6b

150009 - Staff's 2nd INTs No. 13 - Attachment No. 1

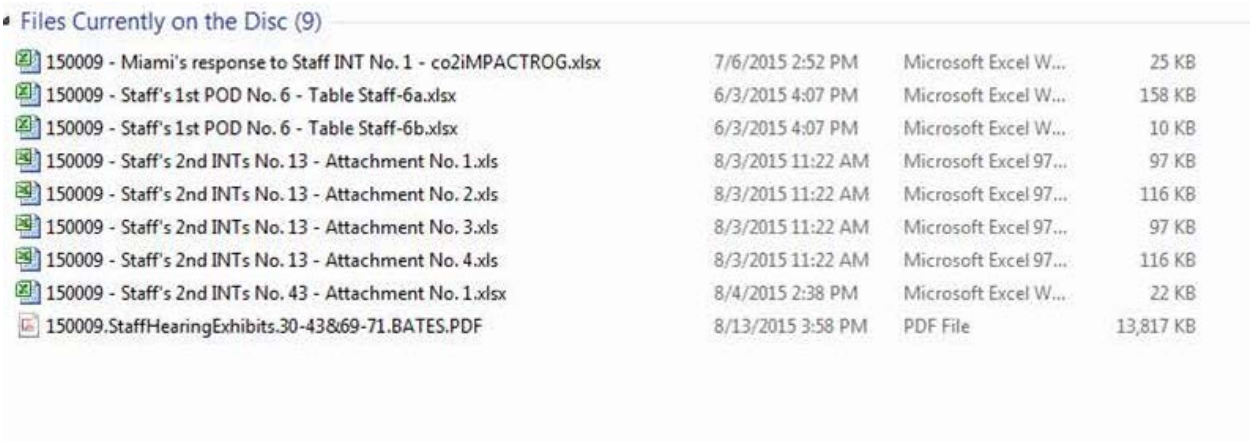
150009 - Staff's 2nd INTs No. 13 - Attachment No. 2

150009 - Staff's 2nd INTs No. 13 - Attachment No. 3

150009 - Staff's 2nd INTs No. 13 - Attachment No. 4

150009 - Staff's 2nd INTs No. 43 - Attachment No. 1

150009.StaffHearingExhibitss.30-43&69-71.BATES



42

Miami's Responses to Staff's First Request for Production of Documents (Nos. 1 and 2)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 42
PARTY: STAFF RE: FPL
DESCRIPTION: Miami's Responses to Staff's First Request for Production of Documents

Q.

Please provide any documentation that supports the City of Miami's response to Staff's First Set of Interrogatories to City of Miami, No. 2(b).

A.

The inflation rate is equivalent to the 2.5% assumed in FP&L's analysis for O&M escalation as shown on the system input tab of FP&L's detailed work sheets. No other documents were utilized.

Q.

Please provide any forecasted Carbon Dioxide pricing schedules (alternative to Florida Power & Light's) relied upon for formulating COM Witness Meehan's Direct Testimony in this Docket.

A.

Mr. Meehan did not review alternative CO_2 pricing schedules. He is testifying with respect to what he considers the apparent facial implausibility of FP&L's forecast and the need for a thorough investigation of this issue.

43

Late-filed exhibit #9 to the deposition of Steven D. Scroggs

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 43
PARTY: STAFF RE: FPL
DESCRIPTION: Steven D. Scroggs

LATE FILED DEPOSITION EXHIBIT NO. 9

TO THE DEPOSITION OF STEVEN SCROGGS

DOCKET NO. 150009-EI

New Nuclear Update

Steve Scroggs Bill Maher Steve Reuwer

February 18, 2015

Proprietary & ~~Confidential~~ Information

Project schedule review resulted in new COD dates of June 2027 and June 2028

Summary Issues

Area	Topics	Key Points
SCA Appeal	Appellant briefs	• Appellant briefs received January 23, no surprises • FPL and FDEP Reply Briefs in May • 3rd DCA Tribunal will hear case in Q3 2015, decision in Q4 • Supreme Court Appeal possible following DCA decision
Land Exchange	Negotiating Exchange Agreement	• Draft Exchange Agreement negotiated, minor close out items remain • New ENP Superintendent, NPS Senior Management and DOI Secretary supportive • Expect Final EIS to be published in Q2 2015, with execution of Exchange Agreement to follow
COLA Schedule	Environmental Topics	• Draft EIS in Federal Register • Public meeting scheduled in April
Project Schedule	Initial Assessments	• Developed scope of work for preliminary study areas • First RFP issued to qualified vendors; award 2nd QTR • $5million total through 2016 (CWIP account)

Proprietary & Confidential Information

FPL

Agenda

- **Specific Topics**
  - Initial Assessments
- **Project Update**
  - 2015 Budget Spend Curve
  - 2014 Projection to Actual Walk
  - 2015 Projection to Current Estimate Walk
  - Key Events/Future Activities

Proprietary ~~& Confidential~~ Information

FPL

Turkey Point 6 & 7

Florida Power & Light Company

UPDATED PROJECT SCHEDULE

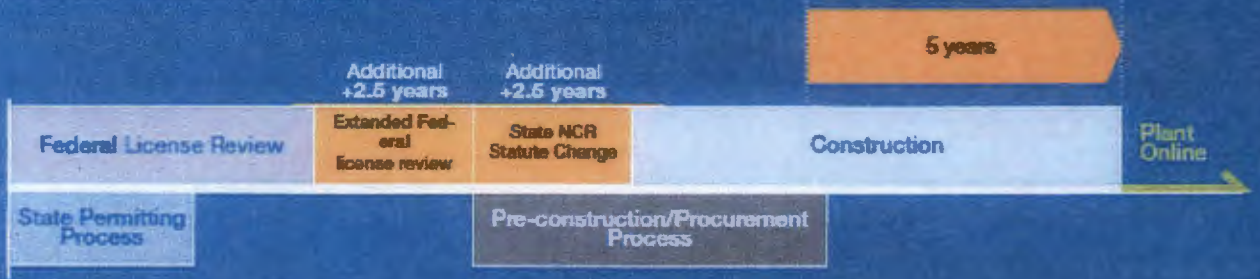
Prior to 2013 changes to Florida Nuclear Cost Recovery Law, pre-construction work could take place in parallel with federal licensing.



Post-2013

Combination of Florida law change & NRC review schedule drive project schedule change

After 2013, pre-construction work must follow completion of Federal licensing, which has been extended by 2 ½ years. This results in a longer project schedule.



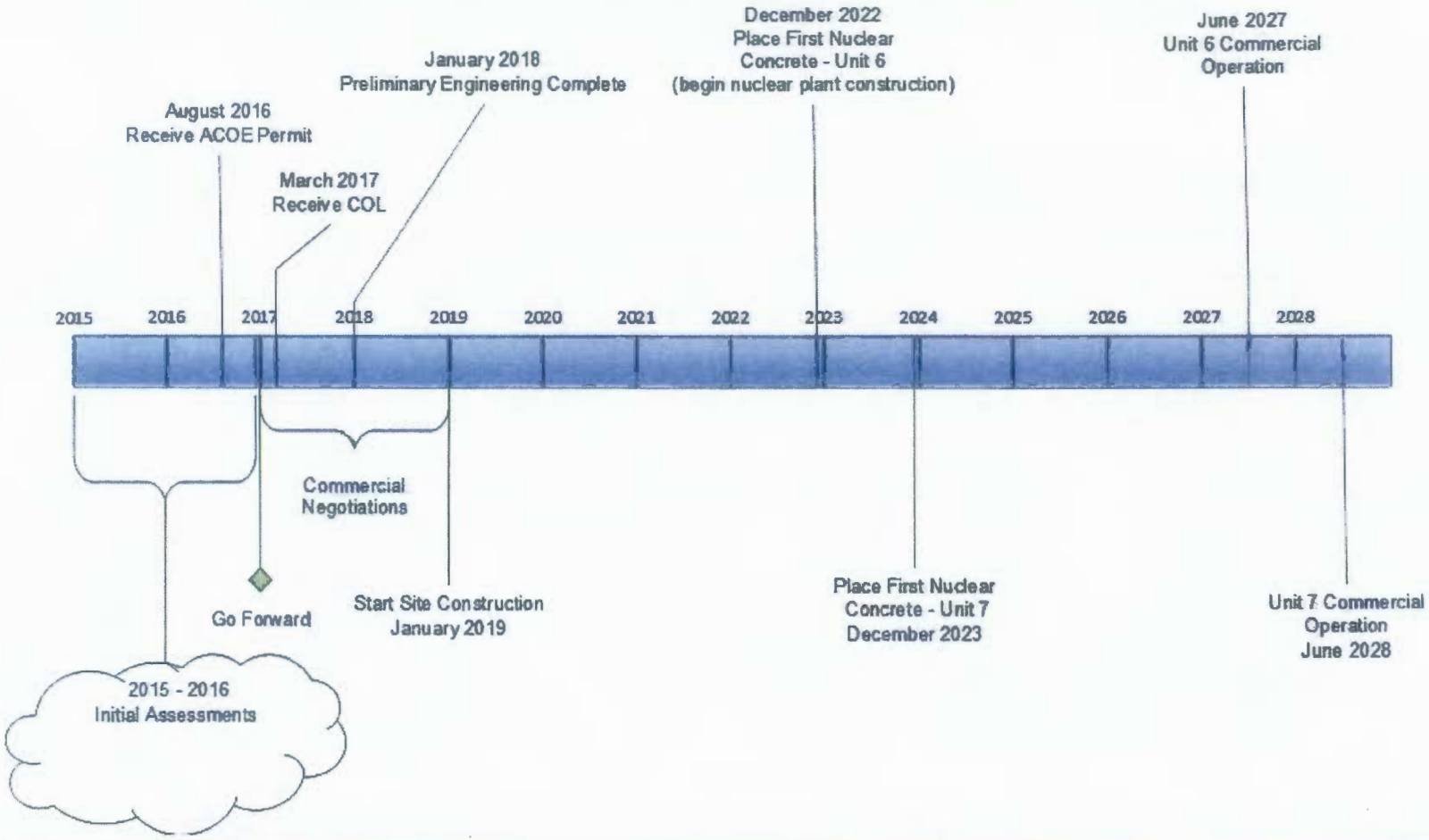
Draft exhibit for March testimony to communicate schedule shift

Proprietary ~~& Confidential~~ Information

FPL

150009 Hearing Exhibits - 00151

Level 1 Baseline Schedule Summary



Initial Assessments will be performed in 2015 and 2016 to improve schedule detail and to support decision to Go Forward

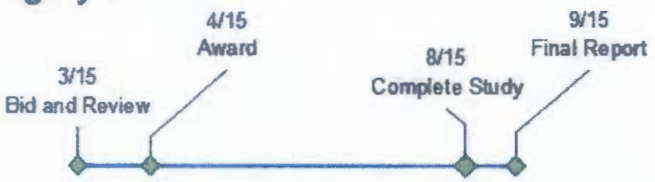
Proprietary & ~~Confidential~~ Information

FPL

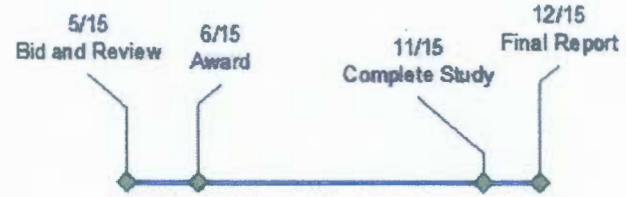
Initial Assessments Schedule



Category A



Category B



Category C



Category D



Proprietary & Confidential Information

Initial Assessments

- **Category A**
  - Master site development plan, offsite facilities/laydown plan
  - Module/sub module assembly and logistics plan
  - Assessment of heavy lifting equipment and options
- **Category B**
  - Island Retaining Wall conceptual development
  - Island backfill sequence, evaluate fill supply, delivery methods and rates
  - Update level 2 pre FNC-6 schedule
- **Category C**
  - Dewatering plan development
  - Slurry Wall execution plan
  - Concrete- aggregate supply, transportation, storage

Categories reflect similar/sequential tasks for bidding work scopes

Proprietary & ~~Confidential~~ Information

FPL

Initial Assessments

- **Category D**
  - Retaining wall material, batch plant location/design study
  - Evaluate non-critical path work on FNC-6 schedule
  - Site Surveying specification
  - Cooling towers, circulating water system design layout
  - Road, Bridges, Potable water pipeline, transmission construction plan for 359th street access
  - Reclaimed Water Treatment Plant construction plan
  - Underground Injection Control construction plan
  - Radial Collector Wells construction plan
  - Reclaimed Water pipeline construction plan

Categories reflect similar/sequential tasks for bidding work scopes

Proprietary & ~~Confidential~~ Information

FPL

For each phase of the initial assessment work, the following contracting options will be evaluated to determine the best approach

Initial Assessments Contracting Strategy

- **Contracting Options**
  - Engineer of Choice only (EOC)
  - Competitive bidding (incl EOC)-all studies
  - Sole source specific priority item-competitive bid all remaining studies
  - Single Source, appropriate to specific study scope
- **Commercial Options**
  - Firm Price (Lump Sum)
  - Time and Materials – Not To Exceed
  - Combination (study specific)

Category A initial assessments are being competitively bid with four qualified vendors

Proprietary & ~~Confidential~~ Information

FPL.

Agenda

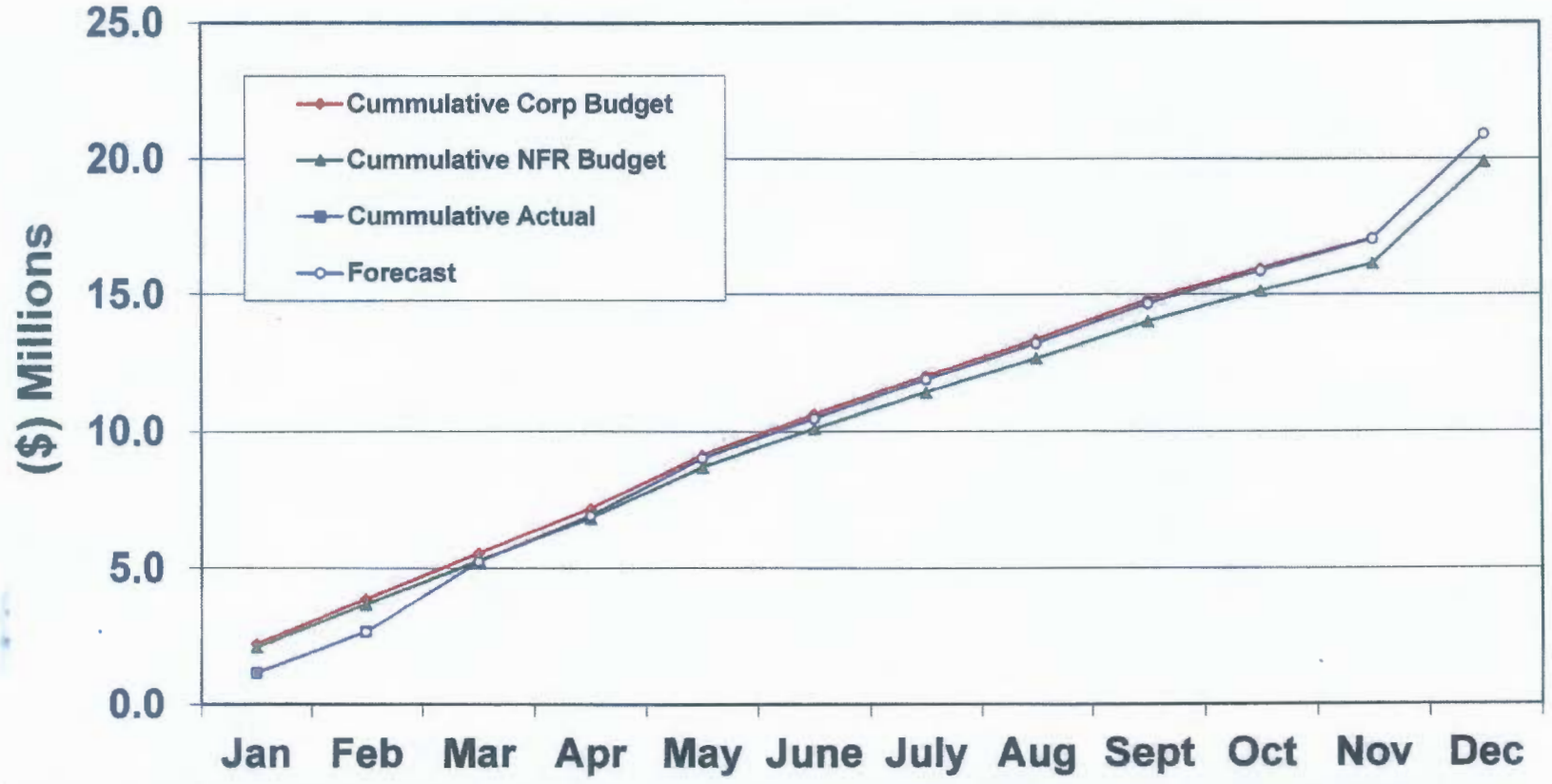
- **Specific Topics**
  - Initial Assessments
- **Project Update**
  - 2015 Budget Spend Curve
  - 2014 Projection to Actual Walk
  - 2015 Projection to Current Estimate Walk
  - Key Events/Future Activities

Proprietary & ~~Confidential~~ Information

FPL

New Nuclear Construction – Pre-Construction 2015 Cumulative Spend (Excludes AFUDC)

2015 Budget Spend Curve



NRC activities will be focus of 2015 costs

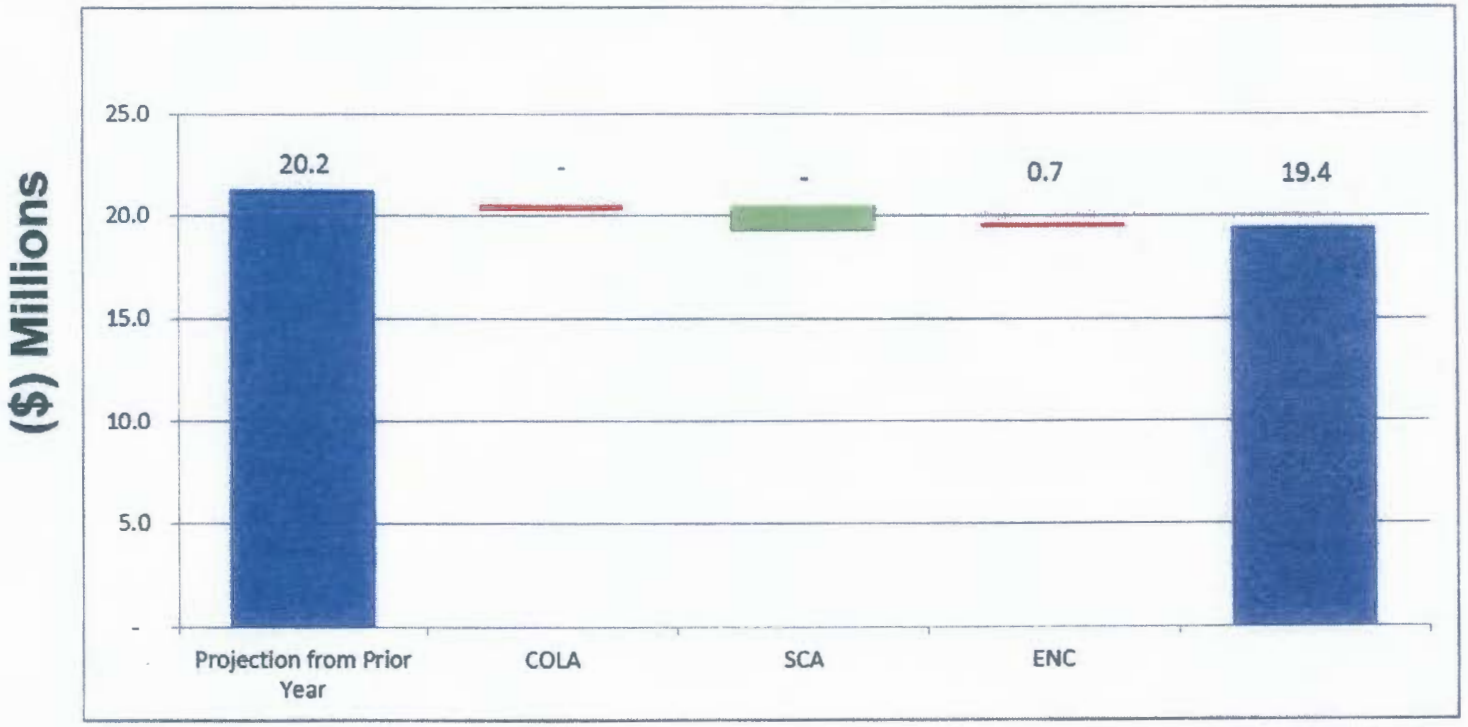
NFR = Nuclear Filing Requirements

Proprietary & ~~Confidential~~ Information

FPL

2014 actual costs were slightly below original projection

2014 Projection to Actual Walk



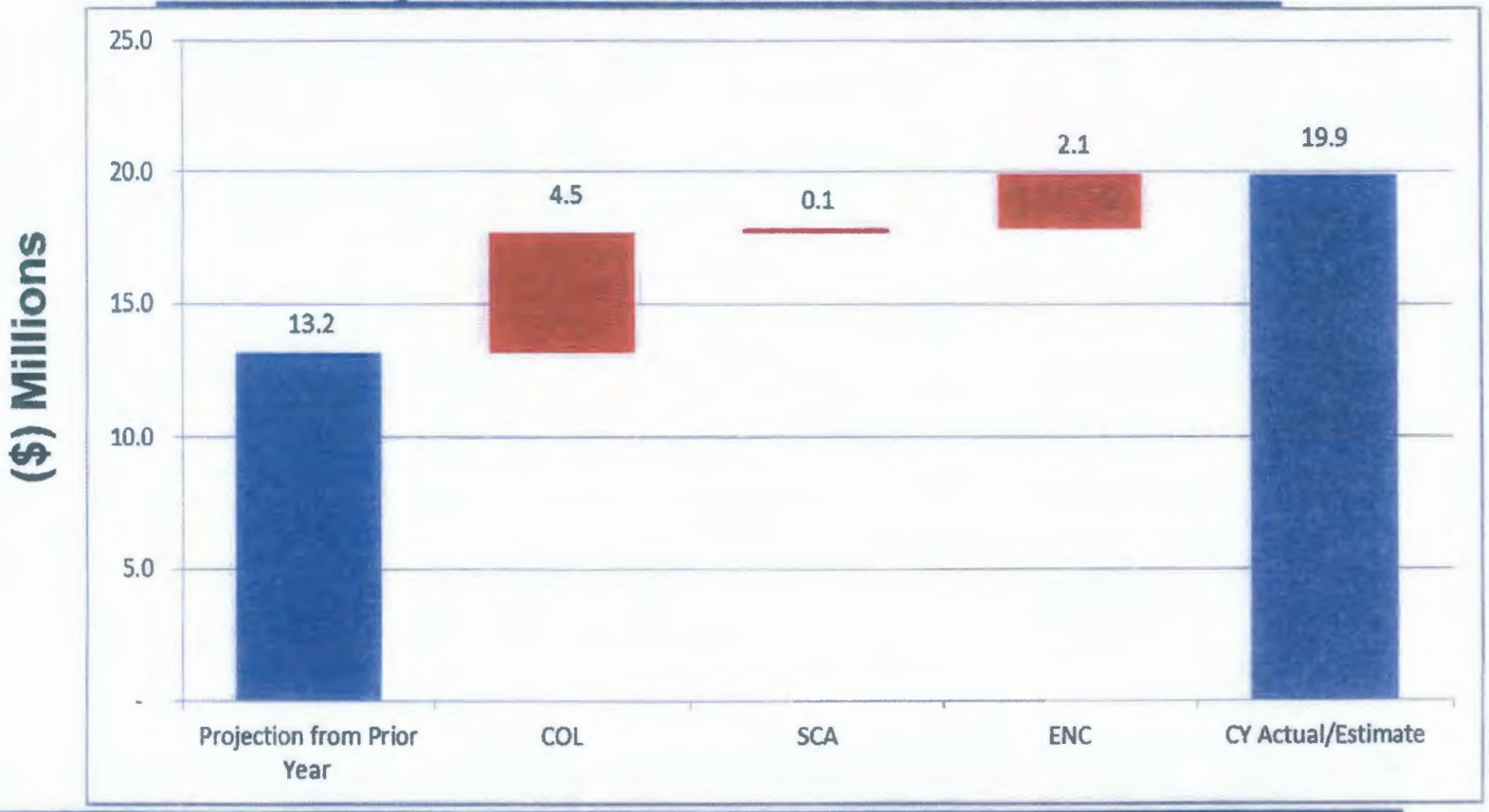
Reduction due to lower permitting expenses and legal services associated with SCA filing

Proprietary & ~~Confidential~~ Information

FPL

2015 increased estimate due to COL and Engineering challenges

2015 Projection to Current Estimate Walk



Major drivers are Bechtel/NRC fees (COLA) and APOG fees (Engineering)

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Upcoming and recent events for the project

Key Events

- **NRC COLA**
  - Draft NRC EIS – Feb 2015
  - Final NRC EIS – Feb 2016
  - Final SER – Oct 2016
  - COL Decision – Dec 2016 - early 2017 (estimated)
- **Corps Wetlands Permit**
  - Public Notice of Permit Application – Q1 2015
- **Site Certification**
  - Appellant Briefs – Jan 2015
  - Oral Arguments – Q3 2015
- **Land Exchange**
  - Draft Exchange Agreement – Q1 2015
  - Land Exchange executed – Q3 2015

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New Nuclear Update

Steve Scroggs Bill Maher Steve Reuwer

May 4, 2015

Proprietary & ~~Confidential~~ Information

150009 Hearing Exhibits - 00162

Project schedule review resulted in new COD dates of June 2027 and June 2028

Summary Issues

Area	Topics	Key Points
SCA Appeal	Appellant briefs	• FPL and FDEP Reply Briefs in May • 3rd DCA Tribunal will hear case in Q4 2015, decision in 2016 • Supreme Court Appeal possible following DCA decision
Land Exchange	Exchange Agreement	• Language agreed supporting exchange • Expect Final EIS to be published in Q3 2015, with execution of Exchange Agreement to follow
COLA	Environmental and Safety	• Public meetings on draft EIS held April • Public comment meetings well attended • RAI completion on track for Q2 2015
Project Schedule	Initial Assessments	• First Initial Assessment work released • Preparing Second RFP to qualified vendors; award Q2 • $5 million total through 2016 (CWIP account)

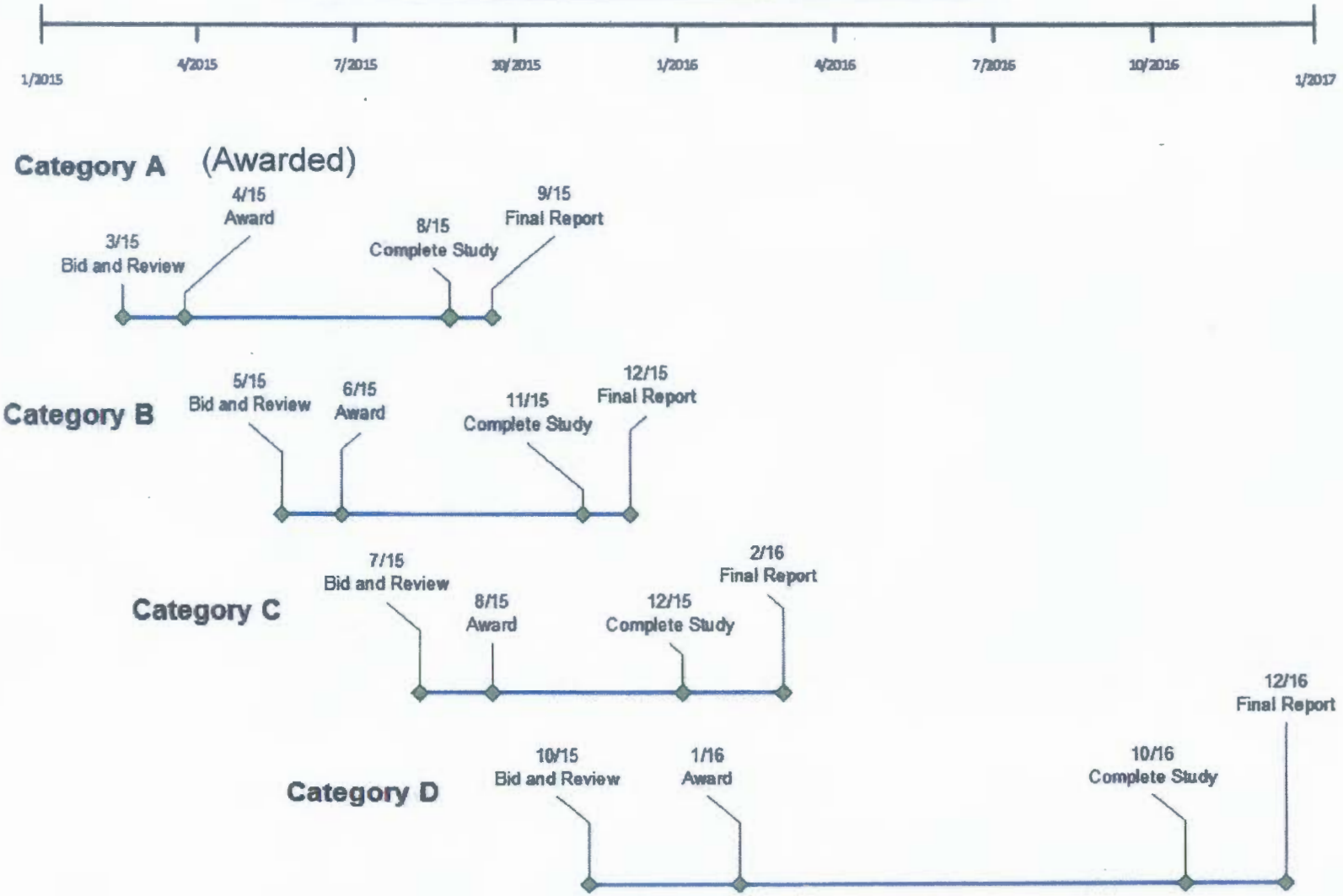
Proprietary & Confidential Information

Agenda

- **Specific Topics**
  - Initial Assessments schedule
- **Project Update**
  - COL Activities
  - Other Key Events
  - 2015 Budget Spend Curve
- **Backup**
  - Initial Assessments

Proprietary & ~~Confidential~~ Information

Initial Assessments Schedule



Proprietary & ~~Confidential~~ Information

Agenda

- **Specific Topics**
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Upcoming and recent events related to COL

COL Activities

- **Environmental**
  - Public Comment Meeting – April 22/23
  - FPL submitting comments – May 22
- **Safety**
  - Public meeting requested – week of May 18
  - 5 RAIs remaining
  - Chapter status (19 total)
    - -- 9 - completed with no open items
    - -- 5 - no open questions, NRC action on chapter to complete
    - -- Balance - RAI and design change dependent
- **Legal**
  - Contentions

Progress being maintained for COL issuance in Q1 2017

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Upcoming and recent events for the project

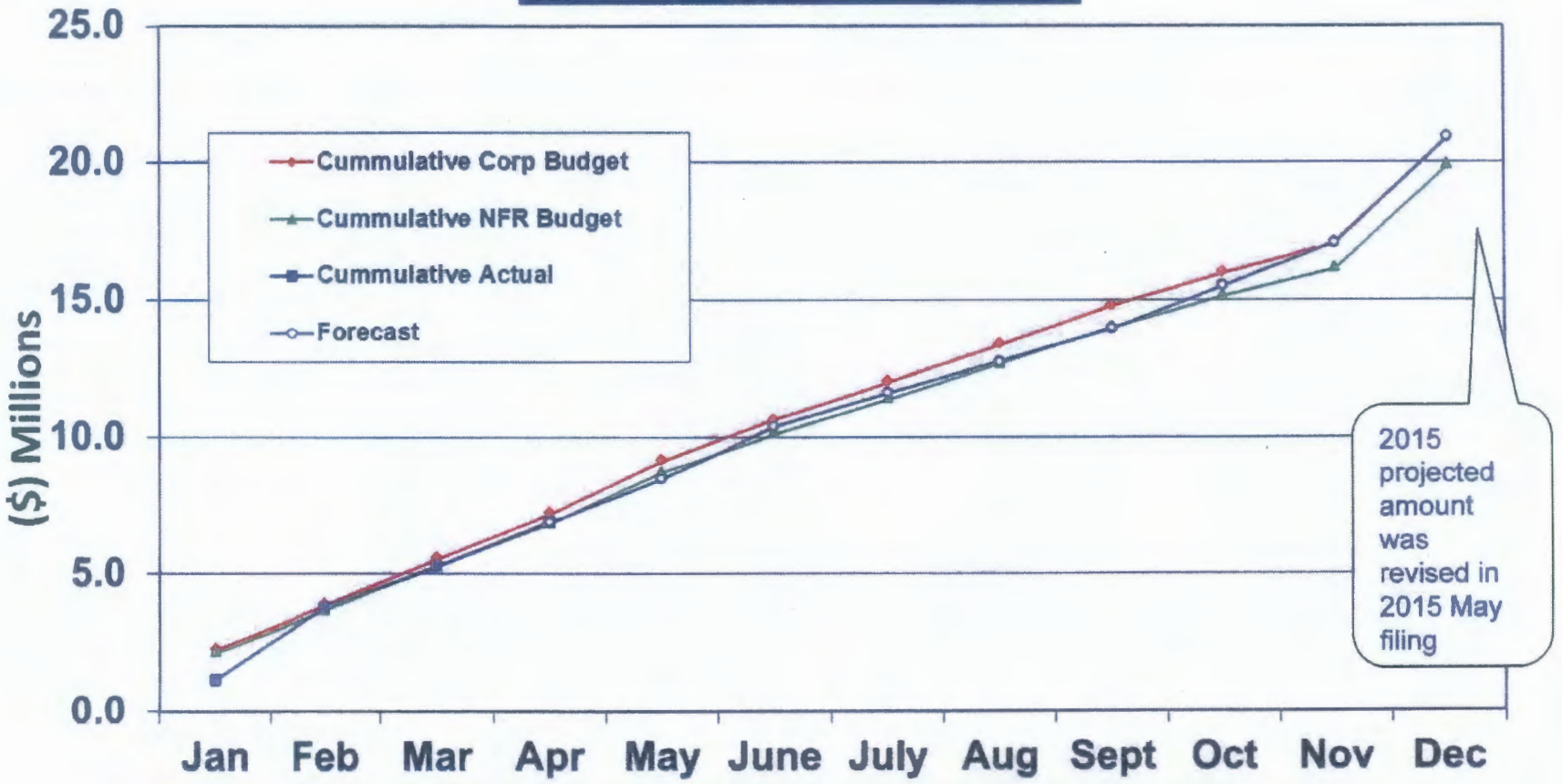
Other Key Events

- **Corps Wetlands Permit**
  - Public Notice of Permit Application – Q1 2015
- **Site Certification**
  - Appellant Briefs – Jan 2015
  - Oral Arguments – Q4 2015
- **Land Exchange**
  - Final EIS published – Q3 2015
  - Land Exchange executed – Q4 2015

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2015 budget includes completing NRC review process, Land Exchange, Site Certification Appeal, and Compliance

2015 Spend Curve



Remaining costs for PTN 6&7 licensing phase are currently projected at $19.6 M in 2015 and $22.2 M in 2016

NFR = Nuclear Filing Requirements

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Agenda

- **Specific Topics**
  - Initial Assessments schedule
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  - COL Activities
  - Other Key Events
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- **Backup**
  - Initial Assessments

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Initial Assessments

- **Category A (awarded)**
  - Master site development plan, offsite facilities/laydown plan
  - Module/sub module assembly and logistics plan
  - Assessment of heavy lifting equipment and options
- **Category B**
  - Island Retaining Wall conceptual development
  - Island backfill sequence, evaluate fill supply, delivery methods and rates
  - Update level 2 pre FNC-6 schedule
- **Category C**
  - Dewatering plan development
  - Slurry Wall execution plan
  - Concrete- aggregate supply, transportation, storage

Categories reflect similar/sequential tasks for bidding work scopes

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Initial Assessments

- **Category D**
  - Retaining wall material, batch plant location/design study
  - Evaluate non-critical path work on FNC-6 schedule
  - Site Surveying specification
  - Cooling towers, circulating water system design layout
  - Road, Bridges, Potable water pipeline, transmission construction plan for 359th street access
  - Reclaimed Water Treatment Plant construction plan
  - Underground Injection Control construction plan
  - Radial Collector Wells construction plan
  - Reclaimed Water pipeline construction plan

Categories reflect similar/sequential tasks for bidding work scopes

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FPL

EUGENE T. MEEHAN
INDEPENDENT CONSULTANT

Mr. Meehan is an Independent Consultant specializing in regulatory economics and electricity markets, power procurement, electric planning and asset and corporate transaction involving electric marketing, production, transmission and distribution. He has over thirty-five years of experience consulting with electric and gas utilities, regulators and governments and has testified as an expert witness before numerous state and federal regulatory agencies, as well as appeared in federal court and arbitration proceedings.

Mr. Meehan's practice concentrates on serving energy industry clients, with a focus on helping clients manage the transition from regulatory to more competitive environments. He has performed consulting assignments for over fifty large electric, gas, and combination utilities in the areas of retail access, regulatory strategy, strategic planning, financial and economic analysis, merger and acquisition advisory services, power contract analysis, market power and market definition, stranded cost analysis, power pooling, power markets and risk management, ISO and PX development, and costing and pricing. In addition, he has advised numerous utilities on power procurement issues and administered power procurements on behalf of utilities and regulators.

Mr. Meehan has experience leading advisory work on several major restructuring and unbundling assignments. These assignments were multi-year projects that involved integration of regulatory and business strategy, as well as development of regulatory filings associated with the recovery of stranded cost and rate unbundling.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 44
PARTY: CITY OF MIAMI (MIAMI) RE:
FLORIDA POWER & LIGHT (FPL)
DESCRIPTION: Eugene T. Meehan ETM-1

Education

Boston College, BA, Economics, *cum laude*
New York University (NYU), Graduate School of Business, completed core courses for the doctoral program.

Professional Experience

2015 - **Independent Consultant**

NERA Economic Consulting

1999-2014 Senior Vice President

1996-1999 Vice President

1973-1980 Senior Economic Analyst; Research Assistant

Deloitte & Touche Consulting Group

1994-1996 Principal

Energy Management Associates, Inc.

1980-1994 Vice President

Areas of Expertise

Restructuring/Stranded Cost Recovery

Mr. Meehan has directed several multi-year projects associated with restructuring and stranded cost recovery. These projects involved facilitating the development of an integrated regulatory and business strategy and formulating regulatory filings to accomplish strategy. As part of these assignments, Mr. Meehan facilitated sessions with senior management to set and track filing strategy. Clients include Public Service Gas & Electric and Baltimore Gas and Electric.

Unbundling/Generation Pricing

Mr. Meehan has formulated unbundling strategies, with a specialization in generation pricing. He has advised several utilities in standard offer pricing and has testified on shopping credits on behalf of First Energy and Baltimore Gas and Electric.

Power Procurement

Mr. Meehan has been involved in power procurement activities for a variety of utilities and regulatory agencies. He has advised utilities in developing and implementing evaluation processes for new generation, with the objective of achieving the best portfolio evaluation. He has helped regulators in Ireland and Canada design and implement portfolio evaluation processes. He has testified before FERC and state regulatory agencies on competitive power procurement. In addition, Mr. Meehan helped to design and implement the New Jersey BGS auction process.

Power Contracts

Mr. Meehan has extensive experience with power contracts and power contract issues. He has reviewed and testified on the three principal types of power contracts: integrated utility to integrated utility contracts, IPP to utility contract, and integrated or wholesale utility to distribution utility contracts. He has testified in power contracts disputes on behalf of Carolina Power and Light, Duke Power Company, Southern Company, Orange and Rockland Utilities, and Tucson Electric Power. He has also advised Oglethorpe Power Corporation in the reform of its wholesale contracts with its distributor cooperative members.

Retail and Wholesale Settlements

In addition to his expertise on power pooling issues, Mr. Meehan has significant experience with assignments related to the settlement process. He has focused on the issues of credit management as new entrants appear in retail and wholesale markets and has designed efficient specifications for retail settlement systems, including the use of load profiling, and examined the risk and cost allocation issues of alternative settlement systems.

Risk Management

Mr. Meehan has advised several large utilities on price risk management. These assignments have included evaluation of price management service offers solicited from power marketers in association with management of assets and entitlements, as well as provision of price managed service for various terms.

Marginal Costs

Mr. Meehan has provided comprehensive marginal cost analyses for over 25 North American Utilities. These assignments required detailed knowledge of utility operations and planning.

Power Supply and Transmission Planning

Mr. Meehan has advised electric utilities on economic evaluations of generation and transmission expansion. He has testified on the economics of particular investments, the prudence of planning processes, and the prudence of particular investment decisions. He has reviewed the economic and rate implications of several large nuclear plants and has testified before state and federal regulators with respect to nuclear economics and the prudence of nuclear investments.

Generation Strategy

Mr. Meehan has led NERA efforts on a client task force charged with developing an integrated generation asset/power marketing strategy.

Power Pooling

Mr. Meehan has in-depth working knowledge of the operating, accounting, and settlement processes of all United States power pools and representative international power pools. He has provided consulting services for New York Power Pool members on a continuous basis since 1980, advising the Pool and its members on production cost modeling, transmission expansion, competitive bidding and reliability, and marginal generating capacity cost quantification. In NEPOOL, he has quantified the benefits of continued utility membership in the Pool and the impact of the Pool settlement process on marginal cost. He has worked with a major PJM utility to explore the impact of PJM restructuring proposals upon generating asset valuation and examine the implications of alternative restructuring proposals. He has consulted for Central and Southwest Corporation, Entergy, and Southern Company on issues that involved the internal pooling arrangements of the utility operating companies of those holding companies, as well as for various utilities on the impact of pooling arrangements on strategic alternatives.

Representative Assignments

Worked with Public Service Electric & Gas Company (PSE&G) to direct a three year NERA advisory effort on restructuring. Facilitated a two-day senior management meeting to set regulatory strategy in 1997. Throughout 1997 and 1998, worked over half time at PSE&G to help implement that strategy and advised on testimony preparation, cross-examination, and briefing. Also advised PSE&G on business issues related to securitization, energy settlement and credit requirements for third party suppliers. During 1999, advised PSE&G during settlement negotiations and litigation of the settlement. PSE&G achieved a restructuring outcome that involved continued ownership of generation by an affiliate and the securitization of $2.5 billion in stranded costs.

Worked on separate assignments for a large utility in the Northeast and a large utility in the Southeast, advising on the evaluation of risk management offers from power marketers. The assignments included reviewing proposals, attending interviews with marketers and providing advice on these, and the developing analytical software to evaluate offers.

Worked with government of Ontario beginning in 2004 to help design the RFP and economic evaluation process for the solicitation of 2500 Mw of new generating capacity. Supervising NERA's portfolio-based economic evaluation on behalf of the Ontario Ministry of Energy.

Testified on behalf of Pacific Gas & Electric Company before the FERC in a case benchmarking the PSA between the distribution utility and a soon-to-be-created generating company. This effort involved developing detailed expertise in applying the Edgar standard and a detailed review of DWR procurement during the western power crisis. In addition, this effort involved the review of more than 100 power contracts in the WECC.

Directed NERA's efforts, on behalf of the electricity regulator in Ireland, to design an RFP and implementation process for the purchase of 500 Mw of new generating capacity in 2003. NERA advised on the RFP, the portfolio evaluation method, and the power contract and also conducted the economic evaluation.

Reviewed the economic evaluation conducted by Southern Company Service for affiliated operating companies in connection with an RFP for over 2000 Mw of new generating capacity. Submitted testimony before FERC on behalf of Southern Company Service.

Worked with Baltimore Gas and Electric (BG&E) to conduct a one and one-half year consulting assignment that involved providing restructuring advice. The project began in March/April 1998 with senior management discussions and workshops on plan development and filing strategy. Advised BG&E in the development of testimony, rebuttal testimony, and public information dissemination. Worked to review and coordinate testimony from all witnesses and offered testimony on shopping credits and in defense of the case settlement. BG&E achieved a restructuring outcome enabling it to retain generation ownership. As part of this assignment, advised BG&E on generation valuation and unregulated generation business strategy.

Directed the efforts of a large Southeastern utility to develop a short-term power contract portfolio and to evaluate the relative value of power options, forwards, and unit contracts to determine the optimal mix of instruments to manage price risk.

Testified for XCEL Energy on the use of competitive bids for new generation needs. Examined whether XCEL was prudent not to explore a self-build plan and the reasonableness of relying on ten-year or shorter contracts as opposed to life-of-facility contracts, in order to meet needs and facilitate a possible future transition to competition. This project addressed the comparability of fixed bids to rate base plant additions.

Advised and testified on behalf of First Energy in the Ohio restructuring proceeding on the issues of generation unbundling and stranded cost. Defended the First Energy shopping credit proposal.

Advised Consolidated Edison and Northeast Utilities on merger issues and testified in Connecticut and New Hampshire merger proceedings. Testimony focused on retail competition in gas and electric commodity markets.

Directed NERA's effort to train selected representatives of a major European power company in American power marketing and risk management practices. The project involved numerous meetings and interviews with power marketing firms.

Led NERA's effort to advise the New England ISO on the development of an RTO filing. Examined performance-based ratemaking for transmission and market operator functions.

Examined ERCOT power market conditions during the period of time from 1997 to 1999 and testified on behalf of Texas New Mexico Power Company for the prudence of its power purchase activity.

Advised a Midwestern utility on restructuring of a wholesale contract with an affiliate. Involved forecasting of the unbundled wholesale cost-of-service and market prices, as well as development of a regulatory strategy for gaining approval of contract restructuring and the transfer of generation from regulated to EWG states.

Performed market price forecasts for numerous utility clients. These forecasts have employed both traditional modeling and newly developed statistical approaches.

Examined the credit issues associated with the entry of new entities into retail and wholesale settlement market. These assignments involved a review of current Pool credit procedures, examination of commodity and security trading credit requirements, coordination with financial institutions, and recommendations concerning credit exposure monitoring, credit evaluation processes, and credit requirements.

Oversight of EMA's consulting and software team in designing and implementing the LOLP capacity payment, a portion of the UK wholesale settlement system.

Advised Oglethorpe Power Corporation in the reform of its contracts with its distribution cooperative members and the evolution of full requirement power wholesale power contracts into contracts that preserve Oglethorpe's financial integrity and are suitable for a competitive environment.

Developed long run marginal and avoided costs of natural gas service, as well as avoided cost methods and procedures. These costs have been used primarily for the analysis of gas DSM opportunities. Clients include Consolidated Edison Company, Southern California Edison Company, Niagara Mohawk Power Corporation, and Elizabethtown Gas Company.

Review of power contracts and testimony in numerous power contract disputes

Development of long run avoided costs of electricity service and avoided cost methods and procedures. These costs have been used to assess DSM and cogeneration, as well as to develop integrated resource plans. Clients include Public Service Company of Oklahoma, Central Maine Power Company, Duquesne Light Company, and the New York investor-owned utilities.

Advised Central Maine Power Company (CMP) on the development of a competitive bidding framework. This framework was implemented in 1984 and was the first of its kind in the nation. CMP adopted the framework outlined in EMA's report and won prompt regulatory approval.

Advised a utility in the development of an incentive ratemaking plan for a new nuclear facility. This assignment involved strategic analysis of alternate proposals and quantification of the financial impact of various ratemaking alternatives. Presented strategic and financial results in order to convince senior management to initiate negotiations for the incentive plan.

Advised and testified on behalf of the New York Power Pool utilities on the methodology for measuring pool marginal capacity costs. This work included development of the methodology and implementation of the system for quantifying LOLP-based marginal capacity costs.

Provided testimony on behalf of the investor-owned electric utilities in New York State, concerning the proper methodology to use when analyzing the cost-effectiveness of conservation programs. This methodology was adopted by the Commission and used as the basis for DSM evaluation in New York from 1982 through 1988.

Developed the functional design of a retail access settlement system and business processes for a major PJM combination utility. This design is being used to construct a software system and develop business procedures that will be used for retail settlements beginning January 1999.

Reviewed the power pool operating and interchange accounting procedure of the New York Power Pool, the Pennsylvania, New Jersey, Maryland Interconnection, Allegheny Power System, Southern Company, and the New England Power Pool as part of various consulting assignments and in connection with the development of production simulation software.

Summarized and analyzed the operational NEPOOL to examine the feasibility of incorporating NEPOOL interchange impacts with Central Maine and accounting procedure of the New England Power Pool Power Company's buy-back tariffs.

Developed and presented a two-day seminar delivered to electric industry participants in the UK (prior to privatization), outlining the structure and operation of power pools and bulk power market transactions in North America.

Benchmark analysis and FERC testimony of PGE's proposed twelve-year contract between PG&E and Electric Gen LLC (contract value in excess of $15 billion).

Responsible for NERA's overall efforts in advising New Jersey's Electric Distribution Companies on the structuring and conduct of the Basic Generation Service auctions (the 2002 auction involved $3.5 billion, and the 2003 and 2004 auctions involved over $4.0 billion).

Publications, Speeches, Presentations, and Reports

Capacity Adequacy in New Zealand's Electricity Market, published in *Asian Power*, September 18, 2003

Central Resource Adequacy Markets For PJM, NY-ISO AND NE-ISO, a report written February 2004

Ex Ante or *Ex Post*? Risk, Hedging and Prudence in the Restructured Power Business, The Electricity Journal, April 2006

Distributed Resources: Incentives, a white paper prepared for Edison Electric Institute, May 2006

Restructuring Expectations and Outcomes, a presentation presented at the Saul Ewing Annual Utility Conference: The Post Rate Cap and 2007 State Regulatory Environment, Philadelphia, PA, May 21, 2007

Making a Business of Energy Efficiency: Sustainable Business Models for Utilities, prepared for Edison Electric Institute, August 2007

Perspectives on Ownership Issues for Traditional Generating & Alternative Resources: Should we allow utilities back in the market or limit ownership to merchants? A presentation presented at the Energy in the Northeast Conference sponsored by Law Seminars Intl., October 18, 2007

Restructuring at a Crossroads, presented at Empowering Consumers Through Competitive Markets: The Choice Is Yours, Sponsored by COMPETE and the Electric Power Supply Association, Washington, DC, November 5, 2007

*Competitive Electricity Markets: The Benefits for Customers and the Environmen*t, a white paper prepared for COMPETE Collation, February 2008

The Continuing Rationale for Full and Timely Recovery of Fuel Price Levels in Fuel Adjustment Clauses, The Electricity Journal, July 2008

Impact of EU Electricity Competition Directives on Nuclear Financing presented to: SMI – Financing Nuclear Power Conference, London, UK, May 20, 2009

Using History As A Guide, a presentation presented at the Electric Power Research Institute (EPRI) Conference: Electricity Pricing Structures for the 21st Century, July 14 – 15, 2011, Nashville, TN

Testimony

Forums

Arkansas Public Service Commission

Federal Energy Regulatory Commission

Florida Public Service Commission

Maine Public Utilities Commission

Minnesota Public Service Commission

Nevada Public Service Commission

New York Public Service Commission

Nuclear Regulatory Commission – Atomic Safety and Licensing Board

Oklahoma Public Service Commission

Public Service Commission of Indiana

Public Utilities Commission of Ohio

Public Utilities Commission of Nevada

Public Utilities Commission of Texas

Public Utilities Commission of New Hampshire

United States District Court

United States Senate Committee on Energy and Natural Resources

Various arbitration proceedings

Clients

American Electric Power Company

Arkansas Power & Light Company

Baltimore Gas & Electric

Carolina Power & Light Company

Central Maine Power

Consolidated Edison Company of New York, Inc.

Dayton Power and Light Company

Florida Coordinating Group

Houston Lighting & Power Company

Minnesota Power and Light Company

Nevada Power Company

Niagara Mohawk Power Corporation

Northern Indiana Public Service Company

Oglethorpe Power Corporation

Pacific Gas and Electric Company

Power Authority of the State of New York

Public Service and Electric Company

Public Service Company of Oklahoma

Sierra Pacific Power Company

Southern Company Services, Inc.

Tucson Electric Power Company

Texas-New Mexico Power Company

Recent Expert Testimony and Expert Reports

Supplemental Testimony on behalf of Texas-New Mexico Power Company, Docket No. 15660, September 5, 1996.

Direct Testimony on behalf of Long Island Lighting Company before the Federal Energy Regulatory Commission, September 29, 1997.

Rebuttal Testimony on behalf of Texas-New Mexico Power Company, SOAH Docket No. 473-97-1561, PUC Docket No. 17751, March 2, 1998.

Prepared Testimony and deposition testimony on behalf of Central Maine Power Company, United Stated District Court Southern District of New York, 98-civ-8162 (JSM), March 5, 1999.

Prepared Direct Testimony Before the Public Service Commission of Maryland on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, June 1999.

Rebuttal Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, March 22, 1999.

NORCON Power Partners LP v. Niagara Mohawk Energy Marketing, before the United States District Court, Southern District of New York, June 1999.

Prepared Supplemental Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, July 23, 1999.

Prepared Supplemental Reply Testimony Before the Maryland Public Service Commission, on behalf of Baltimore Gas & Electric Company, PSC Case Nos. 8794/8804, August 3, 1999.

Direct Testimony on behalf of Niagara Mohawk, Before the New York State Public Service Commission, PSC Case No. 99-E-0681, September 3, 1999.

Rebuttal Testimony on behalf of Niagara Mohawk, PSC Case No. 99-E-0681 Before the New York State Public Service Commission, November 10, 1999.

Arbitration deposition on behalf of Oglethorpe Power Corporation, last quarter of 1999.

Direct Testimony Before the Public Utilities Commission of Ohio on behalf of FirstEnergy Corporation, Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company, Case No. 99-1212-EL-ETP re: Shopping Credits.

Direct Testimony on behalf of Niagara Mohawk, Before the New York State Public Service Commission, PSC Case No. 99-E-0990, February 25, 2000.

Testimony on behalf of Consolidated Edison Company of New York, Inc., State of Connecticut, Department of Public Utility Control, Docket No.: 00-01-11, April 28, 2000 and June 30, 2000.

Testimony on behalf of Texas-New Mexico Power Company, Fuel Reconciliation Proceeding before the Texas PUC, June 30, 2000.

Testimony on behalf of Consolidated Edison Company of New York, Inc., Before the New Hampshire Public Service Commission, Docket No.: DE 00-009, June 30, 2000.

Rebuttal Testimony Before the Public Utilities Commission of the State of Colorado, Docket No. 99A-549E, November 22, 2000.

Testimony Before the Public Utilities Commission of the State of Colorado, Docket No. 99A-549E, January 19, 2001.

DETM Management, Inc. Duke Energy Services Canada Ltd., And DTMSI Management Ltd., Claimants vs. Mobil Natural Gas Inc., And Mobil Canada Products, Ltd., Respondents. American Arbitration Association Cause No. 50 T 198 00485 00, August 27, 2001.

State of New Jersey Board of Public Utilities, In the Matter of the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act of 1999, Before President Connie O. Hughes, Commissioner Carol Murphy on Behalf of the Electric Distribution

Companies (Public Service Electric and Gas Company, GPU Energy, Consolidate Edison Company and Conectiv) Docket No.: EX01050303, October 4, 2001.

Direct Testimony Before the Federal Energy Regulatory Commission on behalf of Pacific Gas and Electric Company, Docket No.: ER02-456-000, November 30, 2001.

Fourth Branch Associates/Mechanicville vs. Niagara Mohawk Power Corporation, January 2002 (Expert Report).

Arbitration Deposition on behalf of Oglethorpe Power Corporation, March 2002.

Direct Testimony and Deposition Testimony Before the Federal Energy Regulatory Commission on behalf of Electric Generation LLC in Response to June 12 Commission Order, Docket No.: ER02-456-000, July 16, 2002.

Rebuttal Testimony Before the Federal Energy Regulatory Commission on behalf of Electric Generation LLC in Response to June 12 Commission Order, Docket No.: ER02-456-000, August 13, 2002.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company, in the matter of the Application of Nevada Power Company to Reduce Fuel and Purchased Power Rates, PUCN Docket No. 02-11021, November 8, 2002 and subsequent Deposition Testimony.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, Docket No. 03-1014, January 10, 2003.

Direct Testimony Before the Public Utility Commission Of Texas on behalf of Texas-New Mexico Power Company, Application Of Texas-New Mexico Power Company For Reconciliation Of Fuel Costs, April 1, 2003.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company, PUCN Docket No. 02-11021, April 1, 2003.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company, Docket No. 03-1014, May 5, 2003.

Testimony Before the Public Service Commission of New York on behalf of Consolidated Edison Company of New York, Inc., Case No.: 00-E-0612, September 19, 2003.

State of New Jersey Board of Public Utilities, In the Matter of the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act of 1999, Before President Connie O. Hughes, Commissioner Carol Murphy on Behalf of the Electric Distribution Companies (Public Service Electric and Gas Company, GPU Energy, Consolidate Edison Company and Conectiv), September 2003.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's Deferred Energy Case, November 12, 2003.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, January 12, 2004.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, May 28, 2004.

Direct Testimony on behalf of Texas-New Mexico Power Company, First Choice Power Inc. and Texas Generating Company LP to Finalize Stranded Cost under PURA § 39.262, January 22, 2004.

Rebuttal Testimony on behalf of Texas-New Mexico Power Company, First Choice Power Inc. and Texas Generating Company LP to Finalize Stranded Cost under PURA § 39.262, April, 2004.

State of New Jersey Board of Public Utilities, In the Matter of the Provision of Basic Generation Service Pursuant to the Electric Discount and Energy Competition Act of 1999, Before President Connie O. Hughes, Commissioner Carol Murphy on Behalf of the Electric Distribution Companies (Public Service Electric and Gas Company, GPU Energy, Consolidate Edison Company and Conectiv), September 2004.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's Deferred Energy Case, November 9, 2004.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, January 7, 2005.

Expert Report on behalf of Oglethorpe Power Corporation, March 23, 2005.

Arbitration deposition on behalf of Oglethorpe Power Corporation, April 1, 2005.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's December 2005 Deferred Energy Case.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2006 Deferred Energy Case, January 13, 2006.

Remand Rebuttal for Public Service Company of Oklahoma before the Corporation Commission of the State of Oklahoma, Cause No. PUD 200200038, **Confidential**, March 17, 2006

Answer Testimony on behalf of the Colorado Independent energy Association, AES Corporation and LS Power Associates, LP, Docket No. 05A-543E, April 18, 2006.

Cross-Answer Testimony on behalf of the Colorado Independent energy Association, AES Corporation and LS Power Associates, LP, Docket No. 05A-543E, May 22, 2006.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2006 Deferred Energy Case, Docket No. 06-01016, June 2006.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Deferred Energy Case, December 2006.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Application for Recovery of Costs of Achieving Final Resolution of Claims Associated with Contracts Executed During the Western Energy Crisis, December 2006.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's Application for Recovery of Costs of Achieving Final Resolution of Claims Associated with Contracts Executed During the Western Energy Crisis, December 2006.

Direct Testimony Before the Public Utilities Commission of the State of Hawaii, on behalf of Hawaiian Electric Company, Inc., Docket No. 2006-0386, December 22, 2006.

Direct Testimony Before the Public Utilities Commission of the State of Hawaii, on behalf of Hawaiian Electric Company, Inc., Docket No. 05-0315, December 29, 2006.

Rebuttal Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2007 Deferred Energy Case, January 2007.

Declaration Before the State of New York Public Service Commission, on behalf of Consolidated Edison Company of New York, Inc.'s Long Island City Electric Network, Case 06-E-0894 – Proceeding on Motion of the Commission to Investigate the Electric Power Outage and Case 06-E-1158 – In the Matter of Staff's Investigation of Consolidated Edison Company of New York, Inc.'s Performance During and Following the July and September Electric Utility Outages. July 24, 2007.

Direct Testimony Before The Public Utilities Commission of Colorado, In The Matter of the Application of Public Service Company of Colorado for Approval of its 2007 Colorado Resource Plan, April 2008.

Answer Testimony Before the Public Utilities Commission of the State of Colorado on behalf of Trans-Elect Development Company, LLC, and The Wyoming Infrastructure Authority, Docket No. 07A-447E, April 28, 2008.

Rebuttal Testimony Before the Public Utilities Commission of Nevada, Application of Sierra Pacific Power Company d/b/a/ NV Energy Seeking Acceptance of its Eight Amendment to its 2008-2007 Integrated Resource Plan, Docket No. 10-02023.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's 2008 Deferred Energy Case, February 2009.

Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Nevada Power Company's 2008 Deferred Energy Case, February 2009.

Direct Testimony Before the Public Utilities Commission of Texas, on behalf of Entergy Texas, Inc. Docket No. 33687, April 29, 2009.

Direct Testimony Before The Public Utilities Commission Of Nevada On Behalf of Nevada Power Company D/B/A Nevada Energy, 2010 – 2029 Integrated Resource Plan, June 26, 2009.

Before the Public Service Commission of New York, Case 09-E-0428 Consolidated Edison Company of New York, Inc. Rate Case, Rebuttal Testimony, September 2009.

Direct Testimony Before the Public Utilities Commission of Nevada on Behalf of Sierra Pacific Power Company's 2009 Deferred Energy Case, February 2010.

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Direct Testimony Before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company's Eighth Amendment to its 2008 – 2027 Integrated Resource Plan, Docket No. 10-03023, July 2010.

Rebuttal Testimony Before the Public Utilities Commission of Nevada, Application of Nevada power Company d/b/a NV Energy Seeking Acceptance of its Triennial Integrated Resource Plan covering the period 2010-2029, including authority to proceed with the permitting and construction of the ON Line transmission project, Docket No. 10-02009.

Rebuttal Testimony Before the Public Utilities Commission of Nevada, Petition of Nevada Power Company d/b/a NV Energy requesting a determination under NRS 704.7821 that the terms and conditions of five renewable power purchase agreements are just and reasonable and allowing limited deviation from the requirements of NAC 704.8885, Docket No. 10-03022.

Rebuttal Testimony Before the Public Utilities Commission of Nevada, on behalf of Nevada Power Company d/b/a NV Energy, 2010 Deferred Energy Case, Docket No. 10-03003, filed August 3, 2010

Rebuttal Testimony Before the Public Utilities Commission of Nevada, on behalf of Sierra Pacific Power Company d/b/a NV Energy Electric Department, 2010 Deferred Energy Case, Docket No. 10-03004, filed August 3, 2010

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Sierra Pacific Power Company, d/b/a NV Energy, Docket No. 11-03 __ 2011 Electric Deferred Energy Proceeding, February 2011.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Nevada Power Company, d/b/a NV Energy, Docket No. 11-03 __ 2011 Electric Deferred Energy Proceeding, February 2011.

Testimony Before the Atomic Safety and Licensing Board, Nuclear Regulatory Commission, In the Matter of Entergy Nuclear Operations, Inc., Dockets Nos. 50-247-LR and 50-286-LR, March 30, 2012.

Rebuttal Testimony Before the Public Utilities Commission of Ohio, In Support of AEP Ohio's Modified Electric Security Plan, Case No. 10-2929, May 11, 2012.

Prefiled Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Sierra Pacific Power Company, d/b/a NV Energy, Docket No. 12-03 __ 2012 Electric Deferred Energy Proceeding, February 2012.

Prefiled Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Nevada Power Company, d/b/a NV Energy, Docket No. 12-03 __ 2012 Electric Deferred Energy Proceeding, February 2012.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Sierra Pacific Power Company, d/b/a NV Energy, Docket No. 13-03 __ 2013 Electric Deferred Energy Proceeding, February 2013.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Nevada Power Company, d/b/a NV Energy, Docket No. 13-03 __ 2013 Electric Deferred Energy Proceeding, February 2013.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Sierra Pacific Power Company, d/b/a NV Energy, Docket No. 14-02 __ 2014 Electric Deferred Energy Proceeding, February 2014.

Direct Testimony Before the Public Utilities Commission of Nevada, on behalf of Nevada Power Company, d/b/a NV Energy, Docket No. 14-02 __ 2014 Electric Deferred Energy Proceeding, February 2014.

January 2015

2015 Feasibility Analyses Results for the Turkey Point 6 & 7 Project:
Case # 1 Analysis - 40-Year Operating Life; Total Costs,
Total Cost Differentials, and Breakeven Costs for All Fuel
and Environmental Compliance Cost Scenarios in 2015$
(millions, CPVRR, 2015 - 2068)

(1)	(2)	(3)	(4)	(5) = (3) - (4)	(6)				
Fuel Cost Forecast	Environmental Compliance Cost Forecast	Total Costs for Plans		Total Cost Difference Plan without TP 6 & 7 minus Plan with TP 6 & 7	Breakeven Nuclear Capital Costs ($/kW in 2015$) Per Exhbit ROB-5	Breakeven Nuclear Capital Costs ($/kW in 2015$) No Transmission Advantage	Breakeven Nuclear Capital Costs ($/kW in 2015$) No Transmission or Carbon Advantage	Breakeven Nuclear Capital Costs ($/kW in 2015$) No Transmission and 50% Carbon Advanatge	Breakeven Nuclear Capital Costs ($/kW in 2015$) 50% Transmission and 50% Carbon Advanatge
		Resource Plan w/ TP 6 & 7	Resource Plan w/o TP 6 & 7						
High Fuel Cost	Env I	140,810	151,571	10,762	5,254	4,424	3,001	3,712	4,127
High Fuel Cost	Env II	148,047	159,595	11,548	5,639	4,809	3,029	3,919	4,334
High Fuel Cost	Env III	155,298	167,645	12,348	6,031	5,201	3,064	4,132	4,548
Medium Fuel Cost	Env I	125,989	135,525	9,536	4,654	3,824	2,402	3,113	3,528
Medium Fuel Cost	Env II	133,186	143,498	10,312	5,034	4,204	2,425	3,314	3,729
Medium Fuel Cost	Env III	140,393	151,496	11,103	5,421	4,591	2,455	3,523	3,938
Low Fuel Cost	Env I	110,950	119,248	8,298	4,049	3,220	1,797	2,508	2,923

Note: The TP 6 & 7 non-binding cost estimate range to which the breakeven cost is compared is $3,844/kW to $5,589/kW in 2015$.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 45
PARTY: CITY OF MIAMI (MIAMI) RE:
FLORIDA POWER & LIGHT (FPL)
DESCRIPTION: Eugene T. Meehan ETM-2

2015 Feasibility Analyses Results for the Turkey Point 6 & 7 Project:
Case # 2 Analysis - 60-Year Operating Life; Total Costs,
Total Cost Differentials, and Breakeven Costs for All Fuel
and Environmental Compliance Cost Scenarios in 2015$
(millions, CPVRR, 2015 - 2088)

(1)	(2)	(3)	(4)	(5) = (3) - (4)	(6)				
Fuel Cost Forecast	Environmental Compliance Cost Forecast	Total Costs for Plans: Resource Plan w/ TP 6 & 7	Total Costs for Plans: Resource Plan w/o TP 6 & 7	Total Cost Difference Plan without TP 6 & 7 minus Plan with TP 6 & 7 *	Breakeven Nuclear Capital Costs ($/kW in 2015$) Per Exhibit ROB-6	Breakeven Nuclear Capital Costs ($/kW in 2015$) No Transmission Advantage	Breakeven Nuclear Capital Costs ($/kW in 2015$) No Transmission or Carbon Advantage	Breakeven Nuclear Capital Costs ($/kW in 2015$) No Transmission and 50% Carbon Advanatge	Breakeven Nuclear Capital Costs ($/kW in 2015$) 50% Transmission and 50% Carbon Advanatge
High Fuel Cost	Env I	165,666	178,785	13,119	6,408	5,578	3,815	4,696	5,111
High Fuel Cost	Env II	177,061	191,427	14,366	7,018	6,188	3,984	5,086	5,501
High Fuel Cost	Env III	188,470	204,108	15,638	7,640	6,809	4,165	5,487	5,902
Medium Fuel Cost	Env I	149,624	161,367	11,743	5,734	4,904	3,142	4,023	4,438
Medium Fuel Cost	Env II	160,969	173,950	12,982	6,341	5,511	3,307	4,409	4,824
Medium Fuel Cost	Env III	172,319	186,565	14,246	6,959	6,129	3,484	4,806	5,222
Low Fuel Cost	Env I	133,349	143,709	10,360	5,058	4,228	2,466	3,347	3,762

Note: The TP 6 & 7 non-binding cost estimate range to which the breakeven cost is compared is $3,844/kW to $5,589/kW in 2015$.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 46
PARTY: CITY OF MIAMI (MIAMI) RE:
FLORIDA POWER & LIGHT (FPL)
DESCRIPTION: Eugene T. Meehan ETM-3

Docket No. 150009-EI
Duke Energy Florida
Exhibit No. ___ (TGF-1)

SCHEDULE APPENDIX

REDACTED

EXHIBIT (TGF-1)

DUKE ENERGY FLORIDA, INC.
LEVY NUCLEAR UNITS 1 & 2
COMMISSION SCHEDULES

JANUARY 2014 - DECEMBER 2014
DOCKET NO. 150009-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 47
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)
DESCRIPTION: Thomas G. Foster TGF-1

Table of Contents
Levy Nuclear Units 1 & 2
January 2014 - December 2014

Page(s)	Schedule	Description	Sponsor
3	2014 Summary	2014 True-Up Summary	T. G. Foster
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5 - 6	Appendix A	Detail for 2014 Beginning Balance and Amortization of Reg Asset	T. G. Foster
7	Appendix B	Other Exit / Wind-Down Expense Variance Explanation	T. G. Foster
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2014 Summary
Levy Nuclear Units 1 & 2
January 2014 - December 2014
Duke Energy Florida

Witness: Thomas G. Foster
Docket No. 150009-EI
Duke Energy Florida
Exhibit: (TGF- 1)

				12-Month Total
1.	Final Costs for the Period			
	a. Carrying Cost on Unrecovered Investment		$	13,310,606
	b. Period Exit Costs			9,816,636
	c. Period Other Exit / Wind-down Costs and Interest			381,251
	d. Total Period Revenue Requirement		$	23,508,493
2.	Projected Amount for the Period (Order No. PSC 14-0701-FOF-EI)		$	30,342,148
3.	Final True-Up Amount for the Period (over)/under	(Line 1d. - Line 2.)	$	(6,833,655)
4.	Amortizaton of Unrecovered Investment and Prior Period Over/Under Balances (Order No. PSC 14-0701-FOF-EI)		$	75,293,261
5.	Total Revenue Requirements for 2014	(Line 1d. + Line 4.)	$	98,801,754

DUKE ENERGY FLORIDA
Nuclear Cost Recovery Clause (NCRC) - Levy Nuclear Units 1 & 2
2014 Detail - Calculation of the Revenue Requirements
January 2014 through December 2014

REDACTED

Witness: T. G. Foster/C. Fallon
Docket No. 150009-EI
Duke Energy Florida
Exhibit No. ___ (TGF-1)

Line	Description		Beginning of Period Amount	Actual January 2014	Actual February 2014	Actual March 2014	Actual April 2014	Actual May 2014	Actual June 2014	Actual July 2014	Actual August 2014	Actual September 2014	Actual October 2014	Actual November 2014	Actual December 2014	Period Total	End of Period Total
1	**Uncollected Investment : Generation**																
	a Prior Period Construction Balance (b)			[redacted]													
	b Wind-Down Costs																
	c Sale or Salvage of Assets																
	d Disposition																
	e Total																
2	**Adjustments**																
	a Non-Cash Accruals (b)			[redacted]													
	b Adjusted System Generation (Line 1e + Line 2a)																
	c Retail Jurisdictional Factor : Generation	92.885%															
	d Retail Uncollected Investment: Generation																
3	**Uncollected Investment : Transmission**																
	a Prior Period Construction Balance (b)			[redacted]													
	b Wind-Down Costs																
	c Sale or Salvage of Assets																
	d Disposition																
	e Total																
4	**Adjustments**																
	a Non-Cash Accruals (b)			[redacted]													
	d Adjusted System Transmission (Line 3e + Line 4a)																
	e Retail Jurisdictional Factor : Transmission	70.203%															
	f Retail Uncollected Investment: Transmission																
5	**Total Uncollected Investment**																
	a Total Jurisdictional Uncollected Investment (2d + 4f)		214,246,253	6,261,829	200,762	230,672	242,865	2,819,421	5,353	6,469	5,187	8,137	6,129	13,367	16,444	9,816,636	224,062,889
	b Retail Land Transferred to Land Held for Future Use (a)		(66,221,330)														(66,221,330)
	c Total Jurisdictional Uncollected Investment		148,024,923														157,841,559
6	**Carrying Cost on Unrecovered Investment Balance**																
	a Uncollected Investment: Additions for the Period (Beg Balance: Line 5c.) (a)		148,024,923	6,261,829	200,762	230,672	242,865	2,819,421	5,353	6,469	5,187	8,137	6,129	13,367	16,444	$9,816,636	157,841,559
	b Plant-in-Service (a)		1,010,952														(1,010,952)
	c Period Recovered Wind-down / Exit Costs															9,816,636	9,816,636
	d Amortization of Uncollected Investment (2010)			2,435,326	2,435,326	2,435,326	2,435,326	2,435,326	2,435,326	2,435,326	2,435,326	2,435,326	2,435,326	2,435,326	2,435,326	29,223,910	29,223,910
	e Additional Amortization of Uncollected Investment Balance			3,905,376	3,905,376	3,905,376	3,905,376	3,905,376	3,905,376	3,905,376	3,905,376	3,905,376	3,905,376	3,905,376	3,905,376	46,864,516	(46,864,516)
	f Prior Period Carrying Charge Unrecovered Balance (a)		24,221,851	21,816,090	19,410,330	17,004,570	14,598,809	12,193,049	9,787,289	7,381,528	4,975,768	2,570,008	164,247	(2,241,513)	(4,647,273)		(4,647,273)
	g Prior Period Carrying Charge Recovered (a)		(354,786)	(29,566)	(29,566)	(29,566)	(29,566)	(29,566)	(29,566)	(29,566)	(29,566)	(29,566)	(29,566)	(29,566)	(29,566)		0
	h Prior Period Under/(Over) Recovery (Prior Month)			0	4,701,138	(2,447,534)	(1,000,987)	(1,001,389)	1,573,222	(1,243,795)	(838,670)	(1,269,923)	(1,281,841)	(1,298,837)	(1,306,688)	(6,734,088)	(6,734,088)
	i Net Investment		$171,235,822	$171,186,514	$163,515,448	$154,786,688	$147,486,757	$142,750,787	$135,198,804	$127,644,988	$120,493,899	$112,915,790	$105,320,803	$97,718,069	$90,103,321		$88,768,093
7	Average Net Investment			$171,211,168	$166,570,635	$157,826,920	$150,520,893	$144,496,645	$138,351,696	$130,797,322	$123,646,874	$116,067,290	$108,473,308	$100,866,953	$93,250,667		
8	Return on Average Net Investment																
	a Equity Component	0.00394		674,572	656,288	621,838	593,052	569,317	545,106	515,341	487,169	457,305	427,385	397,416	367,408	6,312,197	
	b Equity Component Grossed Up For Taxes	1.62800		1,098,204	1,068,438	1,012,353	965,490	926,849	887,433	838,976	793,112	744,493	695,783	646,994	598,141	10,276,267	
	c Debt Component	0.00189		324,274	315,485	298,924	285,087	273,677	262,038	247,730	234,187	219,831	205,448	191,042	176,617	3,034,340	
	d Total Return			**1,422,478**	**1,383,923**	**1,311,277**	**1,250,577**	**1,200,526**	**1,149,471**	**1,086,706**	**1,027,299**	**964,324**	**901,231**	**838,036**	**774,758**	**13,310,606**	
9	**Revenue Requirements for the Period (Line 6a + 8d)**			**7,684,308**	**1,584,685**	**1,541,950**	**1,493,442**	**4,019,947**	**1,154,824**	**1,093,174**	**1,032,486**	**972,461**	**907,360**	**851,403**	**791,202**	**23,127,243**	
10	Projected Revenue Requirements for the Period (Order No. PSC 14-0701-FOF-EI)			2,983,170	4,032,219	2,542,937	2,494,831	2,446,725	2,398,620	1,931,845	2,302,408	2,254,303	2,206,197	2,158,091	2,109,986	29,861,331	
11	Over/Under Recovery For the Period			4,701,138	(2,447,534)	(1,000,987)	(1,001,389)	1,573,222	(1,243,795)	(838,670)	(1,269,923)	(1,281,841)	(1,298,837)	(1,306,688)	(1,318,783)	(6,734,088)	
12	**Other Exit / Wind-Down**																
	a Accounting			(3,157)	13,305	14,342	6,923	10,330	4,083	12,032	5,001	3,256	3,128	2,768	2,669	$74,680	
	b Corporate Planning			9,947	7,876	7,046	7,799	4,876	6,124	4,174	4,771	579	2,130	1,539	2,882	$59,743	
	c Legal			0	29,750	31,407	18,683	20,640	21,874	26,913	21,274	25,149	19,497	19,615	38,055	$272,857	
	d Nuclear Generation			0	0	0	0	0	1,940	0	0	0	0	0	0	1,940	
	e Total Other Exit / Wind-Down Costs			6,790	50,931	52,795	33,405	35,846	34,021	43,119	31,046	28,984	24,755	23,922	43,606	$409,220	
13																	
	a Jurisdictional Factor (A&G)			0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221		
	b Jurisdictional Factor (Generation)			0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885	0.92885		
14	Jurisdictional Amount			6,330	47,478	49,216	31,140	33,416	31,708	40,196	28,941	27,019	23,077	22,300	40,650	381,472	
15	Prior Period Unrecovered Balance (a)		(520,198)	(483,500)	(446,802)	(410,103)	(373,405)	(336,707)	(300,009)	(263,311)	(226,612)	(189,914)	(153,216)	(116,518)	(79,819)		
16	Prior Period Costs Recovered (a)		(440,379)	(36,698)	(36,698)	(36,698)	(36,698)	(36,698)	(36,698)	(36,698)	(36,698)	(36,698)	(36,698)	(36,698)	(36,698)	(36,698)	
17	Prior Month Period (Over)/Under Recovery			0	(33,745)	7,400	9,133	(8,945)	(6,671)	(8,377)	111	(11,147)	(13,071)	(17,014)	(17,794)		
18	Unamortized Balance		(520,198)	(483,500)	(480,547)	(436,449)	(390,618)	(362,865)	(332,837)	(304,515)	(267,706)	(242,154)	(218,527)	(198,842)	(179,938)	(143,239)	
19	Projected Carrying Costs for the Period																
	a Balance Eligible for Interest			(498,684)	(475,157)	(430,190)	(393,397)	(364,506)	(335,332)	(302,766)	(271,584)	(246,994)	(225,337)	(206,041)	(177,962)		
	b Monthly Commercial Paper Rate			0.00%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%		
	c Interest Provision			(23)	(24)	(25)	(25)	(23)	(18)	(15)	(16)	(14)	(12)	(13)	(13)	(221)	
	d Total Costs and Interest (Line 14 + Line 19c)			6,307	47,455	49,191	31,116	33,393	31,690	40,181	28,926	27,005	23,065	22,287	40,637	381,251	
20	Recovered (Order No. PSC 14-0701-FOF-EI)			40,052	40,055	40,058	40,061	40,064	40,067	40,070	40,072	40,075	40,078	40,081	40,084	480,817	
21	Over/Under Recovery For the Period			(33,745)	7,400	9,133	(8,945)	(6,671)	(8,377)	111	(11,147)	(13,071)	(17,014)	(17,794)	553	(99,566)	
22	**Revenue Requirements for the Period**			**7,690,614**	**1,632,139**	**1,591,141**	**1,524,558**	**4,053,340**	**1,186,514**	**1,133,355**	**1,061,411**	**999,466**	**930,425**	**873,691**	**831,838**	**23,508,493**	
23	Recovered (Order No. PSC 14-0701-FOF-EI)			3,023,222	4,072,274	2,582,995	2,534,892	2,486,789	2,438,686	1,971,915	2,342,481	2,294,378	2,246,275	2,198,172	2,150,070	30,342,148	
24	**Over/Under Recovery For the Period**			**4,667,393**	**(2,440,135)**	**(991,854)**	**(1,010,334)**	**1,566,551**	**(1,252,172)**	**(838,559)**	**(1,281,070)**	**(1,294,912)**	**(1,315,851)**	**(1,324,482)**	**(1,318,232)**	**(6,833,655)**	

Note:
(a) Please see Appendix a for Beginning Balance Support [redacted]

This amount represents accruals for anticipated expenses that were not incurred or the payment of the actual amount was lower than the accrual.

[redacted] This amount represents expenses incurred and cash paid in a previous period that did not have an offsetting accrual adjustment.

Levy 2014 - Beginning Balance Support Schedule Explanation

Appendix A
Witness: Thomas G. Foster
Docket 150009-EI
Duke Energy Florida
Exhibit No. ____ (TGF-1)
(Page 1 of 2)

2014

Unrecovered Investment Beginning Balance for Carrying Cost Calculation

Line No.

6a. Unrecovered Investment Beginning Balance **$ 148,024,923** (a-b)

		Generation	2013 Retail Separation Factor		Retail	
2013 Detail (Line 17d)	Generation	213,611,260	92.885%		$198,412,819	
2013 Detail (Line 19e)	Transmission	22,553,786	70.203%		15,833,434	
		236,165,046		(a)	**214,246,253**	Exhibit (TGF-2) Docket No. 140009-EI 2013 Detail Sheet Line 20a.

Less: **RETAIL - Real Estate Transferred to Land Held for Future Use (per 2013 Settlement)**

		System	2013 Retail Separation Factor		Retail	
2013 Detail (Line 16a)	Generation Land (accrued)	60,250,765	92.885%		$55,963,923	
2013 Detail (Line 18b)	Transmission Land (accrued)	17,636,269	70.203%		12,381,190	
		$77,887,034			$68,345,113	
Less: Non-Land in Real Estate Acquisition Line (I.e. Permitting) -- Not transferred to LHFFU as of 12/31/2013					2,123,783	
				(b)	**66,221,330**	Exhibit (TGF-2) Docket No. 140009-EI 2013 Detail Sheet Line 20b.

6b. Transfers to Plant in Service **$ 1,010,952** Exhibit (TGF-2) Docket No. 140009-EI 2013 Detail Sheet Line 22.

This amount represents the amount of Levy projects that are currently in service at the updated Retail (Jurisdictionalized) rate.

Represents Amortization to achieve 2014 Revenue Requirement		Annual Amount		Monthly Amount
6d. Amortization of Uncollected Investment (2010)	$	29,223,910	**$**	**2,435,326**
6e. Additional Amortization of Uncollected Investment Balance	$	46,864,516	**$**	**3,905,376**

6f. 2013 Detail (TGF-2 2014)

Line 7. Prior Period Carrying Charge Unrecovered Preconstruction Balance (Incl. 2010 Reg Asset)	$	33,272,152
Line 15. Prior Period Preconstruction (Over)/Under Recovery		(6,711,170)
Line 24. Prior Period Carrying Charge Unrecovered Construction Balance		(464,035)
Line 31. Prior Period Construction (Over)/Under Recovery		(1,875,096)
This is the remaining amount of the 2013 Activity	**$**	**24,221,851**

6g. Amortization of Prior Period Unrecovered Carrying Charge **$ (354,786)**

Amount to Amortize over 12 Months
Comes from amount in Appendix A (Page 2 of 2) ((All 2014 Collection/Refund excl. O&M))
All Items except O&M in the 2014 Collection / (Refund)

Other Exit & Wind-Down Costs

Line No.

15. Prior Period Unrecovered Costs Balance Eligible for interest **$ (520,198)**

2013 Detail (TGF-2 2014) in Docket No. 140009-EI

Line 36. Prior Period Unrecovered Balance Eligible for interest 60,748
This is the remaining amount of the 2012 Uncollected Balance.

Line 42. Prior Period (Over)/Under Recovery (580,946)
This is the remaining amount of the 2013 Activity

16. Amortization of Unrecovered Balance Eligible for interest (a) **$ (440,379)**

Sum of the amounts in Appendix A (Page 2 of 2) attached in this Exhibit, in the 2014 Collection / (Refund) for O&M

Summary of 2014 Amortization Activity (For 2014 Summary)

Prior Period (Over) / Under Recovery	(795,165)	TGF-4 2014 Projection Filing Docket No. 130009-EI (Schedule P-1) Line 6.
Additional Amortization of Uncollected Investment Balance	46,864,516	TGF-4 2014 Projection Filing Docket No. 130009-EI (Schedule P-1) Line 7.
Collection of Remaining 2010 Deferred Regulatory Asset	29,223,910	TGF-4 2014 Projection Filing Docket No. 130009-EI (Schedule P-1) Line 8.
Period Amortizaton of Unrecovered Investment and Prior Period Over/Under Balances	**75,293,261**	

Prior Period Over / (Under) Support Schedules

DEF - Levy Nuclear Units 1&2

Appendix A
Witness: Thomas G. Foster
Docket No. 150009-EI
Duke Energy Florida
Exhibit No. __ (TGF - 1)
(Page 2 of 2)

	Note 1 2012 True Up	2012 Est-Actual	2014 Collection/ (Refund) *
Preconstruction Rev Req.	16,543,722	12,835,927	3,707,795
Preconstruction Carrying Cost Rev Req.	12,675,742	12,335,295	340,447
Construction Carrying Cost Rev Req.	16,269,349	16,733,385	(464,036)
Recoverable O&M Revenue Req.	988,205	927,458	60,747
DTA	19,479,375	19,479,375	0
	65,956,393	62,311,440	3,644,953

Note 1: 2012 Est-Actual amounts are per Order PSC-12-0650-FOF-EI, Docket 120009-EI, Pg 26

	Note 2 2013 Est-Actual	2013 Projection	2014 Collection/ (Refund) *
Preconstruction Rev Req.	13,514,466	17,198,302	(3,683,836)
Preconstruction Carrying Cost Rev Req.	7,833,531	7,809,647	23,884
Construction Carrying Cost Rev Req.	14,000,362	14,279,402	(279,040)
Recoverable O&M Revenue Req.	523,974	1,025,100	(501,126)
	35,872,333	40,312,451	(4,440,118)

Note 2: 2013 Projection amounts are per Order PSC-12-0650-FOF-EI, Docket 120009-EI, Pg 27

LEVY COUNTY NUCLEAR 1 & 2
Site Selection, Preconstruction Costs, and Carrying Costs on Construction Cost Balance
True-Up Filing: Other Wind-Down & Exit Expenditures Allocated or Assigned to Other Recovery Mechanisms

EXPLANATION: Provide variance explanations comparing the actual system total expenditures shown on 2014 Detail Schedule with the expenditures approved by the Commission on Est/Act Detail 2014 Schedules.

Appendix B
Witness: Thomas G. Foster
Docket No. 150009-EI
Duke Energy Florida
Exhibit No. ____ (TGF-1)

COMPANY:
Duke Energy Florida

DOCKET NO.:
150009-EI

For Year Ended 12/31/2014

Line No.	Description	(A) System Estimated/Actual	(B) System Actual	(C) Variance Amount	(D) Explanation
	Allocated or Assigned Expenditures				
1	Accounting	$112,772	$74,680	($38,092)	
2	Corporate Planning	178,521	59,743	(118,778)	
3	Legal	125,000	272,857	147,857	
4	Nuclear Generation	0	1,940	1,940	
5	Total	$416,293	$409,220	($7,073)	Minor variance from estimated amount

System Estimated / Actual taken from May 1, 2014 Filing in Docket No. 140009-EI

DUKE ENERGY FLORIDA
Average Rate of Return - Capital Structure
FPSC Adjusted Basis
December 2012

Appendix C
Witness: Thomas G. Foster
Docket No. 150009-EI
Duke Energy Florida
Exhibit No. ____ (TGF-1)

	System Per Books	Specific Adjustments	Pro Rata Adjustments	System Adjusted	FPSC Adjusted Retail	Ratio	Low Point		Mid Point		High Point	
							Cost Rate	Weighted Cost	Cost Rate	Weighted Cost	Cost Rate	Weighted Cost
Common Equity	$4,767,157,537	657,669,241	($813,779,810)	$4,611,046,968	$3,753,238,636	46.36%	9.50%	4.40%	10.50%	4.87%	11.50%	5.33%
Preferred Stock	33,496,700		(5,024,850)	28,471,850	23,175,138	0.29%	4.51%	0.01%	4.51%	0.01%	4.51%	0.01%
Long Term Debt - Fixed	4,491,809,896	0	(673,817,682)	3,817,992,215	3,107,718,483	38.39%	5.78%	2.22%	5.78%	2.22%	5.78%	2.22%
Short Term Debt *	232,034,133	(51,903,909)	(27,021,386)	153,108,838	124,625,494	1.54%	0.60%	0.01%	0.60%	0.01%	0.60%	0.01%
Customer Deposits												
Active	214,453,652		(32,170,253)	182,283,398	182,283,398	2.25%	5.36%	0.12%	5.36%	0.12%	5.36%	0.12%
Inactive	1,280,766		(192,128)	1,088,638	1,088,638	0.01%						
Investment Tax Credit												
Post '70 Total	3,450,862		(517,665)	2,933,197								
Equity **					1,309,719	0.02%	9.58%	0.00%	10.59%	0.00%	11.59%	0.00%
Debt **					1,077,805	0.01%	5.85%	0.00%	5.85%	0.00%	5.85%	0.00%
	1,365,618,849	155,326,427	(228,157,434)	1,292,787,842	1,052,286,240	13.00%						
FAS 109 DIT - Net	(218,650,949)		32,799,891	(185,851,058)	(151,276,570)	-1.87%						
Total	**$10,890,651,446**	**$761,091,759**	**($1,747,881,316)**	**$9,903,861,889**	**$8,095,526,982**	**100.00%**		**6.76%**		**7.23%**		**7.69%**

Equity	4.88%
Debt	2.35%
Total	7.23%

* Daily Weighted Average
**Cost Rates Calculated Per IRS Ruling

LEVY COUNTY NUCLEAR 1 & 2
Site Selection, Preconstruction Costs, and Carrying Costs on Construction Cost Balance
Estimated / Actual Filing: Description of Monthly Cost Additions

EXPLANATION: Provide a description of the major tasks performed within these Categories for the year.
List generation expenses separate from transmission

Appendix D
Witness: C. Fallon
Docket No. 150009-EI
Duke Energy Florida
Exhibit No. ____ (TGF - 1)
(Page 1 of 2)

COMPANY:
Duke Energy Florida

DOCKET NO.:
150009-EI

For Year Ended 12/31/2014

Line No.	Major Task & Description for amounts on 2014 Detail Schedule	Description
	Generation:	
1	Wind-Down Costs	Spend performed in accordance with Rule 25-6.0423(7).
2	Sale or Salvage of Assets	The amount of proceeds received from either selling, transferring or otherwise receiving salvage value for the nuclear assets
3	Disposition	The cost of winding-down and exiting the nuclear project contracts
	Transmission:	
1	Wind-Down Costs	Spend performed in accordance with Rule 25-6.0423(7).
2	Sale or Salvage of Assets	The amount of proceeds received from either selling, transferring or otherwise receiving salvage value for the nuclear assets
3	Disposition	The cost of winding-down and exiting the nuclear project contracts

LEVY COUNTY NUCLEAR 1 & 2
Site Selection, Preconstruction Costs, and Carrying Costs on Construction Cost Balance
True-Up Filing: Regulatory Asset Category - Variance in Additions and Expenditures

REDACTED

Appendix D
Witness: C. Fallon
Docket No. 150009-EI
Duke Energy Florida
Exhibit: (TGF - 1)
(Page 2 of 2)

EXPLANATION: Provide variance explanations comparing the annual system total expenditures shown on 2014 Detail Schedule with the expenditures approved by the Commission on Est/Actual Detail 2014. List the Generation expenses separate from Transmission in the same order appearing on 2014 Detail Schedule.

COMPANY:
Duke Energy - FL

DOCKET NO.:
150009-EI

For Year Ended 12/31/2014

Line No.	Major Task & Description for amounts on Schedule	(A) System Estimated/Actual	(B) System Actual	(C) Variance Amount	(D) Explanation
	Generation:				
1	Wind-Down Costs (a)	[redacted]			Variance primarily relates to storage costs for Levy long-lead equipment that were not incurred because of the disposition of the Levy assets.
2	Sale or Salvage of Assets				
3	Disposition				Variance primarily relates to an estimated maximum LLE purchase order termination cost that was originally reasonably anticipated in 2014, but ultimately was not due or paid in 2014
4	Total Generation Costs				
	Transmission:				
1	Wind-Down Costs (b)	[redacted]			
2	Sale or Salvage of Assets				
3	Disposition				
4	Total Transmission Costs				

Note:
[redacted]
This amount represents accruals for expenses that were not and will not be paid.

[redacted]
This amount represents expenses incurred and cash paid in a previous period that did not have an offsetting accrual adjustment.

System Estimated / Actual taken from May 1, 2014 Filing in Docket No. 140009-EI

LEVY COUNTY NUCLEAR 1 & 2
True-Up Actual Filing: Contracts Executed

REDACTED

COMPANY: Duke Energy Florida

EXPLANATION: Provide a list of contracts executed in excess of $1 million including, a description of the work, the dollar value and term of the contract, the method of vendor selection, the identity and affiliation of the vendor, and current status of the contract.

DOCKET NO.: 150009-EI

Appendix E
Witness: C. Fallon
Docket No. 150009-EI
Duke Energy Florida
Exhibit No. ___ (TGF - 1)
For Year Ended: 12/31/2014

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.	Contract No.	Status of Contract	Term of Contract	Original Amount	Actual Expended as of Prior Year End (2013)	Actual Expended in 2014	Estimate of Final Contract Amount	Name of Contractor	Affiliation of Vendor	Method of Selection	Nature and Scope of Work
1	414310	Terminated: January 28, 2014	[redacted]				Note	Westinghouse Electric Co. LLC.	Direct	Sole Source. Award based on vendor constructing the selected reactor technology.	To design, engineer, supply, equip, construct and install a fully operational two unit AP1000 Facility at the Levy Nuclear Plant Site. Final contract amount includes change orders.
2	N/A	Note 2	Note 2	Note 2			Note	Carlton Fields Jorden Burt	Direct	Note 2	Legal Work – DEF Levy Units 1 & 2

Line 1: Costs or credits associated with terminating the EPC contract and related long lead equipment purchase orders are subject to litigation in federal court and are unknown at this time.

Line 2: Estimate of final contract amount cannot be determined at this time.

Docket No. 150009-EI
Duke Energy Florida
Exhibit No. ____ (TGF-2)

SCHEDULE APPENDIX

EXHIBIT (TGF-2)

DUKE ENERGY FLORIDA, INC.
CRYSTAL RIVER UNIT 3 UPRATE
COMMISSION SCHEDULES

JANUARY 2014 - DECEMBER 2014
DOCKET NO. 150009-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 48
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)
DESCRIPTION: Thomas G. Foster TGF-2

Docket No. 150009-EI
Duke Energy Florida
Exhibit No. ____ (TGF-2)

Table of Contents
Crystal River Unit 3 Uprate
January 2014 - December 2014

Page(s)	Schedule	Description	Sponsor
3	2014 Summary	2014 Summary	T. G. Foster
4	2014 Detail	2014 Detail Revenue Requirement Calculations	T. G. Foster / M. Teague
5 - 7	Appendix A	Detail for 2014 Beginning Balance & In-Service Project Rev Req Support	T. G. Foster
8	Appendix B	Other Exit / Wind-Down Expense Variance Explanation	T. G. Foster
9	Appendix C	Average Rate of Return - Capital Structure	T. G. Foster
10 - 11	Appendix D	Major Task Categories and Expense Variances	M. Teague
12	Appendix E	Summary of Contracts and Details over $1 Million	M. Teague

2014 Summary
CR3 Uprate
January 2014 - December 2014
Duke Energy Florida

Witness: Thomas G. Foster
Docket No. 150009-EI
Duke Energy Florida
Exhibit No. ____ (TGF- 2)

				12-Month Total
1.	Final Costs for the Period			
	a. Carrying Cost on Unrecovered Investment		$	23,797,280
	b. Period Exit Costs (including Sale of Assets)		$	(488,483)
	c. Period Other Exit / Wind-down Costs and Interest		$	196,407
	d. Other - Adjustments		$	(3,699)
	e. Total Period Revenue Requirement		$	23,501,504
2.	Projected Amount for the Period (Order No. PSC 13-0493-FOF-EI)		$	24,572,133
3.	Final True-Up Amount for the Period (over)/under	(Line 1e. - Line 2.)	$	(1,070,629)
4.	Amortizaton of Unrecovered Investment and Prior Period Over/Under Balances (Order No. PSC 13-0493-FOF-EI)		$	44,019,016
5.	Total Revenue Requirements for 2014	(Line 1e. + Line 4.)	$	67,520,520

DUKE ENERGY FLORIDA
Nuclear Cost Recovery Clause (NCRC) - CR3 Uprate
2014 Detail - Calculation of the Revenue Requirements
January 2014 through December 2014

Witness: T.G. Foster / M. Teague
Docket No. 150009-EI
Duke Energy Florida
Exhibit: (TGF- 2)

Line	Description		Beginning of Period Amount	Actual January 14	Actual February 14	Actual March 14	Actual April 14	Actual May 14	Actual June 14	Actual July 14	Actual August 14	Actual September 14	Actual October 14	Actual November 14	Actual December 14	Period Total
1	**Uncollected Investment**															
	a EPU Construction & Wind-Down Costs (c)		374,171,055	2,058	13,839	6,323	2,612,188	1,475	1,367	536	2,426	1,384	2,330	(309,418)	715	2,335,223
	b Sale or Salvage of Assets		0	0	(5,075)	0	(76,883)	(309,000)	(62,900)	0	0	0	0	0	0	(453,858)
	c Disposition		0	0	0	0	0	0	0	0	0	0	0	0	0	0
	d Total		374,171,055	2,058	8,764	6,323	2,535,305	(307,525)	(61,533)	536	2,426	1,384	2,330	(309,418)	715	$1,881,365
2	**Adjustments**															
	a Non-Cash Accruals (c)		2,293,285	0	0	0	(2,605,445)	0	0	0	0	0	0	312,160	0	($2,293,285)
	b Joint Owner Credit		(29,950,263)	746	(658)	(582)	(210,910)	(16,793)	47,178	(44)	(35)	(227)	(277)	22,189	(59)	(159,472)
	c Other (b)		(28,108,647)	0	0	0	0	0	0	0	0	0	0	0	0	0
	d Adjusted System Generation Construction Cost Additions		318,405,430	2,804	8,106	5,741	(281,050)	(324,318)	(14,355)	492	2,391	1,157	2,053	24,931	656	($571,392)
	Retail Jurisdictional Factor : Current Year Activity	92.885%														
	Retail Jurisdictional Factor: (Beg Bal YE 2012 only and POD Sale)	91.683%														
	e Period Project Investment			2,604	7,529	5,333	(261,053)	(258,989)	(13,334)	457	2,221	1,075	1,907	23,157	609	($488,483)
	f Beginning Balance - pre 2013 Investment		279,911,057													
	g Beginning Balance - 2013 Investment		12,170,084													
3	**Carrying Cost on Unrecovered Investment Balance**															
	a Uncollected Investment: Costs for the Period (Beg Balance: Line 2.f and 2.g)		292,081,140	2,604	7,529	5,333	(261,053)	(258,989)	(13,334)	457	2,221	1,075	1,907	23,157	609	291,592,657
	b Plant-in-Service (Beg Bal: YE 2013) (a)		29,995,096	0	0	0	0	0	0	0	0	0	0	0	0	29,995,096
	c Period Recovered Wind-down / Exit Costs		0	0	0	0	0	0	0	0	0	0	0	0	0	(488,483)
	d Amortization of Unrecovered Investment (a)		0	(3,683,571)	(3,683,571)	(3,683,571)	(3,683,571)	(3,683,571)	(3,683,571)	(3,683,571)	(3,683,571)	(3,683,571)	(3,683,571)	(3,683,571)	(3,683,571)	(44,202,846)
	e Prior Period Carrying Charge Unrecovered Balance (a)		(1,289,590)	(1,207,159)	(1,124,727)	(1,042,296)	(959,865)	(877,434)	(795,002)	(712,571)	(630,140)	(547,709)	(465,277)	(382,846)	(300,415)	(300,415)
	f Prior Period Carrying Charge Recovered (a)			(82,431)	(82,431)	(82,431)	(82,431)	(82,431)	(82,431)	(82,431)	(82,431)	(82,431)	(82,431)	(82,431)	(82,431)	
	g Prior Period Under/(Over) Recovery (Prior Month)				(24,237)	(19,637)	(22,152)	(289,973)	(290,453)	(46,333)	(33,014)	(31,662)	(33,220)	(32,805)	(11,882)	(870,135)
	h Net Investment		$260,796,454	$257,197,920	$253,577,468	$249,954,494	$246,064,817	$242,175,770	$238,529,832	$234,896,151	$231,263,761	$227,629,814	$223,996,287	$220,383,594	$216,748,025	$216,712,648
4	Average Net Investment			$258,997,187	$255,374,273	$251,752,398	$247,995,914	$244,105,834	$240,337,069	$236,696,492	$233,063,220	$229,429,846	$225,795,903	$222,172,585	$218,548,290	
5	Return on Average Net Investment															
	a Equity Component	0.00394		1,020,449	1,006,175	991,904	977,104	961,777	946,928	932,584	918,269	903,954	889,636	875,360	861,080	11,285,220
	b Equity Component Grossed Up For Taxes	1.62800		1,661,293	1,638,055	1,614,821	1,590,727	1,565,775	1,541,600	1,518,248	1,494,943	1,471,639	1,448,329	1,425,088	1,401,840	
	c Debt Component	0.00189		490,541	483,679	476,819	469,704	462,336	455,198	448,303	441,422	434,540	427,657	420,795	413,930	5,424,924
	d Total Return			2,151,834	2,121,734	2,091,640	2,060,431	2,028,111	1,996,798	1,966,551	1,936,365	1,906,179	1,875,986	1,845,883	1,815,770	23,797,280
6	Revenue Requirements for the Period (Lines 3a + 5d)			$2,154,438	$2,129,263	$2,096,973	$1,799,378	$1,769,122	$1,983,465	$1,967,008	$1,938,586	$1,907,253	$1,877,893	$1,869,040	$1,816,379	$23,308,797
7	Projected Revenue Requirements for the Period (Order No. PSC 13-0493-FOF-EI)			$2,178,675	$2,148,900	$2,119,125	$2,089,350	$2,059,575	$2,029,798	$2,000,023	$1,970,248	$1,940,473	$1,910,697	$1,880,921	$1,851,146	$24,178,932
8	Over/Under Recovery For the Period			($24,237)	($19,637)	($22,152)	($289,973)	($290,453)	($46,333)	($33,014)	($31,662)	($33,220)	($32,805)	($11,882)	($34,767)	($870,135)
9	**Other Exit / Wind-Down**															
	a Accounting			3,157	6,133	16,597	4,668	10,330	4,083	12,032	5,001	3,256	3,128	2,768	2,669	73,822
	b Corporate Planning			10,489	7,498	8,648	7,971	4,550	6,527	4,404	2,770	395	405	340	2,624	56,621
	c Legal			975	10,711	15,454	14,506	11,256	16,651	12,989	12,411	2,423	334	0	1,296	99,006
	d Joint Owner Credit			(1,202)	(2,001)	(3,345)	(2,231)	(2,148)	(2,241)	(2,419)	(1,659)	(499)	(318)	(255)	(542)	(18,859)
	e Total Other Exit / Wind-Down Costs			13,419	22,341	37,354	24,914	23,988	25,020	27,006	18,523	5,575	3,549	2,853	6,047	210,590
10	Jurisdictional Factor (A&G)			0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	
11	Jurisdictional Amount			12,510	20,827	34,822	23,225	22,362	23,324	25,176	17,267	5,197	3,309	2,659	5,637	196,314
12	Prior Period Unrecovered Balance (a)		661,239	587,445	513,652	439,858	366,065	292,271	218,478	144,684	70,891	(2,903)	(76,696)	(150,490)	(224,283)	
13	Prior Period Costs Recovered (a)			73,794	73,794	73,794	73,794	73,794	73,794	73,794	73,794	73,794	73,794	73,794	73,794	
14	Prior Month Period (Over)/Under Recovery			0	(20,560)	(12,241)	1,758	(9,837)	(10,701)	(9,741)	(7,891)	(15,798)	(27,870)	(29,760)	(30,412)	
15	Unamortized Balance		661,239	587,445	493,092	407,058	335,022	251,392	166,897	83,363	1,679	(87,913)	(189,577)	(293,130)	(397,336)	
16	Carrying Costs for the Period															
	a Balance Eligible for Interest			630,597	540,402	461,365	383,532	299,470	215,456	132,847	47,209	(48,418)	(151,026)	(254,904)	(357,620)	
	b Monthly Commercial Paper Rate			0.00%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	
	c Interest Provision			29	27	27	24	19	12	7	3	(3)	(8)	(16)	(27)	93
	d Total Costs and Interest (Line 11 + Line 16c)			12,538	20,854	34,848	23,249	22,380	23,336	25,182	17,270	5,194	3,300	2,643	5,611	196,407
17	Recovered (Order No. PSC 13-0493-FOF-EI)			33,099	33,094	33,090	33,086	33,081	33,077	33,073	33,069	33,064	33,060	33,056	33,051	396,900
18	Over/Under Recovery For the Period			(20,560)	(12,241)	1,758	(9,837)	(10,701)	(9,741)	(7,891)	(15,798)	(27,870)	(29,760)	(30,412)	(27,441)	(200,493)
19	Other - Adjustments (a)		(80,177)	(608)	(555)	(502)	(448)	(393)	(339)	(283)	(228)	(171)	(115)	(58)	0	(3,699)
20	Recovered (Order No. PSC 13-0493-FOF-EI)			(608)	(555)	(502)	(448)	(393)	(339)	(283)	(228)	(171)	(115)	(58)	(0)	(3,699)
21	Over/Under Recovery For the Period			0	0	0	0	0	0	0	0	0	0	0	0	0
22	**Revenue Requirements for the Period**			**2,166,369**	**2,149,561**	**2,131,320**	**1,822,179**	**1,791,109**	**2,006,462**	**1,991,907**	**1,955,629**	**1,912,276**	**1,881,078**	**1,871,625**	**1,821,989**	**23,501,504**
23	Recovered (Order No. PSC 13-0493-FOF-EI)			2,211,166	2,181,439	2,151,713	2,121,988	2,092,263	2,062,537	2,032,812	2,003,089	1,973,366	1,943,643	1,913,919	1,884,197	24,572,133
24	**Over/Under Recovery For the Period**			**(44,798)**	**(31,878)**	**(20,393)**	**(299,810)**	**(301,155)**	**(56,075)**	**(40,905)**	**(47,460)**	**(61,090)**	**(62,564)**	**(42,294)**	**(62,209)**	**(1,070,629)**

(a) Please see Appendix A for Beginning Balance support and support of Amortization of Unrecovered Balance and Other-Adjustments calculation.
(b) Other line reflects cost of removal of previously existing assets.
(c) Approximately $2.6M accounting adjustment to correct schedule presentation line in Line.1a and 2a in April 2014.
This amount represents expenses incurred and cash paid in a previous period that did not have an offsetting accrual adjustment.
(c) Approximately $312K accounting adjustment to correct schedule presentation line in Line.1a and 2a in Nov 2014.
This amount represents accruals for anticipated expenses that were not incurred or the payment of the actual amount was lower than the accrual.

DEF - CR3 Uprate

Appendix A
Witness: Thomas G. Foster
Docket No. 150009-EI
Duke Energy Florida
Exhibit (TGF-2)
(Page 1 of 3)

2014 Over/Under Recovery Beginning Balance

Line.					
3b	**Transferred to Plant In-service**		**$**	**29,995,096**	
	EB from TGF-3_2013 Detail (filed March 2014) Line 3b				
3e	**Unrecovered Balance Carrying Cost**		**$**	**(1,289,590)**	
	Prior Period	2,251,684	Exhibit TGF-3 (2014)		Line 3d. Prior Period Carrying Charge Unrecovered Balance
	Current Period	(3,549,147)	Exhibit TGF-3 (2014)		Line 7 (Over)/Under for the Period
	Current Period	7,873	Exhibit TGF-3 (2014)		Appendix A (3 of 3) Line 11 = adjustment for DTA calculation
	Total	(1,289,590)			
3f	**Prior Period Carrying Charge Recovered**			(82,431)	Monthly Amount to Amortize per Order PSC-13-0493-FOF-EI TGF-6 Docket No. 130009-EI 2014 Detail Line 7.
	Other Exit / Wind-Down				
12	Prior Period Unrecovered Balance		**$**	**661,239**	
	Prior Period	431,957	Exhibit TGF-3 (2014)		Line 11 Prior Period Unrecovered Balance
	Current Period	229,282	Exhibit TGF-3 (2014)		Line 17 (Over)/Under for the Period
	Total	661,239			
13	**Prior Period Costs Recovered**			73,794	Monthly Amount to Amortize per Order PSC-13-0493-FOF-EI TGF-6 Docket No. 130009-EI 2014 Detail Line 17.

Annual Amortization Calculation of the Uncollected Investment Balance

	TGF-6 Filed May 1, 2013	
1	Estimated 2013 EB Unrecovered Investment	265,009,070
2	Estimated 2014 Additions	208,008
3	Estimated 2014 EB Investment prior to Amortize (2014 through 2019)	265,217,078
4	Annual Amortization - 2014	44,202,846

Summary of 2014 Amortization Activity (For 2014 Summary)

Amortization of Unrecovered Balance	44,202,846	Exhibit TGF-6 Docket 130009-EI (2014 Revenue Requirement Summary) Line (1.)
Prior Period Over/Under Recoveries	(183,830)	Exhibit TGF-6 Docket 130009-EI (2014 Revenue Requirement Summary) Line (5.)
Period Amortizaton of Unrecovered Investment and Prior Period Over/Under Balances	44,019,016	

Prior Period Over / (Under) Support Schedules

DEF - CR3 Uprate

		2012 True Up	Note 1 2012 Est-Actual	2014 Collection/ (Refund)
1	Construction Carrying Cost Rev Req.	20,403,400	18,254,142	2,149,258
2	Recoverable O&M Revenue Req.	432,585	130	432,456
3	DTA	802,415	787,279	15,136
4	In-service Rev Reqs/Base Refund	(3,242,310)	(3,242,310)	0
5	Total Revenue Requirement	18,396,090	15,799,241	2,596,849

Note 1: 2012 Est-Actual amounts are per Order PSC-12-0650-FOF-EI, Docket 120009-EI, Pg 39

		2013 Est-Actual	Note 2 2013 Projection	2014 Collection/ (Refund)
6	Construction Carrying Cost Rev Req.	27,111,962	28,401,158	(1,289,196)
7	Recoverable O&M Revenue Req.	453,738	173	453,565
8	DTA	-	1,951,664	(1,951,664)
9	In-service Rev Reqs/Base Refund	(6,946)	(3,587)	(3,358)
10	Total Revenue Requirement	27,558,755	30,349,407	(2,790,653)

Note 2: 2013 Projection amounts are per Order PSC-12-0650-FOF-EI, Docket 120009-EI, Pg 40

DEF CR3 Uprate
In Service Project Revenue Requirements 2014 Recovery

Appendix A
Witness: Thomas G. Foster
Docket No. 150009-EI
Duke Energy Florida
Exhibit No. ____ (TGF - 2)
(Page 3 of 3)

	Beg Balance	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1 In-service Project Revenue Requirements														
2 Projected In-service Project Revenue Requirements	(26,686)	(2,224)	(2,224)	(2,224)	(2,224)	(2,224)	(2,224)	(2,224)	(2,224)	(2,224)	(2,224)	(2,224)	(2,224)	(26,686)
3 Prior Years In-service Project Revenue Requirements	(57,190)	(4,766)	(4,766)	(4,766)	(4,766)	(4,766)	(4,766)	(4,766)	(4,766)	(4,766)	(4,766)	(4,766)	(4,766)	(57,190)
4 Under/(Over) Recovery		($73,188)	($66,198)	($59,208)	($52,219)	($45,229)	($38,239)	($31,250)	($24,260)	($17,270)	($10,281)	($3,291)	$3,699	
														($83,876)
5 Cumulative Under/(Over) Recovery	($80,177)	($73,188)	($66,806)	($60,371)	($53,883)	($47,341)	($40,745)	($34,094)	($27,387)	($20,625)	($13,807)	($6,932)	$0	
6 Return on Average Under/(Over) Recovery (c)														
7 Equity Component (a)	0.00394	(288)	(263)	(238)	(212)	(187)	(161)	(134)	(108)	(81)	(54)	(27)	0	($1,754)
8 Equity Component grossed up for taxes (b)	1.62800	(469)	(429)	(387)	(346)	(304)	(261)	(219)	(176)	(132)	(89)	(44)	0	(2,856)
9 Debt Component	0.001894	(139)	(127)	(114)	(102)	(90)	(77)	(65)	(52)	(39)	(26)	(13)	0	(843)
10 Total Return on Under/(Over) Recovery (2014 Detail Line 19)		($608)	($555)	($502)	($448)	($393)	($339)	($283)	($228)	($171)	($115)	($58)	$0	($3,699)
11 Amortization of Beginning Balance		($6,681)	($6,681)	($6,681)	($6,681)	($6,681)	($6,681)	($6,681)	($6,681)	($6,681)	($6,681)	($6,681)	($6,681)	($80,177)
		($7,290)	($7,236)	($7,183)	($7,129)	($7,075)	($7,020)	($6,965)	($6,909)	($6,853)	($6,796)	($6,739)	($6,681)	($83,876)
		($608)	($555)	($502)	($448)	($393)	($339)	($283)	($228)	($171)	($115)	($58)	($0)	($3,699)

Notes:
(a) The monthly Equity Component of 4.87% reflects an 10.5% return on equity.
(b) Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 38.575%.
(c) AFUDC actual monthly rate is calculated using the formula M = $[(1 + A/100)^{1/12} 1] \times 100$; resulting in a monthly accrual rate of 0.00394 (Equity) and 0.001894 (Debt), which results in the annual rate of 7.23%.

2014 Revenue Requirements	($83,876)
Less: Annual Return	$3,699
2014 Beginning Balance	($80,177)

CRYSTAL RIVER UNIT 3 UPRATE
Estimated / Actual Filing: Other Exit / Wind-Down Expenditures Allocated or Assigned to Other Recovery Mechanisms

EXPLANATION: Provide variance explanations comparing the actual system total expenditures shown on 2014 Detail Schedule with the expenditures approved by the Commission on Est/Act Detail 2014 Schedules.

Appendix B
Witness: Thomas G. Foster
Docket No. 150009-EI
Duke Energy Florida
Exhibit: (TGF - 2)

COMPANY:
Duke Energy Florida

DOCKET NO.:
150009-EI

For Year Ended 12/31/2014

Line No.	Description	(A) System Estimated/Actual	(B) System True-Up	(C) Variance Amount	(D) Explanation
	Allocated or Assigned Other Exit / Wind-Down Expenditures				
1	Accounting	$93,570	$73,822	($19,748)	
2	Corporate Planning	82,437	56,621	(25,816)	
3	Legal	75,000	99,006	24,006	
4	Total	$251,007	$229,449	($21,558)	Minor variance from estimated amount.

Note:
System Estimated/Actual from May 1, 2014 Filing in Docket No. 140009-EI.

DUKE ENERGY FLORIDA
Average Rate of Return - Capital Structure
FPSC Adjusted Basis
December 2012

Appendix C
Witness: Thomas G. Foster
Docket No. 150009-EI
Duke Energy Florida
Exhibit No. ___ (TGF - 2)

	System Per Books	Specific Adjustments	Pro Rata Adjustments	System Adjusted	FPSC Adjusted Retail	Ratio	Low Point		Mid Point		High Point	
							Cost Rate	Weighted Cost	Cost Rate	Weighted Cost	Cost Rate	Weighted Cost
Common Equity	$4,767,157,537	657,669,241	($813,779,810)	$4,611,046,968	$3,753,238,636	46.36%	9.50%	4.40%	10.50%	4.87%	11.50%	5.33%
Preferred Stock	33,496,700		(5,024,850)	28,471,850	23,175,138	0.29%	4.51%	0.01%	4.51%	0.01%	4.51%	0.01%
Long Term Debt - Fixed	4,491,809,896	0	(673,817,682)	3,817,992,215	3,107,718,483	38.39%	5.78%	2.22%	5.78%	2.22%	5.78%	2.22%
Short Term Debt *	232,034,133	(51,903,909)	(27,021,386)	153,108,838	124,625,494	1.54%	0.60%	0.01%	0.60%	0.01%	0.60%	0.01%
Customer Deposits												
Active	214,453,652		(32,170,253)	182,283,398	182,283,398	2.25%	5.36%	0.12%	5.36%	0.12%	5.36%	0.12%
Inactive	1,280,766		(192,128)	1,088,638	1,088,638	0.01%						
Investment Tax Credit												
Post '70 Total	3,450,862		(517,665)	2,933,197								
Equity **					1,309,719	0.02%	9.58%	0.00%	10.59%	0.00%	11.59%	0.00%
Debt **					1,077,805	0.01%	5.85%	0.00%	5.85%	0.00%	5.85%	0.00%
Deferred Income Taxes	1,365,618,849	155,326,427	(228,157,434)	1,292,787,842	1,052,286,240	13.00%						
FAS 109 DIT - Net	(218,650,949)		32,799,891	(185,851,058)	(151,276,570)	-1.87%						
Total	**$10,890,651,446**	**$761,091,759**	**($1,747,881,316)**	**$9,903,861,889**	**$8,095,526,982**	**100.00%**		**6.76%**		**7.23%**		**7.69%**

Equity	4.88%
Debt	2.35%
Total	7.23%

* Daily Weighted Average
**Cost Rates Calculated Per IRS Ruling

CRYSTAL RIVER UNIT 3 UPRATE
True-Up Filing: Construction Category - Description of Monthly Cost Additions

EXPLANATION: Provide a description of the major tasks performed within the Construction category for the year.
List generation expenses separate from transmission in the same order appearing on 2014 Detail Schedule.

Appendix D
Witness: M. Teague
Docket No. 150009-EI
Duke Energy Florida
Exhibit No. ____ (TGF - 2)
(Page 1 of 2)

COMPANY:
Duke Energy Florida

DOCKET NO.:
150009-EI

For Year Ended 12/31/2014

Line No.	Major Task & Description for amounts on 2014 Detail Schedule	Description
	Generation:	
1	EPU Construction & Wind-Down Costs	Spend performed in accordance with Rule 25-6.0423(7).
2	Sale or Salvage of Assets	Net Value received in accordance with Duke Energy Procedure AI-9010 regarding Disposition of Assets
3	Disposition	Net Value received in accordance with Duke Energy Procedure AI-9010 regarding Disposition of Assets
	Transmission:	
	N/A	

CRYSTAL RIVER UNIT 3 UPRATE
True-Up Filing: Construction Category - Variance in Additions and Expenditures

EXPLANATION: Provide variance explanations comparing the annual system total expenditures shown on 2014 Detail Schedule with the expenditures approved by the Commission on Est/Actual Detail 2014. List the Generation expenses separate from Transmission in the same order appearing on 2014 Detail Schedule.

Appendix D
Witness: M. Teague
Docket No. 150009-EI
Duke Energy Florida
Exhibit: (TGF - 2)
(Page 2 of 2)

COMPANY:
Duke Energy Florida

DOCKET NO.:
150009-EI

For Year Ended 12/31/2014

Line No.	Construction Major Task & Description for amounts on 2014 Detail Schedule	(A) System Estimated /Actual	(B) System Actual	(C) Variance Amount	(D) Explanation
	Generation:				
1	EPU Wind-Down Costs (a)	$460,822	$41,938	($418,884)	This variance is primarily related to the fact that DEF over-estimated the amount of time necessary to conduct the required preventative maintenance and there was less equipment to be maintained because some of the EPU equipment was sold in the middle of 2014.
2	Sale or Salvage of Assets	0	(453,858)	($453,858)	This variance is explained by inclusion of the NCRC portion of proceeds from the sale, transfer and salvage of EPU-related assets in 2014 in this filing. The proceeds were previously not known and thus not estimated for or included in the 2014 estimated/actual filing.
3	Disposition	0	0	0	
4	Total Generation Costs	$460,822	($411,920)	($872,742)	
	Transmission:				
	N/A				

Note:
(a):Approximately $2.6M adjustment to correct schedule presentation line in 2014 Detail Line. 1a and 2a in April 2014 (no impact on revenue requirement).
This amount represents expenses incurred and cash paid in a previous period that did not have an offsetting accrual adjustment.
Approximately ($312K) accounting adjustment to correct schedule presentation line in Line.1a and 2a in Nov 2014 (no impact on revenue requirement).
This amount represents accruals for anticipated expenses that were not incurred or the payment of the actual amount was lower than the accrual.

System Estimated / Actual from May 1, 2014 Filing in Docket No. 140009-EI.

CRYSTAL RIVER UNIT 3 UPRATE
True-Up Filing: Summary of Contracts Executed Over $1 Million

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY:
Duke Energy Florida

DOCKET NO.:
150009-EI

EXPLANATION: Provide a list of contracts executed in excess of $1 million including, a description of the work, the dollar value and term of the contract, the method of vendor selection, the identity and affiliation of the vendor, and current status of the contract.

Appendix E
Witness: M. Teague
Docket No. 150009-EI
Duke Energy Florida
Exhibit No. ____ (TGF - 2)

For Year Ended 12/31/2014

All EPU-related contracts in excess of $1 million have been closed as of December 31, 2013. No new contracts over $1 million were executed after December 31, 2013.

SCHEDULE APPENDIX

REDACTED

EXHIBIT (TGF-3)

DUKE ENERGY FLORIDA, INC.
LEVY NUCLEAR UNITS 1 & 2
COMMISSION SCHEDULES

JANUARY 2015 - DECEMBER 2016
DOCKET NO. 150009-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 49
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)
DESCRIPTION: Thomas G. Foster TGF-3

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Levy Nuclear Units 1 & 2
January 2015 - December 2016

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4	2015 Detail	2015 Detail Revenue Requirement Calculations	T. G. Foster / C. Fallon
5	2016 Detail	2016 Detail Revenue Requirement Calculations	T. G. Foster / C. Fallon
6	2015 Detail	2015 Detail Revenue Requirement Calculations - LLE Deferred Balance	T. G. Foster / C. Fallon
7	2016 Detail	2016 Detail Revenue Requirement Calculations - LLE Deferred Balance	T. G. Foster / C. Fallon
8	2016 Rate Impact	2016 Estimated Rate Impact	T. G. Foster
9 - 11	Appendix A	Detail for 2015 & 2016 Beginning Balance Support for 2015 Regulatory Amortization Amount	T. G. Foster
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2016 Summary

12-Month Total

(1)	Amortization of Unrecovered Balance (excl. $54M)	$	12,084,506	2016 Detail Rev Req Calc. Line 6f
(2)	Period Carrying Cost on Unrecovered Investment		5,302,187	(2016 Detail Rev Req Calc Line 8d.) + (2016 Detail Rev Req Calc: LLE Deferred Balance Line 4.)
(3)	Period Exit Costs		46,443	2016 Detail Rev Req Calc Line 6a.
(4)	Period Other Exit / Wind-Down Costs incl. Interest		159,263	2016 Detail Rev Req Calc Line 18.
(5)	Prior Period Over/Under Recoveries		(4,132,857)	(2016 Detail Rev Req Calc Line 6g + Line 13) + (2016 Detail Rev Req Calc: LLE Deferred Balance Line 1b.)
(6)	Total 2016 Revenue Requirement	$	13,459,542	
(7)	Revenue Tax Multiplier		1.00072	
(8)	Total 2016 Projected Revenue Requirements	$	13,469,233	

Collection of the Fixed Levy Rate ($3.45 Residential) ceases in May 2015
LLE Adjustment of $54M (System Amount) occurs in May 2015

DUKE ENERGY FLORIDA
Nuclear Cost Recovery Clause (NCRC) - Levy Nuclear Units 1 & 2
2015 Detail - Calculation of the Revenue Requirements
January 2015 through December 2015

Witness: T.G. Foster / C. Fallon
Docket No. 150009-EI
Exhibit: (TGF- 3)

REDACTED

Line	Description		Beginning of Period Amount	Actual January 2015	Actual February 2015	Projected March 2015	Projected April 2015	Projected May 2015	Projected June 2015	Projected July 2015	Projected August 2015	Projected September 2015	Projected October 2015	Projected November 2015	Projected December 2015	Period Total	End of Period Total
1	**Uncollected Investment : Generation**																
	a Prior Period Construction Balance YE 2014																
	b Wind-Down Costs																
	c Sale or Salvage of Assets																
	d Disposition																
	e Total																
2	**Adjustments**																
	a Non-Cash Accruals																
	b Adjusted System Generation (Line 1e + Line 2a)																
	c Retail Jurisdictional Factor : Generation	92.885%															
	d Retail Uncollected Investment: Generation																
3	**Uncollected Investment : Transmission**																
	a Prior Period Construction Balance YE 2014																
	b Wind-Down Costs																
	c Sale or Salvage of Assets																
	d Disposition																
	e Total																
4	**Adjustments**																
	a Non-Cash Accruals																
	b Adjusted System Transmission (Line 3e + Line 4a)																
	c Retail Jurisdictional Factor : Transmission	70.203%															
	d Retail Uncollected Investment: Transmission																
5	**Total Uncollected Investment**																
	a Total Jurisdictional Uncollected Investment (2d + 4d)		224,062,889	10,416	3,461	7,901	7,901	(146,288)	7,901	7,901	7,901	7,901	7,901	7,901	7,901	(61,304)	224,001,584
	b Retail Land Transferred to Land Held for Future Use (a)		(66,221,330)														(66,221,330)
	c LLE Deferred Balance (c)		0					(50,275,957)								(50,275,957)	(50,275,957)
	d Total Jurisdictional Uncollected Investment		157,841,559	10,416	3,461	7,901	7,901	(50,422,245)	7,901	7,901	7,901	7,901	7,901	7,901	7,901	(50,337,261)	107,504,298
	e WACC Adjustment from 2014 (Adjustment to May 2015 Rev Req) (b)							(90,860)									
6	**Carrying Cost on Uncollected Investment Balance**																
	a Uncollected Investment: Additions for the Period (Beg Balance: 2015 Detail Line 5d.)		157,841,559	10,416	3,461	7,901	7,901	(50,422,245	7,901	7,901	7,901	7,901	7,901	7,901	7,901	(50,337,261)	107,504,298
	b Plant-in-Service (a)		1,010,952	0	0	0	0	0	0	0	0	0	0	0	0	0	1,010,952
	c Period Recovered Wind-down / Exit Costs (2014)		9,816,636	0	0	0	0	0	0	0	0	0	0	0	0	0	9,816,636
	d Period Recovered Wind-down / Exit Costs (2015)		0	0	0	0	0	0	0	0	0	0	0	0	0	(61,304)	(61,304)
	e Additional Amortization of Uncollected Investment Balance (2014-2015)		(46,864,516)	(9,447,248)	(9,447,248)	(9,447,248)	(9,447,248)	0	0	0	0	0	0	0	0	(37,788,992)	(84,653,508)
	f Prior Period Carrying Charge Unrecovered Balance (a)		(11,381,362)	(10,432,915)	(9,484,468)	(8,536,021)	(7,587,574)	0	0	0	0	0	0	0	0	0	(7,587,574)
	g Prior Period Carrying Charge Recovered (a)		(11,381,362)	(948,447)	(948,447)	(948,447)	(948,447)	0	0	0	0	0	0	0	0		
	h Over/Under Prior Period				(3,444)	(9,057)	(3,274)	(1,903)	3,454	44,439	44,801	45,167	45,534	45,904	46,278	304,554	304,554
	i Net Investment		$88,768,093	$80,279,708	$71,770,508	$63,267,090	$54,765,014	$4,332,965	$4,490,608	$4,535,047	$4,579,848	$4,625,015	$4,670,549	$4,716,453	$4,762,731		$4,801,486
7	Average Net Investment			$84,523,901	$76,018,178	$67,512,540	$59,010,464	$29,544,088	$4,486,658	$4,531,097	$4,575,898	$4,621,065	$4,666,599	$4,712,503	$4,758,781		
8	Return on Average Net Investment																
	a Equity Component	0.00403		340,631	306,353	272,076	237,812	119,063	18,081	18,260	18,441	18,623	18,806	18,991	19,178	1,406,315	
	b Equity Component Grossed Up For Taxes	1.62800		554,548	498,743	442,940	387,158	193,835	29,436	29,727	30,022	30,318	30,616	30,917	31,222	2,289,483	
	c Debt Component	0.00158		133,801	120,337	106,872	93,414	46,768	7,102	7,173	7,244	7,315	7,387	7,460	7,533	552,406	
	d Total Return for the Period			688,349	619,080	549,812	480,572	240,603	36,538	36,900	37,266	37,633	38,003	38,377	38,755	2,841,889	
9	**Revenue Requirements for the Period (Line 5e + 6a + 8d) (b)**			698,765	622,541	557,713	488,473	3,454	44,439	44,801	45,167	45,534	45,904	46,278	46,656	2,689,725	
10	Projected Revenue Requirements for the Period (Order No. PSC 14-0701-FOF-EI)			702,209	631,598	560,987	490,377	0	0	0	0	0	0	0	0	2,385,171	
11	Over/Under Recovery For the Period			(3,444)	(9,057)	(3,274)	(1,903)	3,454	44,439	44,801	45,167	45,534	45,904	46,278	46,656	304,554	
12	**Other Exit / Wind-Down**																
	a Accounting			3,029	2,926	7,405	7,405	7,405	7,405	7,405	7,405	7,405	7,405	7,405	7,405	$80,000	
	b Corporate Planning			2,280	7,570	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	5,169	$61,535	
	c Legal			320	16,721	9,296	9,296	9,296	9,296	9,296	9,296	9,296	9,296	9,296	9,296	$110,000	
	d Joint Owner Credit			0	0	0	0	0	0	0	0	0	0	0	0	0	
	e Total Other Exit / Wind-Down Costs			5,629	27,217	21,869	21,869	21,869	21,869	21,869	21,869	21,869	21,869	21,869	21,869	$251,535	
13	Jurisdictional Factor (A&G)			0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221		
14	Jurisdictional Amount			5,247	25,372	20,386	20,386	20,386	20,386	20,386	20,386	20,386	20,386	20,386	20,386	234,484	
15	Prior Period Unrecovered Balance (a)		(179,385)	(164,436)	(149,488)	(134,539)	(119,590)	(119,590)	(119,590)	(119,590)	(119,590)	(119,590)	(119,590)	(119,590)	(119,590)		
16	Prior Period Costs Recovered (a)			(14,949)	(14,949)	(14,949)	(14,949)										
17	Prior Month Period (Over)/Under Recovery			0	(24,355)	(4,228)	(9,215)	(9,215)	20,375	20,375	20,376	20,378	20,379	20,381	20,382		
18	Unamortized Balance		(179,385)	(164,436)	(173,843)	(163,123)	(157,389)	(166,605)	(146,229)	(125,855)	(105,478)	(85,101)	(64,721)	(44,341)	(23,958)		
19	Projected Carrying Costs for the Period																
	a Balance Eligible for Interest			(169,287)	(144,276)	(156,175)	(145,455)	(147,196)	(156,412)	(136,036)	(115,661)	(95,285)	(74,907)	(54,528)	(34,147)		
	b Monthly Commercial Paper Rate			0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%		
	c Interest Provision			(14)	(11)	(12)	(11)	(11)	(12)	(10)	(9)	(7)	(6)	(4)	(3)	(109)	
	d **Total Costs and Interest (Line 14 + Line 19c)**			5,233	25,361	20,375	20,376	20,375	20,375	20,376	20,378	20,379	20,381	20,382	20,384	234,375	
20	Recovered (Order No. PSC 14-0701-FOF-EI)			29,589	29,589	29,590	29,591	0	0	0	0	0	0	0	0	118,359	
21	Over/Under Recovery For the Period			(24,355)	(4,228)	(9,215)	(9,215)	20,375	20,375	20,376	20,378	20,379	20,381	20,382	20,384	116,016	
22	**Revenue Requirements for the Period (Line 9 + Line 19d)**			703,998	647,902	578,088	508,849	23,830	64,813	65,177	65,545	65,913	66,285	66,661	67,039	2,924,100	

(a) See Appendix A for Beginning Balance Support
(b) 2014 WACC Adjustment (Amount includes interest Jan-May 2015)
(c) This amount represents deferral of $54,127,100 consistent with Order No. PSC-14-0617-FOF-EI, Section 366.93, Fla. Stat. and Rule 25-6.0423, F.A.C.

DUKE ENERGY FLORIDA
Nuclear Cost Recovery Clause (NCRC) - Levy Nuclear Units 1 & 2
2016 Detail - Calculation of the Revenue Requirements
January 2016 through December 2016

Witness: T.G. Foster / C. Fallon
Docket No. 150009-EI
Exhibit: (TGF-3)
REDACTED

Line	Description		Beginning of Period Amount	Projected January 2016	Projected February 2016	Projected March 2016	Projected April 2016	Projected May 2016	Projected June 2016	Projected July 2016	Projected August 2016	Projected September 2016	Projected October 2016	Projected November 2016	Projected December 2016	Period Total	End of Period Total
1	**Uncollected Investment : Generation**																
	a Prior Period Construction Balance YE 2015																
	b Wind-Down Costs																
	c Sale or Salvage of Assets																
	d Disposition																
	e Total																
2	**Adjustments**																
	a Non-Cash Accruals																
	b Adjusted System Generation (Line 1e + Line 2a)																
	c Retail Jurisdictional Factor : Generation	92.885%															
	d Retail Uncollected Investment: Generation																
3	**Uncollected Investment : Transmission**																
	a Prior Period Construction Balance YE 2015																
	b Wind-Down Costs																
	c Sale or Salvage of Assets																
	d Disposition																
	e Total																
4	**Adjustments**																
	a Non-Cash Accruals																
	b Adjusted System Transmission (Line 3e + Line 4a)																
	c Retail Jurisdictional Factor : Transmission	70.203%															
	d Retail Uncollected Investment: Transmission																
5	**Total Uncollected Investment**																
	a Total Jurisdictional Uncollected Investment (2d + 4d)		173,725,628														173,772,070
	b Retail Land Transferred to Land Held for Future Use (a)		(66,221,330)														(66,221,330)
	c Total Jurisdictional Uncollected Investment		107,504,298	3,870	3,870	3,870	3,870	3,870	3,870	3,870	3,870	3,870	3,870	3,870	3,870	46,443	107,550,740
6	**Carrying Cost on Uncollected Investment Balance**																
	a Uncollected Investment: Additions for the Period (Beg Balance: Line 6a.)		107,504,298	3,870	3,870	3,870	3,870	3,870	3,870	3,870	3,870	3,870	3,870	3,870	3,870	46,443	107,550,740
	b Plant-In-Service (a)		1,010,952	0	0	0	0	0	0	0	0	0	0	0	0	0	1,010,952
	c Period Recovered Wind-down / Exit Costs (2014 & 2015)		9,755,332	0	0	0	0	0	0	0	0	0	0	0	0	0	9,755,332
	d Amortization of Uncollected Investment (2014-2015)		(84,653,508)	0	0	0	0	0	0	0	0	0	0	0	0	0	(84,653,508)
	e Period Recovered Wind-down / Exit Costs (2016)		0	0	0	0	0	0	0	0	0	0	0	0	0	46,443	46,443
	f Amortization of Uncollected Investment Balance (2016)			1,007,042	1,007,042	1,007,042	1,007,042	1,007,042	1,007,042	1,007,042	1,007,042	1,007,042	1,007,042	1,007,042	1,007,042	12,084,506	(12,084,506)
	g Prior Period Carrying Charge Unrecovered Balance (a)		(7,283,020)	(6,676,102)	(6,069,183)	(5,462,265)	(4,855,347)	(4,248,428)	(3,641,510)	(3,034,592)	(2,427,673)	(1,820,755)	(1,213,837)	(606,918)	0	0	
	h Prior Period Carrying Charge Recovered		(7,283,020)	(606,918)	(606,918)	(606,918)	(606,918)	(606,918)	(606,918)	(606,918)	(606,918)	(606,918)	(606,918)	(606,918)	(606,918)		
	i Uncollected Return from the Prior Period		0	0	0	0	0	0	0	0	0	0	0	0	0		0
	j Net Investment		$4,801,486	$4,405,232	$4,005,109	$3,604,985	$3,204,861	$2,804,737	$2,404,613	$2,004,489	$1,604,366	$1,204,242	$804,118	$403,994	$3,870		$0
7	Average Net Investment			$4,603,359	$4,203,235	$3,803,111	$3,402,988	$3,002,864	$2,602,740	$2,202,616	$1,802,492	$1,402,369	$1,002,245	$602,121	$201,997		
8	Return on Average Net Investment																
	a Equity Component	0.00403		18,552	16,939	15,327	13,714	12,102	10,489	8,877	7,264	5,652	4,039	2,427	814	116,196	
	b Equity Component Grossed Up For Taxes	1.62800		30,203	27,577	24,952	22,326	19,702	17,076	14,452	11,826	9,201	6,575	3,951	1,325	189,167	
	c Debt Component	0.00158		7,287	6,654	6,020	5,387	4,754	4,120	3,487	2,853	2,220	1,587	953	320	45,642	
	d Total Return for the Period			**37,490**	**34,231**	**30,972**	**27,713**	**24,456**	**21,196**	**17,939**	**14,679**	**11,421**	**8,162**	**4,904**	**1,645**	**234,809**	
9	**Revenue Requirements for the Period (Line 6a + Line 8d)**			**41,360**	**38,101**	**34,843**	**31,584**	**28,326**	**25,066**	**21,809**	**18,549**	**15,292**	**12,033**	**8,774**	**5,515**	**281,252**	
10	**Other Exit / Wind-Down**																
	a Accounting			6,867	6,867	6,867	6,867	6,867	6,867	6,867	6,867	6,867	6,867	6,867	6,867	$82,400	
	b Corporate Planning			5,282	5,282	5,282	5,282	5,282	5,282	5,282	5,282	5,282	5,282	5,282	5,282	$63,381	
	c Legal			2,083	2,083	2,083	2,083	2,083	2,083	2,083	2,083	2,083	2,083	2,083	2,083	$25,000	
	d Joint Owner Credit			0	0	0	0	0	0	0	0	0	0	0	0	0	
	e Total Other Exit / Wind-Down Costs			14,232	14,232	14,232	14,232	14,232	14,232	14,232	14,232	14,232	14,232	14,232	14,232	$170,781	
11	Jurisdictional Factor (A&G)			0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221		
12	Jurisdictional Amount			13,267	13,267	13,267	13,267	13,267	13,267	13,267	13,267	13,267	13,267	13,267	13,267	159,204	
13	Prior Period Unrecovered Balance (a)		(3,574)	(3,276)	(2,979)	(2,681)	(2,383)	(2,085)	(1,787)	(1,489)	(1,191)	(894)	(596)	(298)	0	0	
14	Prior Period Costs Recovered (a)		(3,574)	(298)	(298)	(298)	(298)	(298)	(298)	(298)	(298)	(298)	(298)	(298)	(298)		
15	Prior Month Period (Over)/Under Recovery			0	13,267	13,267	13,268	13,269	13,270	13,271	13,272	13,273	13,274	13,275	13,276		
16	Unamortized Balance		(3,574)	(3,276)	10,289	23,854	37,420	50,987	64,555	78,124	91,695	105,266	118,838	132,411	145,986		
17	Projected Carrying Costs for the Period																
	a Balance Eligible for Interest			3,208	3,506	17,071	30,636	44,202	57,770	71,338	84,907	98,477	112,048	125,621	139,194		
	b Monthly Commercial Paper Rate			0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%		
	c Interest Provision			0	0	1	2	3	4	5	6	7	8	9	10	59	
	d Total Costs and Interest (Line 12 + Line 17c)			13,267	13,267	13,268	13,269	13,270	13,271	13,272	13,273	13,274	13,275	13,276	13,277	159,263	
18	**Other Exit / Wind-Down Revenue Requirements for the Period**			**13,267**	**13,267**	**13,268**	**13,269**	**13,270**	**13,271**	**13,272**	**13,273**	**13,274**	**13,275**	**13,276**	**13,277**	**159,263**	
19	**Total Revenue Requirements for the Period (Line 9 + Line 18)**			**54,627**	**51,368**	**48,111**	**Page 16 of 17**	**41,597**	**38,338**	**35,081**	**31,822**	**28,566**	**25,308**	**22,051**	**18,793**	**440,515**	

(a) See Appendix A for Beginning Balance Support

DUKE ENERGY FLORIDA
Nuclear Cost Recovery Clause (NCRC) - Levy Nuclear Units 1 & 2
2015 Detail - Calculation of the Revenue Requirements - LLE Deferred Balance
January 2015 through December 2015

Line	Description		Beginning of Period Amount	Actual January 2015	Actual February 2015	Projected March 2015	Projected April 2015	Projected May 2015	Projected June 2015	Projected July 2015	Projected August 2015	Projected September 2015	Projected October 2015	Projected November 2015	Projected December 2015	Period Total	End of Period Total
1	**Uncollected Investment : LLE Deferred Balance**																
	a Uncollected Investment: LLE Deferred Balance ($54M System)		0	0	0	0	0	50,275,957	0	0	0	0	0	0	0	50,275,957	50,275,957
	b Prior Period Carrying Charge Unrecovered Balance		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	c Prior Period Carrying Charge Recovered		0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d Over/Under Prior Period			0	0	0	0	0	204,719	411,107	414,455	417,830	421,233	424,664	428,122	3,153,738	3,153,738
	e Net Investment		$0	$0	$0	$0	$0	$50,275,957	$50,480,676	$50,891,783	$51,306,238	$51,724,068	$52,145,301	$52,569,965	$52,998,087		$53,429,695
2	Average Net Investment		$0	$0	$0	$0	$0	$25,137,978	$50,480,676	$50,891,783	$51,306,238	$51,724,068	$52,145,301	$52,569,965	$52,998,087		
3	Return on Average Net Investment																
	a Equity Component	0.00403		0	0	0	0	101,306	203,437	205,094	206,764	208,448	210,146	211,857	213,582	1,560,634	
	b Equity Component Grossed Up For Taxes	1.62800		0	0	0	0	164,926	331,196	333,893	336,612	339,354	342,118	344,904	347,712	2,540,715	
	c Debt Component	0.00158		0	0	0	0	39,793	79,911	80,562	81,218	81,879	82,546	83,218	83,896	613,023	
	d Total Return for the Period			**0**	**0**	**0**	**0**	**204,719**	**411,107**	**414,455**	**417,830**	**421,233**	**424,664**	**428,122**	**431,608**	**3,153,738**	
4	**Revenue Requirements for the Period (Line 3d)**			**0**	**0**	**0**	**0**	**204,719**	**411,107**	**414,455**	**417,830**	**421,233**	**424,664**	**428,122**	**431,608**	**3,153,738**	
5	Projected Revenue Collected for the Period			0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Over/Under Recovery For the Period			0	0	0	0	204,719	411,107	414,455	417,830	421,233	424,664	428,122	431,608	3,153,738	

DUKE ENERGY FLORIDA
Nuclear Cost Recovery Clause (NCRC) - Levy Nuclear Units 1 & 2
2016 Detail - Calculation of the Revenue Requirements - LLE Deferred Balance
January 2016 through December 2016

Witness: T. G. Foster
Docket No. 150009-EI
Exhibit: (TGF - 3)

Line	Description		Beginning of Period Amount	Actual January 2016	Actual February 2016	Projected March 2016	Projected April 2016	Projected May 2016	Projected June 2016	Projected July 2016	Projected August 2016	Projected September 2016	Projected October 2016	Projected November 2016	Projected December 2016	Period Total	End of Period Total
1	**Uncollected Investment : LLE Deferred Balance**																
	a Uncollected Investment: LLE Deferred Balance		50,275,957	0	0	0	0	0	0	0	0	0	0	0	0	0	50,275,957
	b Prior Period Carrying Charge Unrecovered Balance		3,153,738	2,890,926	2,628,115	2,365,303	2,102,492	1,839,680	1,576,869	1,314,057	1,051,246	788,434	525,623	262,811	0	0	0
	c Prior Period Carrying Charge Recovered		3,153,738	262,811	262,811	262,811	262,811	262,811	262,811	262,811	262,811	262,811	262,811	262,811	262,811		
	d Over/Under Prior Period			0	0	0	0	0	0	0	0	0	0	0	0	0	0
	e Net Investment		$53,429,695	$53,166,883	$52,904,072	$52,641,260	$52,378,449	$52,115,637	$51,852,826	$51,590,014	$51,327,203	$51,064,391	$50,801,580	$50,538,768	$50,275,957		$50,275,957
2	Average Net Investment		53,429,695	$53,298,289	$53,035,477	$52,772,666	$52,509,854	$52,247,043	$51,984,231	$51,721,420	$51,458,608	$51,195,797	$50,932,986	$50,670,174	$50,407,363		
3	Return on Average Net Investment																
	a Equity Component	0.00403		214,792	213,733	212,674	211,615	210,556	209,496	208,437	207,378	206,319	205,260	204,201	203,142	2,507,603	
	b Equity Component Grossed Up For Taxes	1.62800		349,682	347,958	346,234	344,510	342,786	341,060	339,336	337,612	335,888	334,164	332,440	330,716	4,082,382	
	c Debt Component	0.00158		84,371	83,955	83,539	83,123	82,707	82,291	81,875	81,459	81,043	80,627	80,211	79,795	984,996	
	d Total Return for the Period			**434,053**	**431,913**	**429,773**	**427,633**	**425,493**	**423,351**	**421,211**	**419,071**	**416,931**	**414,791**	**412,651**	**410,511**	**5,067,378**	
4	**Revenue Requirements for the Period (Line 3d)**			**434,053**	**431,913**	**429,773**	**427,633**	**425,493**	**423,351**	**421,211**	**419,071**	**416,931**	**414,791**	**412,651**	**410,511**	**5,067,378**	
5	Projected Revenue Collected for the Period			434,053	431,913	429,773	427,633	425,493	423,351	421,211	419,071	416,931	414,791	412,651	410,511	5,067,378	
6	Over/Under Recovery For the Period			0	0	0	0	0	0	0	0	0	0	0	0	0	
7	**Revenue Requirements for the Period**			**434,053**	**431,913**	**429,773**	**427,633**	**425,493**	**423,351**	**421,211**	**419,071**	**416,931**	**414,791**	**412,651**	**410,511**	**5,067,378**	

Schedule P-8

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY:

DOCKET NO.: 150009-EI

EXPLANATION: Using the billing determinants and allocation factors used in the previous year's cost recovery filings, provide an estimate of the rate impact by class of the costs requested for recovery. Current billing determinants and allocation factors may be used, if available.

Exhibit: TGF-3

For the Year Ended: 12/31/2016

Witness: T.G. Foster

Rate Class	(1) 12CP & 1/13 AD Demand Allocator (%)	(2) Production Demand Costs $	(3) Effective Mwh's @ Secondary Level	(4) **Capacity Cost Recovery Factor (c/Kwh)**	(5) **Capacity Cost Recovery Factor ($/kw-Mo)**
Residential					
RS-1, RST-1, RSL-1, RSL-2, RSS-1					
Secondary	60.859%	$8,197,212	19,495,155	0.042	
General Service Non-Demand					
GS-1, GST-1					
Secondary			1,575,864	0.034	
Primary			8,616	0.034	
Transmission			3,564	0.033	
TOTAL GS	4.010%	$540,157	**1,588,044**		
General Service					
GS-2 Secondary	0.284%	$38,307	165,610	0.023	
General Service Demand					
GSD-1, GSDT-1, SS-1					
Secondary			12,013,676		0.11
Primary			2,384,319		0.11
Transmission			10,895		0.11
TOTAL GSD	30.991%	$4,174,287	**14,408,890**		
Curtailable					
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3					
Secondary			-		0.08
Primary			121,778		0.08
Transmission			-		0.08
TOTAL CS	0.178%	$24,019	**121,778**		
Interruptible					
IS-1, IST-1, IS-2, IST-2, SS-2					
Secondary			89,382		0.10
Primary			1,588,841		0.10
Transmission			316,913		0.10
TOTAL IS	3.504%	$471,954	**1,995,136**		
Lighting					
LS-1 Secondary	0.173%	$23,297	385,378	**0.006**	
	100.000%	13,469,233	38,159,991	**0.035**	

2015
Line No.

WACC Adjustment from 2014

5e. Adjusted Dec Surveillance from 2012 to 2013- Staff Data Request LV-15-14

	Beginning Balance	Jan	Feb	March	April	May Adjustment
	(87,249)	(87,249)	(87,960)	(88,676)	(89,398)	(90,126)
Equity	0 00403	(352)	(354)	(357)	(360)	(363)
Eq -G/U	1 62800	(572)	(577)	(582)	(587)	(591)
Debt	0 00158	(138)	(139)	(140)	(142)	(143)
	Total	(711)	(716)	(722)	(728)	(734)
						$ (90,860)

Unrecovered Investment Beginning Balance for Carrying Cost Calculation

6f. Prior Period Unrecovered Balance **$ (11,381,362)**

Line 6f. 2014 Detail Prior Period Carrying Charge Unrecovered Balance (4,647,273)

Line 11 2014 Detail (6,734,088)

Other Exit & Wind-Down Costs

15. Prior Period (Over)/Under Recovery $ (179,385)

Line 15 2014 Detail Prior Period (Over)/Under Recovery (79,819)

Line 21 2014 Detail Over/Under Recovery For the Period (99,566)

2016
Line No.

Unrecovered Investment Beginning Balance for Carrying Cost Calculation

6f. Prior Period Unrecovered Balance $ **12,084,506**
Monthly amount to recover $ 1,007,042

6g. Prior Period Unrecovered Balance $ **(7,283,020)**
Monthly amount to recover $ (606,918)

Line 6f. 2015 Detail Prior Period Carrying Charge Unrecovered Balance (7,587,574)

Line 11 2015 Detail 304,554

Other Exit & Wind-Down Costs

13. Prior Period (Over)/Under Recovery $ **(3,574)**

Line 15 2015 Detail Prior Period (Over)/Under Recovery (119,590)

Line 21 2015 Detail Over/Under Recovery For the Period 116,016

Line No.

6a	Uncollected Investment: Additions for the Period	107,504,298
6b	*Less:* 'Plant-in-Service (a)	1,010,952
6c	*Less:* Period Recovered Wind-down / Exit Costs (2014-2015)	9,755,332
6d	Amortization of Uncollected Investment (2014-2015)	(84,653,508)
	Total Uncollected Investment as of YE 2015	**12,084,506**
	$54M System -- LLE Deferred Balance	54,127,100
	Retail (92 885%)-- LLE Deferred Balance	**50,275,957**
	Retail Unrecovered Investment (excl Carrying Cost & Over/Under)	**62,360,463**

DUKE ENERGY FLORIDA
Nuclear Cost Recovery Clause (NCRC) - Levy Nuclear Units 1 & 2

APPENDIX A
Witness: Thomas G. Foster
(TGF - 3)
(Page 2 of 3)

REDACTED

THIS SCHEDULE IS INCLUDED TO SUPPORT THE CALCULATION OF THE MONTHLY REVENUE REQUIREMENT FOR THE MONTHS (JANUARY 2015 - APRIL 2015)

Line	Description		Beginning of Period Amount	Projected January 2015	Projected February 2015	Projected March 2015	Projected April 2015	Projected May 2015	Projected June 2015	Projected July 2015	Projected August 2015	Projected September 2015	Projected October 2015	Projected November 2015	Projected December 2015	Period Total	End of Period Total
1	**Uncollected Investment : Generation**																
	a Prior Period Construction Balance YE 2014																
	b Wind-Down Costs																
	c Sale or Salvage of Assets																
	d Disposition																
	e Total																
2	**Adjustments**																
	a Non-Cash Accruals																
	b **Adjusted System Generation (Line 1e + Line 2a)**																
	c Retail Jurisdictional Factor - Generation	92.885%															
	d Retail Uncollected Investment: Generation																
3	**Uncollected Investment : Transmission**																
	a Prior Period Construction Balance YE 2014																
	b Wind-Down Costs																
	c Sale or Salvage of Assets																
	d Disposition																
	e Total																
4	**Adjustments**																
	a Non-Cash Accruals																
	d **Adjusted System Transmission (Line 3e + Line 4a)**																
	e Retail Jurisdictional Factor - Transmission	70.203%															
	f Retail Uncollected Investment: Transmission																
5	**Total Uncollected Investment**																
	a Total Jurisdictional Uncollected Investment (2d + 4f)		224,062,889														224,062,889
	b Retail Land Transferred to Land Held for Future Use (a)		(66,221,330)														(66,221,330)
	c Total Jurisdictional Uncollected Investment		157,841,559	0	0	0	0	0	0	0	0	0	0	0	0	0	157,841,559
6	**Carrying Cost on Uncollected Investment Balance**																
	a Uncollected Investment: Additions for the Period (Beg Balance: Line 5c. above)		157,841,559	0	0	0	0	0	0	0	0	0	0	0	0	0	157,841,559
	b Plant-in-Service (a)		1,010,952	0	0	0	0	0	0	0	0	0	0	0	0	0	1,010,952
	c Period Recovered Wind-down / Exit Costs		9,816,636	0	0	0	0	0	0	0	0	0	0	0	0	0	9,816,636
	d Additional of Uncollected Investment (2015)		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	e Additional Amortization of Uncollected Investment Balance		(46,864,516)	9,447,248	9,447,248	9,447,248	9,447,248	9,447,248	9,447,248	9,447,248	9,447,248	9,447,248	9,447,248	9,447,248	9,447,248	113,366,976	(160,231,492)
	f Prior Period Carrying Charge Unrecovered Balance (a)		(11,381,362)	(10,432,915)	(9,484,468)	(8,536,021)	(7,587,574)	(6,639,128)	(5,690,681)	(4,742,234)	(3,793,787)	(2,845,340)	(1,896,894)	(948,447)	0		0
	g Prior Period Carrying Charge Recovered (a)		(11,381,362)	(948,447)	(948,447)	(948,447)	(948,447)	(948,447)	(948,447)	(948,447)	(948,447)	(948,447)	(948,447)	(948,447)	(948,447)		
	Over/Under Prior Period				0	0	0	0	0	0	0	0	0	0	0		
	h Net Investment		$88,768,093	$80,269,292	$71,770,491	$63,271,690	$54,772,889	$46,274,087	$37,775,286	$29,276,485	$20,777,684	$12,278,883	$3,780,081	($4,718,720)	($13,217,521)		($13,217,521)
7	Average Net Investment			$84,518,693	$76,019,892	$67,521,090	$59,022,289	$50,523,488	$42,024,687	$33,525,886	$25,027,084	$16,528,283	$8,029,482	($469,319)	($8,968,120)		
8	Return on Average Net Investment	2012 WACC in effect when 2015 Rates were Set															
	a Equity Component	0.00394		333,004	299,518	266,033	232,548	199,063	165,577	132,092	98,607	65,121	31,636	(1,849)	(35,334)	1,786,016	
	b Equity Component Grossed Up For Taxes	1.62800		542,131	487,616	433,102	378,589	324,075	269,560	215,046	160,532	106,017	51,503	(3,010)	(57,524)	2,907,637	
	c Debt Component	0.00189		160,078	143,982	127,885	111,788	95,691	79,595	63,498	47,401	31,305	15,208	(889)	(16,986)	858,556	
	d Total Return for the Period			702,209	631,598	560,987	490,377	419,766	349,155	278,544	207,933	137,322	66,711	(3,899)	(74,510)	3,766,192	
9	**Revenue Requirements for the Period (Line 6a + 8d)**			702,209	631,598	560,987	490,377	419,766	349,155	278,544	207,933	137,322	66,711	(3,899)	(74,510)	3,766,193	
10	Projected Revenue Requirements for the Period (Order No. PSC 14-0701-FOF-EI)			702,209	631,598	560,987	490,377	419,766	349,155	278,544	207,933	137,322	66,711	(3,899)	(74,510)	3,766,193	
11	Over/Under Recovery For the Period			0	0	0	0	0	0	0	0	0	0	0	0	0	
10	**Other Exit / Wind-Down**																
	a Accounting			10,262	10,262	10,262	10,262	10,262	10,262	10,262	10,262	10,262	10,262	10,262	10,262	$123,148	
	b Corporate Planning			16,070	16,070	16,070	16,070	16,070	16,070	16,070	16,070	16,070	16,070	16,070	16,070	$192,838	
	c Legal			5,417	5,417	5,417	5,417	5,417	5,417	5,417	5,417	5,417	5,417	5,417	5,417	$65,000	
	d Joint Owner Credit			0	0	0	0	0	0	0	0	0	0	0	0	0	
	e Total Other Exit / Wind-Down Costs			31,749	31,749	31,749	31,749	31,749	31,749	31,749	31,749	31,749	31,749	31,749	31,749	$380,986	
11	Jurisdictional Factor (A&G)			0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221	0.93221		
12	Jurisdictional Amount			29,597	29,597	29,597	29,597	29,597	29,597	29,597	29,597	29,597	29,597	29,597	29,597	355,159	
13	Prior Period Unrecovered Balance (a)		(179,385)	(164,436)	(149,488)	(134,539)	(119,590)	(104,641)	(89,693)	(74,744)	(59,795)	(44,846)	(29,898)	(14,949)	(0)		
14	Prior Period Costs Recovered (a)			(14,949)	(14,949)	(14,949)	(14,949)	(14,949)	(14,949)	(14,949)	(14,949)	(14,949)	(14,949)	(14,949)	(14,949)		
15	Unamortized Balance		(179,385)	(164,436)	(149,488)	(134,539)	(119,590)	(104,641)	(89,693)	(74,744)	(59,795)	(44,846)	(29,898)	(14,949)	(0)		
16	Projected Carrying Costs for the Period																
	a Balance Eligible for Interest			(157,112)	(142,164)	(127,215)	(112,266)	(97,317)	(82,369)	(67,420)	(52,471)	(37,522)	(22,574)	(7,625)	7,324		
	b Monthly Commercial Paper Rate			0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%		
	c Interest Provision			(8)	(7)	(6)	(6)	(5)	(4)	(3)	(3)	(2)	(1)	(0)	0	(45)	
	d **Total Costs and Interest (Line 12 + Line 16c)**			29,589	29,589	29,590	29,591	29,592	29,592	29,593	29,594	29,595	29,595	29,596	29,597	355,114	
20	Recovered (Order No. PSC 14-0701-FOF-EI)			29,589	29,589	29,590	29,591	29,592	29,592	29,593	29,594	29,595	29,595	29,596	29,597	355,114	
21	Over/Under Recovery For the Period			0	0	0	0	0	0	0	0	0	0	0	0	0	
24	**Revenue Requirements for the Period (Line 9 + Line 16d)**			731,798	661,187	590,577	519,967	449,358	378,747	308,137	237,527	166,917	96,307	25,697	(44,913)		
25	**2015 Capacity Cost Recovery**			9,215,650	9,145,040	9,074,430	9,003,820	8,933,210	8,862,600	8,791,990	8,721,380	8,650,769	8,580,159	8,509,549	8,438,940	105,927,536	

(a) See Appendix A for Beginning Balance Support

DEF Revenue Requirement Allocation Schedule

APPENDIX A
Witness: Thomas G. Foster
(TGF - 3)
(Page 3 of 3)

THIS SCHEDULE IS INCLUDED TO SUPPORT THE CALCULATION OF THE MONTHLY REVENUE REQUIREMENT FOR THE MONTHS (JANUARY 2015 - APRIL 2015)

Allocation of 2015 Revenue Requirements	Schedule	Amount	Amount Allocated / Amortized	Remaining Balance to Allocate	Unrecovered Balance
Amount to Allocate	2015 Est Rate Impact	$106,003,803			
Revenue Tax Multiplier		1.00072			
Total Amount for the Projection Period Rev. Requirement		**$105,927,535**			
Allocation Methodology					
• First to Allocate Current Period Carrying Costs					
Carrying Costs on Regulatory Asset	2015 Detail	3,766,192	3,766,192	$ 102,161,343	-
• Second to any (over)/under recovery from Prior Periods (Note 1)	2015 Detail	(11,560,747)	(11,560,747)	113,722,090	-
• Third to Current Period Other Exit & Wind-down Costs	2015 Detail	355,114	355,114	113,366,976	-
• Fourth to Current Period Exit Costs	2015 Detail	-	-	113,366,976	-
• Fifth to Regulatory Asset Balance (Note 3)	2015 Detail	113,366,976	113,366,976		-
		$105,927,535	**$105,927,535**	**$0**	-
• Balance of Regulatory Asset (Note 3)		147,013,971	160,231,492		**($13,217,521)**

Net Unrecovered Balance at YE 2015 **($13,217,521)**

Note 1: Prior period over recoveries were applied against cost components identified above and reflected in the NFR schedules herein.

Note 2: The 2010 Retail Regulatory Asset has been fully amortized at YE 2014.

Note 3: The amount shown is the remaining balance at Year End 2015 (Retail).

LEVY COUNTY NUCLEAR 1 & 2

Estimated / Actual Filing: Other Exit / Wind-Down Expenditures Allocated or Assigned to Other Recovery Mechanisms

EXPLANATION: Provide variance explanations comparing the actual system total expenditures shown on 2015 Detail Schedule with the expenditures provided to the Commission in the 2015 Detail Projection Schedules.

Appendix B
Witness: Thomas G. Foster
Docket No. 150009-EI
Exhibit: (TGF - 3)

COMPANY:
Duke Energy Florida

DOCKET NO.:
150009-EI

For Year Ended 12/31/2015

Line No.	Description	(A) System Projection	(B) System Estimated/Actual	(C) Variance Amount	(D) Explanation
	Allocated or Assigned Other Exit / Wind-Down Expenditures				
1	Accounting	$123,148	$80,000	($43,148)	Minor variance from estimated amount.
2	Corporate Planning	$192,838	$61,535	(131,302)	DEF estimates fewer hours for wind-down activities than originally projected.
3	Legal	$65,000	$110,000	45,000	Minor variance from estimated amount.
4	Total	$380,986	$251,535	($129,451)	Overall minor variance from estimated amount.

Note:
System Projection from May 1, 2014 Filing in Docket No. 140009-EI.

DUKE ENERGY FLORIDA
Average Rate of Return - Capital Structure
FPSC Adjusted Basis
December 2014

Appendix C
Witness: Thomas G. Foster
Docket No. 150009-EI
(TGF - 3)

	System Per Books	Retail Per Books	Pro Rata Adjustments	Specific Adjustments	Adjusted Retail	Cap Ratio	Low-Point Cost Rate	Low-Point Weighted Cost	Mid-Point Cost Rate	Mid-Point Weighted Cost	High-Point Cost Rate	High-Point Weighted Cost
Common Equity	5,222,186,481	4,623,579,568	(812,717,155)	729,976,602	4,540,839,016	47.51%	9.50%	4.51%	10.50%	4.99%	11.50%	5.46%
Long Term Debt	4,640,661,936	4,108,713,810	(722,215,796)	0	3,386,498,014	35.44%	5.33%	1.89%	5.33%	1.89%	5.33%	1.89%
Short Term Debt *	83,881,000	74,265,919	(13,054,212)	164,565,046	225,776,753	2.36%	1.22%	0.03%	1.22%	0.03%	1.22%	0.03%
Customer Deposits											0	0
Active	216,296,806	216,296,806	(38,019,920)	0	178,276,886	1.87%	2.23%	0.04%	2.23%	0.04%	2.23%	0.04%
Inactive	1,651,583	1,651,583	(290,310)	0	1,361,273	0.01%						
Investment Tax Credits **	425,513	376,737	(66,222)	0	310,515	0.00%						
Deferred Income Taxes	2,119,038,625	1,876,138,228	(329,781,223)	(167,311,918)	1,379,045,088	14.43%						
FAS 109 DIT - Net	(212,931,026)	(188,523,245)	33,137,977	0	(155,385,267)	-1.63%						
Total	**12,071,210,918**	**10,712,499,406**	**(1,883,006,858)**	**727,229,731**	**9,556,722,278**	**100.00%**		**6.47%**		**6.95%**		**7.42%**

* Daily Weighted Average
** Cost Rates Calculated Per IRS Ruling

Equity	4.99%
Debt	1.96%
Total	6.95%

LEVY COUNTY NUCLEAR 1 & 2
Site Selection, Preconstruction Costs, and Carrying Costs on Construction Cost Balance
Estimated / Actual Filing: Description of Monthly Cost Additions

EXPLANATION: Provide a description of the major tasks performed within these Categories for the year.
List generation expenses separate from transmission

Appendix D
Witness: C. Fallon
Exhibit: (TGF - 3)
(Page 1 of 2)

COMPANY:
Duke Energy Florida

DOCKET NO.:
150009-EI

For Year Ended 12/31/2015

Line No.	Major Task & Description for amounts on 2015 Detail Schedule	Description
	Generation:	
1	Wind-Down Costs	Spend performed in accordance with Rule 25-6.0423(7).
2	Sale or Salvage of Assets	The amount of proceeds received from either selling, transferring or otherwise receiving salvage value for the nuclear assets.
3	Disposition	The cost of winding-down and exiting the nuclear project contracts
	Transmission:	
1	Wind-Down Costs	Spend performed in accordance with Rule 25-6.0423(7).
2	Sale or Salvage of Assets	The amount of proceeds received from either selling, transferring or otherwise receiving salvage value for the nuclear assets.
3	Disposition	The cost of winding-down and exiting the nuclear project contracts

LEVY COUNTY NUCLEAR 1 & 2
Site Selection, Preconstruction Costs, and Carrying Costs on Construction Cost Balance
Est/Act Filing: Regulatory Asset Category - Variance in Additions and Expenditures

REDACTED

EXPLANATION: Provide variance explanations comparing the annual system total expenditures shown on 2015 Detail Schedule with the expenditures provided to the Commission on 2015 Projection Detail schedule. List the Generation expenses separate from Transmission in the same order appearing on 2015 Detail Schedule.

Appendix D
Witness: C. Fallon
Exhibit: (TGF - 3)
(Page 2 of 2)

COMPANY:
Duke Energy - FL

DOCKET NO.:
150009-EI

For Year Ended 12/31/2015

Line No.	Major Task & Description for amounts on Schedule	(A) System Projection	(B) System Estimated / Actual	(C) Variance Amount	(D) Explanation
	Generation:				
1	Wind-Down Costs (a)	[redacted]			DEF did not project costs in the May 1, 2014 filing, due to uncertainties around the LNP
2	Sale or Salvage of Assets				DEF did not project sales / credits in the May 1, 2014 filing, due to uncertainties around the LNP
3	Disposition				
4	Total Generation Costs				
	Transmission:				
1	Wind-Down Costs (b)	[redacted]			
2	Sale or Salvage of Assets				
3	Disposition				
4	Total Transmission Costs				

Note:
System Projection from May 1, 2014 Filing in Docket No. 140009-EI.

LEVY COUNTY NUCLEAR 1 & 2
Estimated/ Actual Filing: Contracts Executed

REDACTED

COMPANY:
Duke Energy Florida

EXPLANATION: Provide a list of contracts executed in excess of $1 million including, a description of the work, the dollar value and term of the contract, the method of vendor selection, the identity and affiliation of the vendor, and current status of the contract.

Appendix E
Witness: C. Fallon
Docket No. 150009-EI
Exhibit: (TGF - 3)

DOCKET NO.:
150009-EI

For Year Ended: 12/31/2015

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.	Contract No.	Status of Contract	Term of Contract	Original Amount	Actual Expended as of Prior Year End (2014)	Estimated Amount to be Expended in 2015	Estimate of Final Contract Amount	Name of Contractor	Affiliation of Vendor	Method of Selection	Nature and Scope of Work
1	414310	Terminated: January 28, 2014	[redacted]			Note 1	Note 2	Westinghouse Electric Co. LLC.	Direct	Sole Source. Award based on vendor constructing the selected reactor technology.	To design, engineer, supply, equip, construct and install a fully operational two unit AP1000 Facility at the Levy Nuclear Plant Site. Final contract amount includes change orders.
2	N/A	Note 2	Note 2	Note 2	[redacted]		Note 2	Carlton Fields Jorden Burt	Direct	Note 2	Legal Work – DEF Levy Units 1 & 2

Note 1: Costs or credits associated with terminating the EPC contract and related long lead equipment purchase orders are subject to litigation in federal court and are unknown at this time.

Note 2: Estimate of final contract amount cannot be determined at this time.

LEVY COUNTY NUCLEAR 1 & 2
Projection Filing: Contracts Executed

REDACTED

EXPLANATION: Provide a list of contracts executed in excess of $1 million including, a description of the work, the dollar value and term of the contract, the method of vendor selection, the identity and affiliation of the vendor, and current status of the contract.

Appendix E
Witness: C. Fallon
Docket No. 150009-EI
Exhibit: (TGF - 3)

COMPANY: Duke Energy Florida

DOCKET NO.: 150009-EI

For Year Ended: 12/31/2016

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
Line No.	Contract No.	Status of Contract	Term of Contract	Original Amount	Estimated Expended as of Prior Year End (2015)	Estimated Amount to be Expended in 2016	Estimate of Final Contract Amount	Name of Contractor	Affiliation of Vendor	Method of Selection	Nature and Scope of Work
1	414310	Terminated: January 28, 2014	[redacted]			Note 1	Note 2	Westinghouse Electric Co. LLC.	Direct	Sole Source. Award based on vendor constructing the selected reactor technology.	To design, engineer, supply, equip, construct and install a fully operational two unit AP1000 Facility at the Levy Nuclear Plant Site. Final contract amount includes change orders.
2	N/A	Note 2	Note 2	Note 2	[redacted]		Note 2	Carlton Fields Jorden Burt	Direct	Note 2	Legal Work – DEF Levy Units 1 & 2

Note 1: Costs or credits associated with terminating the EPC contract and related long lead equipment purchase orders are subject to litigation in federal court and are unknown at this time.

Note 2: Estimate of final contract amount cannot be determined at this time.

SCHEDULE APPENDIX

EXHIBIT (TGF-4)

DUKE ENERGY FLORIDA, INC.
CRYSTAL RIVER UNIT 3 UPRATE
COMMISSION SCHEDULES

JANUARY 2015 - DECEMBER 2016
DOCKET NO. 150009-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 50
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)
DESCRIPTION: Thomas G. Foster TGF-4

Table of Contents
Crystal River Unit 3 Uprate
January 2015 - December 2016

Page(s)	Schedule	Description	Sponsor
3	Summary	2016 Revenue Requirement Summary	T. G. Foster
4	2015 Detail	2015 Detail Revenue Requirement Calculations	T. G. Foster / M. Teague
5	2016 Detail	2016 Detail Revenue Requirement Calculations	T. G. Foster / M. Teague
6	2016 Rate Impact	2016 Estimated Rate Impact	T. G. Foster
7 - 9	Appendix A	Detail for 2015 & 2016 Beginning Balance & In-Service Project Rev Req Support	T. G. Foster
10	Appendix B	Other Exit / Wind-Down Expense Variance Explanation	T. G. Foster
11	Appendix C	Average Rate of Return - Capital Structure	T. G. Foster
12 - 13	Appendix D	Major Task Categories and Expense Variances	M. Teague
14	Appendix E	Summary of Contracts and Details over $1 Million	M. Teague
15	Appendix F	2013 - 2019 Unrecovered Investment Amortization Schedule	T. G. Foster

CR3 Uprate
2016 Revenue Requirement Summary
Duke Energy Florida

Witness: Thomas G. Foster
Docket No. 150009-EI
Exhibit: (TGF- 4)

(1)	Amortization of Unrecovered Balance	43,681,007	See 2016 Detail line 3d
(2)	Period Carrying Cost on Unrecovered Investment	14,790,552	See 2016 Detail line 5d
(3)	Period Exit Costs	-	See 2016 Detail line 3c
(4)	Period Other Exit / Wind-Down Costs incl. Interest	73,763	See 2016 Detail line 13d
(5)	Prior Period Over/Under Recoveries	(2,075,578)	See 2016 Detail lines: 3e and 10
(6)	Total 2016 Revenue Requirement	56,469,745	
(7)	Revenue Tax Multiplier	1.00072	
(8)	Total 2016 Projected Revenue Requirements	56,510,403	

DUKE ENERGY FLORIDA
Nuclear Cost Recovery Clause (NCRC) - CR3 Uprate
2015 Detail - Calculation of the Revenue Requirements
January 2015 through December 2015

Witness: T.G. Foster / M. Teague
Docket No. 150009-EI
Exhibit: (TGF-4)

Line	Description		Beginning of Period Amount	Actual January 15	Actual February 15	Estimated March 15	Estimated April 15	Estimated May 15	Estimated June 15	Estimated July 15	Estimated August 15	Estimated September 15	Estimated October 15	Estimated November 15	Estimated December 15	Period Total
1	**Uncollected Investment**															
	a EPU Construction & Wind-Down Costs		376,506,278	2,011	0	2,000	110,000	34,700	34,700	34,700	34,700	0	0	0	0	252,811
	b Sale or Salvage of Assets		(453,858)	(90,519)	0	(36,000)	0	0	0	0	0	0	0	0	0	(126,519)
	c Disposition		0													0
	d Total		376,052,420	(88,508)	0	(34,000)	110,000	34,700	34,700	34,700	34,700	0	0	0	0	$126,292
2	**Adjustments**															
	a Non-Cash Accruals		0	0	0	0	0	0	0	0	0	0	0	0	0	$0
	b Joint Owner Credit		(30,109,734)	7,275	0	(164)	(9,041)	(2,852)	(2,852)	(2,852)	(2,852)	0	0	0	0	(13,339)
	c Other (b)		(28,108,647)	0	0	0	0	0	0	0	0	0	0	0	0	0
	d Adjusted System Generation Construction Cost Additions		317,834,039	(81,233)	0	(34,164)	100,959	31,848	31,848	31,848	31,848	0	0	0	0	$112,953
	Retail Jurisdictional Factor : Current Year Activity	92.885%														
	Retail Jurisdictional Factor: (Beg Bal YE 2012 & POD sale)	91.683%														
	e Exit / Wind-down Costs			(75,453)	0	(31,301)	93,775	29,582	29,582	29,582	29,582	0	0	0	0	105,349
	f Beginning Balance - pre 2013 Investment		279,911,057													279,911,057
	g Beginning Balance - post 2013 Investment		12,170,084													12,170,084
	h Collected 2014 Portion of Regulatory Asset		(44,202,846)													(44,202,846)
	i Total Jurisdictional Unrecovered Investment		247,878,294	(75,453)	0	(31,301)	93,775	29,582	29,582	29,582	29,582	0	0	0	0	247,983,643
	j WACC Adjustment from 2014 & I/O Adjustment 2014 (Adjust May 2015 Rev Req) (c)							(229,139)								
3	**Carrying Cost on Unrecovered Investment Balance**															
	a Uncollected Investment: Costs for the Period (2i)		247,878,294	(75,453)	0	(31,301)	93,775	29,582	29,582	29,582	29,582	0	0	0	0	247,983,643
	b Plant in Service		29,995,096	0	0	0	0	0	0	0	0	0	0	0	0	29,995,096
	c Period Recovered Wind-down / Exit Costs		0	0	0	0	0	0	0	0	0	0	0	0	0	105,349
	d Amortization of Unrecovered Investment (a)		0	(3,640,084)	(3,640,084)	(3,640,084)	(3,640,084)	(3,640,084)	(3,640,084)	(3,640,084)	(3,640,084)	(3,640,084)	(3,640,084)	(3,640,084)	(3,640,084)	(43,681,007)
	e Prior Period Carrying Charge Unrecovered Balance (a)		(1,170,549)	(1,173,008)	(1,175,466)	(1,177,924)	(1,180,382)	(1,182,840)	(1,185,298)	(1,187,756)	(1,190,214)	(1,192,672)	(1,195,130)	(1,197,588)	(1,200,047)	(1,200,047)
	f Prior Period Carrying Charge Recovered (a)		29,497	2,458	2,458	2,458	2,458	2,458	2,458	2,458	2,458	2,458	2,458	2,458	2,458	
	g Prior Period Under/(Over) Recovery (Prior Month)				(143,326)	(68,318)	(99,703)	25,670	(267,116)	(39,128)	(38,844)	(16,738)	(45,795)	(45,571)	(45,341)	(829,322)
	h Net Investment		$216,712,648	$212,994,653	$209,284,238	$205,542,077	$201,924,907	$198,243,842	$194,334,184	$190,652,514	$186,971,128	$183,282,266	$179,593,929	$175,905,816	$172,217,933	$172,172,822
4	Average Net Investment			$214,853,651	$211,105,509	$207,378,998	$203,699,291	$200,050,322	$196,140,664	$192,458,994	$188,777,608	$185,103,537	$181,415,200	$177,727,087	$174,039,204	
5	Return on Average Net Investment															
	a Equity Component	0.00403		865,860	850,755	835,737	820,908	806,203	790,447	775,610	760,774	745,967	731,103	716,240	701,378	9,400,982
	b Equity Component Grossed Up For Taxes	1.62800		1,409,621	1,385,031	1,360,581	1,336,440	1,312,500	1,286,849	1,262,694	1,238,541	1,214,435	1,190,237	1,166,040	1,141,845	
	c Debt Component	0.00158		340,113	334,180	328,281	322,456	316,680	310,491	304,663	298,835	293,019	287,180	281,342	275,504	3,692,744
	d Total Return			1,749,734	1,719,211	1,688,862	1,658,896	1,629,180	1,597,340	1,567,357	1,537,376	1,507,454	1,477,417	1,447,382	1,417,349	18,997,557
6	Revenue Requirements for the Period (Lines 2j + 3a + 5d) (c)			$1,674,281	$1,719,211	$1,657,561	$1,752,671	$1,429,622	$1,626,922	$1,596,939	$1,566,958	$1,507,454	$1,477,417	$1,447,382	$1,417,349	$18,873,768
7	Projected Revenue Requirements for the Period (Order No. PSC 14-0701-FOF-EI)			$1,817,608	$1,787,529	$1,757,265	$1,727,001	$1,696,738	$1,666,050	$1,635,783	$1,583,696	$1,553,250	$1,522,987	$1,492,723	$1,462,459	$19,703,090
8	Over/Under Recovery For the Period			($143,326)	($68,318)	($99,703)	$25,670	($267,116)	($39,128)	($38,844)	($16,738)	($45,795)	($45,571)	($45,341)	($45,111)	($829,322)
9	**Other Exit / Wind-Down**															
	a Accounting			3,029	2,926	7,405	7,405	7,405	7,405	7,405	7,405	7,405	7,405	7,405	7,405	80,000
	b Corporate Planning			0	4,620	5,370	5,370	5,370	5,370	5,370	5,370	5,370	5,370	5,370	5,370	58,320
	c Legal			4,126	3,636	4,224	4,224	4,224	4,224	4,224	4,224	4,224	4,224	4,224	4,224	50,000
	d Joint Owner Credit			(588)	(919)	(1,397)	(1,397)	(1,397)	(1,397)	(1,397)	(1,397)	(1,397)	(1,397)	(1,397)	(1,397)	(15,479)
	e Total Other Exit / Wind-Down Costs			6,567	10,263	15,601	15,601	15,601	15,601	15,601	15,601	15,601	15,601	15,601	15,601	172,841
10	Jurisdictional Factor (A&G)			0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	
11	Jurisdictional Amount			6,122	9,567	14,544	14,544	14,544	14,544	14,544	14,544	14,544	14,544	14,544	14,544	161,124
12	Prior Period Unrecovered Balance (a)		(424,777)	(390,872)	(356,967)	(323,062)	(289,157)	(255,253)	(221,348)	(187,443)	(153,538)	(119,634)	(85,729)	(51,824)	(17,919)	
13	Prior Period Costs Recovered (a)		(406,857)	(33,905)	(33,905)	(33,905)	(33,905)	(33,905)	(33,905)	(33,905)	(33,905)	(33,905)	(33,905)	(33,905)	(33,905)	
14	Prior Month Period (Over)/Under Recovery			0	(9,667)	(6,218)	(1,242)	(1,241)	(1,241)	(1,240)	(1,240)	(1,239)	(1,239)	(1,239)	(1,238)	
15	Unamortized Balance		(424,777)	(390,872)	(366,634)	(338,948)	(306,285)	(273,622)	(240,958)	(208,293)	(175,629)	(142,963)	(110,298)	(77,631)	(44,965)	
16	Carrying Costs for the Period															
	a Balance Eligible for Interest			(404,763)	(378,803)	(348,629)	(315,966)	(283,302)	(250,638)	(217,974)	(185,309)	(152,644)	(119,978)	(87,312)	(54,645)	
	b Monthly Commercial Paper Rate			0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	
	c Interest Provision			(34)	(28)	(26)	(24)	(21)	(19)	(16)	(14)	(11)	(9)	(7)	(4)	(213)
	d Total Costs and Interest (Line 11 + Line 16c)			6,088	9,539	14,517	14,520	14,522	14,525	14,527	14,530	14,532	14,535	14,537	14,539	160,911
17	Recovered (Order No. PSC 14-0701-FOF-EI)			15,755	15,757	15,759	15,761	15,763	15,765	15,767	15,769	15,771	15,773	15,775	15,777	189,194
18	Over/Under Recovery For the Period			(9,667)	(6,218)	(1,242)	(1,241)	(1,241)	(1,240)	(1,240)	(1,239)	(1,239)	(1,239)	(1,238)	(1,238)	(28,283)
19	Other - Adjustments (a)		7,873	59	53	48	43	37	32	27	21	16	11	5	0	353
20	Recovered (Order No. PSC 14-0701-FOF-EI)			60	55	49	44	38	33	27	22	16	11	5	0	360
21	Over/Under Recovery For the Period			(1)	(1)	(1)	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	0	(7)
22	**Revenue Requirements for the Period**			1,680,428	1,728,803	1,672,127	1,767,234	1,444,182	1,641,479	1,611,493	1,581,509	1,522,003	1,491,962	1,461,924	1,431,888	19,035,031
23	Period Costs Recovered (Order No. PSC 14-0701-FOF-EI)			1,833,423	1,803,341	1,773,073	1,742,806	1,712,540	1,681,848	1,651,578	1,599,487	1,569,037	1,538,771	1,508,504	1,478,236	19,892,643
24	**Over/Under Recovery For the Period**			(152,995)	(74,538)	(100,946)	24,428	(268,358)	(40,369)	(40,085)	(17,978)	(47,035)	(46,809)	(46,580)	(46,348)	(857,612)

(a) Please see Appendix A for Beginning Balance support and support of Amortization of Unrecovered Balance and Other-Adjustments calculation.
(b) Other line reflects cost of removal of previously existing assets.
(c) 2014 WACC Adjustment and I/O Adjustment (Amount includes interest Jan-May 2015). See Appendix A for calculation.

DUKE ENERGY FLORIDA
Nuclear Cost Recovery Clause (NCRC) - CR3 Uprate
2016 Detail - Calculation of the Revenue Requirements
January 2016 through December 2016

Witness: T.G. Foster / M. Teague
Docket No. 150009-EI
Exhibit: (TGF- 4)

Line	Description		Beginning of Period Amount	Projected January 16	Projected February 16	Projected March 16	Projected April 16	Projected May 16	Projected June 16	Projected July 16	Projected August 16	Projected September 16	Projected October 16	Projected November 16	Projected December 16	Period Total
1	**Uncollected Investment**															
	a EPU Construction & Wind-Down Costs		376,759,089	0	0	0	0	0	0	0	0	0	0	0	0	0
	b Sale or Salvage of Assets		(580,377)	0	0	0	0	0	0	0	0	0	0	0	0	0
	c Disposition		0	0	0	0	0	0	0	0	0	0	0	0	0	0
	d Total		376,178,712	0	0	0	0	0	0	0	0	0	0	0	0	$0
2	**Adjustments**															
	a Non-Cash Accruals		0	0	0	0	0	0	0	0	0	0	0	0	0	$0
	b Joint Owner Credit		(30,123,074)	0	0	0	0	0	0	0	0	0	0	0	0	0
	c Other (b)		(28,108,647)	0	0	0	0	0	0	0	0	0	0	0	0	0
	d Adjusted System Generation Construction Cost Additions		317,946,991	0	0	0	0	0	0	0	0	0	0	0	0	$0
	Retail Jurisdictional Factor : Current Year Activity	92.885%														
	Retail Jurisdictional Factor: (Beg Bal YE 2012 only)	91.683%														
	e Exit / Wind-Down Costs for the Period			0	0	0	0	0	0	0	0	0	0	0	0	$0
	f Beginning Balance - pre 2013 Investment		279,911,057													279,911,057
	g Beginning Balance - post 2013 Investment		12,170,084													12,170,084
	h Collected Reg Asset - 2014 & 2015		(87,883,854)													(87,883,854)
	i Total Jurisdictional Unrecovered Investment		204,197,287	0	0	0	0	0	0	0	0	0	0	0	0	204,197,287
3	**Carrying Cost on Unrecovered Investment Balance**															
	a Uncollected Investment: Costs for the Period (Beg Balance: 2i)		204,197,287	0	0	0	0	0	0	0	0	0	0	0	0	204,197,287
	b Plant-in-Service		29,995,096	0	0	0	0	0	0	0	0	0	0	0	0	29,995,096
	c Period Recovered Wind-down / Exit Costs		0	0	0	0	0	0	0	0	0	0	0	0	0	0
	d Amortization of Unrecovered Investment (a)		0	(3,640,084)	(3,640,084)	(3,640,084)	(3,640,084)	(3,640,084)	(3,640,084)	(3,640,084)	(3,640,084)	(3,640,084)	(3,640,084)	(3,640,084)	(3,640,084)	(43,681,007)
	e Prior Period Carrying Charge Unrecovered Balance (a)		(2,029,376)	(1,860,261)	(1,691,146)	(1,522,032)	(1,352,917)	(1,183,803)	(1,014,688)	(845,573)	(676,459)	(507,344)	(338,229)	(169,115)	0	0
	f Prior Period Carrying Charge Recovered (a)		(2,029,376)	(169,115)	(169,115)	(169,115)	(169,115)	(169,115)	(169,115)	(169,115)	(169,115)	(169,115)	(169,115)	(169,115)	(169,115)	
	g Prior Period Under/(Over) Recovery (Prior Month)			0	0	0	0	0	0	0	0	0	0	0	0	
	h Net Investment		$172,172,815	$168,701,845	$165,230,876	$161,759,907	$158,288,938	$154,817,968	$151,346,999	$147,876,030	$144,405,060	$140,934,091	$137,463,122	$133,992,152	$130,521,183	$130,521,183
4	Average Net Investment			$170,437,330	$166,966,361	$163,495,391	$160,024,422	$156,553,453	$153,082,484	$149,611,514	$146,140,545	$142,669,576	$139,198,606	$135,727,637	$132,256,668	
5	Return on Average Net Investment															
	a Equity Component	0.00403		686,862	672,874	658,886	644,898	630,910	616,922	602,934	588,946	574,958	560,970	546,982	532,994	7,319,136
	b Equity Component Grossed Up For Taxes	1.62800		1,118,212	1,095,440	1,072,667	1,049,895	1,027,123	1,004,350	981,578	958,805	936,033	913,260	890,488	867,715	
	c Debt Component	0.00158		269,802	264,308	258,813	253,319	247,824	242,330	236,835	231,340	225,846	220,351	214,857	209,362	2,874,987
	d Total Return			1,388,014	1,359,748	1,331,480	1,303,214	1,274,947	1,246,680	1,218,413	1,190,145	1,161,879	1,133,611	1,105,345	1,077,077	14,790,552
6	Projected Revenue Requirements for the Period (3a + 5d)			$1,388,014	$1,359,748	$1,331,480	$1,303,214	$1,274,947	$1,246,680	$1,218,413	$1,190,145	$1,161,879	$1,133,611	$1,105,345	$1,077,077	$14,790,552
7	**Other Exit / Wind-Down**															
	a Accounting			3,433	3,433	3,433	3,433	3,433	3,433	3,433	3,433	3,433	3,433	3,433	3,433	41,200
	b Corporate Planning			2,503	2,503	2,503	2,503	2,503	2,503	2,503	2,503	2,503	2,503	2,503	2,503	30,035
	c Legal			1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	15,000
	d Joint Owner Credit			(591)	(591)	(591)	(591)	(591)	(591)	(591)	(591)	(591)	(591)	(591)	(591)	(7,088)
	e Total Other Exit / Wind-Down Costs			6,596	6,596	6,596	6,596	6,596	6,596	6,596	6,596	6,596	6,596	6,596	6,596	79,147
8	Jurisdictional Factor (A&G)			0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	
9	Jurisdictional Amount			6,148	6,148	6,148	6,148	6,148	6,148	6,148	6,148	6,148	6,148	6,148	6,148	73,781
10	Prior Period Unrecovered Balance (a)		(46,202)	(42,352)	(38,502)	(34,652)	(30,802)	(26,951)	(23,101)	(19,251)	(15,401)	(11,551)	(7,700)	(3,850)	(0)	
11	Prior Period Costs Recovered (a)		(46,202)	(3,850)	(3,850)	(3,850)	(3,850)	(3,850)	(3,850)	(3,850)	(3,850)	(3,850)	(3,850)	(3,850)	(3,850)	(3,850)
12	Unamortized Balance		(46,202)	(42,352)	(38,502)	(34,652)	(30,802)	(26,951)	(23,101)	(19,251)	(15,401)	(11,551)	(7,700)	(3,850)	(0)	
13	Projected Carrying Costs for the Period															
	a Balance Eligible for Interest			(41,203)	(37,353)	(33,503)	(29,652)	(25,802)	(21,952)	(18,102)	(14,252)	(10,401)	(6,551)	(2,701)	1,149	
	b Monthly Commercial Paper Rate			0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	
	c Interest Provision			(3)	(3)	(3)	(2)	(2)	(2)	(1)	(1)	(1)	(0)	(0)	0	(18)
	d Total Costs and Interest (Line 9 + Line 13c)			6,145	6,146	6,146	6,146	6,147	6,147	6,147	6,147	6,148	6,148	6,148	6,149	73,763
14	Projected Expenditures for the Period			6,145	6,146	6,146	6,146	6,147	6,147	6,147	6,147	6,148	6,148	6,148	6,149	73,763
15	**Revenue Requirements for the Period**			**1,394,160**	**1,365,894**	**1,337,626**	1,309,360	**1,281,093**	**1,252,827**	**1,224,560**	**1,196,292**	**1,168,026**	**1,139,759**	**1,111,493**	**1,083,226**	**14,864,316**

(a) Please see Appendix A for Beginning Balance support and support of Amortization of Unrecovered Balance and Other-Adjustments calculation.
(b) Other line reflects cost of removal of previously existing assets.

DUKE ENERGY FLORIDA
Nuclear Cost Recovery Clause (NCRC) - CR3 Uprate
2016 Projection Filing: Estimated Rate Impact

Schedule P-8

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY:

DOCKET NO.: 150009-EI

EXPLANATION: Using the billing determinants and allocation factors used in the previous year's cost recovery filings, provide an estimate of the rate impact by class of the costs requested for recovery. Current billing determinants and allocation factors may be used, if available.

Exhibit: **TGF-4**

For the Year Ended: **12/31/2016**

Witness: **T.G. Foster**

Rate Class	(1) 12CP & 1/13 AD Demand Allocator (%)	(2) Production Demand Costs $	(3) Effective Mwh's @ Secondary Level	(4) **Capacity Cost Recovery Factor (c/Kwh)**	(5) **Capacity Cost Recovery Factor ($/kw-Mo)**
Residential					
RS-1, RST-1, RSL-1, RSL-2, RSS-1					
Secondary	60.859%	$34,391,548	19,495,155	**0.176**	
General Service Non-Demand					
GS-1, GST-1					
Secondary			1,575,864	**0.143**	
Primary			8,616	**0.142**	
Transmission			3,564	**0.140**	
TOTAL GS	4.010%	$2,266,237	**1,588,044**		
General Service					
GS-2 Secondary	0.284%	$160,718	165,610	**0.097**	
General Service Demand					
GSD-1, GSDT-1, SS-1					
Secondary			12,013,676		**0.47**
Primary			2,384,319		**0.47**
Transmission			10,895		**0.46**
TOTAL GSD	30.991%	$17,513,296	**14,408,890**		
Curtailable					
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3					
Secondary					**0.35**
Primary			121,778		**0.35**
Transmission					**0.34**
TOTAL CS	0.178%	$100,771	**121,778**		
Interruptible					
IS-1, IST-1, IS-2, IST-2, SS-2					
Secondary			89,382		**0.41**
Primary			1,588,841		**0.41**
Transmission			316,913		**0.40**
TOTAL IS	3.504%	$1,980,090	**1,995,136**		
Lighting					
LS-1 Secondary	0.173%	$97,743	385,378	**0.025**	
	100.000%	56,510,403	38,159,991	**0.148**	

2015 Over/Under Recovery Beginning Balance

Line.					
2j	WACC & J/O Adjustments				
		May 2015 Adjustment	$	(229,139)	
			(64,650)	DEF's Response PSC Audit No. CR 11-14 (adjusting J/O credit)	
			(155,383)	DEF's Response PSC Audit No. CR 14-14 (adjusting WACC) 2014 Impact	
			(220,033)	Total Adjustments Beginning Balance January 2015 on Appendix A (page 3 of 3)	
			(9,107)	2015 Carrying Cost (Jan - May) calculated on Appendix A (page 3 of 3)	
			(229,139)	**Total Adjustment w/carrying cost reflected in May 2015 on Line 2j**	
3b	Transferred to Plant In-service		$	29,995,096	
			Exhibit TGF-2 Filed March 2, 2015		Line 3b. Plant in Service
3e	Unrecovered Balance Carrying Cost		$	(1,170,549)	
	Prior Period		(300,415)	Exhibit TGF-2 Filed March 2, 2015	Line 3e. Prior Period Carrying Charge Unrecovered Balance
	Current Period		(870,135)	Exhibit TGF-2 Filed March 2, 2015	Line 8 (Over)/Under for the Period
	Total		(1,170,549)		
3f	**Prior Period Carrying Charge Recovered**		$	29,497	
	Prior Period		(308,287)	Please refer to Appendix A (page 2 of 3) Line 1	
	Current Period		337,785	Please refer to Appendix A (page 2 of 3) Line 5	
	Total		29,497		
	Other Exit / Wind-Down				
12	Prior Period Unrecovered Balance		$	(424,777)	
	Prior Period		(224,283)	Exhibit TGF-2 Filed March 2, 2015	Line 12 Prior Period Unrecovered Balance
	Current Period		(200,493)	Exhibit TGF-2 Filed March 2, 2015	Line 18 (Over)/Under for the Period
	Total		(424,777)		
13	Prior Period Costs Recovered		$	(406,857)	
	Prior Period		(224,283)	Please refer to Appendix A (page 2 of 3) Line 2	
	Current Period		(182,574)	Please refer to Appendix A (page 2 of 3) Line 6	
	Total		(406,857)		
	Other - Adjustments		$	7,873	
19	Other - Adjustments		7,873	Appendix A (3 of 3) Line 3 adjustment for DTA Calculation	

2016 Over/Under Recovery Beginning Balance

	Regulatory Asset Carrying Cost			
3e	**Unrecovered Balance Carrying Cost**	$	(2,029,376)	
	Prior Period	(1,200,047)	Line 3e of 2015 Detail	
	Current Period	(829,322)	Line 8 of 2015 Detail	
	Current Period (Other - Adjustments) Line 21.	(7)	Line 21 of 2015 Detail Other - Adjustments ($7 CC difference due to changing WACC in 2015 from Projection). DEF reflected the $7 credit on this line for administrative purposes.	
	Total	(2,029,376)		
	Other Exit / Wind-Down			
10	**Prior Period (Over)/Under Recovery**	$	(46,202)	
	Prior Period	(17,919)	Line 12 of 2015 Detail	
	Current Period	(28,283)	Line 18 of 2015 Detail	
	Total	(46,202)		

Annual Amortization Calculation

	TGF-3 Filed March 1, 2014		YE 2013 - Actual
1	Net Investment	Lines 2f + 2g (TGF-4) 2015 Detail	292,081,140
2	Less: Transferred to Plant-in-Service	Line 3b (TGF-4) 2015 Detail	29,995,096
3	Investment to Amortize	(2015 through 2019)	262,086,044
4	Annual Amortization (2015 & 2016)	Line 3d (TGF-4) 2015 Detail & 2016 Detail	$ 43,681,007
	See Appendix F for Amortization Detail 2013-2019		
	2015 BB Investment prior to CY Amort		217,883,198
	2015 Additions		105,349
	Total (Exclusive of Prior Period Over/Under Recoveries)		217,988,547
	Less: **2015 Amortization**		43,681,007
	Less: **Collection of Wind-Down / Exit Costs 2015**		105,349
	2015 EB Unrecovered Investment (Exclusive of Prior Period O/U Recoveries)		174,202,190
	2015 (Over)/Under Recovery for the Period	(2015 Detail: Line 3e & 3g)	(2,029,369)
	2015 EB Unrecovered Investment	(Period Total 2015 Detail: Line 3h)	$172,172,822

		2013 True Up	2013 Est-Actual	Note 1 2015 Collection/ (Refund) *
1	Construction Carrying Cost Rev Req.	26,803,675	27,111,962	(308,287)
2	Recoverable O&M Revenue Req.	229,455	453,738	(224,283)
3	Inservice Rev Reqs/Base Refund	927	(6,946)	7,873
4	Total Revenue Requirement	27,034,057	27,558,755	(524,697)

Note 1: Per Order PSC-14-0617-FOF-EI, Docket No. 140009-EI, pg 40 (Issue 7)
The final 2013 net over-recovery of $524,697 should be included in setting the allowed 2015 NCRC recovery.

		2014 Est-Actual	2014 Projection	Note 2 2015 Collection/ (Refund) *
5	Construction Carrying Cost Rev Req.	24,516,716	24,178,932	337,785
6	Recoverable O&M Revenue Req.	214,326	396,900	(182,574)
7	Inservice Rev Reqs/Base Refund	(3,699)	(3,699)	-
8	Total Revenue Requirement	24,727,343	24,572,133	155,210

Note 2: Per Order PSC-14-0617-FOF-EI, Docket No. 140009-EI, pg 40 (Issue 8)

DEF
Other - Adjustments (2015 ONLY)
NO ADJUSTMENTS FOR 2016

Appendix A
Witness: Thomas G. Foster
(TGF - 4)
(Page 3 of 3)

	Beg Balance 2015	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1 Inservice Project Revenue Requirements	$0	0	0	0	0	0	0	0	0	0	0	0	0	0
2 Projected Inservice Project Revenue Requirements	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 Prior Years Project Inservice Revenue Requirements	7,873	656	656	656	656	656	656	656	656	656	656	656	656	7,873
4 Under/(Over) Recovery	$7,873	$7,217	$6,561	$5,905	$5,249	$4,593	$3,937	$3,280	$2,624	$1,968	$1,312	$656	$0	
5 Cumulative Under/(Over) Recovery	$7,873	$7,217	$6,561	$5,905	$5,249	$4,593	$3,937	$3,280	$2,624	$1,968	$1,312	$656	$0	
6 Equity Component (a)	0.00403	$29	$26	$24	$21	$19	$16	$13	$11	$8	$5	$3	$0	$175
7 Equity Component grossed up for taxes (b)	1.62800	47	43	39	34	30	26	22	17	13	9	4	0	284
8 Debt Component (c)	0.001583	11	10	9	8	7	6	5	4	3	2	1	0	69
9 Total Return on Under/(Over) Recovery (2015 Detail Line 21)		$59	$53	$48	$43	$37	$32	$27	$21	$16	$11	$5	$0	$353

Notes:
(a) The monthly Equity Component of 4.99% reflects an 10.5% return on equity.
(b) Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 38.575%.
(c) AFUDC actual monthly rate is calculated using the formula $M = [(1 + A/100)^{1/12} 1] \times 100$; resulting in a monthly accrual rate of 0.00403 (Equity) and 0.001583 (Debt), which results in the annual rate of 6.95%.

DEF CR3 Uprate
Calculation for 2015 Carrying Costs to be applied to the 2014 Adjustments
WACC Adjustment from 2014 & J/O Adjustment 2014 : Line 2j (2015 Detail)

	Beg Balance 2015	Jan	Feb	Mar	Apr	May	May Adjustment	Total
1 DEF's Response PSC Audit No. CR 11-14 (adjusting J/O credit)	$ (64,650)							
2 DEF's Response PSC Audit No. CR 14-14 (adjusting WACC) 2014 impact	$ (155,383)							
3 **2014 Adjustment - Including Carrying Cost (Appendix A- 2j)**	**(220,033)**	0	(1,792)	(1,807)	(1,821)	(1,836)	(1,851)	(9,107)
4 Under/(Over) Recovery	(220,033)	($220,033)	($221,825)	($223,631)	($225,452)	($227,288)	($229,139)	(220,033)
5 Cumulative Under/(Over) Recovery (Appendix A- 2j)	($220,033)	($220,033)	($221,825)	($223,631)	($225,452)	($227,288)	($229,139) *	($229,139)
6 Equity Component (a)	0.00403	($887)	($894)	($901)	($909)	($916)		($4,506)
7 Equity Component grossed up for taxes (b)	1.62800	(1,444)	(1,455)	(1,467)	(1,479)	(1,491)		(7,337)
8 Debt Component (c)	0.001583	(348)	(351)	(354)	(357)	(360)		(1,770)
9 Total Return on Under/(Over) Recovery		($1,792)	($1,807)	($1,821)	($1,836)	($1,851)		($9,107)

Notes:
(a) The monthly Equity Component of 4.99% reflects an 10.5% return on equity.
(b) Requirement for the payment of income taxes is calculated using a Federal Income Tax rate of 38.575%.
(c) AFUDC actual monthly rate is calculated using the formula $M = [(1 + A/100)^{1/12} 1] \times 100$; resulting in a monthly accrual rate of 0.00403 (Equity) and 0.001583 (Debt), which results in the annual rate of 6.95%.
*Transferred ($229,139) to 2015 Detail Line 2j.

CRYSTAL RIVER UNIT 3 UPRATE

Estimated / Actual Filing: Other Exit / Wind-Down Expenditures Allocated or Assigned to Other Recovery Mechanisms

EXPLANATION: Provide variance explanations comparing the actual system total expenditures shown on 2015 Detail Schedule with the expenditures provided to the Commission in the 2015 Detail Projection Schedules.

Appendix B
Witness: Thomas G. Foster
Docket No. 150009-EI
Exhibit: (TGF - 4)

COMPANY:
Duke Energy Florida

DOCKET NO.:
150009-EI

For Year Ended 12/31/2015

Line No.	Description	(A) System Projection	(B) System Estimated/Actual	(C) Variance Amount	(D) Explanation
	Allocated or Assigned Other Exit / Wind-Down Expenditures				
1	Accounting	$96,377	$80,000	($16,377)	Minor variance from estimated amount.
2	Corporate Planning	$84,910	$58,320	(26,591)	Minor variance from estimated amount.
3	Legal	$40,000	50,000	10,000	Minor variance from estimated amount.
4	Total	$221,287	$188,320	($32,967)	

Note:
System Projection from May 1, 2014 Filing in Docket No. 140009-EI.

DUKE ENERGY FLORIDA
Average Rate of Return - Capital Structure
FPSC Adjusted Basis
December 2014

Appendix C
Witness: Thomas G. Foster
Docket No. 150009-EI
(TGF - 4)

	System Per Books	Retail Per Books	Pro Rata Adjustments	Specific Adjustments	Adjusted Retail	Cap Ratio	Low-Point Cost Rate	Low-Point Weighted Cost	Mid-Point Cost Rate	Mid-Point Weighted Cost	High-Point Cost Rate	High-Point Weighted Cost
Common Equity	5,222,186,481	4,623,579,568	(812,717,155)	729,976,602	4,540,839,016	47.51%	9.50%	4.51%	10.50%	4.99%	11.50%	5.46%
Long Term Debt	4,640,661,936	4,108,713,810	(722,215,796)	0	3,386,498,014	35.44%	5.33%	1.89%	5.33%	1.89%	5.33%	1.89%
Short Term Debt *	83,881,000	74,265,919	(13,054,212)	164,565,046	225,776,753	2.36%	1.22%	0.03%	1.22%	0.03%	1.22%	0.03%
Customer Deposits											0	0
Active	216,296,806	216,296,806	(38,019,920)	0	178,276,886	1.87%	2.23%	0.04%	2.23%	0.04%	2.23%	0.04%
Inactive	1,651,583	1,651,583	(290,310)	0	1,361,273	0.01%						
Investment Tax Credits **	425,513	376,737	(66,222)	0	310,515	0.00%						
Deferred Income Taxes	2,119,038,625	1,876,138,228	(329,781,223)	(167,311,918)	1,379,045,088	14.43%						
FAS 109 DIT - Net	(212,931,026)	(188,523,245)	33,137,977	0	(155,385,267)	-1.63%						
Total	12,071,210,918	10,712,499,406	(1,883,006,858)	727,229,731	9,556,722,278	100.00%		6.47%		6.95%		7.42%

* Daily Weighted Average
** Cost Rates Calculated Per IRS Ruling

Equity	4.99%
Debt	1.96%
Total	6.95%

CRYSTAL RIVER UNIT 3 UPRATE
Actual Estimated Filing: Construction Category - Description of Monthly Cost Additions

EXPLANATION: Provide a description of the major tasks performed within the Construction category for the year.
List generation expenses separate from transmission in the same order appearing on 2015 Detail Schedule.

Appendix D
Witness: M. Teague
Docket No. 150009-EI
Exhibit: (TGF - 4)
(Page 1 of 2)

COMPANY:
Duke Energy Florida

DOCKET NO.:
150009-EI

For Year Ended 12/31/2015

Line No.	Major Task & Description for amounts on 2015 Detail Schedule	Description
	Generation:	
1	EPU Construction & Wind-Down Costs	Spend performed in accordance with Rule 25-6.0423(7).
2	Sale or Salvage of Assets	Net Value received in accordance with Duke Energy Procedure AI-9010 regarding Disposition of Assets
3	Disposition	Net Value received in accordance with Duke Energy Procedure AI-9010 regarding Disposition of Assets
	Transmission:	
	N/A	

CRYSTAL RIVER UNIT 3 UPRATE
Estimated / Actual Filing: Construction Category - Variance in Additions and Expenditures

EXPLANATION: Provide variance explanations comparing the annual system total expenditures shown on 2015 Detail Schedule with the expenditures provided to the Commission on 2015 Projection Detail schedule. List the Generation expenses separate from Transmission in the same order appearing on 2015 Detail Schedule.

Appendix D
Witness: M. Teague
Docket No. 150009-EI
Exhibit: (TGF - 4)
(Page 2 of 2)

COMPANY:
Duke Energy Florida

DOCKET NO.:
150009-EI

For Year Ended 12/31/2015

Line No.	Construction Major Task & Description for amounts on 2015 Detail Schedule	(A) System Projection	(B) System Estimated /Actual	(C) Variance Amount	(D) Explanation
	Generation:				
1	EPU Wind-Down Costs	$130,000	$252,811	$122,811	Costs included for preservation of assets and disposition efforts.
2	Sale or Salvage of Assets (1)	0	($126,519)	($126,519)	Proceeds from the auction held in 2014 and final payment from the sale of the POD.
3	Disposition	0	0	0	
4	Total Generation Costs	$130,000	$126,292	($3,708)	
	Transmission:				
	N/A				

Note:
System Projection from May 1, 2014 Filing in Docket No. 140009-EI.

CRYSTAL RIVER UNIT 3 UPRATE
Estimated/Actual & Projection Filing: Summary of Contracts Executed Over $1 Million

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY:
Duke Energy Florida

DOCKET NO.:
150009-EI

EXPLANATION: Provide a list of contracts executed in excess of $1 million including, a description of the work, the dollar value and term of the contract, the method of vendor selection, the identity and affiliation of the vendor, and current status of the contract.

Appendix E
Witness: M. Teague
Docket No. 150009-EI
Exhibit: (TGF - 4)

For Year Ended 12/31/2016

All EPU-related contracts in excess of $1 million have been closed as of December 31, 2013. No new contracts over $1 million were executed after December 31, 2013.

CR3 Uprate Unrecovered Investment Amortization Schedule
Exclusive of Prior Period Carrying Cost (Over)/Under Impacts, Adjustments, & Other Exit / Wind-Down Activity

Appendix F
Witness: Thomas G. Foster
Docket No. 150009-EI
Exhibit: (TGF - 4)

From PSC Filed Exhibits		2013 Actual	2014 Actual (a)	2015 (b)	2016 (b)	2017 (b)	2018 (b)	2019 (c)
Line 2f + 2g	**Beginning Balance Project Investment**	$ 279,911,057	$ 292,081,140	$ 291,592,657	$ 291,698,006	$ 291,698,006	$ 291,698,006	$ 291,698,006
Line 3b	***less:* Transferred to Base Rates**	(29,985,613)	(29,995,096)	(29,995,096)	(29,995,096)	(29,995,096)	(29,995,096)	(29,995,096)
	Beginning Balance -- NCRC	$ 249,925,444	$ 262,086,044	$ 261,597,561	$ 261,702,910	$ 261,702,910	$ 261,702,910	$ 261,702,910
	Prior Period Exit Cost Recoveries	0	0	488,483	383,135	383,135	383,135	383,135
Line 2h	Prior Period Amortization Recovery	0	0	(44,202,846)	(87,883,854)	(131,564,861)	(175,245,868)	(218,926,876)
Line 3a - 3b	**Beginning Balance to be Recovered (Before O/U Recovery)**	$ 249,925,444	$ 262,086,044	$ 217,883,198	$ 174,202,190	$ 130,521,183	$ 86,840,176	$ 43,159,168
Line 3c	Exit Cost / Wind -Down Additions	12,170,084	(488,483)	105,349	0	0	0	0
Line 3b	Transfers to Base Rates	(9,483)	0	0	0	0	0	0
Line 3d	Period Amortization	0	(44,202,846)	(43,681,007)	(43,681,007)	(43,681,007)	(43,681,007)	(43,159,168)
	Ending Balance (Before Over/Under Recovery)	$ 262,086,044	$ 217,883,198	$ 174,202,190	$ 130,521,183	$ 86,840,176	$ 43,159,168	$0

Line 3h	**Ending Balance (as shown on Exhibits incl. O/U)**	$ 260,788,581	$ 216,712,648	$ 172,172,822	$ 130,521,183
End of Period Carrying Cost (Over)/Under Impacts, Adjustments, & Other Exit / Wind-Down Activities, are not included in Amortization or Capital Recovery - shown for illustrative purposes only					
	(Over)/Under	(1,297,463)	(1,170,549)	(2,029,369)	0
Line 3e	(Over)/Under	(1,289,590)	(1,170,549)	(2,029,376)	0
	Variance	7,873	(0)	(7)	0
Appendix A	Other - Adjustments	7,873	0	(7)	0
		0	(0)	0	0

Note (a):
TGF-6 Filed May 1, 2013

	For 2014 Rates
Estimated YE 2013 Balance	$ 265,009,070
Estimated 2014 Wind-down Costs	208,008
Total Amount to be Amortized	265,217,078
Annual Amortization (2014)	**$ 44,202,846**

Note (b):
TGF-3 Filed March 3, 2014

	YE 2013 - Actual
Additions for the Period	$ 292,081,140
Less: Transferred to Plant-in-Service	29,995,096
2013 Actual EB Investment to Amortize	262,086,044
Annual Amortization (2015-2018)	**$ 43,681,007**

Note (c):

Estimated Amount of True-Up for 2019	$ (521,839)
Annual Amortization (2019)	**$ 43,159,168**

DUKE ENERGY®

Information Use

CRYSTAL RIVER UNIT 3

ADMINISTRATIVE PROCEDURE

AI-9010

Conduct of CR3 Investment Recovery

REVISION 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 51
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)
DESCRIPTION: Mark R. Teague MT-1

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3 Investment Recovery Asset Pricing Governance 17
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SUMMARY OF CHANGES 21

1.0 PURPOSE

1. This procedure outlines the asset pricing requirements and minimum reviews and approvals required for the execution of transactions and the record keeping requirements necessary for the disposition of assets (materials and equipment) from Crystal River Unit 3 (CR3) during the Decommissioning Transition Organization (*DTO*) phase. Additionally, the disposition of CR3 new nuclear fuel (fabricated and at CR3) is governed by this procedure. Upstream supplies (Enriched Uranium Product and UF6 Converter material) will be governed by this procedure.

1.1 Scope

1. Transactions include, but are not limited to the following:
   - Transfer of assets to Duke affiliated companies (*both regulated and non-regulated*)
   - Sale of assets
   - Sale of assets as scrap
   - Donating assets to charitable organizations
   - Disposal of assets.
2. Transactions under this procedure must conform to all existing applicable company policies.
3. It is essential that asset divesture records of all transactions are documented and preserved.
4. In accordance with the governance, the review and approval of each asset disposition is documented on a form similar to Attachment 1, Asset Disposition Review.
5. This procedure does not cover Real Property.
6. All transactions will comply with tax regulations. Internal transfers within DEF, or to DEC, DEP, DEO, DEI, and DEK do not require a tax surcharge as these entities have a Direct Pay Permit. A copy of these Direct Pay Permits is on file with Supply Chain at Crystal River 3.

2.0 REFERENCES

1. ADM-SUBS-00106, Project Assurance Nuclear Cost Recovery Clause Library (NCRCL) Program Manual
2. AI-9003, System Evaluation, Categorization and Abandonment
3. CR3 Investment Recovery Project Execution Plan
4. MCP-NGGC-0001, NGG Contract Initiation, Development and Administration
5. RDC-0001, Records Management Program
6. SCD211, Affiliate Asset Transfer Transactions
7. Affiliate Asset Transfer e-form on the Duke Energy PORTAL
8. Delegation of Authority (DOA)
9. Code of Business Ethics
10. Records Management Policy
11. Sales/Use and Excise Tax Policy
12. Purchasing Authority Policy
13. PMC-PRC-NA-AD-0013, Project Assurance Program Manual

3.0 DEFINITIONS

1. **154 Inventory** – Material that is put into an inventory system (Passport, EMAX or Nuclear Asset Suite (NAS)) and whose dollars are captured in FERC account 0154 at time of receipt. As part of the CR3 Settlement Agreement, all previous account 0154 Inventory is now part of the Regulated Asset, though for simplicity these are referred to in this procedure as 0154 Inventory.
2. **AAT – Affiliate Asset Transfer** - Transferring material internally between regulated, non-regulated and non-utility affiliates subject to governance under various federal and state guidelines and is documented on the Affiliate Asset Transfer Electronic Form found on the PORTAL. Only Regulated assets are transferred in accordance with the Intercompany Affiliate Transfer Agreement. The Code of Conduct and other applicable rules and regulations dictate how assets move between Regulated and Non-regulated or Non-utility affiliates.

3.0 DEFINITIONS (continued)

3. **Assets** - Described in the following categories and sub-categories.

   a. **Inventory** – These include materials in the 154 Account.

   b. **Pre-Expensed O&M Material** - Material bought directly for O&M work and not put in Inventory. Disposition at cost following the Inventory disposition guidance in this document; however, the accounting treatment may be different.

   c. **Other** – These include other materials and equipment that are not in the 154 Inventory Account and are not pre-expensed O&M material.

      1) Training equipment, trailers, etc.

      2) **Purchased but not installed** capital equipment in the Construction Work In Progress (CWIP) 107 Account.

         - For example, the LP Rotor(s) for the EPU project
         - Typically, these assets have little value as they are without warranty, and without performance guarantees.
         - These assets may be disposed during the actual Decommissioning phase of the project.

      3) **Purchased and installed but never been put in-service** capital equipment in the CWIP 107 Account.

         - For example, the Steam Generators
         - Typically, these assets have little value as they are without warranty, and without performance guarantees.
         - These assets are normally disposed during the actual Decommissioning phase of the project.

      4) **Installed and in-service** capital equipment in the Electric Plant In Service (EPIS) 101 and 106 Accounts.

         - The 101 Account is final and the 106 Account represents equipment that has not been unitized.
         - Typically, these assets have little value as they are used, without warranty, and without performance guarantees.
         - These assets are normally disposed during the actual Decommissioning phase of the project.

4. **Asymmetrical Pricing** - A pricing rule established by FERC which states that the franchised utility must receive the higher of cost or market price for providing non-power goods or services to a nonutility / non-regulated utility affiliate, and must not pay more than market price for a non-power good or service received from a non-utility / non-regulated utility affiliate.

5. **AUP - Average Unit Price** - An inventory item's average unit cost. In the Nuclear Asset Suite system, this is referred to as CUP (Calculated Unit Price)

3.0 DEFINITIONS (continued)

6. **Capital Material** – Typically other material whose cost is captured in a capital project at time of purchase, or was 0154 inventory that has already been issued out to a capital project.
   - Some of this material can also be described as a Pre-Capitalized Asset, or material whose quantity is tracked in PassPort, and at the time of issue, no additional accounting entries are generated.
7. **Disposition** – The disposal of an asset through sale, transfer, or discarding.
8. **FMV – Fair Market Value** - The current price at which an asset can be bought or sold in the market.
9. **IATA - Intercompany Asset Transfer Agreement** - A document between Duke Energy's regulated, franchised affiliates (DEC, DEI, DEK, DEO-T&D, DEP & DEF) which has been approved or accepted on an interim basis by the state commissions.
10. **NBV – Net Book Value** – The capital asset original cost, estimated, if not known, less the amounts credited to accumulated depreciation with respect to such property.

4.0 **RESPONSIBILITIES**

1. **GM Decommissioning** or their designee is responsible for the approval of this procedure.
2. **Corporate Communications** is responsible for following the guidance in Attachment 4, Duke RFP Guidelines if an Affiliate Bid is Anticipated when applicable.
3. **CR3 Financial Services Manager** and **Director Florida Accounting** are responsible for ensuring the correct accounting is used for transactions and determining net book value.
4. **Director – Major Projects Finance** and the **Managing Director – Major Projects Supply Chain** are responsible for the content of this procedure.
5. **Crystal River 3 Supply Chain Management** is responsible for:
   - Communicating the requirements of this procedure to all persons involved in the Investment Recovery processes.
   - Maintaining adequate internal controls over the Investment Recovery process and utilizing effective contract management processes.

5.0 INSTRUCTIONS

5.1 Expectations

1. This procedure applies to the governance of the CR3 Investment Recovery (IR) processes used in Major Project's Supply Chain.
2. The CR3 Investment Recovery Project, Project Execution Plan is documented at: https://nuc.duke-energy.com/sites/CR3DDR. All levels of management in the CR3 organization and Major Projects Supply Chain should be briefed on these documents.
3. All disposition transactions shall be performed in a prudent manner.
4. Transactions, including related contracts or other legally binding agreements, must be approved by the appropriate authority prior to execution by Duke Energy.
5. Individual transactions cannot be separated into multiple transactions for the purpose of circumventing an individual's authorized approval limit. However, transactions may be evaluated for required authority limits individually where the transactions are discrete, separate and independent of each other. The Delegation of Authority amounts and Purchasing Authority amounts apply to each transaction.
6. All CR3 Inventory (154) spare part material is listed as "For Sale" in the power industry RAPID database (www.rapidpartsmart.com). This material can be sold for AUP/CUP to other utilities via this tool at any time. Once internal fleet transfers are complete, we may sell RAPID spare parts for less than AUP/CUP to other utilities or to affiliates (see exception in Step 9).
7. Under the IR Project, all Inventory (Account 154) assets will be disposed of in the following manner:
   a. Utilize Duke Energy internal Inventory transfers to the fleet per the Affiliate Asset Transfer e-form and process. This should follow an approach where multiple lines of CR3 inventory are matched to an affiliate and to a specific plant.
      - The one exception to using the Affiliate Asset Transfer e-form is transferring material from CR3 within Duke Energy Florida (DEF). In these cases, a Material Transfer or Material Request can be utilized within Passport to document this transfer.
   b. Account 154 Inventory is normally transferred among regulated affiliated utilities at AUP/CUP. However, asymmetrical pricing is generally used for non-regulated utility affiliates and non-utility affiliates.
      - There is an exception in which a transfer to a regulated affiliate can take place at less than AUP/CUP. (See Step 9 for that exception.)

5.1 Expectations (continued)

c. If not transferred internally, then segregate and bid out inventory or obtain price quotes from distributors, other utilities and/or Original Equipment Manufacturer's (OEM's), and/or re-sellers. Asset Recovery Supply Chain and/or Auction Companies can be utilized to sell material to distributors, OEM's, and re-sellers as well.

- This establishes the FMV of bulk inventory disposal and generally yields a higher value than salvage or scrap pricing.
- Obsolete inventory may be marketed at a target market directly or through third party vendors.

d. For remaining Inventory, utilize Asset Recovery Supply Chain or Auction Companies for disposition at salvage or scrap value. Note some inventory items (consumable materials, commodities, short lead time material, low value, etc.) may be salvaged or scrapped immediately.

8. Under the IR Project, all **Other** assets (non-inventory) will be dispositioned as identified below:

a. Generally, **Other** assets may be transferred among regulated affiliated utilities at NBV or at cost for pre-expensed O&M material if the regulated affiliates identify a need. However, asymmetrical pricing, for transfers, is used for non-regulated utility affiliates and non-utility affiliates when those entities identify a need. There is an exception in which a transfer to a regulated affiliate can take place at less than NBV. (See Step 9 for that exception.)

b. If not transferred internally, determine the FMV by obtaining price quotes, bids, or market intelligence as applicable and bid out. In some cases, Duke affiliates may want to bid and compete against the external market. These type of sales transactions must be conducted at arm's length to ensure the integrity of the process. Additionally, any Duke affiliate winning bid is subject to approval by State Commissions and perhaps by FERC via a waiver (FERC waiver/ approval required if the winning bid is a Duke non-utility affiliate or a Duke non-regulated utility affiliate), Attachment 4, Duke RFP Guidelines if an Affiliate Bid is Anticipated provides information to be followed in these cases.

1) The bidding process for the disposition of materials and equipment shall be conducted as follows:

a) The bidding process shall follow MCP-NGGC-0001.

b) The Power Advocate sourcing tool or similar should be used for all bid events, thereby maintaining consistency with all bid event sales and document retention.

c) The standard approved legal form contracts or those prepared by Duke Energy's Legal Department shall be used for all third party asset contract sales in accordance with MCP-NGGC-0001.

5.1 Expectations (continued)

c. For remaining **Other** material, utilize Asset Recovery Supply Chain or an Auction Company for disposition at salvage or scrap value.

9. There may be instances where NBV or AUP/CUP may be at a higher value than FMV, in these cases, Commission(s) approval will be required to transfer at less than NBV or AUP/CUP.

a. Internal transfers may not have a warranty or performance guarantee associated with the Other material and consideration should also be made for any removal and shipping costs. These costs or values should be considered when comparing NBV to FMV (of an equivalent asset) and can result in a win/win for Duke Energy Florida and the internal transferee regulated affiliate.

A hypothetical example could be that Equipment A at CR3 has a NBV of $15,000,000 dollars and a regulated affiliate needs this type of equipment; however, the current FMV from a manufacturer is $17,000,000 delivered. The regulated affiliate has to pay $1,000,000 in shipping costs from CR3, $5,000,000 to modify Equipment A for their use, and the warranty and performance guarantees are estimated to be worth $1,500,000; thus, the regulated affiliate doesn't want to pay any more than $9,500,000 for Equipment A from CR3. From the standpoint of CR3, current salvage value (current FMV in this hypothetical example) on Equipment A is $500,000; thus, both parties (CR3 and the other regulated affiliate) would both be potentially better off at a less than NBV and this transaction would require utility commission approval in both jurisdictions.

5.2 **Asset Pricing**

1. **Duke Energy Internal Transfers** - Assets are priced at either: Average Unit Price (AUP/CUP), Net Book Value (NBV), or Fair Market Value (FMV) and transferred internally via the AAT form for those assets under $10,000,000 dollars as per the AAT process.

- The pricing used is dependent, in part, on whether the disposition is to a Duke Regulated Affiliate or not. Pricing governance is contained in Attachment 3, Investment Recovery Asset Pricing Governance (subject to the exception described in Section 5.1, Step 9).

2. **Sales Disposition** – Assets are priced at FMV and sold via a quote or bid process.

5.3 **Disposition Transaction Review and Approvals**

1. **Duke Energy Internal Asset Transfers** – An AAT e-form will be completed for Duke internal asset transfers and this e-form requires the appropriate DOA (sufficient approval authority in accordance with Purchasing Authority Policy) for transfer request and transfer sending. The AAT e-form has its own set of approvals. Note that an AAT e-form and Attachment 1, Asset Disposition Review are not required for internal DEF transfers, these are documented in Passport per the Material Transfer process and must be transferred at cost (AUP/CUP or NBV).

   a. Prior to any Duke Energy internal transfer approval, the IR Project Manager, Supply Chain Management, Engineering Manager, Director Florida Accounting, and the CR3 Finance Manager shall sign off as reviewers on Attachment 1, Asset Disposition Review - see further clarifications below.

      - The review is required by the CR3 Finance manager if the internal transfer is over $100,000 and the Director Florida Accounting is required to review if the internal transfer is greater than $250,000. The Tax Manager will sign off if the internal transfer is not within DEF, or to DEC, DEP, DEO, DEI or DEK.

   b. If the Asset value is over $1,000,000, then the following approvals (not DOA specific) shall be required and delineated on Attachment 1, Asset Disposition Review:

      - GM Decommissioning or designee
      - Rates and Regulatory Strategy Director or designee
      - Florida Regulatory Legal Associate General Counsel or designee.

   c. If any asset is to be transferred internally and the facts demonstrate that AUP/CUP or NBV is greater than FMV, then State Commission(s) approval would be required to transfer at a lower value than NBV and perhaps FERC approval as well.

   d. Review and Approval documents, including the AAT e-form, shall be filed and maintained by Configuration Control.

5.3 Disposition Transaction Review and Approvals (continued)

2. **Sales Disposition** –Sales disposal should be based on FMV as determined via quotes, bids or market intelligence.

   a. Prior to any Duke Energy sale the following shall sign off as reviewers on Attachment 1, Asset Disposition Review:

      - IR Project Manager
      - Supply Chain Management
      - Engineering Manager
      - Tax Manager
      - CR3 Finance Manager [1)]
      - Director Florida Accounting [1)]

      1) The review is required by the CR3 Finance manager if the internal transfer is over $100,000 and the Director Florida Accounting is required to review if the internal transfer is greater than $250,000.

   b. Approvals will follow the business unit DOA and Supply Chain Purchasing Authority.

   c. If the Asset value is over $1,000,000 dollars, then the following approvals (not DOA specific) shall be required and delineated on Attachment 1, Asset Disposition Review:

      - GM Decommissioning or designee
      - Rates and Regulatory Strategy Director or designee
      - Florida Regulatory Legal Associate General Counsel or designee

   d. In some cases, Duke affiliates may want to bid and compete against the external market during a sales event. These type of sales transactions must be conducted at arm's length to ensure the integrity of the process. Additionally, any Duke affiliate winning bid is subject to approval by State Commissions and perhaps by FERC via a waiver (FERC waiver/ approval required if the winning bid is a Duke non-utility affiliate or a Duke non-regulated utility affiliate), Attachment 4, Duke RFP Guidelines if an Affiliate Bid is Anticipated provides information to be followed in these cases. Where a bid event is conducted and another Duke Energy entity is the winning bidder, then the hardcopy contract document signatures will satisfy the internal DOA requirements.

5.4 **Project Assurance**

1. All decisions involving asset disposition shall be made and, where practical and appropriate, documented in such a manner as to demonstrate that each decision is reasonable and prudent based upon the information reasonably available to the Company at the time the decision was made.
2. Documentation of this decision making process will be prepared to justify to the Company's regulators that best effort towards investment recovery has been made.
3. The CR3 IR Project maintains applicable project documentation in accordance with the Records Management Program. Identification and handling of Quality Assurance records shall be performed using the Investment Recovery Project Assurance Plan and RDC-0001, CR3 Records Management Program.

5.5 **Removal of Installed Assets**

1. The removal of installed assets must be performed in a manner that maintains configuration control and supports relied upon system functionality, as established by the system abandonment process (AI-9003) and schedule.
2. To ensure compliance with the system abandonment process, each installed asset requested shall be evaluated and approved by plant management.
   a. Approval is documented on a form similar to Attachment 2, Installed Plant Equipment Removal Agreement.

6.0 **RECORDS**

1. The following documents are records when completed. Submit to Site or Corporate Configuration Control and Information Services personnel for processing and storage in accordance with RDC-0001, Records Management Program or ADM-SUBS-00106, Project Assurance Nuclear Cost Recovery Clause Library (NCRCL) Program Manual:
   - Attachment 1, Asset Disposition Review
   - Attachment 2, Installed Plant Equipment Removal Agreement
   - Review and Approval documents including AAT e-form

Asset Disposition Review

Buyer Info

Date: _____ Sold by: _____ _____
Name Phone

Affiliate Asset Transfer (AAT)? ☐ Yes ☐ No AAT e-Form #: _____

Purchasing Entity (buyer): _____
Company or Duke Operating Unit

Asset for Disposition

Description*:

Asset Offered Internally? ☐ Yes ☐ No (If No, Provide Justification*)

**Attach additional pages as necessary*

Asset Disposition Accounting

Pricing:

Asset Value: ☐ NBV $_____ ☐ AUP/CUP $_____

Asset Sales Price: $_____ Shipping & Handling $_____ Sales Quantity $_____

Sales Tax $_____ **OR** Non-Taxable Code _____
(External sales only) (See examples and note below)

Cost to Remove (if applicable): $_____ Total Cost to Buyer: $_____

Accounting (check one):

☐ Inventory Account 154 ☐ CWIP Account 107 EPU ☐ CWIP Account 107 POD
☐ CWIP Account 107 SGR ☐ CWIP Account 107
☐ EPIS Account 101 ☐ EPIS Account 106 Other (specify) _____

Accounting WBS: _____ _____ _____ _____
Resp Ctr Project Activity Resource

Note: If non-taxable, a code should be entered indicating the reason and supporting documentation should be attached or available.

Examples of Non-Taxable Codes

- NT/EC - NT Exemption Certificate
- NT/DP – NT Direct Pay Permit
- NT/IC – NT Intercompany Transfer
- NT/OS – NT Out-Of-State Transaction

Asset Disposition Review (continued)

Disposition Review and Approval

Asset Reviews:

Asset not required in support of CR3: _____ / _____
CR3 Engineering Mgr Date

_____ /
Tax Mgr Date
(Not required for internal transfers within DEF, or to DEC, DEP, DEO, DEI, and DEK)

_____ /
CR3 Financial Services Mgr Date
If Asset value is ≥ $100,000.00

_____ /
Director Florida Accounting Date
If Asset Value is ≥ $250,000.00

_____ /
Supply Chain Mgmt Date

IR Project Review:

_____ /
CR3 IR Project Mgr Date

Asset Approvals:

_____ /
GM Decommissioning Date
If Asset Value is ≥ $1,000,000.00

_____ /
FL Assoc Gen'l Counsel II Date
If Asset Value is ≥ $1,000,000.00

_____ /
Rates & Reg Strategy-FL Date
If Asset Value is ≥ $1,000,000.00

ATTACHMENT 2
Sheet 1 of 2

Installed Plant Equipment Removal Agreement

Request

Date: _____ Prepared by: _____ _____
Name Phone

Affiliate Asset Transfer (AAT)? ☐ Yes ☐ No AAT e-Form #: _____

AAT Requestor Charge Number: _____

Requesting Entity (buyer): _____
Company or Duke Operating Unit

Requestor Contact:_____ _____
Name Phone

Component Requested

System Abandoned? ☐ Yes ☐ No

Description*: (include boundaries as applicable and why feasible to remove)

Unique Risk Exposure to Removal*:

Estimated Removal Timeframe: _____ _____
Start Finish

**Attach additional pages as necessary*

Installed Plant Equipment Removal Agreement (continued)

Estimated Cost

Man-hours

Engineering _____ Operations _____ Health Physics _____

Craft _____ Planning _____ Oversight _____

Other (specify)_____

Total Labor Cost: $_____

Other

Dose _____ mRem Shipping & Handling $ _____ Other (specify) _____

Component Cost: ☐ NBV $_____ ☐ AUP/CUP $_____ ☐ FMV $_____

Total Cost Buyer: $_____

Agreement to Remove
(Record name of individual contacted and date)

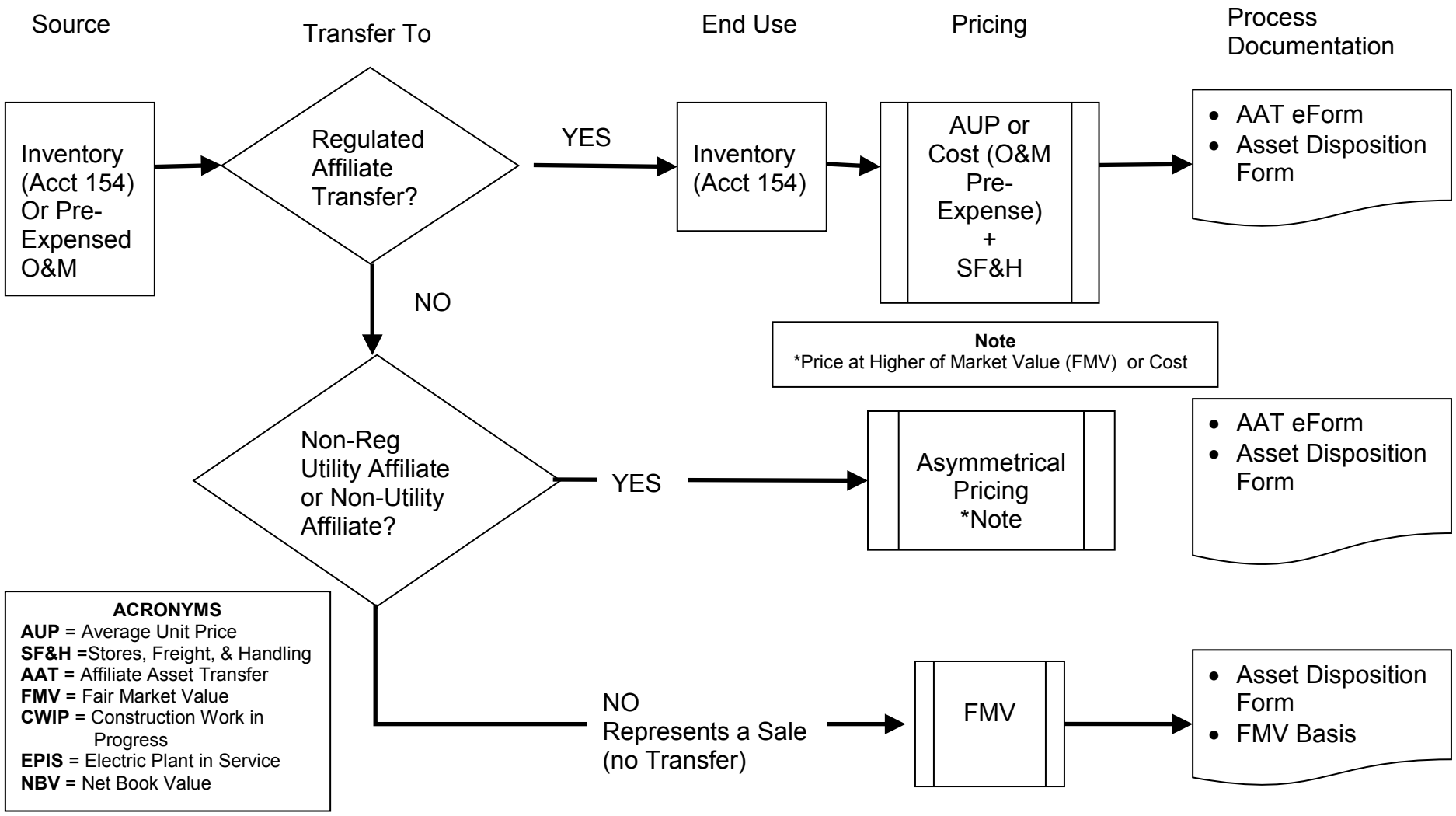
Receipt/Need by Date: _____

_____/_____ _____/_____
CR3 Engineering Manager Date CR3 Operations Manager Date

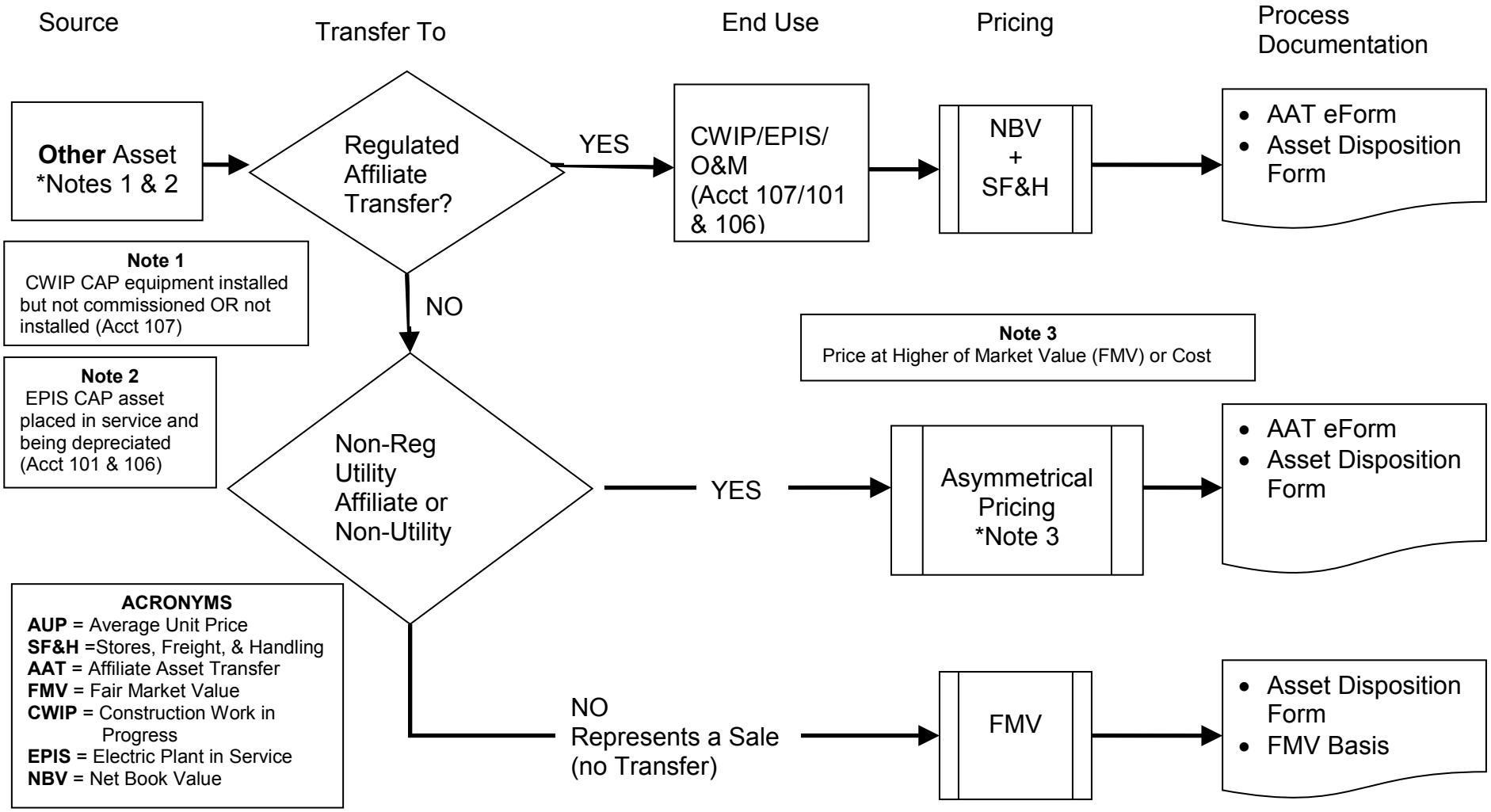
_____/_____ _____/_____
CR3 Maintenance Manager Date CR3 Plant Manager Date

_____/_____
CR3 GM Decommissioning Date

Investment Recovery Asset Pricing Governance



Investment Recovery Asset Pricing Governance (continued)



September 20, 2007

Duke RFP Guidelines if an Affiliate Bid is Anticipated

The fundamental objective of the guidelines is to assure that an affiliate will have *no undue advantage over non-affiliates* in an RFP issued by a regulated entity. These guidelines do not apply if no affiliate is bidding or as soon as there are no affiliates in contention.[1]

FERC has ruled that compliance with the guidelines is not mandatory, but has said that compliance will greatly increase the likelihood of FERC approval of an affiliate transaction without a lengthy and expensive hearing. These guidelines were established by FERC in the *Edgar, Allegheny, and Ameren* cases.

Legal should be consulted prior to the design of the RFP when the RFP issuer wishes to allow or anticipates affiliate bids. These guidelines apply to both asset transfers and power purchase agreements.

Standards of Conduct and Code of Conduct apply whether or not an affiliate is bidding.

FOUR PRINCIPLES

1. TRANSPARENCY

- No bidder should have an informational advantage.
- Simultaneously release information to all bidders.
- Allow all interested parties to bid instead of sending invitations to specific bidders.
- Widely publicize the RFP (e.g., post RFP on web site and issue a press release).
- All communications between Duke (or an independent third party on behalf of Duke) and any bidder should be made available to all other bidders (e.g., receiving questions and posting answers on web site).
- Negotiation after a short list has been compiled or a winner has been selected is acceptable. If an affiliate is involved, an independent third party should participate in the negotiation on behalf of the issuer.
- Generally, a Duke shared support group which provides information or services to the issuer in connection with the RFP should not also provide information or services to the affiliate bidder in connection with the RFP unless such information is provided simultaneously to all bidders. Seek a legal opinion under the specific facts if this situation arises.

[1] In Ohio, CAM is an affiliate of DE Ohio Retail for Ohio Code of Conduct purposes and should be treated as an affiliate for the purpose of these guidelines.

2. DEFINITION

- RFP should reflect clear and nondiscriminatory definition of products sought including all relevant aspects.
- Capacity and term desired should be stated along with other relevant characteristics which usually will include fuel type, plant technology, and transmission requirements for example.
- If there are changes in the product specification, re-bids should be allowed.
- The RFP should not define products in a way that favors affiliates.

3. EVALUATION

- RFP should clearly specify evaluation criteria.
- Price criteria should specify the relative importance of each item.
- Non-price criteria should specify the relative importance of items (e.g., firm transmission reservation requirements, acceptable delivery points, credit evaluation, plant technology, plant performance requirements, and plant in-service date).

4. OVERSIGHT

- Use an independent third party ("ITP") in the design, administration, and evaluation stages.
- ITP should have no financial interest in any of the bidders or in the outcome.
- ITP should not own or operate facilities that participate in the market affected by the RFP.
- ITP should be able to make a determination that the RFP process is transparent and fair and that the issuer's decision is not influenced by any affiliate relationships.
- ITP should be the sole link for transmitting information between issuer and bidders throughout the RFP process.
- ITP should be able to assess all bids based on both price and non-price factors. ITP should have access to the same information that the issuer uses in evaluation.

If any questions arise, you can consult FERC Legal at 980-373-6609.

SUMMARY OF CHANGES
PRR 670281

SECTION/STEP	CHANGE
1.0.1, 1.1.5	Allows AI-9010 to be the governing document for CR3 New Fuel sales (*76 new fuel assemblies at CR3*) and upstream uranium sales (*enriched and converted*). "Nuclear Fuel" deleted from Step 1.1.5.
1.1.1, 5.1.8.b, 5.3.2.d, Att 4	Allows other Duke entities to compete in the open market for any CR3 sales – this can be used for the LP Rotors for example and identifies additional commission/ FERC approvals / waivers that may be needed in case Duke is the winning bidder for any of these type events.
3.0.1	Added clarification to the definition of 0154 Inventory
3.0.10	Refined the definition of Net Book Value in accordance with FERC description.
4.0.2, 4.0.3	Added additional responsibilities for Corporate Communications, CR3 Financial Services Manager, and Director Florida Accounting.
5.1.6	Added new step to describe the RAPID database.
5.1.7, 5.1.9	Added new Step 9 and references to it to describe instances where NBV or AUP/CUP may be at a higher value than FMV.
5.1.7.c	Added Auction Companies to the statement and extended sales audience
5.1.7.d	Added Auction Companies to the statement & added scrapped
5.1.8.b.1.c	Added Duke Energy's Legal Department could provide an approved legal form
5.1.8.c	Added Auction Company
5.1.9.a	Added "current" to clarify FMV where applicable
5.2.1	Clarified that the AAT form is for those Assets less than $10,000,000 dollars
5.3.1, 5.3.2, Att 1	Added Supply Chain Management as an approval authority for internal transfers.
Various	Changed title from FL Reg and Property Accounting Mgr to Director Florida Accounting. Replaced Asset Transaction Price with Asset Value to align terminology.
5.3.2.d	Added and clarified that hardcopy Contract signatures can satisfy DOA requirements
4.0.1	Replaced VP Project Management & Construction with GM Decommissioning or their designee
5.3.1.b	Replaced VP Project Management & Construction with GM Decommissioning
5.3.2.c	Replaced VP Project Management & Construction with GM Decommissioning
Attachment #1, Page 2 of 2	Replaced VP-PMC with GM Decommissioning
Attachment #2, Page 2 of 2	Removed Director and added GM

CR3 Investment Recovery Project (IRP) Project Execution Plan

Rev 0

Project Management and Construction Department

Duke Energy

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 52
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)
DESCRIPTION: Mark R. Teague MT-2

Please Note: This document contains confidential information and is subject to Duke Energy's Code of Business Ethics Policy. Please limit distribution accordingly.

Approval

Revision Summary				
Rev. Number	**Effective Date**	**Prepared By**	**Approved By**	**Approved By**
0	2/25/14	Jeff LaPratt	Magdy Bishara	Terry Hobbs

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PROJECT SPONSORS

Role, Department / Group	Name	Phone No.
GM – Decommissioning	T. Hobbs	[redacted]

KEY PROJECT STAKEHOLDERS

Role, Department / Group	Name	Phone No.
VP-PMC	Mike Delowery (acting)	[redacted]
State Reg General Council	John Burnett	[redacted]
State President – FL	Alex Glen	[redacted]
VP-Chief Procurement Officer	Ron Reising	[redacted]
MGR EGR-DTO	Emin Ortalan (acting)	[redacted]

PROJECT MANAGEMENT CONTACTS

Role, Department / Group	Name	Phone No.
PM - PMC	Jeff LaPratt	[redacted]
SC Lead	Chris Hendricks	[redacted]
MGR – Major Projects	Magdy Bishara	[redacted]

*The location of the Expanded Contact list is included in the Appendix.

PLAN REVISION CONTROL

Rev No.	Primary Author(s)	Revision Description	Rev Date
0	Project Manager	Initial Issue	02/25/14

1.0 INTRODUCTION & PROJECT DESCRIPTION

[NOTE: This is classified as a White project per PMCoE standards. Deviations from the standard PMC Project Execution Plan (PEP) template are highlighted in bracketed notes similar to this one. These deviations are deemed acceptable by approval of this PEP.]

This document presents the Project Execution Plan for the CR3 Investment Recovery Project (hereinafter "IRP" or "Project").

Name of Station	Location	Project	Completion Date
CR3 Nuclear Plant	Crystal River, Florida	Investment Recovery	April 30, 2015

Project Description

In accordance with the August 1, 2013 Settlement Agreement (Doc No. 04433-13, Docket No. 130208-EI) with the Florida Public Service Commission (FPSC) Duke Energy is committed to using reasonable and prudent efforts to sell or otherwise salvage assets that would otherwise be included in the CR3 Regulatory Asset.

This project will develop and implement a program under which saleable CR3 plant assets are identified, maintained, marketed, sold, and removed from the site.

2.0 PROJECT OBJECTIVES & APPROVALS

The primary objective of this plan is to deliver the Project scope of maximizing return to customers and shareholders on CR3 assets through asset identification, redeployment, and disposition. The scope is to be delivered with quality, on budget, on time, and in a safe environmentally sound and prudent manner.

This project is undertaken with the following secondary objectives:

- Minimize cost and impact to CR3 decommissioning activities and trust fund, customers and shareholders.
- Identify preservation needs to avoid premature obsolescence of otherwise marketable assets.
- Coordinate with the Decommissioning Project to avoid conflicts.
- Ensure asset removal activities are performed event free.
- Ensure all decisions are made in a prudent manner and thoroughly documented.
- Ensure all sales/affiliate asset transfers are properly classified for proper accounting treatment.
- Comply with all applicable laws, rules, regulations and ordinances.
- Minimize risk associated with the re-sale and subsequent use or disposal of project assets.

Total Authorized, Current Projections

Table 1: Key Project Objectives	
Scope	Reduce the CR3 Reg Asset through the disposition of assets in the following categories: • Inventory (FERC 154 Account) • Construction Work in Progress (CWIP) • Electric Plant In-service (EPIS)
Total Project Cost	$3,408,104
Schedule [Project Completion Date]	April 30, 2015
Quality [Performance Objective]	Obtain prudence determination on all asset dispositions or transfers as appropriate

Internal Project Approvals

The IRP is a White, non-construction project that doesn't fit the traditional PMC construction stage-gate process. Per PMCoE standard PJM-00001-POLICY, *Achieving Excellence in Project Management*, for white projects, compliance with PMCoE Standards is at department discretion; therefore, elements of this PEP and approvals are tailored specifically for this project.

Duke Energy, and CR3 by extension, committed to performing the IRP as part of the August 1, 2013 Settlement Agreement with the FPSC, and acts as the authorization to implement this Project. Duke Energy Finance, Legal, and Regulatory Rates & Strategies have determined that because disposition proceeds go to reduce the Regulatory Asset (Reg Asset), that costs associated with the disposition shall be added to the Reg Asset for a net reduction. As such, no traditional funding approvals are necessary (e.g.; 201, WPCO). The Project Sponsor acknowledges estimated costs contained in the Project Charter. In no case is it prudent for costs to exceed disposition proceeds; the Project monitors these and will initiate discussion on project continuance should costs approach disposition proceeds.

PMC management has determined that the following project elements be developed and maintained for the Project:

- Project Charter
- Class 3 (or better) estimate
- Baseline Schedule
- Risk Assessment and Analysis
- PEP

The approval of this PEP recognizes the above positions in addition to project approach.

3.0 IRP SCOPE BASELINE

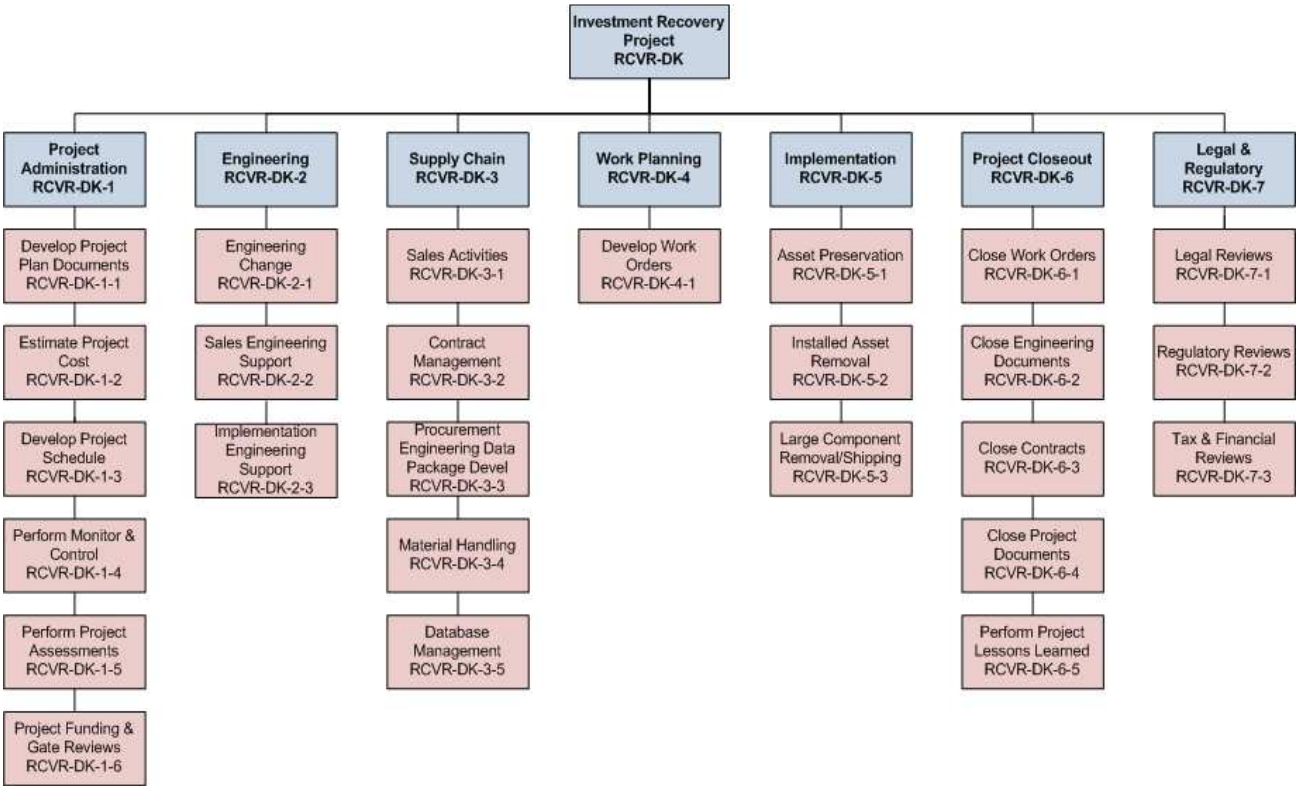
The CR3 Investment Recovery Project consists of the following scope:

- Inventory and catalogue saleable assets.
- The financial analysis to determine asset value.
- The engineering, procurement, and construction activities necessary to preserve saleable assets.
- Sales and marketing activities, including the establishment of strategic partnerships.
- Contract development and execution for necessary engineering, procurement, maintenance/preservation, asset removal and shipment, and warranty.
- Limited to the following plant equipment assets:
    - Warehouse inventory (FERC Account 154)
    - Construction Work in Progress (CWIP) (FERC Account 107); which is further subdivided into:
        - EPU
        - EPU Point of Discharge (POD) helper cooling towers
        - SGR
        - Other
    - Electric Plant In-Service (EPIS) (FERC Accounts 101 and 106)
- The scope specifically excludes nuclear fuel and real property.

The level 1 Scope of Work (SOW) for the Project is broken into a PMC WBS package. The work scope in the WBS includes activities necessary to plan, organize, integrate, budget, measure, and control performance. These activities ensure that the Project accomplishes the mission on schedule in a safe, prudent, and cost-effective manner.

WORK BREAKDOWN STRUCTURE

The WBS is used to organize and integrate the Project Scope Baseline. Figure 1 shows the top levels of the Project.



4.0 SCHEDULE BASELINE

The Project Baseline Schedule approval form is provided in Appendix F. The Project Controls Manager is responsible for establishing and documenting the schedule Baseline process and to assist the Project Manager in setting up the Schedule Management system for the Project.

The following major milestones are contained in the schedule:

Milestone	Baseline	Forecast Date	Actual Date	Critical Path
Initial funding milestone with Project Charter	Jul 13	Jul 13	Jul 13	N
Develop Project Scope and Level 1 Schedule	Jul 13	Jul 13	Jul 13	N
Build Team and Processes	Aug 13	Aug 13	Aug 13	N
Begin Investment Recovery	Aug 13	Aug 13	Aug 13	N
Approve Governance	Oct-13	Oct-13	Oct-13	N
Commence Market of CWIP Large Components (internal)	Oct-13	Oct-13	Oct-13	N
Develop Duke Inventory Match Lists	Nov-13	Nov-13	Nov-13	N
Commence Market of CWIP Large Components (external)	Nov-13	Nov-13	Nov-13	N
Commence Market of EPIS Components (external)	Nov-13	Nov-13	Nov-13	N
Commence Tranche 6 Disposition	Jan-14	Jan-14	Jan-14	N
Commence Tranche 1 Disposition	Feb-26	Feb-26		N
Nuclear Fleet Review Completed – Commence Pull & Ship	Mar-14	Mar-14		N
Commence Tranche 2 Disposition	Apr-14	Apr-14		N
Complete Market of CWIP Large Components (internal)	Apr-14	Apr-14		N
Complete Tranche 1 Disposition	Apr-14	Apr-14		N
Fossil Fleet Review Completed – Commence Pull & Ship	Apr-14	Apr-14		N
Commence Tranche 3 Disposition	May-14	May-14		N
Complete Tranche 2 Disposition	May-14	May-14		N
Complete Market of EPIS Components (external)	Jun-14	Jun-14		N
Commence Tranche 4 Disposition	Jul-14	Jul-14		N
Complete Tranche 3 Disposition	Jul-14	Jul-14		N
Commence Tranche 5 Disposition	Aug-14	Aug-14		N
Complete Tranche 4 Disposition	Aug-14	Aug-14		N
Complete Market of CWIP Large Components (external)	Aug-14	Aug-14		N
Complete Tranche 5 Disposition	Sep-14	Sep-14		N
Complete Tranche 6 Disposition	Sep-14	Sep-14		N
Cleanup & Project Closeout Complete	Apr-15	Apr-15		N
Complete Investment Recovery	Apr-15	Apr-15		N

5.0 COST BASELINE

Upon approval of the Initiate Gate Package by Duke Energy Management, the Project Cost Baseline will be established and documented through the Cost Baseline approval process. The Initiate Gate approved estimate will be used as the basis of the Cost Baseline. The Project Controls Lead is responsible for establishing and documenting the Cost Baseline process and assisting the Project Manager to set up the Cost Management System for the Project.

The Project Cost Breakdown Structure (CBS) is as follows:

Project Level 2 Number	Oracle Level 1 Task	Level 1 Task Description	Oracle Level 2 Task	Level 2 Task Description	Passport WO #
20104219	1000	Project Management	1001	Project Management	1868133-13
			1002	Contracts	1868133-13
			1003	Materials/Other	1868133-13
			1004	Project Management Other	1868133-13
	2000	Sales	2001	Sales Labor	1868133-14
			2002	Sales Material Handling	1868133-15
			2003	Sales Contracts	1868133-14
	3000	Removal Costs	3001	Removal Costs - LPT	1868133-15
			3002	Removal Costs - POD	1868133-15
			3003	Removal Costs - CWP	1868133-15
			3004	Removal Costs - EPU Preservation	1868133-15
			3005	Removal Costs - POD Preservation	1868133-15
			3006	Removal Costs - Other Preservation	1868133-15
			3999	Removal Costs - Non-reimbursable	1868133-15

The Project Cost Baseline and subsequent performance reporting to key stakeholders and sponsors will be made in the Financial View. The Project does not receive any AFUDC charges and none will be reported.

TOTAL PROJECT COST BASELINE & ESTIMATE AT COMPLETION (EAC) FORECAST

The Total Project Cost Baseline will include PMC and other entities baselines.

Total Project Cost Baseline [Financial View]

Cost Baseline	Expected	Range
PMC	$3,408,104	$3,067,294 - $4,089,725 (Min – Max)
Other Entities	$0.0	$0.0
Total Project	$3,408,104	$3,067,294 - $4,089,725 (Min – Max)

Total Project Cost History [As Approved by Project Charter]

Charter Revision	Expected	Range	Approval Date
Rev 0 (initial)	$1,500,000	$1,500,000	07/16/13
Rev 1/EAC	$3,408,104	$3,067,294 - $4,089,725 (Min – Max)	02/20/14

6.0 IRP ORGANIZATION

See Appendix A for IRP Organization Chart

DUTIES AND RESPONSIBILITIES FOR EACH PROJECT MEMBER/ORGANIZATION

Project Sponsor
The Project Sponsor is an executive level manager who functions as the primary customer of the Project team. The success of the Project is determined by the satisfaction of the Sponsor. The Project Sponsor for this project is the GM Decommissioning.

Project Manager (PM)
The PM has the overall authority and responsibility for execution of the Project in order to achieve all work safely, within budget, and on schedule. The work must be completed in compliance with all required local, state, and federal laws and regulations. The PM is responsible for planning, executing, controlling, and closing the Project. This is largely accomplished by coordinating the efforts of the Project team to develop and implement the Project Execution Plan and by taking corrective action when Project objectives are in jeopardy. The PM reports to the Manager of Nuclear Projects.

Specific responsibilities of the PM include:

- Preparation of the Project Execution Plan
- Directing and managing the Project team for the execution of the Project

- Organizing and leading the Monthly Executive Meeting of the Project
- Managing the interfaces between stakeholders and within the Project team
- Manage and develop project team organization
- Identify and obtain resources to ensure project success (either matrix or directly assigned)
- Responsible for resolution of critical issues/opportunities
- Provide direction to project team leaders to promote project success, continuity, and consistency
- Monitor and report project performance and initiate any needed corrective action to keep the project on track
- Primary interface with CR3 Decommissioning Management. Includes providing status updates and resolving critical issues/opportunities needing management awareness or involvement
- Primary interface with the PMC Leadership Team. Includes providing status updates and resolving critical issues/opportunities needing senior management awareness or involvement
- Reviews and assesses overall schedule for achievability of critical milestones and adequacy of contingency plans

Supply Chain Functions

The Supply Chain (SC) Organization is the primary resource for IRP asset dispositions and is the largest contributor to the Project. The SC roles in the IRP are:

Supply Chain IRP Lead

The IRP Supply Chain Lead has overall supervisory responsibility for the IRP sales organization. The IRP Sales Lead and direct reports in **Contracts** and **Sales**, have responsibility for the following:

- Compile a list of site assets, inventory, and other items of value that will be redeployed, sold or scrapped.
- Provide a level of oversight for on-site asset recovery dispositions.
- Manage the population of the Investment Recovery Database.
- Identify potential buyers and determine sale/marketing plan for various assets.
- Develop / coordinate the contract bid, evaluation and execution process for assets that will be sent out for bid.
- Provide technical input on requested assets as required by potential customers.
- Qualify bidders to assure credit worthiness, or advance payment where credit worthiness is in doubt.
- Provide technical input and manage the results / inquiries from Recovery Seeker

- Assure that a signed contract is in hand, based on standard forms approved by the Legal department, or an alternate form approved by the Legal Department before releasing the project asset to the buyer.
- For international sales (direct or indirect), assure that all regulatory approvals are obtained before releasing the project asset to the buyer.
- Complete Affiliate Asset Transfer Forms for all assets transferred to other Duke Energy affiliates.
- Work with Field Organizations/Contractors for the coordination to release assets from the site.
- Package and ship smaller assets to successful purchasers.
- Manage the retrieval of documentation and generation of Certificates of Conformance required for the sale of safety related assets.
- Coordinate assets that will be dispositioned by the Corp Asset Group
- Manage and Monitor invoicing and outstanding receivables.

Major Projects Materials Lead

- Coordinates accounting and control of CWIP materials.
- Supports removal and shipping of CWIP materials.

Supply Chain Support – Asset Recovery

- Primary interface for salvage of equipment.
- Supports asset disposition through their known channels.

Financial Analyst

- Provide leadership and management of finance.
- Track costs and value of divested materials.
- Ensures proper accounting of monies received from assets divested.
- Provides NBV and other cost information.

Legal / Regulatory / Tax Support

- Contract form development and negotiation support.
- Provide legal interpretation/guidance on contractual issues.
- Assist in contract dispute resolution, as necessary.
- Support the Affiliate Asset Transfer process.
- Provide support to ensure that the project remains within governance and demonstrates prudency.
- Supply advice and assistance on export control regulations.

- Provide guidance on tax issues.

Engineering

- On an as-needed basis, provides support for the removal of major assets.
- Provides technical information on assets.

Major Projects Implementation

- Provide leadership and management of large or complex asset removal tasks.
- Assist the Task Managers in monitoring contractor's work planning and execution for removal tasks
- Work with the Task Managers to resolve any work practices considered significantly inefficient, ineffective or unsafe.
- Performs necessary inspections of the Contractor's work to assure compliance with QA/QC policies and procedures.
- Identifies any deficiencies and works with the appropriate Task Managers to have these resolved by the Contractor.
- Assure that the Contractor assigns sufficient qualified workers to meet planned performance.
- Assist the Task Managers with monitoring corrective and preventive actions taken on incident investigations and non-conformances (NCRs).
- Report any barriers to the Task Managers to achieving key milestones and/or any recovery plans in place to mitigate barriers.
- Interface with the appropriate Task Managers to address any potential scope or technical issue.
- Participate in the oversight of the Contractor's implementation of their site-specific safety and environmental programs.
- Coordinate and oversee the Contractor's implementation of Duke Energy's lifting and rigging program.

Project Controls (PC) Supv / Principal PC Specialist / Scheduler

- Review schedule updates for accuracy, reasonableness and impacts.
- Interface with Station scheduling regarding tie-ins and resource requirements.
- Prepare schedule update summaries (e.g., Key Milestones, Critical Path and Look Ahead, etc.) as requested by the IRP PM.
- Evaluate schedule variance corrective actions for appropriateness and reasonableness and provide results to the Project Manager and other appropriate Project team members.
- Evaluate forecasts regarding accuracy, appropriateness and reasonableness of schedule logic, durations and resources for remaining activities.

- Develop and maintain project cost estimate/cash flow forecast, analyze trends and provide current information to the PM, other appropriate Project team members and appropriate Project and Department Management.
- Review Monthly Work-Hour and Cost Transaction Reports for appropriateness and reasonableness of labor, materials and subcontract charges made to the project, including where charges may not be covered or where they exceed the Project Funding Authorization. Follow up with appropriate personnel regarding any inappropriate and/or unreasonable charges.
- Maintain Change Management System for identified changes in project cost, schedule, and cash flow. This includes Change Orders for work scopes. Develop cost / schedule forecast for identified scope changes.
- Support annual Corporate Budgeting process and provide monthly cash flow projections.
- Provide schedule updates for Duke Energy's subproject within the integrated project schedule.
- Incorporate contractual and key stakeholder activities into overall project schedule.
- Provide project reports to Project Leadership Team on overall Project performance and forecasts compared to key milestones, Project funding, and annual budgets.

Project Assurance Advisor

The Project Assurance Advisor provides support to the Project through education and awareness of Company policy. The Advisor ensures that all material decisions involving expenditures for which cost recovery is sought are made and documented in a manner that will allow Duke Energy to achieve full and fair recovery through the regulatory process. They execute duties specific to the Project include: developing and delivering education and awareness programs to Project personnel and ensuring that documentation of Project decisions is adequate to explain the basis for the decision, and reasonableness thereto. They also develop the Project Assurance Plan for the Project.

RACI CHART FOR PROJECT ORGANIZATION

A Responsible, Accountable, Consult, Inform (RACI) chart that further clarifies organizational responsibilities by activity is provided in Appendix B.

7.0 DISPOSITION STRATEGY & MANAGEMENT

[NOTE: Section titled changed from Procurement Strategy to Disposition Strategy due to the unique nature of the Project]

Strategic Approach and Rational

The Project will disposition assets in a manner that maximizes the reduction of the Regulatory Asset. The methodology employs a systematic, sequential approach as illustrated in Appendix D – DISPOSITION STRATEGY FLOWCHART.

The illustrated systematic approach focuses on internal transfer of the asset first as, per the Affiliate Asset Transfer Agreement (AATA) and Affiliate Asset Transfer (AAT) process, assets transferred internally are at Average Unit Price (AUP). Large asset distribution efforts have historically returned a fractional percentage of AUP overall, therefore, receiving AUP or greater for an asset is advantageous to our customers.

Following internal transfers, in terms of expected returns, are marketing to utilities, then 3rd party resellers, then salvage and scrap (in order from high to low).

Assets are segregated (or "bucketed") by AUP tranches. Large asset distribution efforts have also shown that the overwhelming amount of total value is returned by a small amount of the asset set. In the case of the CR3 inventory asset set of 1.4M items, Tranches 1 through 5 represent approximately 12,000 items and approximately 85% of inventory value. The project will place special focus on Tranches 1 through 5 and the requisite marketing effort they demand.

Disposition of Tranche 6 is labor intensive to disposition due to the significant number of items, with expected return being low.

Governance

Governance for the Project is provided in AI-9010, *Conduct of CR3 Investment Recovery*. The strategic approach outlined above is congruent with the requirement stated in AI-9010.

Guidance

Guidance for consistent implementation of each sales track (Affiliate Transfer, Utility/OEM, 3rd Party Reseller, and Scrap/Salvage) is contained in Investment Recovery Guidance Document IRGD-001, *Sales Track Guidance and Documentation Package Development*. This guidance document also provides information on Project Assurance (PA) SharePoint organization and file naming convention for PA documents; with each disposition having a completed checklist of required actions completed.

8.0 IMPLEMENTATION AND IMPLEMENTATION MANAGEMENT

[NOTE: Section titled changed from Construction to Implementation due to the unique nature of the Project]

Removal of Installed Assets

The removal of installed assets must be performed in a manner that maintains configuration control and supports relied upon system functionality, as established by the system abandonment process (AI-9003, *System Evaluation and Categorization*) and schedule.

To ensure compliance with the system abandonment process, each installed asset requested will be evaluated and the removal approved by plant management. This approval process will also review risks associated with the removal to ensure that the plant is willing to accept those risks for the sake of disposition. Approval is documented on a form contained in AI-9010, *Conduct of Investment Recovery*.

Large Component Removal and Shipping

Multiple large CWIP components that are not installed, such as the Low and High Pressure Turbines, POD Cooling Tower, and feed water heaters, will be removed for shipping by the Major Projects Implementation group. These are significant efforts requiring specialized skills and equipment.

The removal of an installed asset or large component removal and shipping activities are handled as a stand-alone task with a specific task plan developed. Costs to remove installed assets will be the sole responsibility of the buyer.

Implementation oversight shall be provided by Duke Energy's PMC department.

9.0 INTEGRATION, COMMISSIONING AND TURNOVER STRATEGY & MANAGEMENT

[This section is not applicable to the Project as there are no integration, commissioning or turnover activities associated in this non-construction project.]

10.0 SCOPE MANAGEMENT

The Scope Baseline will be controlled and maintained by the Project Manager in accordance with PJM-00008-ENTSTD. Changes to the Scope Baseline will be managed through the Integrated Change Control (ICF) process utilizing Integrated Change Control Forms (ICF)processed in the PassPort system.

11.0 SCHEDULE MANAGEMENT

The Project will use Primavera P6 or higher version as the primary scheduling software.

The Project Scheduler is responsible for the following weekly activities at a minimum:

1. Quality of the fully Integrated schedule
2. Weekly schedule review meetings
3. Schedule updates
4. Change trends.

Schedule Development

A detailed, resource loaded Level 3, including Duke Energy critical interface points is developed for all disposition activities. Additional schedule elements for the removal of installed assets and large component removal and shipping activities will be developed and added to the overall integrated schedule.

The Project Controls Manager will then implement the PMC Schedule Baseline approval process as per the PMC-PRC-00-AD-0009 PMC Project Schedule Management procedure. This process establishes the fully Integrated Baseline schedule. The Project Scheduler will refer to the PMC-PRC-00-AD-0009 PMC Schedule Management procedure regarding file naming, data archive, and overall schedule management process details for the Project.

Upon approval/sign-off on the Project Schedule Baseline, the Project Manager then officially accepts the Level 3 schedule as the Baseline schedule.

The Schedule Baseline will then be controlled and maintained by the Project Manager with assistance from the Scheduler. Changes to the Schedule Baseline will be managed through the ICF process. The Project will utilize Primavera P6.8.1 or higher version as the primary scheduling software.

Schedule Analysis

The Schedule will be reviewed and analyzed for float, completeness, logic, open ends, contractual dates, and milestones, on a weekly basis by the on-site Project Controls personnel. Any feedback or corrections on the schedule will be communicated by Project Controls to the contractor and also noted as minutes from the weekly on-site Project Controls meeting.

Earned Value Reporting and Analysis

One of the key responsibilities of the Scheduler is to track, analyze, and audit the Earned Value. The analysis will be communicated through the internal weekly Project Controls reports as well as monthly reports which will be circulated to the Project Manager and other key individuals. For this Project, Earned Value metrics will include:

- Schedule Variance

- Cost Variance
- Estimate at Completion (EAC)
- Estimate to Completion (ETC)

12.0 COST AND FINANCIAL MANAGEMENT

Upon Establishing the Project Cost Baseline Structure, Project Controls develops a Cost and Finance Management system for the Project in accordance with PJM-00012 and PMC-PRC-NA-AD-0014 Cost & Contingency Management Procedure.

The Project will maintain and communicate total cost-to-date, un-awarded costs, pending change orders, ETC, and EAC through monthly reports.

Accruals will be recorded in compliance with the corporate accrual policy. The Cost Baseline will be controlled and maintained by the Project Manager with assistance from Project Controls and Finance Lead.

The Project Cost Lead is responsible for assembling the updated Project Cost package by the 10th of each month for team review. The team includes the Project Director, Finance Lead, Implementation Manager, and or Supply Chain.

The Project Manager will approve the final communication package regarding Project cost performance prior to mass distribution.

The Project Controls Cost Lead and Finance Lead will assist the PM to control and maintain the total Cost Baseline of the Project. Changes to the Cost Baseline will be managed in accordance with PMC-PRC-NA-AD-0014 Cost & Contingency Management Procedure.

Contingency Management

Per PMC-PRC-NA-AD-0014 Cost & Contingency Management Procedure, project contingency (Estimate uncertainty & Risk Contingency) drawdown will process through Change Control process utilizing ICFs. ICFs and contingency drawdown will be analyzed on a monthly basis and will document use of Contingency drawdown and Deviations against appropriate CBS. Contingency balance will be assessed against ETC and Risk profile and adequate explanation will be added in the report.

Risk update meeting will be conducted to evaluate updated Risk EMV for the project, Risk coverage ratio will be determined and analysis will be communicated in the analysis section to reflect the project's assessment on update risk profile.

Accounting Considerations

Accounting considerations are contained in Investment Recovery Guidance Document IRGD-001, *Sales Track Guidance and Documentation Package Development*. This provides a "roadmap" to how the IRP accounting is setup and how the Project ensures that it is accurately capturing and reporting IRP costs and sales, and that IRP net sales are correctly reflected as a reduction to the Reg Asset.

CBS and WBS Relationship

The CBS and WBS are aligned as follows:

Project Level 2 Number	Oracle Level 1 Task	Level 1 Task Description	Oracle Level 2 Task	Level 2 Task Description	WBS Element(s)
20104219	1000	Project Management	1001	Project Management	RCVR-DK-1-1, RCVR-DK-1-2, RCVR-DK-1-3, RCVR-DK-1-4, RCVR-DK-1-6, RCVR-DK-6-4, RCVR-DK-6-5
			1002	Contracts	RCVR-DK-3-2, RCVR-DK-6-3 PM contracts only
			1003	Materials/Other	TBD
			1004	Project Management Other	RCVR-DK-1-5, RCVR-DK-7-1, RCVR-DK-7-2, RCVR-DK-7-3
	2000	Sales	2001	Sales Labor	RCVR-DK-2-1, RCVR-DK-2-2, RCVR-DK-2-3, RCVR-DK-3-1, RCVR-DK-3-3, RCVR-DK-3-5, RCVR-DK-6-2
			2002	Sales Material Handling	RCVR-DK-3-4
			2003	Sales Contracts	RCVR-DK-3-2, RCVR-DK-6-3
	3000	Removal Costs	3001	Removal Costs - LPT	RCVR-DK-4-1, RCVR-DK-5-3, RCVR-DK-6-1
			3002	Removal Costs - POD	RCVR-DK-4-1, RCVR-DK-5-3, RCVR-DK-6-1
			3003	Removal Costs - CWP	RCVR-DK-4-1, RCVR-DK-5-2, RCVR-DK-6-1
			3004	Removal Costs - EPU Preservation	RCVR-DK-4-1, RCVR-DK-5-1, RCVR-DK-6-1
			3005	Removal Costs - POD Preservation	RCVR-DK-4-1, RCVR-DK-5-1, RCVR-DK-6-1
			3006	Removal Costs - Other Preservation	RCVR-DK-4-1, RCVR-DK-5-1, RCVR-DK-6-1
			3999	Removal Costs - Non-reimbursable	RCVR-DK-4-1, RCVR-DK-5-1, RCVR-DK-6-1

13.0 RESOURCE MANAGEMENT

Staffing

The Project will utilize a cross functional team to plan, execute, monitor, control and close the Project as mentioned under "Organization Duties & Responsibilities and Approval Entities" section. Personnel that are working on the Project will charge their time and expenses as per the appropriate CBS. The hours and expenses of the internal personnel charging to the Project will be reviewed on a monthly basis. The Finance Lead will be responsible for running the Duke Energy direct labor report and will review the

report, along with the Project Controls Lead and the Project Manager, to ensure that all time and expenses being charged to the Project have been done so appropriately.

Kick-off Meeting

The Project Manager will conduct a Project Kick-Off Meeting on-site with all members of the Project team to go over execution strategy in detail including processes, procedures, roles and responsibilities, ground rules on-site, contract management at Site level, interface with other entities during execution phase, communication plan and rules, etc.

CR3 SUPPORT

Plant Operations

The project will interface with operations to obtain necessary equipment clearances to allow work to proceed safely and to maintain configuration control and protect spent fuel pool interface systems.

Training

The project leadership team is committed to ensuring only properly trained and qualified individuals are assigned to work independently. Existing CR3, Duke Energy fleet or industry training material will be used whenever possible to minimize the need to develop new training material. When needed, additional training will be designed and specific training material will be developed. Fleet training procedures will be used as a reference to guide project training activities.

As each individual is hired, specific initial and continuing training needs will be identified by comparing the individual's knowledge, skill, and experience with the position-to-training matrix. In addition, individual qualification requirements will be identified. Training personnel and project supervision will collaborate to determine the topics from which training exemptions will be granted. Training and qualification requirements and completion status will be maintained in the station's personnel qualification database.

Radiation Protection

Radiation Protection and Control will be implemented for the project in accordance with Site Radiation Control & Protection Manual. The project will interface with the site Radiation Protection staff responsible for ALARA planning, work permit development, and briefings. The project will integrate with station field resources for RP coverage and surveys.

Radiation Protection will also be responsible for oversight of vendor plans for material removal. This includes responsibility for survey and release of any material leaving the radiation controlled area and site.

Engineering

Duke Energy staff will have the primary responsibility for the design and field implementation support of the project. Vendors will be utilized as required to provide specialized analysis and skills.

CR3 Site Engineering will support project development, contractor adherence to performance requirements, maintain knowledge of current project issues, facilitate the resolution of technical issues, and ensure internal stakeholders adequately and expeditiously review project deliverables.

Security

Duke Energy will maintain responsibility for site security and protection. All project site activities will be subject to the site security plan. The project will interface with the site security supervisor to integrate project activities with Security.

14.0 QUALITY MANAGEMENT

The Project will abide to CR3 Nuclear Oversight Program and Policies. The CR3 Nuclear Oversight Staff will be utilized to accomplish these functions. The goal of the Nuclear Oversight (NOS) is to provide nuclear oversight for the execution of the Project in accordance with the CR3 QA Program manual and Nuclear Oversight policies and Procedures including AD-NO-ALL-0500, Major and Complex Project Oversight.

Lessons Learned

Application of lessons learned and operating experience will be integrated into the planning and execution of the Project. Lessons learned and operating experience from other Duke generating plant retirements and industry operating experience from similar work activities will be incorporated. Formal disposition of Operating Experience will be in accordance with CAP0200, Conduct of Performance Improvement as applicable.

Corrective Action Program

The Corrective Action Program (CAP) establishes the processes and responsibilities for documenting and resolving problems, including conditions adverse to quality. The program is designed to address problems in a manner consistent with the nature of the condition and its importance to nuclear safety,

industrial safety, or equipment reliability. The Project will utilize the station corrective action program throughout the duration of the project to address all issues related to owner and vendor actions.

Safety Conscience Work Environment

Project leadership will work to maintain a safety conscience work environment on the project. The project will integrate into the station Safety Culture Program, ADM0119.

15.0 RISK MANAGEMENT

The Risk Management process through-out the Project will be in accordance with in accordance with PJM-00004, PJM-00013, PJM-00013 Guide and PMC-PRC-NA-AD-0016 Risk Management Procedure.

The Project will utilize a Risk Register, Top Ten Post Response Strategy Risk Matrix, Risk Radar and Risk Trend tools to monitor, control, and communicate the status of Project risks on monthly basis at a minimum.

The Project will utilize the current available template of the Risk Register tool as provided on the PMCoE SharePoint Site. The PMC Project Controls Lead will ensure that the Project risk register is updated on a monthly basis, in advance of and in support of the monthly Project review meeting.

16.0 COMMUNICATION MANAGEMENT

Emergency Incidents

The affected party will immediately notify the Duke Energy Project Manager. The PMC Project Manager maintains the Incident Notification log through-out the Project life-cycle for record and audit purposes.

For Safety Incidents

- The first person at the site of an accident or incident where medical assistance is required shall immediately call 5555 or the appropriate emergency number for the work location.
- The Site Safety Lead or Project Implementation Manager will notify the PMC Project Manager & PMC Safety Lead (Charlotte) per the Management Intervention Plan (MIP).
- The Site Safety Lead will complete the first notice of serious event or OSHA recordable, approved by Site management & distributed as instructed through Plantview (PMC internal only), per the Management Intervention Plan (MIP) .

- The PMC Project Manager will make notifications per the Management Intervention Plan (MIP).
- The Project Implementation Manager will make notifications per the Management Intervention Plan (MIP).

For Environmental Incidents

- The Site Environmental Lead or Project Implementation Manager will make notifications per the Management Intervention Plan (MIP).
- The Site Environmental Lead or PMC Site Construction Manager will immediately notify the PMC Project Director & PMC Environmental Lead (Charlotte).
- The PMC Project Director will notify the GM-PMC and Plant/Station manager.
- The PMC Site Construction Manager will notify the PMC Manager-Site Construction.

NOTE: The PMC Environmental Lead (Charlotte) coordinates and manages all agency notifications through Duke Energy EHSS. Contractors will not make agency notifications or public comment releases to the press.

Meeting Schedules

Project meetings will be held on a weekly and monthly basis.

Key Decisions

The Project Manager will use the ICF Change Control Process to seek VP, PMC approval prior to implementing a key decision on the Project which is not addressed at any other forum. For instance, the Project decision to Re-Baseline schedule will be tracked and approved through this process.

Lessons Learned Management

Lessons Learned will be documented in accordance with the PMC-PRC-00-AD-0007 Performance Improvement (PI) procedure.

All Project lessons learned will be documented in Plantview and also reported through the monthly report review process.

After Action Review (AAR)

Following critical evolutions and other major events the Project team will conduct AARs in accordance with the PMC PI procedure.

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Post-Project Debriefing

During the Project's close phase, the Project team will perform a post-Project debriefing to facilitate identification of lessons learned in accordance with the PJM-00019-ENTSTD Project Close Management Standard.

17.0 COMPLIANCE MANAGEMENT [SAFETY, ENVIRONMENTAL, AND REGULATORY]

Safety Plan

The Site occupational health and safety focus incorporates Duke Energy Corporate procedures applicable to the Site, Corporate Development Group - Health and Safety Management System, and applicable operating plant health and safety procedures.

Occupational health and safety expectation includes adequate oversight and continuous improvement throughout the Project.

Environmental Permits

There are no environmental permits expected for the Project. The need for permits required to support large component removal and shipment will be addressed in the individual Task Plan(s) developed.

Environmental Compliance

The Environmental Compliance Plan (ECP) for individual Task Plans will consist of the development and implementation of a Site specific environmental execution plan based on each scope.

Regulatory

Specific guidance for execution of the Project is provided in AI-9010, *Conduct of CR3 Investment Recovery*. Regular review and audit is performed under the purview of the Duke Rates and Regulatory Strategy department.

18.0 DOCUMENT CONTROL & PROJECT ASSURANCE

Document Control

The CR3 Decommissioning Document Retention SharePoint site will be used for capturing and storing Project records. In addition to the documents specified in the Project Assurance Plan, a "working"

section is established to store in-progress project documents (e.g.; action items, contracts, AAT forms, IRP Master Database, Photos, POs, sales data, etc.)

Project Assurance

The Project Manager and other entities involved in planning and executing the Project are responsible for ensuring that the Project is implemented in a reasonable and prudent manner. The role of Project Assurance is to ensure that Project stakeholders understand the regulatory cost recovery process and the importance of managing the Project in a manner that will allow the company to recover Project costs as permitted by relevant laws, rules and regulations. A designated Project Assurance Advisor will be appointed to support and advise the Project management team based on Project type/requirements. The advisor will collaborate with the Project Manager to identify Project decisions and decision milestones that may be subject to regulatory scrutiny and will be available to review and/or advise upon the documentation necessary to demonstrate that those decisions were reasonable and prudent.

Project Assurance issues will be sent via e-mail with copy to the Project email address. Refer to PMC-PRC-NA-AD-0013 Project Assurance Manual for details and process information.

19.0 PROJECT REPORTING AND PERFORMANCE MEASUREMENT TOOL

Project Performance Measurement Tool

The Project Performance Measurement Tool consist of two (2) categories/Key Performance Indicators (KPI) – proceeds / cost, and asset work down curve. Updates of both KPIs will be evaluated and communicated at an agreed frequency (Weekly and Monthly) as per the weekly/monthly reporting distribution sheet. The Project will use the PMC management approved Monthly Report template to communicate performance updates.

Project Reporting – PMC internal

Project reporting includes both weekly and monthly generated reports.

On a weekly basis, the Project Manager will use an exception based weekly report to status the Project update. The weekly report is a SharePoint web report and is to be completed by the Project Director by the close of business every Thursday.

On a monthly basis, the Project core team will jointly update the Project Monthly report for KPIs performance updates in detail. The Project Manager will host a monthly Project progress meeting for PMC management. The meeting will cover all of the items that are to be noted in the monthly report.

The monthly Project team meeting will be held to facilitate a forum for key stakeholders to gain an understanding of the Project status and engage in key issues and risks.

The following are a list of reports regularly generated by the Project team:

- Monthly Project Reports
  - Cost & Financials Analytics
  - Asset work down curves
  - Schedule milestone performance
- Weekly Project Reports
  - Exceptions

20.0 WARRANTY MANAGEMENT

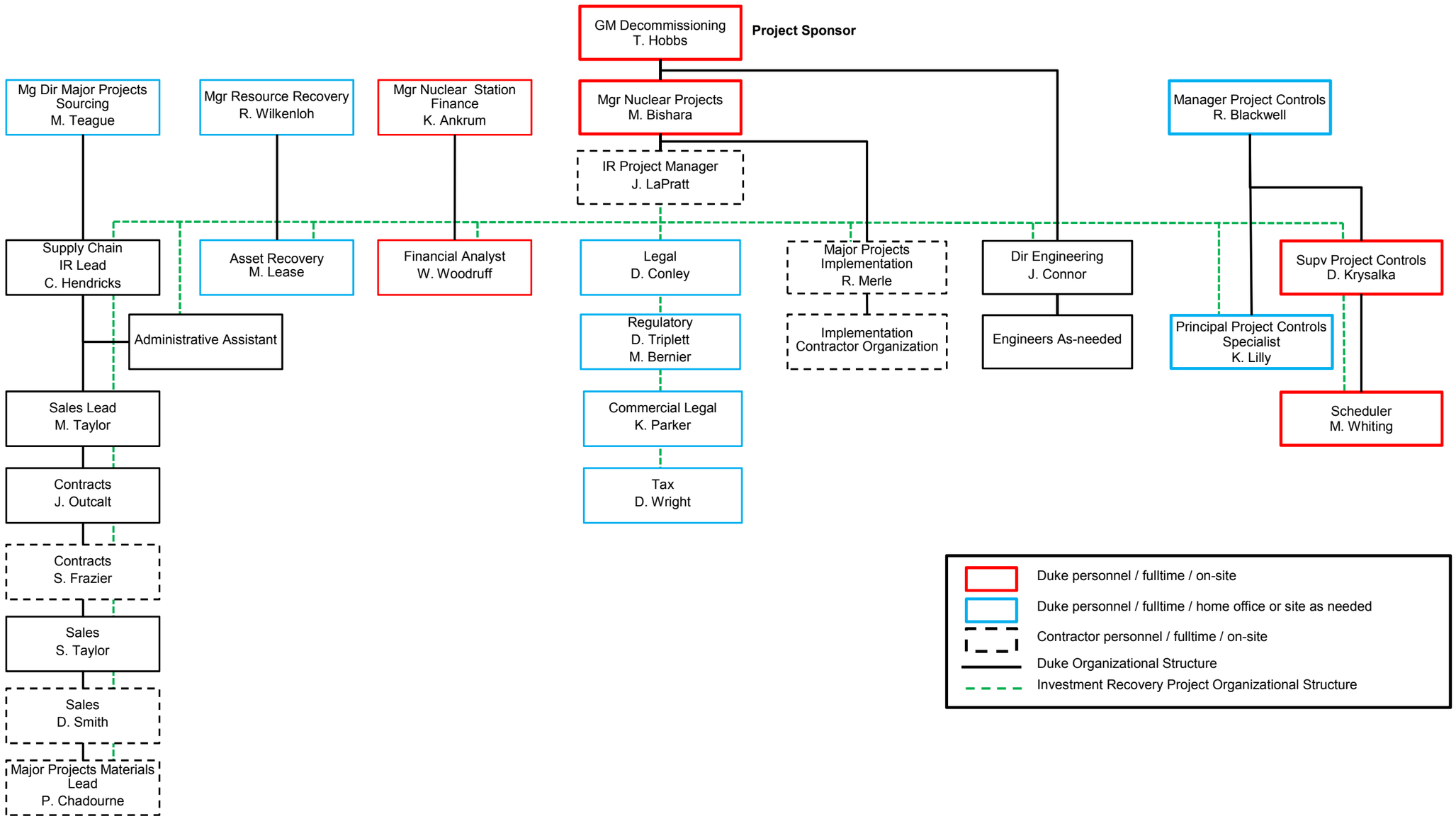
CR3 assets dispositioned to non-Duke entities by this Project are sold as-is, where-is with no warranty by Duke. Supply Chain Contracts personnel will work with asset suppliers as needed to facilitate transfer of manufacturer/supplier warranties when assets are transferred to a Duke affiliate.

21.0 PROJECT CLOSE-OUT MANAGEMENT

Project Close-Out Management will be in accordance with PJM-00019-ENTSTD and PMC-PRC-00-AD-0004 PMC Project Stage Gate Review and Approval procedure. These procedures provides guidance on the Project close-out process, accounts closing, contract closing, final job report, documents transfer, and reporting of standard post Project benefit assessments.

A final Project Close-Out meeting will be held during which the Project Manager and PMC General Manager will review open items and remaining scope of the work. The Project Manager will also review any contractual agreements. This may include any open items for audits, incident investigations, or corrective actions.

APPENDIX A – ORGANIZATION CHART



APPENDIX B – ORGANIZATION RACI[1] CHART

Activity	Project Team Member: Project Manager	Supply Chain Lead	SC Contracts Lead	Proj Cont Specialist/ Supervisor	Proj Cont Scheduler	Proj Cont Estimator	Financial Analyst/ Manager	Project Engineer	Impl Manager	Reg Lead	Legal Lead	Lead Planner
DK-1 Project Administration												
DK1-1 Develop Project Plan Documents	A/R	C	C	C	I	I	C	C	C	C	C	I
DK1-2 Estimate Project Costs	A	C	C	C	C	R	C	C	C	C	C	I
DK1-3 Develop Project Schedule	A	C	I	C	R	I	I	C	C	I	I	C
DK1-4 Perform Monitor and Control	A/R	R	C	R	R	I	R	C	C	C	C	I
DK1-5 Perform Project Assessments	A	C	C	C	C	C	C	C	C	R	R	C
DK1-6 Project Funding and Gate Reviews	A/R	C	C	C	C	C	C	C	C	C	C	C
DK-2 Engineer												
DK2-1 Engineering Change	A	I	I	I	I	I	I	R	C	I	I	I
DK2-2 Sales Engineering Support	A	C	C	I	I	I	I	R	I	I	I	I
DK2-3 Implementation Engineering Support	A	I	I	I	C	I	I	R	C	I	I	C
DK-3 Supply Chain												
DK3-1 Sales Activities	A	R	C	I	I	I	C	C	C	I	I	I
DK3-2 Contract Management	A	C	R	I	I	C	C	C	C	I	I	I
DK3-3 Procurement Engineering Data Package Dev	A	R	C	I	I	I	I	C	I	I	I	I
DK3-4 Material Handling	A	R	I	I	I	I	I	I	I	I	I	I
DK3-5 Database Management	A	R	C	C	I	I	C	C	I	I	I	I
DK-4 Work Planning												
DK4-1 Develop Work Orders	A	I	C	I	C	I	I	C	C	I	I	R
DK-5 Implementation												
DK5-1 Asset Preservation	A	C	C	I	C	I	I	C	R	I	I	C
DK5-2 Installed Asset Removal	A	C	C	I	C	I	I	C	R	I	I	C
DK5-3 Large Component Removal/Shipping	A	C	C	I	C	I	I	C	R	I	I	C
DK-6 Project Closeout												
DK6-1 Close Work Orders	A	C	C	I	C	I	I	C	C	I	I	R
DK6-2 Close Engineering Documents	A	C	C	I	I	I	I	R	C	I	I	C
DK6-3 Close Contracts	A	C	R	I	I	I	C	C	C	I	I	I
DK6-4 Close Project Documents	A/R	C	C	C	C	C	C	C	C	C	C	C
DK6-5 Perform Project Lessons Learned	A/R	C	C	C	C	C	C	C	C	C	C	C
DK-7 Legal & Regulatory Oversight												
DK7-1 Legal Reviews	A	C	C	C	C	C	C	C	C	C	R	C
DK7-2 Regulatory Reviews	A	C	C	C	C	C	C	C	C	R	C	C
DK7-3 Tax & Financial Reviews	A	C	C	C	C	C	R	C	C	C	C	C

[1]**R [responsible]** Those who do work to achieve the task. **A [accountable]** The resource ultimately answerable for the correct and thorough completion of the task. **C [consult]** The resources whose opinions are sought on various activities. This is a two-way communication. **I [inform]** The resources that need to be kept up-to-date on progress. This is a one-way communication.

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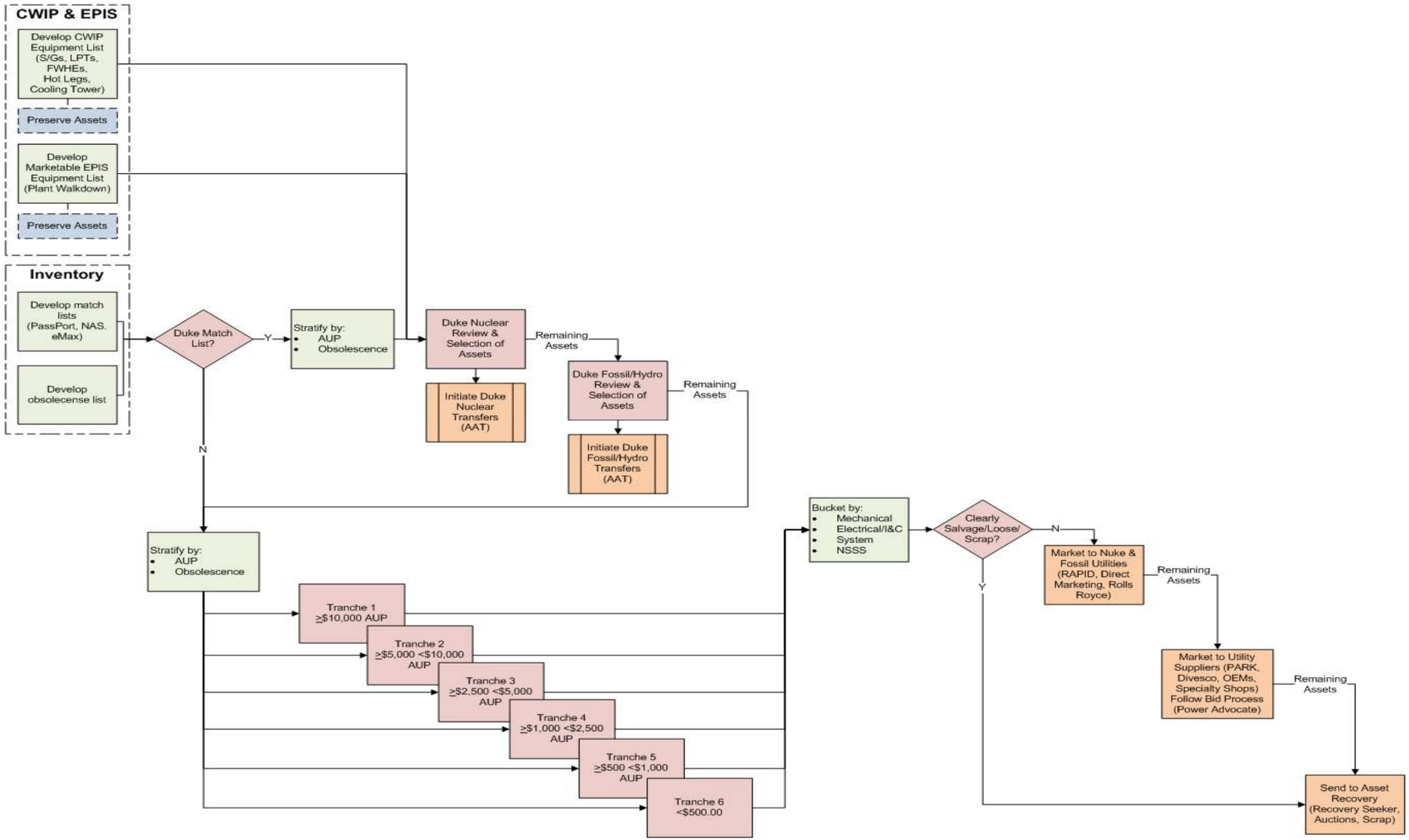
APPENDIX C – CONTACT LIST

Project Management				
Last Name	**First Name**	**Position**	**Extension**	**Cell Phone**
LaPratt	Jeff	PM	[redacted]	[redacted]
Bishara	Magdy	MGR Nuclear Projects	[redacted]	[redacted]
Project Controls & Support				
Last Name	**First Name**	**Position**	**Extension**	**Cell Phone**
Krysalka	Dan	Supv Project Controls	[redacted]	[redacted]
Lilly	Kathy	Prnc Proj Controls Specialist	[redacted]	[redacted]
Woodruff	Wendy	Sr Financial Analyst	[redacted]	[redacted]
Whiting	Mark	Sr Proj Controls Specialist	[redacted]	[redacted]
Supply Chain				
Last Name	**First Name**	**Position**	**Extension**	**Cell Phone**
Teague	Mark	Mgng Dir Major Projs Sourcing	[redacted]	[redacted]
Hendricks	Chris	Mgr Nuc Site Supply Chain	[redacted]	[redacted]
Taylor	Mike	Mgr Nuclear Procurement	[redacted]	[redacted]
Smith	Dave	Contractor – IRP Specialist	[redacted]	[redacted]
Taylor	Steve	Sr Tech Specialist	[redacted]	[redacted]
Outcalt	Jay	Contacts	[redacted]	[redacted]
Frazier	Shannon	Contracts	[redacted]	[redacted]
Chadourne	Paul	Materials Lead	[redacted]	[redacted]
Lease	Michelle	Asset Recovery Coordinator	[redacted]	[redacted]
Engineering				
Last Name	**First Name**	**Position**	**Extension**	**Cell Phone**
Connor	Jim	Dir Nuclear Engineering	[redacted]	[redacted]
Implementation				
Last Name	**First Name**	**Position**	**Extension**	**Cell Phone**
Merle	Russ	Implementation Manager	[redacted]	[redacted]

Legal / Regulatory / Tax				
Last Name	**First Name**	**Position**	**Extension**	**Cell Phone**
Conley	Dave	Associate Gen Counsel	[redacted]	[redacted]
Triplett	Dianne	Associate Gen Counsel	[redacted]	[redacted]
Bernier	Matt	Sr Counsel	[redacted]	[redacted]
Parker	Kristy	Associate Gen Counsel	[redacted]	[redacted]
Wright	Dave	Dir Non-income & Property Tax	[redacted]	[redacted]
Olivier	Marcia	Dir Rates & Reg Strategy	[redacted]	[redacted]

DRAFT

APPENDIX D – DISPOSITION STRATEGY FLOWCHART

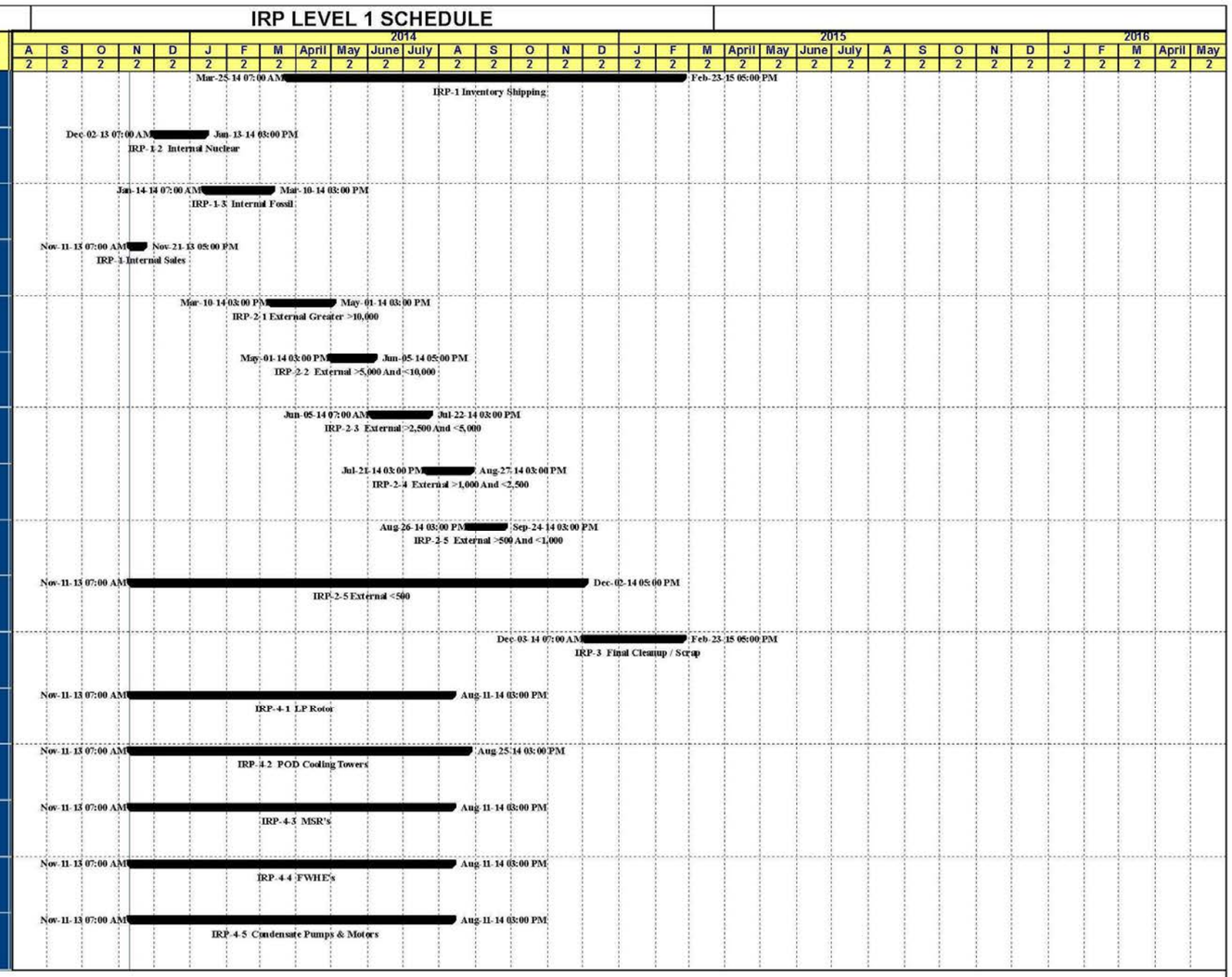


APPENDIX E – LEVEL 1 SCHEDULE

CR3 INVESTMENT RECOVERY SCHEDULE

IRP LEVEL 1 SCHEDULE

Activity ID	Activity Name	Start	Finish	Hrs	Activity Type
IRP-1	Inventory Shipping	Mar-25-14 07:00 AM	Feb-23-15 05:00 PM	1830h	
IRP-1-2	Internal Nuclear	Dec-02-13 07:00 AM	Jan-13-14 03:00 PM	218h	
IRP-1-3	Internal Fossil	Jan-14-14 07:00 AM	Mar-10-14 03:00 PM	318h	
IRP-1-Internal	Sales	Nov-11-13 07:00 AM	Nov-21-13 05:00 PM	80h	
IRP-2-1	External Greater >10,000	Mar-10-14 03:00 PM	May-01-14 03:00 PM	300h	
IRP-2-2	External >5,000 And <10,0	May-01-14 03:00 PM	Jun-05-14 05:00 PM	192h	
IRP-2-3	External >2,500 And <5,00	Jun-05-14 07:00 AM	Jul-22-14 03:00 PM	288h	
IRP-2-4	External >1,000 And <2,50	Jul-21-14 03:00 PM	Aug-27-14 03:00 PM	220h	
IRP-2-5	External >500 And <1,000	Aug-26-14 03:00 PM	Sep-24-14 03:00 PM	160h	
IRP-2-5	External <500	Nov-11-13 07:00 AM	Dec-02-14 05:00 PM	2100h	
IRP-3	Final Cleanup / Scrap	Dec-03-14 07:00 AM	Feb-23-15 05:00 PM	440h	
IRP-4-1	LP Rotor	Nov-11-13 07:00 AM	Aug-11-14 03:00 PM	1498h	
IRP-4-2	POD Cooling Towers	Nov-11-13 07:00 AM	Aug-25-14 03:00 PM	1578h	
IRP-4-3	MSR's	Nov-11-13 07:00 AM	Aug-11-14 03:00 PM	1498h	
IRP-4-4	FWHE's	Nov-11-13 07:00 AM	Aug-11-14 03:00 PM	1498h	
IRP-4-5	Condensate Pumps & Mo	Nov-11-13 07:00 AM	Aug-11-14 03:00 PM	1498h	



Summary

Report Date Jan-21-14

Data Date Nov-11-13

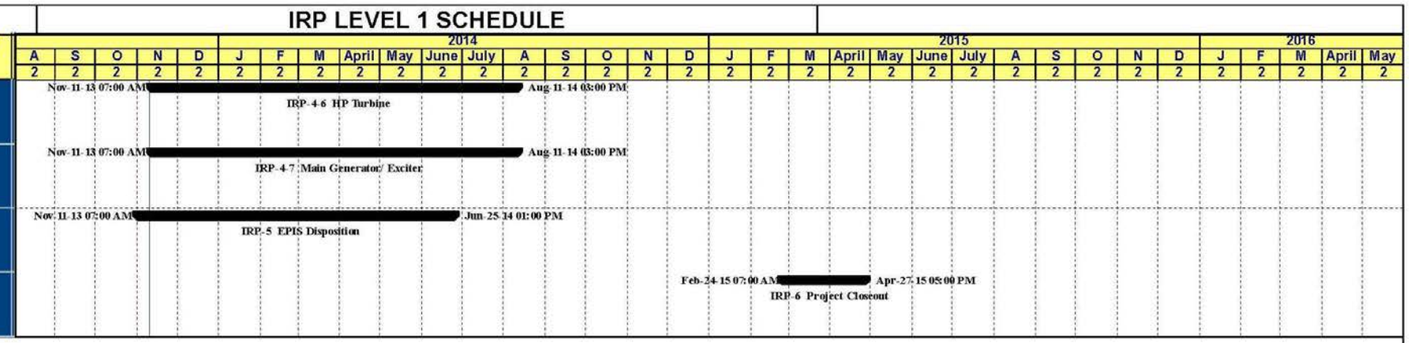
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CR3 INVESTMENT RECOVERY SCHEDULE

IRP LEVEL 1 SCHEDULE

Activity ID	Activity Name	Start	Finish	Hrs	Activity Type
IRP-4-6	HP Turbine	Nov-11-13 07:00 AM	Aug-11-14 03:00 PM	1498h	
IRP-4-7	Main Generator/ Exciter	Nov-11-13 07:00 AM	Aug-11-14 03:00 PM	1498h	
IRP-5	EPIS Disposition	Nov-01-13 07:00 AM A	Jun-25-14 01:00 PM	1246h	
IRP-6	Project Closeout	Feb-24-15 07:00 AM	Apr-27-15 05:00 PM	360h	



Summary

Report Date Jan-21-14

Data Date Nov-11-13 2

APPENDIX F – PMC DOCUMENT APPROVAL FORM

DUKE ENERGY.

Project Management & Construction
Document Approval Form (DAF)

Section A: Document identification and type of action

Document Number: N/A	**Revision Number:** 0
Document Title: CR3 Investment Recovery Project Project Execution Plan	
Type of Action: ☒ New ☐ Suspension ☐ Revision ☐ Ownership Change ☐ Cancellation ☐ Periodic review completed	**Effective Date:** 2/25/2014
Applies to: Project Management & Construction	**Group:** CR3 Decommissioning Transition Org

Applicable to Forms Only
Does form have a parent procedure? ☒ No ☐ Yes Procedure #:
☐ **Communication plan established N/A** ☐ **Impact Reviews Completed N/A**

Description of document action or summary of changes:

The document presents the Project Execution Plan for the CR3 Investment Recovery Project (IRP).

Preparer(s): Jeff LaPratt, IRP PM

Section B: Approval

Jeff LaPratt/IRP PM Approval recommended (print name)	Signature	2/24/14 Date
Magdy Bishara/MGR Major Projects Approval recommended (print name)	Signature	2/24/14 Date
Terry Hobbs/GM Decommissioning Final Approval (print name)	Signature	2/24/14 Date
N/A Approved (for approval of interface documents only)	Signature	Date

RETURN SIGNED FORM TO PMC GOVERNANCE

INVESTMENT RECOVERY GUIDANCE DOCUMENT

IRGD-001

Revision 0

Sales Track Guidance and Documentation Package Development

An Uncontrolled Reference and Assistance Document

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 53
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)
DESCRIPTION: Mark R. Teague MT-3

Note: If any conflicts exist between the current Directives and Procedures and the information contained within this guidance document all directives and procedures shall govern the work described herein.

Sales Guidance and Documentation Package Development

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Sales Guidance and Documentation Package Development

1.0 PURPOSE

This Guidance Document provides instruction to conduct sales and develop complete documentation packages for the Crystal River Unit 3 (CR3) Investment Recovery Project (IRP).

2.0 APPLICABILITY

This Guidance Document applies to the IRP. More specifically, this Guidance Document applies to the sale/transfer of material and the development and retention of sales and other supporting documentation.

3.0 ROLES AND RESPONSIBILITIES

Manager Nuclear Procurement or designee is the single point of contact for reviewing all documentation packages and ensuring all documents are uploaded to the Share Point Site and sales tracking database.

Investment Recovery Project Manager (IRPM) provides oversight of the sales process and documentation retention activities. Additionally, the Investment Recovery PM is responsible for facilitating the removal of equipment installed in the plant.

Investment Recovery Sales Team (IRST) is the point of contact for obtaining sales leads, negotiating the sale, closing the sale, and documenting all aspects of the sale transaction. The CR3 IRST is also responsible for loading all documentation on the Investment Recovery Share Point Site and sales tracking database.

Asset Recovery Sales Team (ARST) processes all salvage transactions, and is responsible for invoicing vendors after Inter-Utility (RAPID), external third party, and salvage sales are completed.

CR3 Financial Analyst determines the Net Book Value (NBV) for Duke Affiliate Transfers and Duke Internal Sales, when available. Completes first half of the Capital-to-Capital or Capital-to-Inventory template and tracks Journal Entries processed by Asset Accounting and performs Journal Entries for transfers within the state of Florida.

4.0 IRP SALES STRATEGY

Organize – Develop a list of and categorize all items available for immediate sale with an explanation of how the sale criteria and categorization was achieved.

Preserve – Determine what preventive maintenance (PM) and preservation activities are required to allow the highest rate of return for all CR3 assets. Develop and implement a plan for the preventive maintenance (PM) and preservation activities.

Analyze – Determine the most effective method for each category and create a schedule for the sale of these items.

Disposition – Distribute the “match” lists within the Duke organization to obtain the highest rate of return. Follow the AI9010 Administrative Procedure for the remaining equipment and material.

5.0 SALES PROCESS AND REQUIRED DOCUMENTATION

5.1 Duke Affiliate Transfer

1. IF non-inventory Capital material, THEN the financial analyst will determine the Net Book Value (NBV) and completes either:
    a. Capital-to-Capital template and sends to requesting location; or
    b. Capital-to-Inventory template and sends to requesting location.
2. IF Inventory material, THEN Calculated Unit Price (CUP) from the CAT ID shall be used for the asset value.
3. Requesting Location shall initiate the Affiliate Asset Transfer (AAT) eForm and route to CR3 Investment Recovery (SCD211, Rev.1).
    a. Completed Capital-to-Capital or Capital-to-Inventory template shall be attached, if required.
4. The IRST shall complete and obtain approvals for Asset Disposition Review form (AI-9010, Attachment 1).
5. IF equipment is installed in the plant, THEN:
    a. IRST will initiate and obtain approvals for Installed Plant Equipment Removal Agreement (AI-9010, Attachment 2).
    b. IRPM facilitates the removal of the equipment with the IRP Implementation group.
6. Manager Nuclear Procurement, or designee, shall review the AAT eForm and if such AAT eForm is satisfactory (see Attachment A for requirements), approval shall be granted.
7. FL legal shall review the AAT eForm and if such eForm is satisfactory, approval shall be granted.
8. IF the equipment is installed in the plant, is Safety Related and is required to maintain a Safety Related classification, return to stock under the appropriate CAT ID, if one does not exist, create a new CAT ID per the established Nuclear Procedures:
    a. Initiate a PICK Ticket, for all listed/sold material, if the plant is Non-Nuclear the requesting site shall create an Material Request (MR).
    b. CR3 Adjust Minimum/Maximum to zero (0) in PassPort to prevent re-order.
9. IF inventory material, THEN:
    a. Initiate a PICK Ticket, if required, for all listed/sold material.
    b. CR3 IRST Adjust Minimum/Maximum to zero (0) in PassPort to prevent re-order.
10. Obtain shipping arrangements from requesting location.
11. Forward a copy of the AAT eForm and shipping information to the warehouse.
12. Ship material to the requesting location.

13. For Capital assets the AAT eForm is sent to Asset Accounting to perform a Journal Entry which transfers the funds.
    a. Journal entry should include the asset value (shipping, stores, etc.) as well as the removal costs, if required.
    b. True-up of actual costs is obtained through the journal entry and attached to the AI9010.
14. Document sale on the Sales Tracking Database and place electronic copies of the following sales documents in the SharePoint site IRP Document Retention File:
    a. AAT eForm, including all Attachments
    b. Asset Disposition Review (AI-9010, Attachment 1)
    c. Installed Plant Equipment Removal Agreement (AI-9010, Attachment 2), if required.
    d. PICK Ticket, if required
    e. Issue Ticket, if required
    f. Shipping documentation
    g. E-mails
    h. Journal entry documentation, if required

5.2 Duke Florida Internal Transfer

1. IF Non-inventory, THEN determine value of asset:
    a. Contact Financial Analyst to determine the NBV of the equipment.
    b. If NBV is not available, the IRST should determine Fair Market Value (FMV).
2. IF Safety Related material is requested, THEN
    a. IRST shall verify the material is not on the Match List.
    b. CAT ID shall be downgraded to Quality Level 4.
3. Complete and obtain approvals for Asset Disposition Review form (AI-9010, Attachment 1).
    a. IF non-inventory asset, THEN AI-9010, Attachment 1 is required.
    b. IF inventory asset, THEN AI9010, Attachment 1 is NOT required.
4. IF equipment is installed in the plant, THEN:
    a. Initiate and obtain approvals for Installed Plant Equipment Removal Agreement (AI-9010, Attachment 2).
    b. IRPM facilitates the removal of the equipment with the IRP Implementation group.
5. IF the item has a CAT ID in the PassPort System and the:
    a. Item is Safety Related (QL 1, 2, 3)
        i. A Material Request shall be completed by the requesting site.

ii. CR3 shall Adjust Minimum/Maximum to "0" to prevent a re-order.

b. Item is non-safety related (QL 4)

i. A Pick Form should be completed by the sending site.

ii. CR3 shall Adjust Minimum/Maximum to "0" to prevent a re-order.

6. Shipping arrangements are coordinated by requesting plant and shipping information shall be sent to the warehouse personnel.
7. Material is shipped to the requesting facility.
8. Document sale on the Sales Tracking Database and place electronic copies of the following sales documents in the SharePoint site IRP Document Retention File:
    a. Asset Disposition Review (AI-9010, Attachment 1)
    b. Installed Plant Equipment Removal Agreement (AI-9010, Attachment 2), if required.
    c. Pick Ticket/Transfer/Material Request, if required
    d. Issue Ticket, if required
    e. Shipping documentation
    f. E-mails
    g. True-up of actual costs documentation, if required
    h. Journal entry documentation, if required
9. A monthly report of all Duke Florida Internal Inventory sales shall be uploaded to the SharePoint site.
10. IF in-state transfer was purchased as or currently is EPIS, Inventory or O&M (101 or 106 accounts), THEN the material can be transferred and the receiving organization will not realize the costs at the time of the transfer.
11. IF in-state transfer was purchased as or currently is CWIP (107 account), THEN the cost is recognized by the receiving organization at the time of the transfer.

5.3 Inter-Utility (RAPID) Sale

1. Price is negotiated at CUP or better, Terms and Conditions are in accordance with the Inter-Utility Sales agreement. Note: Some sale prices may be lower than the CUP due to material condition, shelf life, etc. Approval of the modified sale price shall be obtained prior to sale closure by either the Manager Of Nuclear Procurement or Site Supply Chain Manager.
2. CR3 receives the Purchase Order (PO).
3. Complete and obtain approvals for Asset Disposition Review form (AI-9010, Attachment 1).
4. IF equipment is installed in the plant, THEN:
    a. Initiate and obtain approvals for Installed Plant Equipment Removal Agreement (AI-9010, Attachment 2).

   b. IRPM facilitates the removal of the equipment with the IRP Implementation group.

5. IF inventory, THEN CR3 IRP completes a Material Request and adjusts Minimum/Maximum to "0" to prevent re-order.
6. Shipping arrangements coordinated by requesting plant and CR3 warehouse.
   a. MR and PO are forwarded to CR3 warehouse for issuing and shipping instructions.
7. Material shipped to requesting facility.
   a. Forward shipment tracking information to buyers upon request.
8. Copy of shipping information/issue ticket sent to CR3 IRP.
9. Enter information into Investment Recovery RAPID database spreadsheet.
10. Document sale on the Sales Tracking Database and place electronic copies of the following sales documents in the SharePoint site IRP Document Retention File:
    a. Asset Disposition Review (AI-9010, Attachment 1)
    b. Installed Plant Equipment Removal Agreement (AI-9010, Attachment 2), if required.
    c. Purchase Order
    d. Material Request, if required
    e. Issue Ticket, if required
    f. Shipping documentation
    g. E-mails
    h. Copy of invoice
    i. Tax exempt form

5.4 Duke External Third Party Sale

1. Price is negotiated in accordance with the Terms and Conditions for CR3 Investment Recovery sales. Note: Buyer pays for all shipping and handling (including removal from plant if installed) costs.
   a. See Material Bidding Process 6.0
2. CR3 Receives the Contract/Purchase Order (PO).
3. Complete and obtain approvals for Asset Disposition Review form (AI-9010, Attachment 1).
4. IF equipment is installed in the plant, THEN:
   a. Initiate and obtain approvals for Installed Plant Equipment Removal Agreement (AI-9010, Attachment 2).
   b. IRPM facilitates the removal of the equipment with the IRP Implementation group.

5. IF Inventory, THEN CR3 IRP completes a Material Request (MR) and adjusts Minimum/Maximum to "0" to prevent re-order.
6. Shipping arrangements coordinated by requesting company in accordance with Contract/PO.
    a. MR and Contract/PO are forwarded to CR3 warehouse for issuing and shipping instructions.
7. Material shipped to requesting company.
    a. Forward shipment tracking information to buyers upon request.
8. Copy of shipping information/issue ticket sent to CR3 IRP.
9. Document sale on the Sales Tracking Database and place electronic copies of the following sales documents in the SharePoint site IRP Document Retention File:
    a. PowerAdvocate documents, if required
    b. Buyer Contract/Purchase Order
    c. Asset Disposition Review (AI-9010, Attachment 1)
    d. Installed Plant Equipment Removal Agreement (AI-9010, Attachment 2), if required.
    e. Material Request, if required
    f. Issue Ticket, if required
    g. Shipping documentation
    h. E-mails
    i. Copy of invoice
    j. Tax exempt form
    k. Signed IR Terms and Conditions

5.6 Duke Salvage Sale

1. Price is negotiated in accordance with the Terms and Conditions for CR3 Investment Recovery sales.
    a. See Material Bidding Process 6.0
2. CR3 Receives the Contract/Purchase Order (PO).
3. Complete and obtain approvals for Asset Disposition Review form (AI-9010, Attachment 1).
4. IF equipment is installed in the plant, THEN:
    a. Initiate and obtain approvals for Installed Plant Equipment Removal Agreement (AI-9010, Attachment 2).
    b. IRPM facilitates the removal of the equipment with the IRP Implementation group.

5. CR3 IRP completes a Material Request (MR) and adjusts Minimum/Maximum to "0" to prevent re-order.
6. Shipping arrangements coordinated by requesting company in accordance with Contract/PO.
    a. MR and Contract/PO are forwarded to CR3 warehouse for issuing and shipping instructions.
7. Material shipped to requesting company.
    a. Forward shipment tracking information to buyers upon request.
8. Copy of shipping information/issue ticket sent to CR3 IRP.
9. Document sale on the Sales Tracking Database and place electronic copies of the following sales documents in the SharePoint site IRP Document Retention File:
    a. PowerAdvocate documents, if required
    b. Buyer Contract/Purchase Order
    c. Asset Disposition Review (AI-9010, Attachment 1)
    d. Installed Plant Equipment Removal Agreement (AI-9010 Attachment 2), if required.
    e. Material Request, if required
    f. Issue Ticket, if required
    g. Shipping documentation
    h. Pertinent e-mails
    i. Copy of invoice
    j. Tax exempt form
    k. Signed IR Terms and Conditions

6.0 MATERIAL BIDDING PROCESS

1. IRSTs shall decide on a method of disposition based on the following criteria:
    a. Asset value < $15,000.00 - Items may be marketed and sold at the IRST's discretion
    b. $15,000.00 < Asset value < $100,000.00 – Items must be sold using one of the following methods:
        i. Asset Recovery's Online Surplus Marketplace
            1. Online marketing and sales tool may utilize one or more of the following sales methods:
                a. Auction
                b. Fixed Price Sale
                c. Classified Ad

2. Document sale on the Sales Tracking Database and place electronic copies of the following sales documents in the SharePoint site IRP Document Retention File:
    a. List of companies/individuals automatic emails were disseminated to.
    b. List of companies/individuals who received phone calls.
    c. List of Bidders.
    d. All communications:
        i. Emails
        ii. Posted comments
            1. Questions
            2. Responses
        iii. calls logged with notes regarding conversation.
    e. Amount of each bid.
    f. Number of visitors (names if possible).
    g. All documentation:
        i. T&Cs
        ii. AI-9010 Form
        iii. Screen shots
    h. Time Auction started/ended.

ii. Formal Bid

1. E-mail bid which includes a bid package containing at a minimum:
    a. Bid Cover Letter or Information letter
    b. Instructions to bidder
    c. List of Materials for Sale
    d. Terms and Conditions for CR3 Investment Recovery sales
    e. Bidder Response form

iii. Power Advocate Bid Event

c. Asset Value > $100,000.00

i. Items must be sold using a Power Advocate Bid Event

2. Exception from standard Material Bidding Process
    a. IF an instance occurs where IR is required to make an exception for an asset sale, THEN they shall be documented by the IRST and approved by the Manager of Nuclear Procurement or designee.
    b. Examples of when an exception may occur include, but are not limited to the following:
        i. Contractual restraints only allow sale to one party (original manufacturer)
        ii. Expedited time frame for sale required and the sale price is above CUP

7.0 VENDOR SITE ACCESS

Prior to admittance to the CR3 site all vendor personnel shall have an approved Site Access Form. Prior to picking up material or equipment the vendor shall sign a Duke Energy agreement which includes acceptance of:

- Insurance requirements
- Safety and Security procedures
- Waiver of liability

8.0 CR3 ACCOUNTING STRUCTURE

8.1 CR3 Assets

All CR3 Assets are in one of the following categories:

Account	Description		Account	Description
101	Electric Plant In Service (EPIS)		154	Inventory
107	Construction Work In Progress (CWIP)		163	Stores
106	Capital Cost Not Classified (CCNP)		183	Study

The financial analyst will determine which of the following accounts a Capital Sale will be credited to:

Credit Account	Description
20100423 - SLVGE	Capital Co-Owned
20100426 - SLVGE	Capital Non-Co-Owned
EPU - DISP	EPU
20069122 - SLVGE	EPU POD

Stores Loading rate is not added to Capital items when sold internally to a Duke Energy Affiliate or to Duke Energy Florida.

8.2 CR3 Inventory

All inventory sales are credited as follows:

Credit Account	Description
20016324	Inventory

Stores Loading rate is included on all inventory sales and transfers.

8.3 CR3 Tax Collection

8.3.1 When is Sales Tax Collected

All Duke entities are required by the various states in which they operate to collect sales tax on the sales of used equipment ***unless*** the customer can prove their exemption. Transactions can be exempt because of who the customer is or because of how the customer will be using the item purchased. In either case, the customer would

need to provide exemption documentation to in order to avoid having sales tax added to their bill.

Below are examples of common exemptions:

Entity Based Exemption	**Use Based Exemptions**
Government Entities	Reselling
Nonprofits	Manufacturing
Religious Organization	Research and Development
Educational Institutions	Utility use

Exemptions and exemption documentation will vary from state to state. Not every state will recognize all the exemptions above. When exemption documentation is received verify that it is properly completed and retain a copy for audit purposes. (Some exemption documentation may need to be signed or have an explanation.)

8.3.2 Accounting Structure for Collecting Sales Tax

Operating Unit	0193
Responsibility Center	0193
Location	002090209 (Citrus County, Florida)
GL Account	0241320
Resource Type	99810

Other counties and municipalities and special tax collection rates use different location codes.

All Florida counties and special tax situations will be coded into “The Retail Solution”.

8.3.3 Collecting Sales Tax

Sales for equipment and materials at Crystal River will be made using “The Retail Solution”, the software point of sale system used by Asset Recovery. Before any sale can be made to a customer, a record is created for the customer that includes basic information, such as name, address, phone number, etc. Also included is information pertinent to the collection of state and county sales tax:

a. Tax Location – The tax location is where the sale occurs. In the case of Crystal River, all sales will be completed from Citrus County. Tax coding will be coded in “The Retail Solution” for all municipalities, and the system will calculate the appropriate rate of tax for the sale. If sales are made from other counties, we will provide the necessary coding in “The Retail Solution” to handle these collections as well.

b. Tax Exempt – If the customer is exempt from payment of sales taxes, they must provide Duke Energy exemption documentation (see above). The exemption documentation will include a number, which is recorded in “The Retail Solution”, and the customer record will be coded “no tax”. When sales are processed, the system will not calculate sales tax based on this coding. noted above, Duke Energy must keep a record of the exemption certificate on file for audit purposes.

Sales tax is collected in the county in which the sale is made. For sales made from Crystal River, all applicable tax will be collected and submitted back to Citrus County.

A journal entry is created using a report from "The Retail Solution", in which the funds collected for specific sales will be credited to the appropriate accounting. Funds collected for Florida tax receipts will be credited to the appropriate tax accounting.

8.3.4 How Sales Tax is Handled Through an External Auction Company

The auction company is responsible for verification of the taxable status of the auction registrant. If the auction registrant provides proof of exemption to the auction company, not sales tax is collected or paid to the state or municipality from the sale. If the auction registrant is not tax-exempt, the auction company collects the sales tax from the location from which the sale was actually made.

9.0 SHAREPOINT

9.1 File Naming Convention

Every document shall have the Identification number, which corresponds to the Sales Tracking Database on the Investment Recovery SharePoint Site, and a brief description of the Document type. The following protocol shall be utilized to name files within the Investment Recovery Sales SharePoint Site:

Sale Type	Document Title	Document Title Example
Affiliate Asset Transfers	E-Form Folder Number_Document Title	Efr152v1-000982_eform Efr152v1-000982_AI9010
Florida – Internal Duke	FID Number_Document Title	FID00001_AI9010 FID00001_emails
Inter-Utility (RAPID)	RAPID ID Number_Document Title	R251752_PO R251752_AI9010
Non-Duke (3rd party)	Contract/PO Number_Document Title	ND178596_PO ND178596_AI9010
Salvage	Salvage Number_Document Title	SLVG00001_AI9010 SLVG00001_emails
Disposition – Not Sold	Not Sold Number_Document Title	NS00001_emails
Donations	Donation Number_Document Title	DON00001_AI9010 DON00001_letter
Disposal	Disposal Number_Document Title	DIS00001_AI9010 DIS00001_emails

* Additional documentation for complete sale may be required as delineated in this guidance document.

9.2 File Structure

The file structure, Attachment B, is a quick reference tool designed to assist the project team in determining where documents are stored.

10.0 DEFINITIONS

Duke Affiliate Sale: Any sale which occurs internally between regulated, non-regulated and non-utility affiliate within the Duke Energy organization. These sales require an

Affiliate Asset Transfer Form and consist of moving material outside of the state of Florida.

Duke Florida Internal Sale: Any sale or transfer which occurs internally between regulated, non-regulated and non-utility group within the Duke Energy Florida organization.

Duke Inter-Utility (RAPID) Sale: Any sale which occurs externally between regulated and non-regulated Utilities under the Terms and Conditions as defined on the Readily Accessible Parts Integrated Database (RAPID) web site. (Initiated by the Purchasing utility).

Duke External Third Party Sale: Any sale which occurs externally between regulated, non-regulated and non-utility companies. (Initiated by CR3 IRST).

Duke Salvage Sale: Any sale which occurs externally between a Duke Energy approved salvage company. Material will be sold by Duke Energy Asset Recovery.

Material Request: The process used when material is transferred within the Duke Energy Enterprise, may be used when plants have common CAT IDs but must be used if a no common CAT ID is available.

Pick Ticket or Transfer: The process used when material is transferred within the Duke Energy Enterprise and a common CAT ID is available. Should be initiated by shipping site.

PowerAdvocate: A sourcing website which allows the sales team to provide all pertinent information to the bidders, allows for communication between bidder and seller and accepts all bids and bidder exceptions. PowerAdvocate sourcing tool should be used when the estimated value, CUP or Combined CUP of material is greater than or equal to one hundred thousand dollars (≥ $100,000).

SharePoint: a web based collaboration tool which allows the Project team and work group to perform more effectively by providing a central, virtual location for sharing of information quickly.

11.0 REFERENCES

AI-9010 – Conduct of CR3 Investment Recovery

Affiliate Asset Transfer Form – Enterprise Forms

SCD211, Rev. 1 Affiliate Asset Transfer Transactions

Investment Recovery Project, Project Assurance Plan

MCP-NGGC-0001 – NGG Contract Initiation, Development and Administration

MCP-NGGC-0401 – Material Acquisition (Procurement, Receiving, and Shipping)

12.0 ATTACHMENTS

Attachment A: Affiliate Asset Transfer Information Section eForm Template

Attachment B: IRP Sales Document Retention File Structure

Attachment C: Sales Track Quick Reference Guide

Attachment D: SharePoint Documentation Package Checklist

Sales Guidance and Documentation Package Development

Attachment A: **Affiliate Asset Transfer Information Section eForm Template**

Use this Template as a "copy/paste" tool while completing the Affiliate Asset Transfer eForm, "Asset Transfer Information Section."

CAT ID #'s (NAS & Passport):

Item Description:

Qty transferring:

Capital Item?:

Safety Related?: (If Yes, provide Suitability or PEEVAL # & UTC #)

Contacts at Sending & Receiving locations:

Issue Accounting:

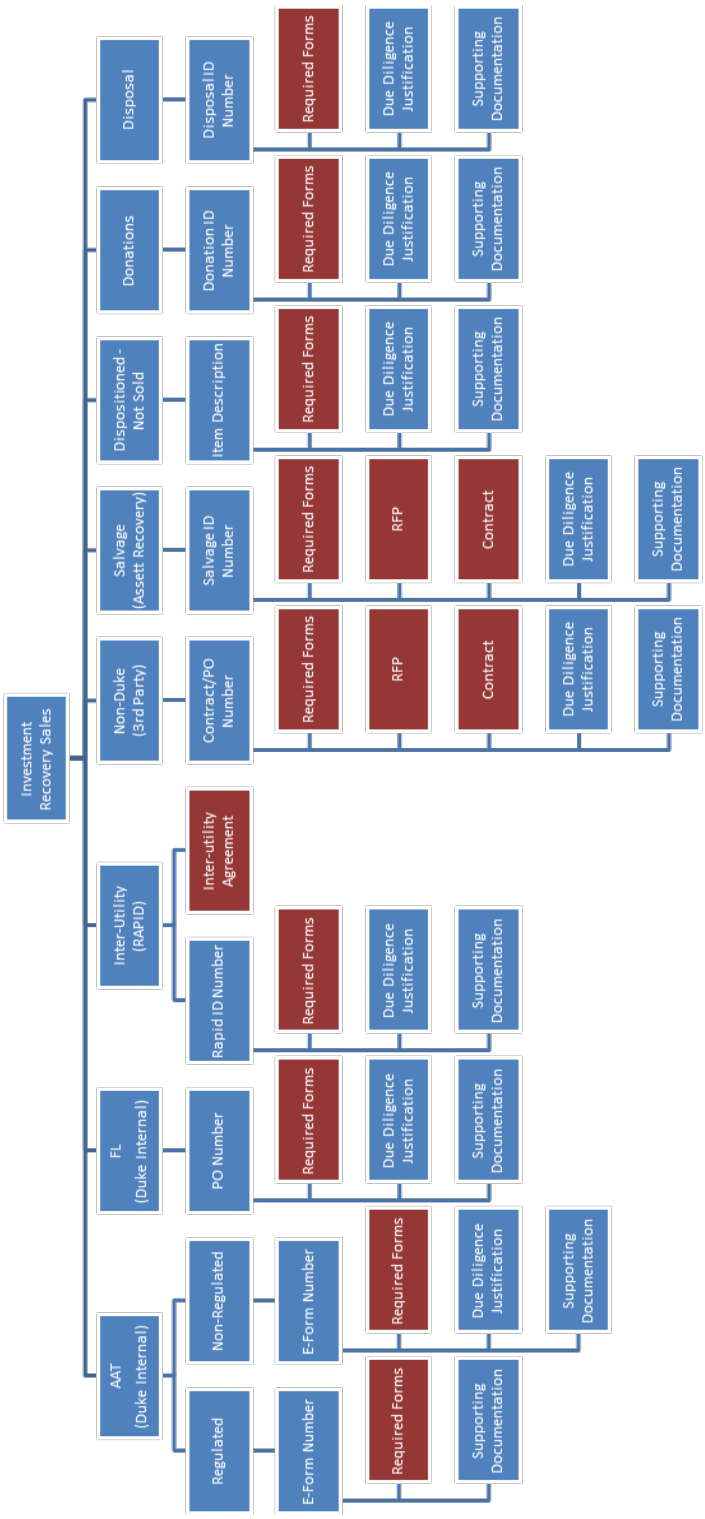
Receiving Accounting:

For transactions between DEF & DEP, note MR #.

Shipping Instructions:

Sales Guidance and Documentation Package Development

Attachment B: Investment Recovery Sales Document Retention File Structure



Sales Guidance and Documentation Package Development

Sales Guidance and Documentation Package Development

Attachment D: SharePoint Documentation Package Checklist

Sale ID No.:_____

Sale Date:_____

		AI-9010, Attachment 1	AI-9010 Attachment 2*	Material Request*	Issue Ticket*	Shipping documentation*	Copy of invoice Proof of Payment	E-mails	AAT eForm	Buyer Contract Purchase Order	Tax exempt form	RFP Documents	RFP Review	RFP Justification
☐	Affiliate	☐	☐	☐	☐	☐	☐	☐	☐					
☐	DEF	☐	☐	☐	☐	☐	☐	☐						
☐	RAPID	☐	☐	☐	☐	☐	☐	☐		☐	☐			
☐	External	☐	☐	☐	☐	☐	☐	☐		☐	☐	☐	☐	☐
☐	Salvage	☐	☐	☐	☐	☐	☐	☐		☐	☐	☐	☐	☐
☐	Scrap	☐	☐	☐	☐	☐	☐	☐		☐	☐	☐	☐	☐

*Documents may not be required for all sales or transfers

Originator: _____

☐ Final Date: _____

☐ Draft

☐ EPU

☐ Non-EPU

EPU Asset(s)	Price	Transaction	Date
Blade vibration sensor, sensor adapter	[redacted]		
7.5 ton Gantry Crane			
Cooling Tower Equipment			
Sealand / contents			
Sealand / contents (4)			
Sealand (2)			
2 Gang boxes; 1 fire safe chest; 1 horz band saw; 5 carts w/lifting eye			
4 Gang boxes; 1 horz band saw; 4 carts w/lifting eye			
Lot 14 - tent, lighting & structural members			
(3) 3500 HP Motors & (2) Lube Oil Skids			
Tent 80 contents (construction tools / materials)			
BID 41681 - Lot 8 Fire cabinets for chemical storage			
Relief Valves			
Relief Valves			
BID 41184 - 34 AKPD 5 stage Pumps			
Reliance Motor, 600 HP, 3 Ph., 1192 RPM, 79.3 Amps,Frame 18EC 5808S, type P, ID No.,00VAAQB441558010A1FM. Cat ID# 9220171740. Bldg Location: BI-3-A. Assets Located in Crystal River, FL.			
Fisher 12 Inch Globe Valve, Butt Weld, Schedule 40, Ansi,Class 600, Chrome-Moly, Type 657, Gr WC9 Astm,A217, Size 70 Actuator, s/n 20159311. Cat ID# 9220215373. Nuclear Quality Level: 1. Bldg Location: 0-0-BH-007-00A. Assets Located in Crystal River, FL.			
Fisher 12 Inch Globe Valve, Butt Weld, Schedule 40, Ansi,Class 600, Chrome-Moly, Type 657, Gr WC9 Astm,A217, Size 70 Actuator, s/n 20159310. Cat ID# 9220215373. Nuclear Quality Level: 1. Bldg Location: 0-0-BH-007-00A. Assets Located in Crystal River, FL.			
Valtek 8 Inch Throttling Globe Valve, Butt Weld, Schedule, 40, Ansi Class 300 Grade CF8m, Class 2, s/n,BL351. Cat ID# 9220200091. Nuclear Quality Level: 1. Bldg Location: 0-0-BH-002-00A. Assets Located in Crystal River, FL.			

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 54
PARTY: DUKE ENERGY FLORIDA (DEF) (DIRECT)
DESCRIPTION: Mark R. Teague MT-4

EPU Asset(s)	Price	Transaction Type	Date
Fisher 8 Inch Globe Valve ,CS,ASTM A216, GR. WCC, BW,Schedule 40, ANSI CLASS 600, Air Operated, AEAJ,9488. Cat ID# 9220218593. Nuclear Quality Level: 1. Bldg Location: BF. Assets Located in Crystal River, FL.	[redacted]		
Fisher EWD-69-376370 8 Inch Straight Thru Globe Valve, Butt Weld,Schedule 40, Ansi Class 600, ASTM A216, GR WCC,Air Operated, Type 657, Size 50 Actuator, Size 8x6, Stl - Body, s/n 0020245855. Cat ID# 9220215074. Nuclear Quality Level: 1. Bldg Location			
Fisher EWD-69-376370 8 Inch Straight Thru Globe Valve, Butt Weld,Schedule 40, Ansi Class 600, ASTM A216, GR WCC,Air Operated, Type 657, Size 50 Actuator, Size 8x6, Stl - Body, s/n 0020245854. Cat ID# 9220215074. Nuclear Quality Level: 1. Bldg Location			
Weir Valve and Controls 54960-A 6 Inch Valve Assembly, BW, ANSI Class 1500, ASME,SA351, Grade CF8M, Limitorque SMB-0-25-1800,Actuator, ASME Section III,CL 2,SCH 160,OS&Y, s/n,2-54960-A. Cat ID# 9220204609. Nuclear Quality Level: 1. Bldg Location: BF. Assets located in Crystal River, FL.			
Weir Valve and Controls 54960-A 6 Inch Valve Assembly, BW, ANSI Class 1500, ASME,SA351, Grade CF8M, Limitorque SMB-0-25-1800,Actuator, ASME Section III,CL 2,SCH 160,OS&Y, s/n,1-54960-A. Cat ID# 9220204609. Nuclear Quality Level: 1. Bldg Location: BF. Assets located in Crystal River, FL.			
Target Rock Corp. 11Z519-002 Globe Valve, 2", Schedule 80, Butt Weld, Stainless Steel, ASME Section III, Class 1,SolenoidOperated Isolation, with ECSA. Cat ID# 9220230957. Nuclear Quality Level: 1. Bldg Location: BF. Assets Located in Crystal River, FL.			

EPU Asset(s)	Price	Transaction Type	Date
Target Rock Corp. 11Z519-001 Globe Valve, 2", Schedule 80, Butt Weld, Stainless Steel, ANSI Class 900, ASME Section III, Class 1,Solenoid Operated Isolation, with ECSA. Cat ID# 9220219156. Nuclear Quality Level: 1. Bldg Location: BF. Assets Located in Crystal River, FL.	[redacted]		
Walworth Co. AC081C08MAC790000M Gate Valve, 8", Schedule 40, Butt Weld, ANSI Class 150, ASTM A216, GR WCB, Carbon Steel. Cat ID# 9220217960. Nuclear Quality Level: 1. Bldg Location: BF. Assets Located in Crystal River, FL.			
Fisher Model EZ Globe Valve, 1" Assembly, SW, Ansi Class 600 with Actuator. Cat ID#9220226161. Bldg Location: BB-BE-008-C Assets Located in Crystal River, FL.			
NUS Systems Rapid Cool Down System to include (3) ICC MSCabinets and (1) Pallet of Accessories. Bldg Location: BG-000-A. Asset Located in Crystal River, FL.			
Conax 7ST3-12000-01 , 7ZG5-10001-02 Lot to include (2) Electrical Canister Type Penetration Units with Power and Control, Instrumentation with Fiber Optic Feedthrough, s/n 8217 and 8218. Cat ID# 9220098490 , 9220211168. Nuclear Quality Level: 1. Bld			
Lot: (Qty-2) ANCHOR DARLING VALVES [For Further Description Info, Refer ToGuidelist PDF 'Lot Numbers 1625 - 1969 ' On Auction Landing Page]. Cat ID# 9220200095 . Nuclear Quality Level:1. Bldg Location: AB-015-00G. Assets Located in Crystal River, FL.			
Lot: (Qty-3) ANCHOR/DARLING VALVE CO VALVES [For Further Description Info, Refer ToGuidelist PDF 'Lot Numbers 1625 - 1969 ' On Auction Landing Page]. Cat ID# 9220215826 . Nuclear Quality Level:1. Bldg Location: AB-015-00G. Assets Located in Crystal River, FL.			

EPU Asset(s)	Price	Transaction Type	Date
Lot: (Qty-7) FLOWSERVE VALVES [For Further Description Info, Refer ToGuidelist PDF 'Lot Numbers 1625 - 1969 ' On Auction Landing Page]. Cat ID# 9220200094 . Nuclear Quality Level:1. Bldg Location: AB-015-00G. Assets Located in Crystal River, FL.	[redacted]	[redacted]	[redacted]
FLOWSERVE VALVE [For Further Description Info, Refer ToGuidelist PDF 'Lot Numbers 1625 - 1969 ' OnAuction Landing Page]. Cat ID# 9220215408 . Nuclear Quality Level:1. Bldg Location: AB-015-00G. Assets Located in Crystal River, FL.			
Velan Valve B15-1064C-02TS Gate Valve, 8 In, Butt Weld, Ansi Class 300, ASTM A216, GR WCB, Manual, Flex Wedge, Schedule 40. Cat ID # 9220211426 , Building Location 0-0 DA-014-00B Assets Located In Crystal River, FL.			
Velan Valve B15-1064C-02TS Gate Valve, 8 In, Butt Weld, Ansi Class 300, ASTM A216, GR WCB, Manual, Flex Wedge, Schedule 40. Cat ID # 9220211426 , Building Location 0-0 DA-014-00B Assets Located In Crystal River, FL.			
Velan Valve B20-0064C-04TY-G Gate Valve, 16 In, Butt Weld, Ansi Class 150, Special Class, Chrome-Moly, ASTM A217, GR C5, VT-20 Gear Operator W/Chain Wheel, Sch 80. Cat ID # 9220214379 , Building Location 0-0-DA-016-00A Assets Located In Crystal River, FL.			
Velan Valve B20-0064C-04TY-G Gate Valve, 16 In, Butt Weld, Ansi Class 150, Special Class, Chrome-Moly, ASTM A217, GR C5, VT-20 Gear Operator W/Chain Wheel, Sch 80. Cat ID # 9220214379 , Building Location 0-0-DA-016-00A Assets Located In Crystal River, FL.			

EPU Asset(s)	Price	Transaction Type	Date
Flowserve FIGURE B1911JTY Gate Valve, 8 In, Butt Weld, Asme Section III Section NC,CL 2, 1050 Psig, Asme SA-216, Grade WCB, Schedule 60, Manual. S/N- B1672 Cat ID# 9220200780Nuclear Quality Level:1Building Location 0-0-DA-012-00A Assets Located in Crystal River, FL.	[redacted]	[redacted]	[redacted]
Flowserve FIGURE B1911JTY Gate Valve, 8 In, Butt Weld, ASME Section III Section NC,CL 2, 1050 Psig, ASME SA-216, Grade WCB, Schedule 60, Manual. Cat ID# 9220200780 Nuclear Quality Level:1Building Location 0-0-DA-012-00A Assets Located In Crystal River, FL.			
Weir Valve & Controls A23903W Gate Valve, A216wcb body bwe, Parallel Disc, 18X12X18, Ansi Class 300, ASME Section III Subsection ND 1998 Edition With 2000 Addenda. Cat ID# 9220204624 Nuclear (Q Level) 1 Building Location 0-0-DA-039-00A Assets Located in Crystal River, FL.			
Weir Valve & Controls A23903W Gate Valve, Parallel Disc, A216wcb body bwe, 18X12X18, Ansi Class 300, ASME Section III Subsection ND 1998 Edition With 2000 Addenda. Cat ID# 9220204624 Nuclear (Q Level) 1 Building Location 0-0-DA-039-00A Assets Located in Crystal River, FL.			
Williams 152W2 Globe Valve, Assembly, 8 In, Sch 40, BW, Ansi Class 150, Astm A216, Grade WCB Carbon Steel, With Limitorque SMB-00-10-4P Motor Operator. Cat ID# 9220216698 , Building Location 0-0-DA-045-00A Assets Located In Crystal River, FL.			
Mcjunkin Red Man Corp. B16-1064C-06TS-G Velan Gate Valve, 10 In, Schedule 40, Butt Weld, Ansi Class 300, Chrome-Moly, ASTM A217, GR WC9, Bevel Gear Operator, Full Port, T-Pattern Body B. Cat ID # 9220217111 , Building Location 0-0-DA-018-00C Assets Located in Crystal River, FL.			

EPU Asset(s)	Price	Transaction Type	Date
Velan Valve B16-1064C-06TS Valve, Globe, 10 In, Schedule 40, Butt Weld, Ansi Class 300, Chrome-Moly, ASTM A217, GR WC9, Manual. Cat ID# 9220217098 , Building Location 0-0-DB-002-00B Assets Located In Crystal River, FL.	[redacted]		
Anchor Darling 4002221 Valve, Gate, 10 In, Butt Weld, Class 2, 2500 Psig, SA351, Grade CF3M, Manual, OS&Y, Standard or Full Port, Date of Mfg: 8/2011. Cat ID# 9220199412 Nuclear Quality Level:1Building Location 0-0-DD-059-00A Assets Located In Crystal River, FL.			
Anchor Darling 4002221 Gate Valve,10 In, Butt Weld, Class 2, 2500 Psig, SA351, Grade CF3M, Manual, OS&Y, Standard or Ful Port Date of Mfg: 8/2011. Cat ID# 9220199412 Nuclear Quality Level:1Building Location 0-0-DD-059-00A Assets Located In Crystal River, FL.			
Edwards Valve Co 735270 Angled Check Valve, Stop, 10 In, Butt Weld, Class 2, 520 PSIG, SA351, Grade CF8M, Manual, Date of Mfg: 8/2011. Cat ID# 9220200075 Nuclear (Q Level) 1 Building Location 0-0-DD-055-00A Assets Located In Crystal River, FL.			
Edwards Valve Co 735270 Check Valve, Stop, 10 In, Butt Weld, Class 2, 520 PSIG, SA351, Grade CF8M, Manual, Date of Mfg: 8/2011. Cat ID# 9220200075Nuclear Quality Level:1 Building Location 0-0-DD-055-00A Assets Located In Crystal River, FL.			
Edwards Valve Co 735277 Globe Angle Valve 10 In, Butt Weld, Class 2, 2500 Psig, Sa351, Grade CF8M, Manual, OS&Y,Standard or Full Port, Date of Mfg: 8/2011. Cat ID# 9220199987Nuclear Quality Level:1Building Location 0-0-DE-063-00A Assets Located in Crystal River, FL.			

EPU Asset(s)	Price	Transaction Type	Date
Edwards Valve Co 735277 Globe Angle Valve, 10 In, Butt Weld, Class 2, 2500 Psig, Sa351, Grade CF8M, Manual, OS&Y,Standard or Full Port, Date of Mfg: 9/2011. Cat ID# 9220199987Nuclear Quality Level:1Building Location 0-0-DE-063-00A Assets Located in Crystal River, FL.	[redacted]	[redacted]	[redacted]
Valtek 4002224 Globe Valve, 8 In, Butt Weld, ASME Section III, Class 2, 450 PSIG, ASME SA351, Grade CF8M, Manual, OS&Y, Date of Mfg: 11/2011. Cat ID# 9220200093 Nuclear Quality Level:1Building Location 0-0-DD-063-00A Assets Located In Crystal River, FL.	[redacted]	[redacted]	[redacted]
Flowserve 4.000E+13 Gate Valve, 6 In, Butt Weld, Class 1, 2500 PSIG, SA351, Grade CF3M, Manual, OS&Y, Standard or Full Port Date of Mfg: 8/2011. Cat ID# 9220199839 Nuclear Quality Level:1Building Location 0-0-DD-071-00A Assets Located In Crystal River, FL.	[redacted]	[redacted]	[redacted]
Williams 30W-2 C5 GO (12") Gate Valve, Flexible Wedge, 12 In, Butt Weld, Schedule 40, Ansi Class 300, Chrome-Moly, ASTM A217, GR C5, Trim 8, Manual, OS&Y. Cat ID# 9220214637 , Building Location 0-0-DE-054-00A Assets Located In Crystal River, FL.	[redacted]	[redacted]	[redacted]
Williams 30W-2 C5 GO (12") Gate Valve, Flexible Wedge, 12 In, Butt Weld, Schedule 40, Ansi Class 300, Chrome-Moly, ASTM A217, GR C5, Trim 8, Manual, OS&Y. Cat ID# 9220214637 , Building Location 0-0-DE-054-00A Assets Located In Crystal River, FL.	[redacted]	[redacted]	[redacted]
Masoneilan 88N-41445A Valve Assembly , Angle,8 In Sch 80 Inlet X 12 In Sch 60 Outlet,Asme Sa-216,Grade Wcc, Mfg. 2011. Cat ID# 9220219086Nuclear Quality Level:1Building Location 0-0-DD-059-00A Assets Located In Crystal River, FL.	[redacted]	[redacted]	[redacted]

EPU Asset(s)	Price	Transaction Type	Date
Masoneilan 88N-41445A Valve Assembly, Angle,8 In Sch 80 Inlet X 12 In Sch 60 Outlet,Asme Sa-216,Grade WCC, Mfg. 2011. Cat ID# 9220219086Nuclear Quality Level:1Building Location 0-0-DD-061-00A Assets Located In Crystal River, FL.	[redacted]		
General Electric 5KV85573446501 Induction Motor, Pump, 2500 Hp, 3 Ph, 4000V, 60 Hz, 1186 Rpm, 8557P70 Frame, WPII Enclosure, Class F Insulation, 1.15 SF, 315A, Nema Code F. S/N- KEH 285001404 Cat ID# 9220225708 Nuclear (Q Level) 4 Building Location.			
Fluidic Techniques Inc Vane, Straightening, Spool Piece, Flanged Both Ends, 16 In, 300 Lb, Astm A106. Cat ID# 9220222128 , Building Location 0-0-DA-012-00B Assets Located In Crystal River, FL.			
Fluidic Techniques Inc Vane, Straightening, Spool Piece, Flanged Both Ends, 16 In, 300 Lb, Astm A106. Cat ID# 9220222128 , Building Location 0-0-DA-012-00C Assets Located In Crystal River, FL.			
Grinnell 24663225NM Valve, Diaphragm, 2-1/2", Fig 2466-3225N-M31.1 Cat ID# 62590810. Nuclear Quality Level: 1. Bldg Location: 0-0-BB-032-00B. Assets Located in Crystal River, FL.			
Yuba, SPX Heat Transfer Lot to include (2) Heat Exchangers, Test Pressure PSI Shell 445, Tubes 650, Test Temperature Min Degree F Shell 70, Tubes 70, Customer Item EH-5A, Mfg. S/n 10-H-468-1A, Feedwater Heaters, Item No. FW-E-2A. Assets Located in Crystal River, FL.			
YUBA HEAT TRANSFER DIV Inlet Channel Head, Heat Exchanger, TYPE AEL. Cat ID # 9220260193 , Building Location D-D-DE-001 00A Assets Located In Crystal River, FL.			

EPU Asset(s)	Price	Transaction Type	Date
Velan Valve B16-1064C-06TS Globe , 10 In, Schedule 40, Butt Weld, Ansi Class 300, Chrome-Moly, Astm A217, Gr Wc9, Manual. Cat ID# 9220217098 , Building Location 0-0-DA-012-00B Assets Located In Crystal River, FL.	[redacted]	[redacted]	[redacted]
Mcjunkin Red Man Corp. B16-1064C-06TS-G Velan Gate Valve, 10 In, Schedule 40, Butt Weld, Ansi Class 300, Chrome-Moly, ASTM A217, GR WC9, Bevel Gear Operator, Full Port, T-Pattern Body B Cat ID # 9220217111 , Building Location 0-0-DA-018-00B Assets Located in Crystal River, FL.			

Integrated Change Form (ICF)

DATE INITIATED	July 15, 2014	TYPE OF CHANGE	
INITIATOR	Jeff LaPratt	CONTRACT/PO#	
MAJOR CONTRACTOR	N/A	ICF NUMBER	
ICF TITLE	IRP Auction		

[redacted]

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 55
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)
DESCRIPTION: Mark R. Teague MT-5

Integrated Change Form (ICF)

DATE INITIATED	July 15, 2014	TYPE OF CHANGE	
INITIATOR	Jeff LaPratt	CONTRACT/PO#	
MAJOR CONTRACTOR	N/A	ICF NUMBER	
ICF TITLE	IRP Auction		

Approve ICF

[redacted]

REASON FOR CHANGE (CHECK ALL THAT APPLY)

OWNER		REGULATORY		OTHER:_____
ENGINEER		VENDOR / NAME		
CONSTRUCTION		OTHER / DESCRIBE		DESCRIBE:

COST IMPACT

CRAFT LABOR	CRAFT	HOURS	RATE		TOTAL

MATERIALS	DESCRIPTION	QTY	COST	TOTAL
	N/A			

EQUIPMENT	DESCRIPTION	QTY	COST	TOTAL
	N/A			

SUB CONTRACTOR	DESCRIPTION	COST	TOTAL
	N/A		

PROF. SERVICES	DESCRIPTION	TOTAL

TOTAL IMPACT COST	

ESTIMATED BY:		DATE	

Integrated Change Form (ICF)

DATE INITIATED	July 15, 2014	TYPE OF CHANGE	
INITIATOR	Jeff LaPratt	CONTRACT/PO#	
MAJOR CONTRACTOR	N/A	ICF NUMBER	
ICF TITLE	IRP Auction		

IRP Auction Justification

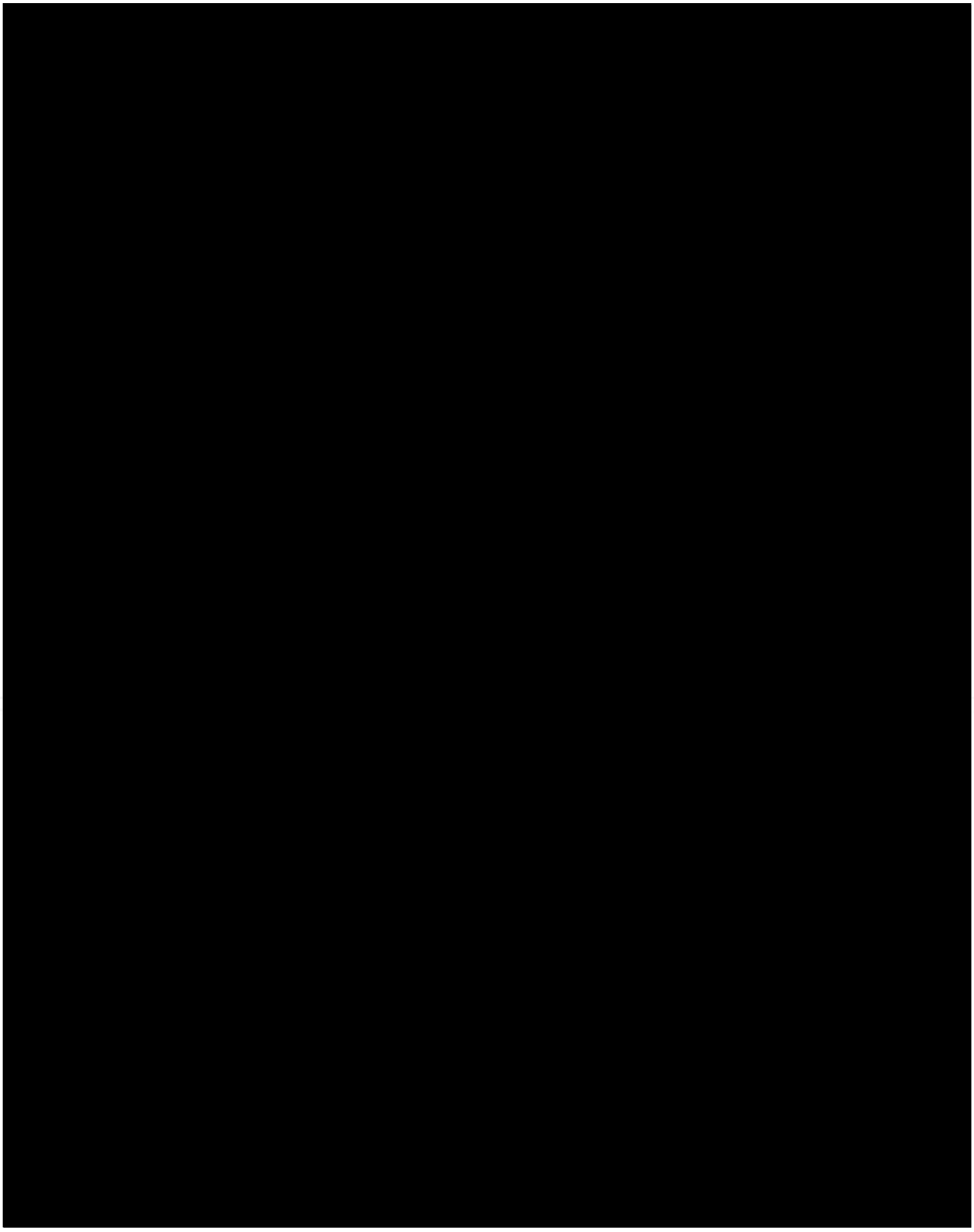
[redacted]

Integrated Change Form (ICF)

DATE INITIATED	July 15, 2014	TYPE OF CHANGE	
INITIATOR	Jeff LaPratt	CONTRACT/PO#	
MAJOR CONTRACTOR	N/A	ICF NUMBER	
ICF TITLE	IRP Auction		

Governance / Plan

[redacted]



Integrated Change Form (ICF)

DATE INITIATED	July 15, 2014	TYPE OF CHANGE	
INITIATOR	Jeff LaPratt	CONTRACT/PO#	
MAJOR CONTRACTOR	N/A	ICF NUMBER	
ICF TITLE	IRP Auction		

[redacted]

Integrated Change Form (ICF)

DATE INITIATED	July 15, 2014	TYPE OF CHANGE	
INITIATOR	Jeff LaPratt	CONTRACT/PO#	
MAJOR CONTRACTOR	N/A	ICF NUMBER	
ICF TITLE	IRP Auction		

[redacted]

CR3 Investment Recovery Project

No-sale Disposition Justification

Commodity: CR3 INSTALLED EPU ASSETS

File name: DISPOSITION OF CR3 EPU INSTALLED ASSETS

Prepared by: David Smith Date: 3/24/2015

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Supply Chain Manager

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CR3 IRP Project Manager

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 56
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)
DESCRIPTION: Mark R. Teague MT-6

Disposition of CR3 EPU Installed Assets

Duke Energy (DE) Crystal River Unit 3 Investment Recovery Project (IRP) awarded a contract to Heritage Global Partners (HGP) to hold an auction event to sell various Crystal River Unit 3 (CR3) installed assets as well as Extended Power Uprate (EPU) installed assets. The following is a list of EPU assets (auction lot numbers included as reference) which were offered by HGP but NOT sold during the auction. The price of the asset combined with the removal costs resulted in a total expense that exceeds the fair market value (FMV) of the component. The removal cost was estimated by Townsend Construction in October, 2013 when the EPIS plant assets were evaluated by the IRP for marketability and re-sale.

1. Lot 1201 Iso phase bus duct cooler (EPU)
   The Iso phase bus duct cooler is large and consists of two fan units with 50 hp motors. The bus duct cooler was marketed for sale internally to DE affiliates, externally to other utilities, the OEM and select third party re-sellers via direct contact and the RAPID website; with no interest. The EPIS Equipment Review and Analysis document estimates the removal cost of the Iso phase Bus Duct Cooler to be $50,000.00 to $75,000.00 dollars. The IRP did not offer this asset on a Power Advocate bid event as the asset was to be included in the scope of the auction. HGP offered the asset during the auction. The high bid received in the auction for the cooler was too low and was not enough to cover the expenses related to CR3 engineering, removal oversight, and operations lockout and tag out costs. Therefore, the IRP determined the sale of the cooler would be cost prohibitive for DEF and its customers. The asset will remain installed and abandoned until final decommissioning and dismantlement of the CR3 station.

2. Lot 1202 CDHE 3A and CDHE 3B (EPU)
   CDHE 3A is two of the newly installed feedwater heat exchangers. The heat exchangers were offered internally to DE and externally to other utilities, the OEM and select third party suppliers via direct contact and the RAPID website; with no interest. The IRP did not offer this asset on a Power Advocate bid event, as it was to be included in the scope of the auction. HGP offered these heat exchangers during the auction, however there was no interest or bids received for the installed heat exchangers. The assets will remain installed and abandoned until final decommissioning and dismantlement of the CR3 station.

3. Lot 1214 Moisture Separator Reheaters (MSRs) EPU
   These four (4) large horizontal pressure tanks with heater tubes were offered internally to DE, other operating utilities, the OEM and select third party re-sellers via direct contact and the RAPID website; with no interest. The IRP performed a Power Advocate Bid Event for this equipment. The Bid Event offer received was determined to be too low to offset DEF removal support costs, and ultimately rejected by the IRP. HGP offered these assets in the auction. The bid received by HGP during the auction was too low, and would not have covered the expenses related to CR3 engineering, removal oversight, operation lockout and tag out costs. Therefore, the IRP determined the sale of the MSRs would be cost prohibitive for DEF and its customers. The assets will remain installed and abandoned until final decommissioning and dismantlement of the CR3 station.

4. Lot 1213a Main Generator

   The installed main generator rewound rotor and new stator core were offered internally to DE and other operating utilities via direct contact and the RAPID website; with no interest. The IRP did not offer this asset on a Power Advocate bid event, as it was to be included in the scope of the auction. HGP offered the main generator during the auction, however there was no interest or bids received for the installed main generator. The asset will remain installed and abandoned until final decommissioning and dismantlement of the CR3 station.

5. CDHE-7A & B

   The belly drain heat exchangers are installed in the Turbine building El 119'. They are small heat exchangers in size and have little market value after removal. The CR3 IRP did not offer these assets in a Power Advocate Bid Event or to other operating utilities. The heat exchangers were deemed not marketable by CR3 IRP and Heritage, and were not included in the auction. The heat exchangers will remain installed and abandoned in place until final decommissioning and dismantlement of the CR3 station.

CR3 Investment Recovery Project (IRP) Closeout and Long-Term SAFSTOR Asset Recovery Plan

Rev 0

CR3 Decommissioning Transition Organization

Duke Energy

Please Note: This document contains confidential information and is subject to Duke Energy's Code of Business Ethics Policy. Please limit distribution accordingly.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 57
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)
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Approval

Section A: Document identification and type of action

Document Number: N/A	**Revision Number:** 0

Document Title:

CR3 Investment Recovery Project (IRP) Closeout and Long-Term SAFSTOR Asset Recovery Plan

Type of Action:		**Effective Date:**
☒ New	☐ Suspension	
☐ Revision	☐ Ownership Change	3/1/15
☐ Cancellation	☐ Periodic review completed	

Applies to:	**Group:**
Generation Operations Support	CR3 Decommissioning Transition Org

Applicable to Forms Only

Does form have a parent procedure? ☒ No ☐ Yes Procedure #:

☒ **Communication plan established** YES ☐ **Impact Reviews Completed N/A**

Description of document action or summary of changes:

The document presents the CR3 Investment Recovery Project (IRP) Closeout and Long Term SAFSTOR Asset Recovery Plan.

Preparer(s): Jeff LaPratt, IRP PM

Section B: Approval of Document/Interface Agreement

Approval recommended (print name)	Signature	Date
Magdy Bishara/MGR Major Projects - DTO	Magdy Bishara	2/25/2015
Final Approval (print name)	**Signature**	**Date**
Ron Jangaon / Dir Sourcing & Warehousing		2/25/2015
Final Approval (print name)	**Signature**	**Date**
Russ Wilkenloh / Mgr Resource Recovery		2/27/2015
Final Approval (print name)	**Signature**	**Date**
Terry Hobbs/GM Decommissioning		3/2/15

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PLAN REVISION CONTROL

Rev No.	Primary Author(s)	Revision Description	Rev Date
0	Project Manager	Initial Issue	3/1/15

1.0 EXECUTIVE SUMMARY

This document presents the Closeout and Turnover Plan for the CR3 Investment Recovery Project (IRP). It discusses the cessation of proactive IRP activities and future responsibilities for asset dispositions.

This document also acts as the interface agreement between the CR3 SAFSTOR organization and Supply Chain (both Fossil and Corporate Asset Recovery) for the management of post-IRP asset dispositions.

NOTE

IRP does not manage nuclear fuel sales. Nuclear fuel sales are managed by the Major Projects Sourcing organization and is not covered under this document.

NOTE

This plan covers the asset recovery activities during the SAFSTOR period and is meant to be a living document. It is subject to change should SAFSTOR activities evolve. Obligations to proactively sell or salvage non-EPU CR3 assets have been met and any proceeds from future dispositions will be credited to the decommissioning trust. Proceeds from future EPU asset disposition, including exchange of scrap value for dismantlement labor, must be credited back to the ratepayers via either the NCRC or the CCR. The EPU asset disposition accounting structure remains in-place during the entire SAFSTOR period and this requirement must be acknowledged in the yet-to-be-developed SAFSTOR II long-term plan. Due to this accounting requirement, the owner of this plan during SAFSTOR I is Ops & Major Projects Finance (CR3 Finance).

Basis for Project Close

In fulfillment of its obligations of the August 1, 2013 Settlement Agreement between DEF and the Office of Public Counsel et. al. (Doc No. 04433-13, Docket No. 130208-EI) Duke Energy has completed its efforts to use reasonable and prudent efforts to sell or otherwise salvage assets that would otherwise be included in the CR3 Regulatory Asset or CR3 EPU Regulatory Asset (collectively: "Reg Asset").

The IRP identified a finite target set of saleable assets that were: 1) included in the reg asset; 2) readily marketable (meaning that they had value and a market existed for them); 3) cost effective to remove and sell (note that installed EPU assets were offered for sale); and 4) did not negate the assumptions used in the Detailed Cost Estimate (DCE) of the Post Shutdown Decommissioning Activities Report (PSDAR). The following categories of assets were included in the target set:

- Warehouse inventory (FERC Account 154)
- Construction Work In Progress (CWIP)

- CWIP – Extended Power Uprate (EPU)
- Electric Plant In Service (EPIS)

Although the proactive asset disposition efforts have concluded, it is expected that further disposition of a small set of non-EPU assets will occur as construction projects wind down, and the plant transitions to SAFSTOR II where most remaining warehouse inventory is no longer needed. These disposition efforts will be performed by the supply chain Corporate Asset Recovery department for surplus materials, and the Supply Chain organization for affiliate asset transfers and outside sales. Any proceeds are credited to the decommissioning trust.

2.0 DEFINITIONS

Surplus Material:	Excess warehouse inventory identified by the SAFSTOR organization as no longer required. Salvaged plant assets identified by the SAFSTOR organization as required to be removed from the plant (e.g.; station batteries to be recycled in order to remove the hazard from site)
Affiliate Asset Transfer:	Transfer of assets requested by a Duke affiliate following the Affiliate Asset Transfer process per MCP-401.
Outside Sale:	Sale of assets to a non-Duke affiliate.

3.0 TURNOVER AND DEMOBILIZATION

Punchlist Items

There remain some of the asset target set that are actively being dispositioned by the IRP team, including some EPU assets. These items are being tracked on an active punchlist and are scheduled to be completed in the first quarter of 2015. (*See the CR3 Decommissioning Document Retention SharePoint site under Investment Recovery/Action Tracking/Open Sales Items*).

Turnover Preparations

On-going meetings will continue with the receiving organizations to ensure that they are fully briefed on project status and are prepared to accept the turnover of responsibilities. Turnover status will be communicated with the plant via the Decommissioning Planning Meeting and other management meetings as necessary.

Turnover

Effective with the approval of this document, Corporate Asset Recovery will be responsible for the disposition of surplus materials, and the processing of outside sales invoicing and payment handling.

Effective May 1st, 2015, Fossil Supply Chain will be responsible for managing internal affiliate asset transfers.

Effective May 1st, 2015, the CR3 SAFSTOR Maintenance Project Manager will be responsible for coordinating removal efforts of installed plant assets for internal affiliate transfers or outside sales.

Effective at project closeout, CR3 SAFSTOR Document Management will be responsible for maintaining the IRP documentation contained in the SharePoint site.

Project Closeout and Demobilization

At the completion of the punchlist disposition efforts and project closeout checklist activities, the IRP team will be released.

The Project Closeout Checklist is maintained on the IRP SharePoint site. It ensures that the following items are complete:

- ☐ All invoices paid
- ☐ All sales proceeds received
- ☐ All journal entries completed (finance)
- ☐ All contracts closed
- ☐ Post-project debrief held
- ☐ Lessons learned compiled
- ☐ Final review of SharePoint documentation for completeness and accuracy ("audit ready")
- ☐ Final review by legal and Rates & Regulatory Strategy on acceptance of project completion
- ☐ Close of applicable project accounts by finance
- ☐ Release project resources

4.0 DOCUMENT MANAGEMENT

IRP documentation of project activities including disposition documents and justifications are maintained in accordance with IRGD-001, *Sales Track Guidance and Documentation Package Development,* on the SharePoint site. The long-term maintenance of the documentation is performed by CR3 SAFSTOR Document Management post project closeout.

It is expected that in addition to the on-going Nuclear Cost Recovery Clause (NCRC) prudency docket, that a similar prudency docket will be opened around the time that the request is made to place the CR3 Reg Asset into the rate base. The IRP documentation will be critical to support a prudency determination.

5.0 ACCOUNTING REQUIREMENTS AND FINANCIAL REPORTING

Accounting

In accordance with the August 1, 2013 Settlement Agreement between DEF and the Office of Public Counsel et. al. (Doc No. 04433-13, Docket No. 130208-EI), proceeds received from the disposition of CR3 assets as part of the IRP are required to be applied to and reduce the Reg Asset.

The accounting proceeds from non-EPU asset dispositions post-IRP will be credited to the decommissioning trust.

EPU asset proceeds will be credited to the NCRC through its 7 year recovery period, and to the Capacity Cost Recovery (CCR) thereafter until all EPU assets are dispositioned. This lasts through completion of CR3 decommissioning, and includes exchange of scrap value for dismantlement labor.

The accounting structure for these proceeds post-IRP are as follows:

Asset Category	Accounting Structure					Period	Recovery Mechanism
	Resp Ctr	Project	Activity	Resource	Account		
Non-EPU	Q047	DASSETREC	SLVGE	99416	0108307	Throughout decommissioning	Decom. Trust
CWIP/EPU	U639	EPU DISP	SLVGE	99416	0182406	1. Through 2017 2. 2018 and after	1. NCRC 2. CRC

Financial Reporting

Collection of post-IRP financial information (proceeds and costs) and reporting is performed by CR3 Finance. This to include on-going reports to SAFSTOR management, Rates & Regularity Strategy (for quarterly EPU Reg Asset and decommissioning trust updates), and others as required.

6.0 ASSET DISPOSITION FUTURE STATE

Governance

Governance for the Project was provided in AI-9010, *Conduct of CR3 Investment Recovery*. This governance no longer applies to post-IRP asset dispositions with the exception of nuclear fuel sales.

Corporate Asset Recovery will comply with their existing procedures, processes, and governance.

Affiliate asset transfers is governed by Affiliate Asset Transfer requirements specified in MCP-NGGC-401 and SCD211, and others as required by the Affiliate Asset Transfer Agreement.

External dispositions outside of Corporate Asset Recovery, will utilize the same sales agreement as IRP used. Note that these sales do not follow the RAPID sales agreement.

Post-IRP Asset Disposition Flows

This following provides a general overview of the various disposition flows expected post-IRP:

Surplus Material

1. CR3 identifies surplus material no longer required or needed to be removed and recycled from site.
2. Corporate Asset Recovery is contacted to perform the sale.
3. Fossil Supply Chain warehouse and/or maintenance resources are utilized to handle and ship the surplus material as required.

Duke Affiliate Request

1. Duke affiliate makes request for asset.
2. Request is forwarded to Fossil Supply Chain point-of-contact supporting CR3 who will coordinate affiliate asset transfer (AAT) activities.
3. CR3 Finance will obtain AUP/NBV for the asset.
4. Fossil Supply Chain will facilitate a meeting with CR3 SAFSTOR management to determine if the request can be approved, considering:
    a. Impact of removal on plant resources.
    b. Urgency of affiliate need.
    c. Impact on PSDAR/DCE assumptions for salvageable assets.
5. Fossil Supply Chain will communicate results with requesting affiliate.
6. If affirmative, then:
    a. Fossil Supply Chain will facilitate AAT approval utilizing EPU Reg Asset or decommissioning trust accounting structure.
    b. SAFSTOR Maintenance Project Manager will coordinate any plant removal activities.

c. Fossil Supply Chain warehouse resources will coordinate non-contaminated shipping activities. Contaminated shipping activities are coordinated by CR3 RP & Chemistry department.

NOTES: AI-9010 governance does not apply.
Affiliate is responsible for all removal and shipping costs.

External Non-Affiliate Request

1. External request for asset received.
2. Request is forwarded to Fossil Supply Chain point-of-contact supporting CR3 who will coordinate activities.
3. Fossil Supply Chain will facilitate a meeting with CR3 SAFSTOR management to determine if the request can be approved, considering:
    a. Impact of removal on plant resources.
    b. Impact on PSDAR/DCE assumptions for salvageable assets.
4. Fossil Supply Chain will communicate results with requestor.
5. If affirmative, then:
    a. Fossil Supply Chain will facilitate sale utilizing the IRP sales agreement, and receipt of buyer's Purchase Order.
    b. Corporate Asset Recovery will perform invoicing and proceed receipt activities, utilizing decommissioning trust or EPU Reg Asset accounting structure.
    c. SAFSTOR Maintenance Project Manager will coordinate any plant removal activities.
    d. Fossil Supply Chain warehouse resources will coordinate non-contaminated shipping activities. Contaminated shipping activities are coordinated by CR3 RP & Chemistry department.

NOTES: CR3 assets are no longer advertised in the RAPID database.
AI-9010 governance does not apply.
Buyer is responsible for all removal and shipping costs.

REDACTED

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January 28, 2014
LNP-EPC-2014-0003
Response (Action) Required YES X /NO

SENT BY E-MAIL AND HAND DELIVERY

Stone & Webster, Inc.
Attn: Mr. Kevin Holderness
Consortium Project Manager
CB&I Stone & Webster
128 S. Tryon Street
Charlotte, NC 28202

Reference: Levy Nuclear Plant EPC Agreement
Progress Energy Florida Contract No. 414310

Subject: Notice of Termination

Dear Mr. Holderness:

Duke Energy Florida, Inc. (DEF, formerly known as Progress Energy Florida, Inc.) hereby gives Westinghouse Electric Company and Stone & Webster, Inc. (Contractor) notice that DEF is terminating Contract Number 414310 – the Engineering, Procurement and Construction Agreement (Agreement) for the Levy County Nuclear Plant (Levy) – under Article 22.4(a) (Failure to Obtain Regulatory Approvals), due to DEF's inability to obtain a Combined Construction Permit and Operating License (COL) for Levy by January 1, 2014.

[redacted]

Should you have any questions regarding this matter, please feel free to contact me.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 58
PARTY: DUKE ENERGY FLORIDA (DEF) (DIRECT)
DESCRIPTION: Christopher M. Fallon CMF-1

15PMA-DR1LEVY-20-000009

Sincerely,

Christopher M. Fallon

Christopher M. Fallon
Owner's Project Director
Vice President, Nuclear Development

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 59
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)

MEMORANDUM

Date: January 16, 2014

To: Chris Fallon

cc: LNP-EPCInbox@pgnmail.com

From: Lawrence Denney

Subject: Levy Nuclear Plant Long-lead Equipment Disposition Plan

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Introduction

This memo describes the methodology DEF is using to disposition the long-lead equipment (LLE) purchased for the Levy Nuclear Plant (Levy) pursuant to the Engineering, Procurement, and Construction (EPC) Agreement executed by Florida Power Corporation (d/b/a Duke Energy Florida) and a consortium of Westinghouse Electric Company and Chicago Bridge & Iron (the Consortium). This memorandum describes the general process for the financial quantification, risk assessment and other qualitative assessments to support a final disposition decision for long-lead equipment (LLE) components. As such, this memo describes the principles and general process that are being employed to achieve the below stated objectives for LLE disposition.

On December 31, 2008 the EPC agreement was executed and on April 30, 2009 was partially suspended, due to a slip in the NRC licensing schedule. Current Levy project work is limited to activities required to obtain the COL and major environmental permits and to resolve certain long-lead equipment procurement activities associated with the eventual termination of the EPC agreement. Presently, the EPC agreement as amended maintains the existing terms and conditions of the EPC agreement and allows the orderly cancellation or disposition of long-lead equipment procurement activities once DEF has completed its evaluation of available options.

On July 31, 2013 a Revised and Restated Settlement Agreement (the Settlement) was reached resolving "certain future actions regarding" Levy and on November 12, 2013 was approved by the Florida Public Service Commission. Among the stipulations in the Settlement is the requirement that DEF will terminate the Levy EPC agreement at the "earliest reasonable and prudent time" and "use its reasonable and prudent efforts to curtail avoidable future LNP costs, to sell or otherwise salvage LNP assets, or otherwise refund any costs that can be recaptured for the benefit of the customers." This plan addresses these regulatory requirements insofar as they are associated with the disposition of LLE for the Levy project.

LLE Disposition Objectives

To support and fulfil the responsibilities and obligations for DEF stated in the Settlement the following are the objectives of the Levy LLE disposition:

- Minimize the financial cost and risks associated with the disposition of LLE
  - Minimize LLE evaluation costs and contract termination costs
  - Maximize Levy LLE cash value
  - Minimize risks of financial loss associated with LLE

— Minimize other costs to Duke Energy
— Evaluate the possibility for future use of LLE to AP1000 projects.

Scope
This plan covers the process of reaching and approving disposition decisions on the LLE components as well as the execution of the decisions. The specific LLE components which are covered by this plan are listed in Table 1. Levy project activities associated with receipt of the COL and other major permits are not within the scope of this plan.

Component	Status	Manufacturer
VFDs	Complete – In storage	Siemens
Steam Generator Tubing	Complete – In storage	Doosan
Reactor Vessel	Suspended- Materials in storage	Doosan
Steam Generator Balance	Suspended- Materials in storage	Doosan
Squib Valves	Suspended- Materials in storage	SPX
Reactor Coolant Pumps	Suspended- Materials in storage	EMD
RCL Pipe	Terminated	Tioga/IBF
CRDM	Not started	WEC
Reactor Vessel Internals	Not started	WEC
Turbine Generator	Not started	Toshiba
Accumulator Tank	Terminated	Mangiarotti
Core Make-Up Tank	Terminated	Mangiarotti
Pressurizer	Terminated	Mangiarotti
PRHR Hx	Terminated	Mangiarotti

Table 1. List of LLE Components

Schedule
Table 2 provides an approximate schedule for the activities associated with the disposition of the LLE. Given the complexity and the many entities, e.g. WEC, various sub-contractors to WEC, which are involved in this analysis providing precise schedule dates is not possible at this time. Therefore, general timeframes when certain major activities are expected to occur are presented in Table 2. This schedule projection supports the evaluation and disposition decision of each LLE component by the June-July timeframe.

Schedule Projection	EPC Contract Wind-Down Activities
TBD	Formal EPC Contract termination
July – Nov 2013	DEF requests information from Westinghouse; refer to letters LNP-EPC-2013-0016, LVP_LVG_000401, LVP_LVG_000421, LNP-EPC-2013-0024

Oct – Dec 2013	Westinghouse develops RFQs for sub-contractors
Oct 2013 – May 2014	Westinghouse works with suppliers for RFQ responses
Oct 2013 – June 2014	Westinghouse reviews RFQ results with Duke
Nov 2013– July 2014	Duke Energy finalizes decisions on LLE components

Table 2. Approximate schedule for EPC contract wind-down activities

Disposition Decision Methodology

There are six disposition options currently being considered for the LLE which can be grouped into two categories: (1) options which permanently dispose of the LLE today and (2) options which store the LLE for future use or disposition. Each LLE component will be analyzed for which option best meets the LLE disposition objectives. A schematic representation of the LLE disposition evaluation process is presented in Figure 1 and each disposition option is described more fully below.



Figure 1. Schematic illustration of the LLE disposition evaluation process[1]

Options which permanently dispose of LLE[2]

Reuse: For some LLE components there could be an alternate application beyond use at Levy or another AP1000 station.

[1] Grey shading indicates the option is no longer under consideration.

[2]

[redacted]

Salvage: The constituent materials of each LLE component have residual value as a raw material. These constituent materials can be sold for recycling, with an offsetting cost to prepare the raw materials for salvage. For this option [redacted]

Sell: The LLE components could be used on another AP1000 project which is either under construction or in the planning stage. DEF requested [redacted]

Purchase: Because some LLE components are in fabrication and are not complete there is the possibility for reuse of the in-process material for an alternate use. [redacted]

Options which store LLE for later disposition

Consignment: Given the costs incurred to produce the LLE and Levy or another AP1000 project in the future, DEF proposed a [redacted]

Continue storage: The final option considered is to continue the status quo with DEF continuing to pay for storage of the LLE. Initially, there were two possibilities which, if realized, would provide value for this option: construction of Levy or future sale of the LLE if the market for AP1000s improves. If neither of these options could be realized, then the LLE would have to be disposed of through one of the disposition options listed in the "Options which permanently dispose of LLE" section.

Dispose of LLE: This option will occur if no future use for the LLE is realized and DEF chooses to either storage or consign the LLE. Permanent disposition of the LLE will occur if there is no future use for the LLE. The continue storage option for potential future construction of Levy was considered and rejected as a viable option at this time based on the qualitative analysis of the risks of proceeding with this option under the 2013 statutory amendments to the nuclear cost recovery statute, Section 366.93, F.S. DEF determined at the time of the Settlement that the statutory amendments to Section 366.93 fundamentally changed the external risks to the Levy Nuclear Project, resulting in substantial uncertainty and unacceptable risk to DEF and its customers to proceed with the Levy Nuclear Project. The same analysis results in the determination that the disposition of LLE by continuing to store LLE for potential future construction of Levy is not at this time a viable option.

The statutory amendments to Section 366.93 sequentially stage regulatory approval to proceed with the project, precluding preconstruction and construction work until the COL is obtained, and requiring Commission approval based upon untested and in some cases undefined statutory standards to proceed with preconstruction, certain material and equipment purchases for the project, and then construction of the project. Receipt of the required regulatory approvals therefore is uncertain, and the time required to obtain them and address any potential appeals during the regulatory approval process is unknown. In addition, the statutory amendments establish new, undefined, and potentially subjective requirements for the utility to demonstrate annually its intent to build the nuclear power plants. For these reasons, DEF determined that the statutory amendments qualitatively result in additional uncertainty and therefore

unacceptable additional risk to the schedule and cost of the Levy Nuclear Project. As a result of this determination, DEF elected not to complete construction of the Levy nuclear power plants pursuant to Section 366.93(6) and Rule 25-6.0423(6). That decision is reflected in the Settlement provisions providing for the recovery of prudent Levy Nuclear Project wind down costs, including the cost to prudently disposition LLE.

The disposition of LLE by continuing to store LLE for future construction of Levy presents DEF and its customers with the same uncertainty and unacceptable risk that resulted in the election not to complete the Levy Nuclear Project that is reflected in the Settlement. Under the statutory amendments DEF cannot determine if and when the sequential regulatory approvals would be obtained and the project constructed, precluding DEF from determining with any accuracy the period necessary to store LLE for potential future construction of Levy. As a result of this uncertainty, there is substantial risk and therefore additional cost to DEF and customers to continue to store LLE for potential future construction of Levy. For all these reasons, this was not considered a viable LLE disposition option.

Decisional process

DEF is in the process of gathering the information needed to accomplish the LLE disposition objectives for each Levy LLE component. Once this information is accumulated, a financial analysis will be prepared for each LLE component that will compare the future costs of each proposed option. Additionally, the risks and other qualitative considerations will be described for each option and each component. For each LLE component the option which minimizes both the financial cost and risks given the qualitative constraints will be selected by the Levy project team.

The approval of the decision on each LLE component will follow the requirements of the appropriate internal policy as provided in the Nuclear Development Project Governance Procedure, PD-BO-NDP-0001. The best effort will be made to aggregate the decisions on each component into a single decision for all of the LLE components, but, at times, the optimal path may prevent such aggregation.

Equipment in fabrication

Mangiarotti supplied components: The LLE components supplied by Mangiarotti have been dispositioned consistent with this LLE disposition plan. The permanent disposition of these LLE components has been completed as documented in letter LNP-EPC-2013-0023.

Tioga equipment: The reactor coolant loop piping supplied by Tioga has been dispositioned consistent with this LLE disposition plan. The permanent disposition of this LLE component has been completed as documented in letter LNP-EPC-2014-00001.

Post-decision activities

For each LLE component the execution of the optimal disposition decision will depend on which option is selected. If the optimum course is:

[redacted]

Levy LLE Disposition

I. General Scope

This section outlines the asset pricing requirements and minimum reviews and approvals required for the execution of transactions and the record keeping requirements necessary for the disposition of LLE assets for Levy.

Transactions under this section must conform to all existing applicable company policies. It is essential that asset divesture records of all transactions are documented and preserved.

All transactions will comply with tax regulations. Internal transfers within DEF, or to DEC, DEP, DEO, DEI, and DEK do not require a tax surcharge as these entities have a Direct Pay Permit.

II. Disposition Path

a. Internal Disposition

Generally, capital assets are transferred among regulated affiliated utilities at Net Book Value (NBV). However, asymmetrical pricing is used for transfers between regulated affiliates and non-regulated utility affiliates and/or non-utility affiliates – the higher of NBV or Fair Market Value (FMV).

For regulated utility to regulated utility transfers, there may be instances where NBV may be at a higher value than FMV, in these cases, Commission(s) approval will be required to transfer at less than NBV.

b. External Bids

If not transferred internally, determine the FMV by obtaining external bids.

The bidding process for the disposition of materials and equipment shall be conducted as follows:

The bidding process shall follow MCP-NGGC-0001.

The Power Advocate sourcing tool should be used for all bid events, thereby maintaining consistency with all bid event sales and document retention.

The standard approved legal form contracts shall be used for all third party asset contract sales in accordance with MCP-NGGC-0001.

III. Approvals

Levy LLE internal sales will follow the Intercompany Affiliate Asset Transfer Agreement (IATA) utilizing the Affiliate Asset Transfer e-form found on the PORTAL. If the value is over $10 M dollars or an internal sale/transfer is proposed at a value less than NBV, then commission(s) approval may be necessary for a transfer/sale to an internal Regulated Entity. Any internal transfer to a non-regulated internal entity must comply with FERC 107, asymmetrical pricing, and/or Rule 25-6.1351, Florida Administrative Code.

All Levy LLE asset external sales will follow the company's DOA guidance for the Business Unit (Nuclear Development) and Supply Chain. Additionally, each sale will be reviewed by the DEF Rates and Regulatory Strategy Director or designee, the DEF Regulatory Legal Associate General Counsel or designee, and the Tax Manager.

CB&I Stone & Webster, Inc.
128 South Tryon Street
Suite 1000
Charlotte, NC 28202
Tel: +1 704-343-7500
Fax: +1 704-331-5646
www.CBI.com

March 20, 2014
L-SHAW-DUKE-000002
Project: Levy Nuclear Project
Response Required Y ☒ N ☐
Response Due By: 3/30/2014

Duke Energy Corporation
Attention: Mr. Christopher Fallon
Vice President, Nuclear Development
526 South Church Street
Mail Code: EC12L
Charlotte, NC 28202

Subject: Levy Termination Costs Estimate for CB&I Stone & Webster, Inc.

Reference:
1. Levy Nuclear Plant EPC Agreement
2. Duke Energy Letter LNP-EPC-2014-0003 dated 28 January 2014
3. Letter APC_LVG-000068 dated 20 February 2014

Dear Mr. Fallon:

As follow-up to Letter APC_LVG_000068 (Reference 3), CB&I Stone & Webster, Inc. (CB&I), is pleased to submit this description of activity and estimate of cost associated with the termination of CB&I work under the Levy Nuclear Plant EPC Agreement.

Orderly Conclusion of CB&I Activity and Proposal for Payment of Cost

Pursuant to discussions with Duke Energy Florida (DEF) under EPC Agreement Article 22.6, CB&I is proceeding with the orderly conclusion of all Levy contract activities. Project Management anticipates the following activities to close:

[redacted]

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 60
PARTY: DUKE ENERGY FLORIDA (DEF) (DIRECT)
DESCRIPTION: Christopher M. Fallon CMF-3

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CMF

[redacted]

Please indicate binding consent by signing below. Contact the undersigned with any questions regarding this correspondence.

Sincerely,

Kevin J. Holderness
Project Manager
CB&I
Levy County Project

Consent and agree on behalf of Duke Energy Corporation

Christopher M. Fallon 3/21/14

Christopher Fallon
Vice President, Nuclear Development

cc:

Franklin, Michael	Duke Energy Florida	Harrod, Bennett	CB&I
Hubner, Edward	CB&I	Document Control	

Attachments:

A. Estimate of Cost of Orderly Conclusion of CB&I Work on the Levy Nuclear Project
B. Form of Mutual Release of Claims

Please Reply To: Kevin J. Holderness
Phone: 704-378-5277
E-Mail Address: kevin.holderness@CBI.com

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CMF

Attachment A
Estimate of Cost of Orderly Conclusion of
CB&I Work on the Levy Project

[redacted]

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CMF

Attachment B
Form of Mutual Release of Claims

Release of Claims

[redacted]

CB&I STONE & WEBSTER, INC.

By:_____

Name:_____

Title:_____

Date: _____

DUKE ENERGY FLORIDA, INC., FLORIDA POWER CORPORATION, and PROGRESS ENERGY FLORIDA, INC.

By: _____

Name: _____

Title: _____

Date: _____

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CMF

JOHN R. THRASHER
Director, Engineering
Nuclear Development

Duke Energy
EC12L / 526 South Church Street
Charlotte, NC 28202

Mailing Address:
EC12L / P.O. Box 1006
Charlotte, NC 28201-1006

o: 704-382-8781
c: 704-617-1375
f: 980-373-2551

john.thrasher@duke-energy.com

April 30, 2014
NPD-CBI-2014-0001
Response (Action) Required YES___ /NO_X_

CB&I Stone & Webster, Inc.
Attn: Mr. Kevin Holderness
Project Manager - Levy County Project
CB&I Stone & Webster
128 S. Tryon Street
Charlotte, NC 28202

References:
1) *Levy Nuclear Plant Project EPC Agreement PEF Contract No. 414310*, dated December 31, 2008
2) LNP-EPC-2014-0003, *Levy Nuclear Plant Project EPC Agreement Notice of Termination*, dated January 28, 2014
3) L-SHAW-DUKE-000002, *Levy Termination Costs Estimate for CB&I Stone & Webster, Inc.*, dated March 20, 2014
4) L-SHAW-DUKE-000003, *CB&I Stone & Webster, Inc. Release of Claims*, Dated April 17, 2014

Subject: Levy Nuclear Plant Project EPC Agreement Mutual Release of Claims

Dear Mr. Holderness,

Duke Energy Florida (DEF) has paid all invoices associated with CB&I Stone & Webster, Inc. termination costs for the Levy EPC Agreement as outlined in Reference 3. Furthermore, DEF has fully executed the Mutual Release of Claims submitted by CB&I Stone & Webster, Inc. with Reference 4.

The attached, fully executed Mutual Release of Claims concludes all required actions and releases all potential claims in connection with the Levy EPC Agreement (Reference 1) for both DEF and CB&I Stone & Webster, Inc.

Thank you for your timely attention to closure of this matter.

Sincerely

John S. Thrasher
Director – Engineering
Nuclear Development

Attachment (Fully Executed Mutual Release of Claims)

cc w/ att: Dhiaa Jamil (DE)
Joe Donahue (DE)
Chris Fallon (DE)
Bob Morgan (DE)
Bob Kitchen (DE)
Betsy Solakoglu (DE)
Erik Wagner (DE)
Michael Franklin (DE)
Mike Taylor (DE)
John Burnett (DEF)
David Conley (DE)
David Fountain (DE)
Matt Martin (DE)
Lawrence Denney (DE)
Kate Nolan (DE)
Patricia C. Smith (DE)
Edward Hubner (CB&I)
Bennett Harrod (CB&I)

ND Document Inbox (File & Records)

Attachment B
Form of Mutual Release of Claims

Release of Claims

[redacted]

CB&I STONE & WEBSTER, INC.
By: Kevin J. Holderness
Name: Kevin J. Holderness
Title: PROJECT MANAGER
Date: 16 APRIL 2014

DUKE ENERGY FLORIDA, INC., FLORIDA POWER CORPORATION, and PROGRESS ENERGY FLORIDA, INC.
By: Christopher M. Fallon
Name: CHRISTOPHER M. Fallon
Title: VICE PRESIDENT
Date: 30 APRIL 2014

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REDACTED

Background:

DEF authorized WEC to contact Tioga regarding the feasibility and potential cost impact (if any) to place a manufacturing hold on the Reactor Coolant-loop (RCL) piping components currently in manufacturing, to allow DEF time to analyze the disposition of the equipment. Tioga responded that there would be a cost associated with a manufacturing hold and that a change order would need to be negotiated. On November 14, 2013, DEF authorized WEC to contact Tioga regarding its cost should DEF terminate the purchase order and cancel manufacturing of the RCL piping. On January 7, 2014 Tioga provided WEC with an all-inclusive cancellation cost of [redacted] These all inclusive costs include such items as cancelling all material orders, purchase orders and existing contracts, bringing work to an orderly conclusion, demobilization costs, any cancellation charges to third parties, costs to scrap or salvage materials and a credit for the salvage or scrap value, etc. In addition, Tioga acquired and renovated a building in the US to store the RCL piping. If this offer is accepted, DEF and WEC shall have no further liability to Tioga for this purchase order and Tioga will have no further liability to DEF and WEC**.** Tioga indicated that because the pipes are in the queue to be bent on [redacted] The table below discusses the potential outcomes for the RCL piping to provide a framework for a decision on the Tioga offer.

Option	Costs	Comments
Terminate PO- stop manufacturing	Cost to terminate PO - [redacted]	Salvage value is included in net cost. DEF and WEC shall have no further liability to Tioga for these POs
Complete manufacturing and store RCL piping – sell when market recovers	Cost to complete manufacturing - [redacted][1] Storage, extended warranty, etc.: [redacted][2] PMO and RCL piping PMO [redacted][3] Storage Plans and obtaining Storage estimates: [redacted][3] Duties and Customs: [redacted][3]	Nuclear market is speculative at this point. Great uncertainty concerning the market for this equipment or any reasonable expectation of equipment value.
Complete manufacturing and store RCL piping – unable to sell, scrap at end of storage period	Cost to complete manufacturing - [redacted] Storage, extended warranty, etc.: [redacted][2] PMO and RCL piping PMO [redacted][3] Storage Plans and obtaining Storage estimates: [redacted][3] Duties and Customs: [redacted][3]	Scrap value estimated to be approximately [redacted][4].

[1] [redacted]

[2] From Levy EPC [redacted]

[3] From email from Linda Iller (WEC) on January 7, 2014.

[4] Estimate [redacted]

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 61
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)
DESCRIPTION: Christopher M. Fallon CMF-4

Complete manufacturing and store RCL piping – Use at Levy	Cost to complete manufacturing - [redacted] Storage/Extended Warranty Costs - [redacted] PMO and RCL piping PMO [redacted][3] Storage Plans and obtaining Storage estimates: [redacted][3] Duties and Customs: [redacted][3]	New Florida nuclear cost recovery legislation raises concerns over the feasibility of new nuclear in Florida. Need to develop a long-term storage plans. Earliest in-service date is beyond 2025 requiring long-term storage of RCL piping.

Other considerations:

[redacted]

- This is the last remaining equipment presently in fabrication under the Levy EPC agreement. For the rest of the equipment to be dispositioned the fabrication has been previously suspended.

[redacted]

Recommendation:

Given the uncertainty regarding the potential in-service date for Levy, the incremental costs to store the RCL piping and the uncertain market for the RCL piping, the offer from Tioga results in approximately [redacted] in savings versus completion of the equipment it is recommended that DEF terminate the Tioga purchase order and cancel manufacturing of the RCL piping.

[5] Have not been provided an estimate for long-term storage, escalated 5 year storage costs for an additional 7 years.

CHRISTOPHER M. FALLON
Vice President
Nuclear Development

Duke Energy
EC12L/526 South Church Street
Charlotte, NC 28202

Mailing Address:
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c: 704.519.6173
f: 980.373.2551

christopher.fallon@duke-energy.com

January 9, 2014
LNP-EPC-2014-0001
Response (Action) Required YES X / NO __

Stone & Webster, Inc.
Attn: Kevin Holderness
Consortium Project Manager
CB&I Stone & Webster
128 S. Tryon Street
Charlotte, NC 28202

References: 1) E-mail from Linda Iller (WEC) to Christopher Fallon (DEF), Tioga PO – Cancellation Offer, sent January 7, 2013
2) Levy Nuclear Plant Project EPC Agreement PEF Contract No. 414310

Subject: Levy Long Lead Equipment Disposition for the Tioga Manufactured Equipment

Dear Mr. Holderness:

The purpose of this letter is to inform the Consortium of Duke Energy Florida's (DEF) acceptance of the cancellation offer for all components Tioga is manufacturing for Levy Units 1 and 2 as provided in Reference 1. This offer includes all cancellation costs from Tioga in the total amount of [redacted] After payment of this amount, DEF will have no further liability to Tioga or the Consortium for the long lead equipment to be supplied by Tioga for Levy Units 1 and 2.

We ask that you proceed with cancellation of the Tioga orders, pending the issuance of a Change Order to formalize our agreement as required by Section 22.1(h) of Reference 2 (which was added by Amendment Number Three).

DEF appreciates the Consortium's assistance in this matter. Should you have any questions, please contact either Mike Franklin (919-546-6967) or myself.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 62
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)
DESCRIPTION: Christopher M. Fallon CMF-5

Sincerely,

Christopher M. Fallon

Christopher M. Fallon
Owner's Project Director
Vice President, Nuclear Development

cc: Dhiaa Jamil (DE)
John Thrasher (DE)
Bob Morgan (DE)
Bob Kitchen (DE)
Lawrence Denney (DE)
Betsy Solakoglu (DE)
Erik Wagner (DE)
Mike Franklin (DE)
David Conley (DE)
Patricia C. Smith (DE)
Matthew Martin (DE)
Kate Nolan (DE)
John Burnett (DE)
Michael Taylor (DE)
Tom Weir (WEC)
Linda Iller (WEC)
Lee Stern (WEC)
Linda Williams (WEC)
Cheryl Halaszynski (WEC)
Joni Falascino (WEC)
LevyProjectCorrespondenceInbox@westinghouse.com
LNP-EPCInbox@pgnmail.com

MEMORANDUM

Date: January 12, 2015

To: Chris Fallon, Vice President -- Nuclear Development

cc: NDDocumentInbox@duke-energy.com

From: Lawrence Denney, Nuclear Regulated Generation & Commercial Support Manager

Subject: Status Update for Levy Nuclear Plant Long-lead Equipment Disposition

---

Introduction

This memo responds to your request for a summary and update of the present status of the disposition of the Levy Nuclear Plant long-lead equipment (LLE). It outlines the progress towards and obstacles encountered in executing the plans documented in the "Levy Nuclear Plant Long-lead Equipment Disposition Plan" memo dated January 16, 2014. That memo documented the plan Duke Energy Florida, Inc. (Duke) established to dispose of the remaining LLE purchased for the Levy County Nuclear Plant (Levy) under the Engineering, Procurement and Construction (EPC) agreement. It presented five different options[1] to maximize the value of the recovery of the disposition of the remaining LLE while simultaneously minimizing any risks that could be incurred from a particular option or action.

Levy LLE

[redacted]

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 63
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)
DESCRIPTION: Christopher M. Fallon CMF-6

[redacted]

Disposition Options

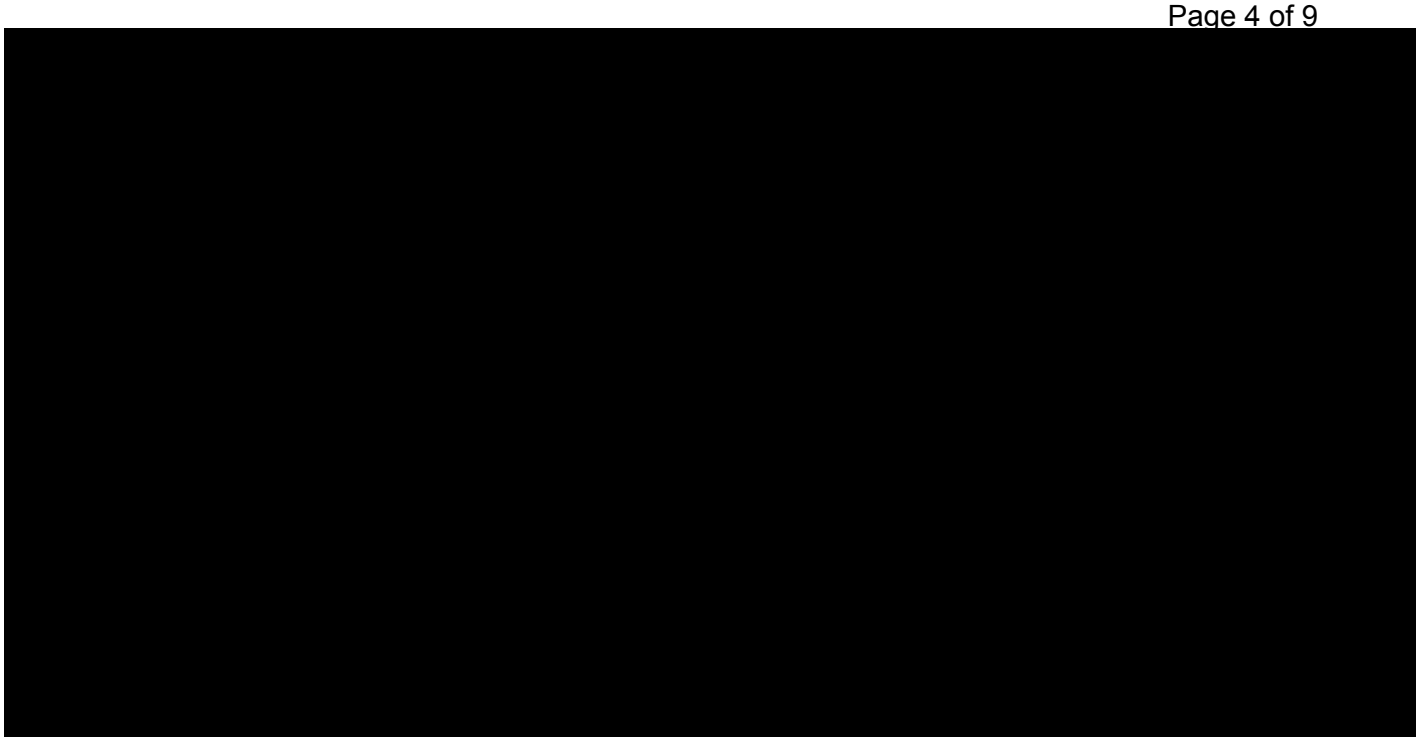
[redacted]

[redacted]

Challenges in working with Westinghouse

Letter Agreement

[redacted]





[redacted]

Review of Purchase Orders

[redacted]

[redacted]

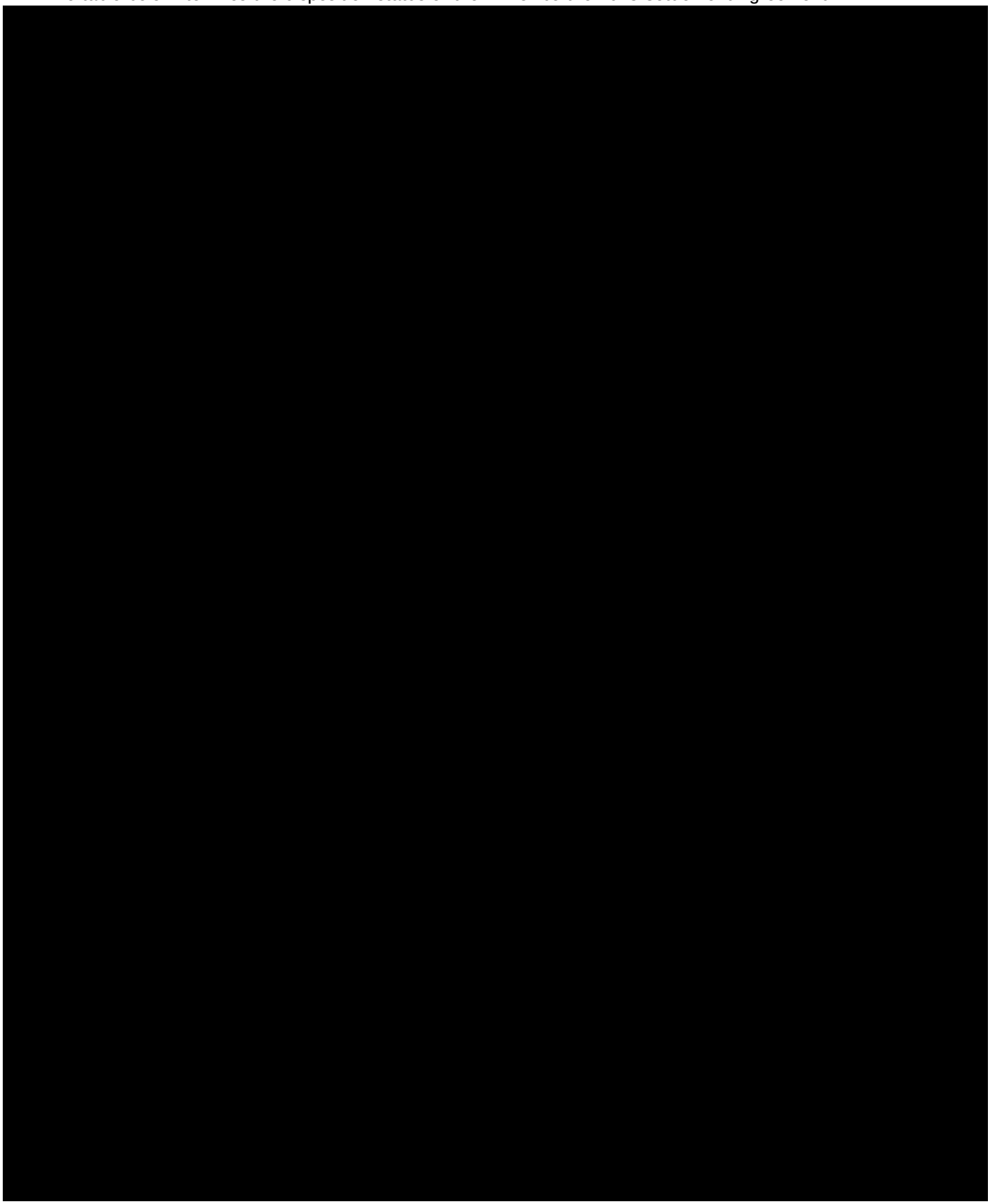
LLE disposition

[redacted]

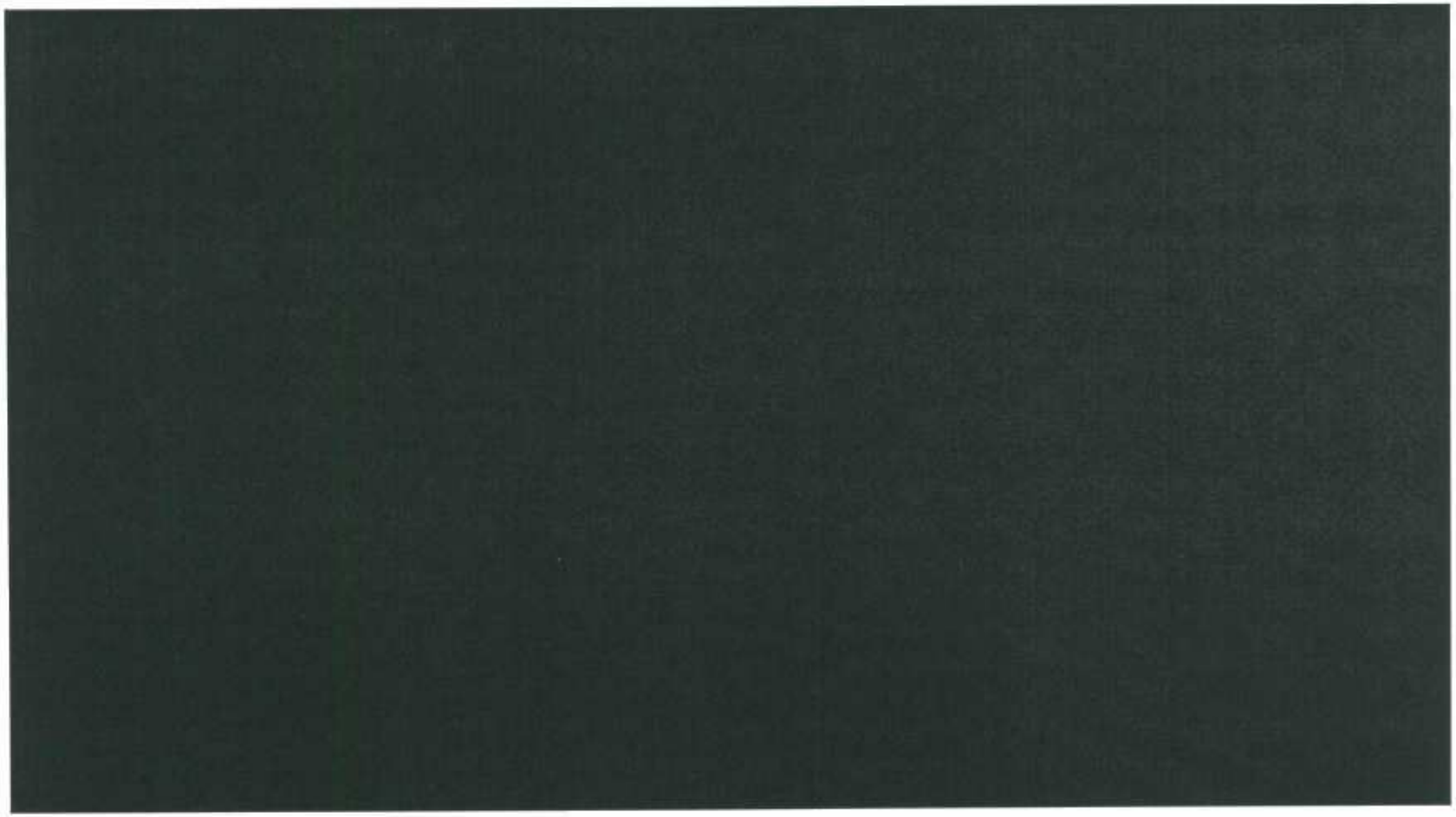
[redacted]

Summary of the Status of LLE

The table below itemizes the disposition status of the LLE since the 2013 Settlement Agreement.







DUKE ENERGY

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 64
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)
DESCRIPTION: Christopher M. Fallon CMF-7

Levy COL Estimated Schedule

Milestone	Current Estimated Schedule*
ACRS Review complete	November 2015
FSER	January 2016
Mandatory Hearing	March 2016
COL Issued	May 2016

* DEF estimate. As of the date of this filing the NRC has not issued an official revised Levy COL schedule.

DUKE ENERGY.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 65
PARTY: DUKE ENERGY FLORIDA (DEF)
(DIRECT)
DESCRIPTION: Christopher M. Fallon CMF-8

State of Florida

Public Service Commission

Office of Auditing and Performance Analysis
Bureau of Auditing
Tampa District Office

Auditor's Report

Duke Energy Florida, Inc.
Nuclear Cost Recovery Clause
Crystal River Unit 3 Uprate

Twelve Months Ended December 31, 2014

Docket No. 150009-EI
Audit Control No. 15-005-2-1
May 15, 2015

Ronald Mavrides
Audit Manager

Linda Hill
Reviewer

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 66
PARTY: STAFF RE: DUKE ENERGY FLORIDA (DEF)
DESCRIPTION: Ronald A. Mavrides RAM-1

Table of Contents

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Purpose

To: Florida Public Service Commission

We have performed the procedures described later in this report to meet the agreed-upon objectives set forth by the Office of Industry Development and Market Analysis in its audit service request dated January 2, 2015. We have applied these procedures to the attached schedule prepared by Duke Energy Florida, Inc. and to several of its related schedules in support of its 2014 Nuclear Cost Recovery Clause for its cost expenditures for the Crystal River Unit 3 Uprate Project in Docket No. 150009-EI.

This audit was performed following General Standards and Fieldwork Standards found in the AICPA Statements on Standards for Attestation Engagements. Our report is based on agreed-upon procedures. The report is intended only for internal Commission use.

Objectives and Procedures

General

Definitions

Utility refers to Duke Energy Florida, Inc.

CR3 refers to the Crystal River Unit 3 Uprate Project.

NCRC refers to the Nuclear Cost Recovery Clause.

CCRC refers to Capacity Cost Recovery Clause.

Construction Costs are costs that are expended to construct the nuclear power plant, but not limited to, the costs of constructing power plant buildings and all associated permanent structures, equipment and systems.

Utility Information

On February 5, 2013, the Utility announced its intent to retire the CR3 plant. Recovery of costs will continue until 2019.

Objectives: The objectives were to determine whether the Utility's 2014 NCRC filing in Docket No. 150009-EI are consistent and in compliance with Section 366.93, Florida Statutes, and Rule 25-6.0423, Florida Administrative Code (F.A.C.).

Procedures: We performed the following objectives and procedures to satisfy the overall objective identified above.

Construction Work In Progress

Objectives: The objectives were to determine whether costs incurred in 2014 for the CR3 Uprate are properly accounted for and stated as required by Section 366.93, Florida Statutes and Rule 25-6.0423, F.A.C.

Procedures: We reconciled the company's transaction details to the general ledger and filing. We judgmentally selected transactions from the transaction details and tested them for: 1) Compliance with contracts, 2) Correct paid amounts, and 3) Correct recording periods. No exceptions were noted.

Recovery

Objectives: The objectives were to determine whether the Utility used the Commission approved CCRC factors to bill customers for the period January 1, 2014, through December 31, 2014, and whether Exhibit TGF-2 reflects amounts in Order No. PSC-14-0701-FOF-EI.

Procedures: We agreed the amount collected on Exhibit TGF-2 to the 2014 NCRC jurisdictional amount approved in Order No. PSC-14-0701-FOF-EI and to the CCRC in Docket No.150001-EI. Our recommendations are discussed in Finding 1

Expense

Operation and Maintenance Expense

Objectives: The objectives were to determine whether Operation and Maintenance (O&M) Expense on Exhibit TGF-2 are: 1) supported by adequate source documentation, 2) appropriately recoverable through the NCRC and that 3) total jurisdictional O&M Expense is accurately calculated.

Procedures: We judgmentally selected costs from the transaction details and reviewed them for the proper period, amounts, and that they are legitimate NCRC costs. For costs that are for a service or product that is under contract, we: 1) Traced the invoiced cost to the construction contract of other type of original source document, 2) Reconciled the invoice to the contract terms and pricing, 3) Ensured that the amounts billed are for actual services or materials received, and 4) Investigated all prior billing adjustments and job order changes to the contract(s). We sorted the transaction detail listings by O&M expense category and reconciled them to the filing. We judgmentally selected one employee each from the months of November and December 2014 from the transaction details for sampling. We used employee time sheets to verify that labor hours charged to employee labor expense are correct. We recalculated employee incentive pay for October 2014. No exceptions were noted.

True-Up

Objective: The objective was to determine whether the True-Up and Interest Provision as filed on Exhibit TGF-2 was properly calculated.

Procedures: We traced the December 31, 2013 True-Up Provision to the Commission Order. We recalculated the True-Up and Interest Provision amounts as of December 31, 2014, using the Commission approved beginning balance as of December 31, 2013, the approved AFUDC rate, and the 2014 costs. No exceptions were noted.

Audit Findings

Finding 1: Rate of Return on Equity

Audit Analysis: Rule 25-6.0423(7)(b), - Nuclear or Integrated Gasification Combined Cycle Power Plant Cost Recovery, F. A.C. states:

> The amount recovered under this subsection will be the remaining unrecovered Construction Work in Progress balance at the time of abandonment and future payment of all outstanding costs and any other prudent and reasonable exit costs. The unrecovered balance during the recovery period will accrue interest at the Utility's overall pretax weighted average midpoint cost of capital on a Commission adjusted basis as reported by the Utility in its Earnings Surveillance Report filed in December of the prior year, utilizing the midpoint of return on equity (ROE) range or ROE approved for other regulatory purposes, as applicable.

The Utility applied the rate reported in its Earnings Surveillance Report filed for December 2012, which was 7.23%. Audit staff believes that the Rule requires that the Utility should have applied the rate reported in its Earnings Surveillance Report filed for December 2013, which was 7.10%. We requested the Utility to calculate the Total Period Revenue Requirement for 2014 using the rate of 7.10%. This calculation reduces the Total Period Revenue Requirement of $23,501,504 as filed to $23,346,121.

The Utility responded by stating:

> The language in the Rule and Statute can reasonably be interpreted in two ways. Duke Energy had interpreted it to mean the WACC will be set based upon the year prior to the year the project is cancelled, and that same WACC would then be used for each year of the recovery period. The rule and statutory language, however, could also be interpreted to mean that every year the WACC is reset at the prior years reported WACC. Given that there are two reasonable interpretations, Duke Energy is willing to adopt the second interpretation. Duke Energy will make an entry to adjust 2014 carrying costs to reflect the change in interpretation and include it in our May 1 filings in the 2015 time period consistent with how actuals will be recorded. Duke will then continue updating the WACC consistent with the second interpretation described above for future periods.

Effect on the General Ledger: Utility should determine the appropriate entry.

Effect on the Filing: Duke has adjusted its May 1, 2015, filing.

Exhibit

Exhibit 1: True-Up

DUKE ENERGY FLORIDA
Nuclear Cost Recovery Clause (NCRC) - CR3 Uprate
2014 Det ail - Calculation of the Revenue Requirements for
January 2014 through December 2014

Witness: T. G. Foster / M. Teague
Docket No. 150009-EI
Exhibit (TGF-2)

Line	Description		Beginning of Period Amount	Actual January 14	Actual February 14	Actual March 14	Actual April 14	Actual May 14	Actual June 14	Actual July 14	Actual August 14	Actual September 14	Actual October 14	Actual November 14	Actual December 14	Period Total
1	Unrecovered Investment															
	a EPU Construction & Wind-Down Costs (c)		374,171,055	2,058	13,819	6,323	2,612,188	2,675	1,367	536	2,426	1,384	2,330	(309,418)	735	2,335,221
	b Sale or Salvage of Assets		0	0	(5,075)	0	(78,683)	(309,000)	(62,900)	0	0	0	0	0	0	(453,658)
	c Disposition		0	0	0	0	0	0	0	0	0	0	0	0	0	0
	d Total		374,171,055	2,058	8,744	6,323	2,533,505	(307,325)	(61,533)	536	2,426	1,384	2,330	(309,418)	735	$1,881,563
2	Adjustments															
	a Non-Cash Accruals (c)		2,293,285	0	0	0	(2,605,445)	0	0	0	0	0	0	312,160	0	($2,293,285)
	b Joint Owner Credit		(39,950,263)	746	(656)	(582)	(210,910)	(16,793)	47,178	(44)	(55)	(227)	(277)	22,189	(59)	(159,472)
	c Other (b)		(15,108,647)	0	0	0	0	0	0	0	0	0	0	0	0	0
	d Adjusted System Generation Construction Cost Additions		318,405,430	2,804	8,108	5,741	(282,050)	(324,118)	(14,355)	492	2,371	1,157	2,053	24,931	656	($571,392)
	Ratio Jurisdictional Factor: Current Year Activity	92.865 %														
	Ratio Jurisdictional Factor: (Beg Bal YE 2012 only and POD Sale)	92.663 %														
	e Period Project Investment			2,604	7,529	5,333	(261,053)	(256,989)	(13,334)	457	2,221	1,075	1,907	23,157	609	($468,483)
	f Beginning Balance - pre 2013 Investment		279,911,057													
	g Beginning Balance - 2013 Investment		12,170,084													
3	Carrying Cost on Unrecovered Investment Balance															
	a Uncollected Investment: Costs for the Period (Beg Balance: Line 2 f and 2 g)		292,081,140	2,604	7,529	5,333	(261,053)	(256,989)	(13,334)	457	2,221	1,075	1,907	23,157	609	$91,582,657
	b Plant-in-Service (Beg Bal YE 2013) (c)		29,995,096	0	0	0	0	0	0	0	0	0	0	0	0	29,995,096
	c Period Recovered thru Base / Fuel Costs	0		0	0	0	0	0	0	0	0	0	0	0	0	(468,483)
	d Amortization of Unrecovered Investment (a)	0		(3,683,571)	(3,683,571)	(3,683,571)	(3,683,571)	(3,683,571)	(3,683,571)	(3,683,571)	(3,683,571)	(3,683,571)	(3,683,571)	(3,683,571)	(3,683,571)	($44,202,846)
	e Prior Period Carrying Charge Unrecovered Balance (a)		(1,289,590)	(1,207,155)	(1,124,727)	(1,042,296)	(959,865)	(877,434)	(795,002)	(712,571)	(630,140)	(547,709)	(465,277)	(382,846)	(300,415)	($300,415)
	f Prior Period Carrying Charge Recovered (c)			(82,431) K	82,431	(82,431)	(82,431)	(82,431)	(82,431)	(82,431)	(82,431)	(82,431)	(82,431)	(82,431)	(82,431)	
	g Prior Period Under/(Over) Recovery (Prior Month)			(24,237)	(19,837)	(22,152)	(199,973)	(190,923)	(190,453)	(46,333)	(53,014)	(31,662)	(33,220)	(32,805)	(13,842)	($170,135)
	h Total Investment		$345,796,454	$29,197,925	$25,377,468	$24,954,898	$24,694,847	$24,504,852	$24,314,155	$24,136,792	$23,996,237	$23,843,504	$23,748,025	$24,712,648		
4	Average Net Investment			$29,697,187	$25,374,273	$24,824,398	$24,695,914	$24,509,834	$24,309,469	$24,225,473	$24,066,220	$23,919,871	$23,795,903	$24,230,336		
5	Return on Average Net Investment															
	a Equity Component	6.602 94		1,028,449	1,008,175	991,904	977,104	961,777	946,928	932,584	918,263	903,954	889,636	875,360	861,060	11,285,220
	b Equity Component Grossed Up For Taxes	1.628 00		1,661,295	1,634,055	1,614,821	1,590,727	1,565,775	1,541,600	1,518,266	1,494,943	1,471,629	1,448,329	1,425,088	1,401,840	18,378,369
	c Debt Component	0.601 89		453,541	443,679	434,213	419,724	412,336	415,198	448,303	441,422	434,560	427,717	420,795	413,970	$5,424,924
	d Total Return			2,151,834	2,121,734	2,091,640	2,060,431	2,028,111	1,986,798	1,966,569	1,936,365	1,906,189	1,875,946	1,845,883	1,815,770	23,797,280
6	Revenue Requirements for the Period (Lines 3e + 5d)			$2,154,428	$2,129,263	$2,096,073	$1,799,378	$1,769,122	$1,963,465	$1,967,008	$1,933,586	$1,907,253	$1,877,893	$1,869,040	$1,816,379	$23,308,797
7	Projected Revenue Requirements for the Period (Order No PSC 13-0493 -FOF-EI)			$2,178,575	$2,148,900	$2,119,125	$2,089,350	$2,059,575	$2,029,798	$2,000,023	$1,970,248	$1,940,473	$1,910,697	$1,880,921	$1,851,146	$24,178,932
8	Over/Under Recovery for the Period			($24,147)	($19,637)	($23,052)	($289,973)	($290,453)	($65,333)	($33,014)	($36,662)	($33,220)	($32,805)	($11,882)	($34,767)	($870,135)
9	Other Exit / Wind-Down															
	a Accounting			3,157	6,133	16,597	4,668	10,330	4,083	12,032	5,001	3,256	3,128	2,768	2,669	73,822
	b Corporate Planning			10,489	7,458	8,648	7,972	6,550	6,527	4,404	2,770	395	405	340	2,624	58,821
	c Legal			975	10,711	15,454	14,506	11,256	16,651	12,969	12,411	2,423	334	0	1,236	99,006
	d Joint Owner Credit			(1,392)	(2,001)	(3,145)	(3,231)	(2,148)	(2,763)	(2,419)	(1,658)	(699)	(318)	(255)	(542)	(19,859)
	e Total Other Exit/Wind-Down Costs			13,419	22,301	37,554	24,914	25,988	25,020	27,008	18,522	5,375	3,549	2,853	6,047	210,590
10	Jurisdictional Factor (A&G)			0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	0.9322	
11	Jurisdictional Amount			12,510	20,817	34,822	23,225	22,162	23,324	25,176	17,267	5,197	3,309	2,659	5,637	196,314
12	Prior Period Unrecovered Balance (a)		661,239	567,445	513,652	439,858	366,065	292,271	218,478	144,684	70,893	(2,903)	(76,696)	(150,490)	(224,283)	
13	Prior Period Costs Recovered (a)			73,794	73,794	73,794	73,794	73,794	73,794	73,794	73,794	73,794	73,794	73,794	73,794	
14	Prior Month Period (Over)/Under Recovery			0	(20,561)	(12,241)	1,758	(9,837)	(10,701)	(9,741)	(7,881)	(15,794)	(27,870)	(29,760)	(30,412)	
15	Unamortized Balance		661,239	567,445	493,092	407,058	335,022	251,392	166,857	81,363	1,679	(87,913)	(180,577)	(253,130)	(327,336)	
16	Carrying Costs for the Period															
	a Balance Eligible for Interest			63,952	540,402	461,365	383,532	299,470	215,456	132,847	47,209	(48,418)	(151,026)	(234,904)	(327,620)	
	b Monthly Commercial Paper Rate			0.00%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	
	c Interest Provision			29	27	27	24	19	12	7	3	(3)	(8)	(16)	(27)	93
	d Total Costs and Interest (Line 11 + line 16c)			12,539	20,844	34,848	23,249	22,180	23,336	25,182	17,270	5,194	3,300	2,643	5,611	196,407
17	Recovered (Order No PSC 13-0493 -FOF-EI)			33,099	33,094	33,090	33,086	33,081	33,077	33,073	33,069	33,064	33,060	33,056	33,051	396,900
18	Over/Under Recovery for the Period			(20,560) K	12,241)	1,758	(9,837)	(10,701)	(9,741)	(7,891)	(15,794)	(27,870)	(29,760)	(30,412)	(27,441)	(200,493)
19	Other - Adjustments (a)		(80,177)	(608)	(555)	(502)	(448)	(393)	(339)	(283)	(228)	(171)	(115)	(58)	0	($3,699)
20	Recovered (Order No PSC 13-0493 -FOF-EI)			(608)	(555)	(502)	(448)	(393)	(339)	(283)	(228)	(171)	(115)	(58)	(0)	($3,699)
21	Over/Under Recovery for the Period			0	0	0	0	0	0	0	0	0	0	0	0	0
22	Revenue Requirements for the Period			2,166,369	2,149,361	2,131,320	1,812,179	1,791,199	2,096,462	1,991,907	1,955,629	1,917,276	1,881,878	1,871,825	1,821,989	23,541,584
23	Recovered (Order No PSC 13-0493 -FOF-EI)			2,211,366	2,181,439	2,151,713	2,121,968	2,092,163	2,062,537	2,032,812	2,001,870	1,973,366	1,943,643	1,913,919	1,884,197	24,572,133
24	Over/Under Recovery for the Period			(44,998) K	31,078)	(20,393)	(289,789)	(300,965)	(34,075)	(40,905)	(46,241)	(56,090)	(61,765)	(42,094)	(62,209)	($1,030,549)

(a) Please see Appendix A for Beginning Balance support and support of Amortization of Unrecovered Balance and Other Adjustments calculation.
(b) Other true offsets cost of removal of previously existing assets
(c) Approximately $2.6M accounting adjustment to correct double presentation of amounts in Line 2a and 2b in April 2014
This amount represents payments received and cash posted to project that did not have an offsetting accrual adjustment
(c) Approximately $812K accounting adjustment to correct schedule presentation error in Line 2a and 2b in Nov 2014.
This amount represents accruals for anticipated expenses that were not incurred or the payment of the actual amount was lower than the accrual

State of Florida

Public Service Commission

Office of Auditing and Performance Analysis
Bureau of Auditing
Tampa District Office

Auditor's Report

Duke Energy Florida, Inc.
Nuclear Cost Recovery Clause
Levy Nuclear Plant Units 1 & 2

Twelve Months Ended December 31, 2014

Docket No. 150009-EI
Audit Control No. 15-005-2-2
May 12, 2015

Ronald Mavrides
Audit Manager

Linda M. Hill
Reviewer

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 67
PARTY: STAFF RE: DUKE ENERGY FLORIDA (DEF)
DESCRIPTION: Ronald A. Mavrides RAM-2

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Purpose

To: Florida Public Service Commission

We have performed the procedures described later in this report to meet the agreed-upon objectives set forth by the Office of Industry Development and Market Analysis in its audit service request dated January 2 , 2015. We have applied these procedures to the attached schedule prepared by Duke Energy Florida, Inc. in support of its 2014 Nuclear Cost Recovery Clause for its construction cost expenditures for the Levy Nuclear Plant Units 1 & 2 for project activity in Docket No. 150009-EI.

This audit was performed following General Standards and Fieldwork Standards found in the AICPA Statements on Standards for Attestation Engagements. Our report is based on agreed-upon procedures. The report is intended only for internal Commission use.

Objectives and Procedures

General

Definitions

Utility refers to Duke Energy Florida, Inc.

LNP refers to the Levy Nuclear Plant.

NCRC refers to the Nuclear Cost Recovery Clause.

CCRC refers to the Capacity Cost Recovery Clause.

Preconstruction costs are costs that are expended after a site has been selected in preparation for the construction of a nuclear power plant, incurred up to and including the date the Utility completes site clearing work.

Construction costs are costs that are expended to construct the nuclear power plant, but not limited to, the costs of constructing power plant buildings and all associated permanent structures, equipment and systems.

Utility Information

On August 1, 2013, the Utility announced its intent to cease the work of pursuing construction of the Levy 1 and 2 reactors. Recovery of costs will continue until 2019

Objectives: The objectives were to determine whether the utility's 2014 NCRC filing in Docket No. 150009-EI are consistent and in compliance with Section 366.93, Florida Statutes and Rule 25-6.0423, Florida Administrative Code (F.A.C.).

Procedures: We performed the following objectives and procedures to satisfy the overall objective identified above.

Construction Work In Progress

Objectives: The objectives were to determine whether Construction Costs for the LNP, are properly accounted for and stated as required by Section 366.93, Florida Statutes and Rule 25-6.0423, F.A.C.

Procedures: We took the beginning balances of the costs and reconciled them to the ending balances for the prior year's filing. We judgmentally selected transactions from the transaction details and tested them for: 1) Compliance with contracts, 2) Correct paid amounts, and 3) Correct recording periods. We reconciled the transaction detail amounts to the filing and the general ledger. No exceptions were noted.

Objectives: The objectives were to determine whether Preconstruction Costs for the LNP are properly accounted for and stated as required by Section 366.93, Florida Statutes and Rule 25-6.0423, F.A.C.

Procedures: We took the beginning balances of the Preconstruction Costs and reconciled them to the ending balances for the prior year's filing. We selected a sample of preconstruction transactions from the provided transaction details and tested them for: 1) Compliance with contracts, 2) Correct paid amounts, and 3) Correct recording periods. We reconciled the transaction detail amounts to the filing and to the general ledger. No exceptions were noted.

Recovery

Objectives: The objectives were to determine whether the Utility used the Commission approved CCRC factors to bill customers for the period January 1, 2014, through December 31, 2014, and whether the 2014 Detail Calculation of the Revenue Requirements reflects amounts in Order No. PSC 14-0701-FOF-EI.

Procedures: We agreed the beginning balances of the 2014 Detail Calculation of the Revenue Requirements to the ending 2013 Detail Calculation of the Revenue Requirements. We agreed the amount collected on the 2014 Detail Calculation of the Revenue Requirements to the 2014 NCRC jurisdictional factors approved in Order No. PSC-14-0701-FOF-EI and to the CCRC in Docket No. 150001-EI. Our recommended adjustment is discussed in Finding 1.

Expense

Operation and Maintenance Expense

Objective: The objectives were to determine whether Operation and Maintenance (O&M) Expense on Exhibit TGF-2 are: 1) Supported by adequate source documentation, 2) Appropriately recoverable through the NCRC and that 3) Total Jurisdictional O&M Expense is accurately calculated.

Procedures: We reconciled the trial balance accounts to the filing. We judgmentally selected costs from the transaction details and reviewed them for the proper period and amounts, and that they are allowable NCRC costs. For costs that are for a service or product that is under contract we: 1) Traced the invoiced cost to the construction contract or other type of original source document, 2) Reconciled the invoice to the contract terms and pricing, 3) Ensured that the amounts billed are for actual services or materials received, and 4) Investigated all prior billing adjustments and job order changes to the contracts.

We sampled costs charged in 2014, including labor, and obtained the supporting backup. We recalculated labor costs using employee time sheets and labor rates for employees who provided labor charged to the NCRC during the sample months. We verified the hours worked and recalculated the labor charges recorded by the Utility charged to the NCRC. We verified other costs for proper account, period, and amount. No exceptions were noted.

True-Up

Objective: The objective was to determine whether the True-Up and Interest Provision as filed on Schedule TGF-2 was properly calculated.

Procedures: We traced the December 31, 2013 True-Up Provision to the Commission Order. We recalculated the True-Up and Interest Provision amounts as of December 31, 2014, using the Commission approved beginning balance as of December 31, 2013, the approved AFUDC rate, and the 2014 costs. No exceptions were noted.

Audit Findings

Finding 1: Rate of Return on Equity

Audit Analysis: Rule 25-6.0423(7)(b), - Nuclear or Integrated Gasification Combined Cycle Power Plant Cost Recovery, F. A.C. states:

> The amount recovered under this subsection will be the remaining unrecovered Construction Work in Progress balance at the time of abandonment and future payment of all outstanding costs and any other prudent and reasonable exit costs. The unrecovered balance during the recovery period will accrue interest at the Utility's overall pretax weighted average midpoint cost of capital on a Commission adjusted basis as reported by the Utility in its Earnings Surveillance Report filed in December of the prior year, utilizing the midpoint of return on equity (ROE) range or ROE approved for other regulatory purposes, as applicable.

The Utility applied the rate reported in its Earnings Surveillance Report filed for December 2012, which was 7.23%. Audit staff believes that the Rule requires that the Utility should have applied the rate reported in its Earnings Surveillance Report filed for December 2013, which was 7.10%. We requested the Utility to calculate the Total Period Revenue Requirement for 2014 using the rate of 7.10%. This calculation reduces the Total Period Revenue Requirement of $23,508,493 as filed to $23,421,244.

The Utility responded by stating:

> The language in the Rule and Statute can reasonably be interpreted in two ways. Duke Energy had interpreted it to mean the WACC will be set based upon the year prior to the year the project is cancelled, and that same WACC would then be used for each year of the recovery period. The rule and statutory language, however, could also be interpreted to mean that every year the WACC is reset at the prior years reported WACC. Given that there are two reasonable interpretations, Duke Energy is willing to adopt the second interpretation. Duke Energy will make an entry to adjust 2014 carrying costs to reflect the change in interpretation and include it in our May 1 filings in the 2015 time period consistent with how actuals will be recorded. Duke will then continue updating the WACC consistent with the second interpretation described above for future periods.

Effect on the General Ledger: Utility should determine the appropriate entry.

Effect on the Filing: Duke has adjusted its May 1, 2015 filing. Duke will continue updating the WACC for future periods.

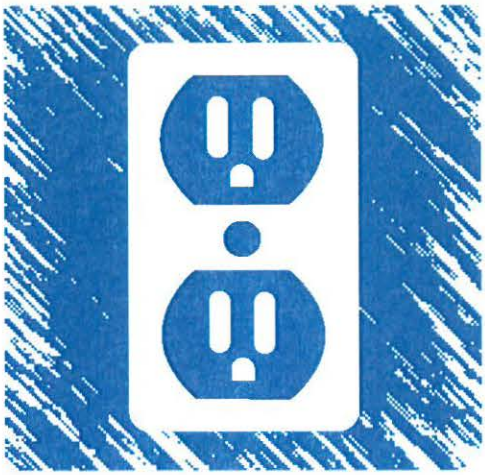
Exhibit

Exhibit 1: True-Up

2014 Summary
Levy Nuclear Units 1 & 2
January 2014 - December 2014
Duke Energy Florida

Witness: Thomas G. Foster
Docket No. 150009-EI
Exhibit: (TGF- 1)

			12-Month Total
1.	Final Costs for the Period		
	a. Carrying Cost on Unrecovered Investment		$ 13,310,606
	b. Period Exit Costs		9,816,636
	c. Period Other Exit / Wind-down Costs and Interest		381,251
	d. Total Period Revenue Requirement		$ 23,508,493
2.	Projected Amount for the Period (Order No. PSC 14-0701-FOF-EI)		$ 30,342,148
3.	Final True-Up Amount for the Period (over)/under	(Line 1d. - Line 2.)	$ (6,833,655)
4.	Amortizaton of Unrecovered Investment and Prior Period Over/Under Balances (Order No. PSC 14-0701-FOF-EI)		$ 75,293,261
5.	Total Revenue Requirements for 2014	(Line 1d. + Line 4.)	$ 98,801,754



Review of Duke Energy Florida Inc.'s Project Management Internal Controls for Nuclear Plant Uprate and Construction Projects

June 2015

BY AUTHORITY OF

The Florida Public Service Commission
Office of Auditing and Performance Analysis

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 68
PARTY: STAFF RE: DUKE ENERGY FLORIDA (DEF)
DESCRIPTION: William Coston WC-1

Review of Duke Energy Florida's Project Management Internal Controls for Nuclear Plant Uprate and Construction Projects

William "Tripp" Coston
Public Utility Analyst IV
Project Manager

June 2015

By Authority of
The State of Florida
Public Service Commission
Office of Auditing and Performance Analysis

PA-15-01-001

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1.0 Executive Summary

1.1 At a Glance

Levy Nuclear Project (LNP)

- Nuclear Regulatory Commission LNP Combined Operating License (COL) application review schedule has been extended to mid-2016 due to final AP1000 design-related issues.
- Duke Energy Florida, Inc. (DEF) performed analyses to assess the process for disposing of certain contracted long-lead equipment for the Levy Nuclear Project.
- DEF and the Westinghouse Electric Company, LLC continued litigation of the Engineering Procurement and Construction (EPC) contract cancelation. The final outcome of this litigation will impact the company's overall project costs.

Crystal River 3 Extended Power Uprate (EPU)

- The company's Investment Recovery Project (IRP) group dispositioned all of the remaining Crystal River Unit 3 (CR3) EPU assets except the remaining Siemens components.
- The CR3 *EPU assets* were a part of a larger decision process for the overall disposition of all CR3 assets. The dispositioning decisions were made on the basis of what was best for maximizing the most efficient and highest recovery value for all CR3 assets.
- The CR3 EPU asset disposition process was executed in compliance with Duke Energy Florida's Investment Recovery governance process.
- All CR3 EPU asset dispositions should be completed by August 2015.

1.2 Audit Execution

1.2.1 Purpose and Objective

This audit addresses DEF's project internal controls and management oversight for Levy Units 1 & 2 and the dispositioning of the Extended Power Uprate assets for Unit 3 located at the Crystal River Energy Complex. The primary objective of this audit is to provide an independent account of project activities and to evaluate internal project controls. Information in this report may be used by the Florida Public Service Commission (Commission) to assess the reasonableness of DEF's cost-recovery requests.

Commission audit staff published previous reports in 2008 through 2014; each entitled *Review of Duke Energy Florida, Inc.'s Project Management Internal Controls for Nuclear Plant Uprate and Construction Projects.* These reports are available on the Commission website at www.floridapsc.com/publications.

1.2.2 Scope

The period of this review is January 2014 to May 2015. Staff examined the adequacy of DEF's project management and internal controls for these projects. The internal controls assessed were related to the following key areas of project activity:

- Planning
- Management and organization
- Cost and schedule controls
- Contractor selection and management
- Auditing and quality assurance

Comprehensive controls are essential for successful project management. However, adequate and comprehensive controls are ineffective if not actively emphasized by management, embraced by the organization, and subject to oversight and revision. Proper internal controls minimize risk, enhance its mitigation and management, and aid efficient, reasoned decision making.

Risk must be timely and accurately identified. Sufficient safeguards created, vetted, and in place will help prevent and mitigate risk. Prudent decision making results from well-defined processes that address identified risks, expectations, and cost. Effective communication, adherence to clear procedures, and vigilant oversight are also essential to ensure prudent project decisions.

Commission audit staff's review places primary importance on internal controls found in the Institute of Internal Auditors' *Standards for the Professional Practice of Internal Auditing* and in the *Internal Control - Integrated Framework* developed by the Committee of Sponsoring Organizations of the Treadway Commission. The framework states that an internal control should consist of five interrelated components:

- Control environment
- Risk assessment
- Control activities
- Information and communication
- Monitoring

To maximize operational effectiveness and efficiency, reliability of financial reporting, and compliance with applicable laws and regulations, all five components must be present and functioning to conclude that internal controls are effective.

1.2.3 Methodology

Initial planning, research, and data collection for this review occurred during January 2015. Additional data collection, analysis, and report writing were conducted in January through May 2015. The information compiled in this report was gathered via company responses to audit staff

document requests, onsite visits to the Crystal River Energy Complex and the DEF St. Petersburg office, and interviews with key project personnel. Audit staff also reviewed testimony, discovery, and other filings in Docket No. 150009-EI. A large volume of information was collected and analyzed by audit staff. Specific information collected from DEF included the following categories:

- Policies and procedures
- Organizational structures
- Contract requests for proposal
- Contractor bids
- Bid evaluation analyses
- Contracts
- Change orders
- Internal audit reports and quality assessment reviews

1.3 Audit Staff Observations

1.3.1 Levy Nuclear Plant

The company continues its legal dispute with Westinghouse over the cancelation of the EPC contract for the Levy plants. This has limited DEF's abilities when working to disposition the Long Lead Equipment (LLE) secured under the EPC contract. During 2014, the company worked with Westinghouse to resolve, discontinue, terminate, or sell the assets purchased through third-party vendors. Presently, the dispositions of all LLE assets, with the exception of the VFD's, were either resolved or being addressed through the EPC cancelation litigation. The remaining open item is noted in section 2.2.

It is difficult to assess the overall approach of DEF's disposition choices due to the legal issues with Westinghouse. In each case, the company was reliant on Westinghouse to be the intermediary for the dispositioning, and all the items were part of the overall contract in dispute. Prior to the cancelation of the EPC, the company made the decision to halt manufacturing of several components at its current milestone payments and negotiate a settlement for the remaining fees. In these cases the company justified its decisions through proper documentation.

The company is still working to obtain the Combined Operating License from the NRC. The application timeline has slipped due to several NRC design concerns for the AP1000. These are issues for Westinghouse to resolve; the Levy application can only be issued once the NRC approves acceptable design modifications.

1.3.2 CR3 Extended Power Uprate

The company moved forward with its planned dispositioning of the eligible CR3 assets in 2014 and 2015. This was performed using Duke Energy's corporate investment recovery guidance procedures. The completion of this effort will allow the company to work with the NRC on the decommissioning plan.

The company dispositioned CR3 equipment via internal transfers, listed bid events, and a public auction. This was in accordance with the latitude given to the recovery team through the

investment recovery guidance procedures. After considering all internal transfers, the company's disposition approach evolved, starting with a listed bid approach and shifting to a public auction. Under the listed bid process, the company listed assets for a designated timeframe, allowing bids to be submitted, considered, and accepted. After evaluation, management made the decision in second quarter 2014 to shift to a public auction approach. The public auction approach allowed the company to divest the majority of remaining assets through a one time, publicized event. Factors considered for this decision included the time, resources, and costs needed to continue with the list bid approach.

The company states that both approaches yielded the same result—the ability to disposition EPU-related assets at the current market value. The company believes that it received the appropriate market value for each asset sold. An overriding consideration is the understanding that, while many nuclear plants contain similar components, the equipment in question is often designed to specification for the intended generating unit. As such, many of the high-valued assets were only marketable at salvage-value.

The company does not believe that either approach lent itself to a more advantageous outcome. Given the differences in various assets, Commission audit staff notes that it is difficult to assess whether one approach was more successful in terms of maximizing the sale price. For both approaches, marketing the assets to the appropriate buyers was a key focus. Commission audit staff believes that DEF made appropriate efforts to identify and market its assets to a wide range of potential buyers under each approach. Commission audit staff believes both approaches were reasonable and allowable under the company's written procedures.

The company is still working to disposition components of the high and low pressure turbines purchased for the EPU. The company anticipates completing the negotiations for possible sale [redacted] by the end of summer. Audit staff notes that the company continues to incur administrative and maintenance costs for this equipment adding to a need for swift action.

2.0 Levy Nuclear Project

Duke Energy Florida Inc.'s (DEF) decided in July 2013 to cancel the construction schedule for the Levy Nuclear project, while still continuing to seek the Combined Operating License (COL) from the Nuclear Regulatory Commission (NRC.) The Florida Public Service Commission (Commission) approved a settlement in Docket No. 130208-EI allowing DEF to implement this plan.

2.1 EPC Cancelation Progress

Since January 2014, DEF has conducted negotiations with Westinghouse to close-out its Engineering, Procurement, and Construction (EPC) contract. The two companies have not been able to resolve the terms of this cancelation, and are seeking legal resolution. Both companies have filed separate lawsuits in this matter, each asking for financial compensation. DEF is seeking a $54 million Long Lead Equipment (LLE) refund and Westinghouse is seeking $512 million for termination fee and termination costs. The current federal court schedule is detailed in **Exhibit 1**.

Duke Energy Florida – Westinghouse Contract Litigation Trial Schedule Duke Energy	
Action	**Date**
Discovery Completion	August 2015
Expert Reports	June-July 2015
Mediation	August 2015
Dispositive Motions	September 2015
Trial	February 2016

Exhibit 1 *Source: Data Request 1.19*

Until the case is resolved, DEF management states it is not at liberty to discuss the pending litigation issues. Due to potential harm to the overall resolution, the company has provided details leading up to the lawsuit, and described how the company has worked to resolve issues outside of the specific EPC-related concerns.

The company states the litigation has not halted its efforts towards finalizing its COL application. DEF is reliant on Westinghouse for critical engineering data to proceed with its COL application. Currently, Westinghouse continues to provide DEF with the necessary critical information to assist in pursuing the operating license. DEF management agrees that it is in the best interest of both companies to complete and receive the Levy COL. This topic is further discussed in section 2.3.

2.2 Asset Disposition

The company developed a disposition plan for handling the LLE initiated through the EPC contract. The plan focuses on minimizing the costs and other risks to the company. The Levy management team considered two options when looking at the status of this equipment: disposal or storage. After review and evaluation, management made the decision to dispose of all LLE items under the EPC contract. The approved plan required the team to consider the following options when handling the LLE:

- Reuse the equipment at another Duke Energy plant
- Sell equipment for salvage/scrap value
- Sell equipment to another AP1000 owner group
- Sell equipment to a Westinghouse sub-contractor.

Exhibit 2 shows the company's decision for the LLE contracts.

Duke Energy Florida
Levy Nuclear Project
Long Lead Equipment Disposition

Contractor/ Equipment	Disposition Date	Original Cost	Paid	Settled Cost	Disposition Decision
Mangiarotti- various equipment components in grouping	11/7/2013			[redacted]	[redacted]
Tioga-Cooling Loop Piping	1/09/2014	[redacted]	[redacted]	[redacted]	[redacted]
Doosan-Steam Generators	11/18/2014	[redacted]	[redacted]		[redacted]
Doosan-Reactor Vessel	11/18/2014	[redacted]	[redacted]		[redacted]
Toshiba-Turbine/Generator	N/A	[redacted]	[redacted]		[redacted]
Siemens-Variable Frequency Drives	Pending	[redacted]	[redacted]		[redacted]
SPX-Squib Valves	12/10/2014	[redacted]	[redacted]	[redacted]	[redacted]
EMD-reactor coolant pumps	11/18/2014	[redacted]	[redacted]		[redacted]
Total		[redacted]	[redacted]	[redacted]	

Exhibit 2 *Source: Data Request 1.22*

Considering these options, during 2014, the company worked with Westinghouse to negotiate the disposition of remaining long-lead items initiated under the EPC contract. At the time of

cancelation, much of this equipment was in various stages of fabrication. Some equipment was fully constructed and maintained in controlled storage facilities. For these key items in storage—the Variable Frequency Drives (VFDs) and the steam generator tubing--the company was paying fees for maintenance and upkeep.

The company notes it has fulfilled its required milestone payments for the LLE since the initial contract inception. In some cases, the company had met all financial obligations for the equipment and this equipment was maintained in storage facilities until future installation. The company did make the decision to take possession of the VFDs, and is in the process of making a decision for long-term resolution of the equipment.

[redacted]

DEF's approach required the company to consider selling or transferring the LLE assets to other nuclear plant owners or other Duke Energy plants. The company considered the possibility of offering these assets for open auction. It determined that there was neither outside demand nor need among Duke Energy affiliates for this equipment. All future AP1000 owners were contacted. The company evaluated these options from late 2013 through April 2014.

The EPC contract contains provisions that, if exercised, allow DEF to assume and possession of individual LLE contracts. In June 2014, the company requested that Westinghouse provide all vendor/manufacturer contract terms so DEF could consider the option of assuming and taking possession of the remaining LLE equipment. Assuming the subcontract and taking possession of the equipment would allow DEF the opportunity to make the determination on how to disposition an asset directly with the sub-vendor. If DEF management agreed to take over the vendor contracts, the company would also assume all remaining liability and costs. DEF considered each item individually and determined which items to offer to buy out without taking possession, purchase directly and take possession, or leave to be resolved through the legal resolution of the contract. These options were evaluated for all remaining LLE contracts. A settlement was reached on the following contracts:

- Mangiarotti equipment (Accumulator tank, PRHR heat exchanger, pressurizer, core makeup tank)
- Tioga-reactor coolant loop piping
- SPX-squib valves

After discussions with DEF, [redacted] To address these concerns, DEF management states that the company adjusted its plan to offer the equipment under an initial general interest listed-bid event in June 2014. This event

was designed to share limited information about each specific asset to potential buyers to give DEF an indication of interest in the equipment.

[redacted] The items were listed in a way to let potential bidders know that a follow-up event would occur with more specific details on the equipment for the interested parties. In the end, [redacted], eliminating the opportunity to complete the auction process.

The company resolved the disposition of the Mangiarotti Equipment and Tioga-reactor cooling looping piping prior to EPC cancelation through settlement arrangements with Westinghouse and the sub-vendors. For these items, DEF management determined it was best to discontinue the manufacturing process, and agreed upon an amount to be paid for already-incurred time and material costs. In total, the company paid approximately [redacted] to resolve these items. After review of company documents, Commission audit staff determined that, given the highly specialized nature of this equipment, the company's approach and decisions were reasonable.

Management made the decision under the EPC contract to assume the SPX-Squib valves. According to DEF, Westinghouse expressed an interest in purchasing this equipment, but the companies could not agree on a contract price. DEF states that in September of 2014, [redacted]

[redacted] No sale was accomplished and company management decided to take possession of the equipment. At this point, DEF had paid approximately [redacted] in milestone payments for this equipment. In the end, the company settled with the manufacturer, allowing DEF to recover approximately [redacted]. The company believes that the selling back to the manufacturer was the appropriate decision given the limited number of potential buyers.

2.3 NRC Licensing

Under the Commission-approved settlement in Docket No. 130208-EI, DEF agreed to continue its efforts to obtain the Levy Combined Operating License. Though related costs are not included within the NCRC docket, the ability for the project to be completed at a future point in time is contingent upon the issuance of the COL.

Currently, at the NRC, the Levy COL application is the lead for in-process AP1000 COL applications. The NRC is using the Levy application for documenting all pending engineering modifications. The NRC has several open engineering design issues for the AP1000, and the Levy final approval schedule is contingent upon the resolution of these open items. The ongoing condensate return issue is the most impactful open design issue. A follow-up meeting with the NRC on the condensate return issue is scheduled for September 2015.

DEF management does not believe COL issuance will be impacted by these design issues. The company states that Westinghouse and the AP1000 Owner's Group (APOG) have been working with each other and the NRC to effectively resolve all outstanding issues. DEF management states that the company believes the current issues will be resolved by the proposed changes to the Levy COL application. The specific design issues in question include:

- Condensate Return
- Main Control Room Dose Calculations
- Hydrogen Vent
- Main Control Room Heat Load

The company continues to work with the U.S. Army Corp of Engineers to finalize the wetland mitigation plan, which is necessary for final 404/10 Permit approval. **Exhibit 3** details events leading to the anticipated COL issue date of May 2016. However, the remaining dates are contingent on Westinghouse resolving open design issues for the AP1000. Currently, the NRC is requiring additional engineering design modifications. The NRC will not move forward on COLA approval until these design issues are resolved. Therefore, the remaining schedule dates are fluid, and most likely will shift.

Levy Nuclear Project NRC COLA Review Schedule	
Environmental Review	**Status**
Phase 1 – Environmental Impact Statement (EIS) scoping summary report issued	Completed- May 2009
Phase 2 – Draft EIS issued to the Environmental Protection Agency (EPA)	Completed - August 2010
Phase 3 – Responses to public comments on draft EIS completed	Completed – April 2012
Phase 4 – Final EIS issued to the EPA	Completed - April 2012
Safety Review	**Status**
Phase A – Requests for Additional Information (RAIs) and Supplemental RAIs	Completed - March 2010
Phase B – Advanced Final Safety Evaluation Report (SER) without Open Items	Completed - September 2011
Phase C – Advisory Committee on Reactor Safeguards (ACRS) Review of Advanced Final SER	Completed – January 2012
ACRS Final Review Complete	Projected—November 2015
Phase D – Final SER	Projected – January 2016
COL Hearing and Approval	**Status**
Formal Hearing	Projected – March 2016
Final Order – COL	Projected –May 2016

Exhibit 3 *Source: DEF Response to Staff Data Request LNP DR 2.1*

DEF does not believe the litigation issues with the EPC contract will impact its cooperation with Westinghouse in addressing the open engineering issues. Management believes that with the two AP1000 projects under construction in the United States, it is in Westinghouse's best interest to resolve these issues timely. DEF states that it believes that Westinghouse is working on the issues, but that the response timeline has not been as efficient as possible.

2. 4 Levy Construction Close-Out Costs

In 2014, the company states it incurred an estimated [redacted] in wind-down costs for the company's effort to terminate the EPC contract with Westinghouse. The company notes that these costs were required for the following efforts:

- Tioga long-lead equipment resolution
- Final payments for the Stone & Webster work completed under the EPC
- Storage, insurance, and monitoring of the LLE (complete and in current production)
- DEF labor involved with LLE disposition
- Westinghouse support necessary to negotiate LLE resolution
- Regulatory and administrative costs

These actions are required to finalize the termination of the EPC contract. Audit staff reviewed these costs and believes the actions supporting the request were reasonable to minimize total costs and comply with contractual obligations.

3.0 Crystal River 3 Extended Power Uprate Project

During 2014, Duke Energy Florida Inc.'s (DEF) Investment Recovery Project (IRP) team continued the process of disposing of certain assets from the Crystal River Unit 3 (CR3), including remaining assets from the Extended Power Uprate project. Originally, DEF expected to complete the EPU portion of the investment recovery project by December 31, 2014. However, the company is still evaluating the options for its Siemens components including the Low Pressure and High Pressure turbines. The IRP team identified limited opportunities to transfer assets within Duke Energy, and then used listed bid events and a public auction to divest itself of most of the targeted CR3 assets.

In making its decisions on the best course of action for disposition of assets, the IRP team considered feasible approaches to disposition of both the EPU-related and non-EPU related items. There was a much greater volume of non-EPU CR3 components than EPU-related components offered for sale. Therefore, while the EPU assets were a factor, the company's decision considered the dispositioning of all CR3 assets.

3.1 EPU Corporate Investment Recovery Plan Execution

Through this process, the company was able to close out the EPU project. The company was able to disposition the major components purchased for this project. In addition to the major assets purchased for the uprate project, secondary EPU project assets such as tents and tools were also included in the disposition sale.

The organizational structure for the IRP team did not change during 2014. Towards the end of 2014, needed resources declined. For the remainder of 2015, the company has committed two part-time staff members to manage and support the completion of EPU assets disposition. The company is in the process of completing a self-assessment of the IRP process.

The corporate-approved Investment Recovery Plan outlined the approach the IRP team used for the disposition all of CR3 assets. This plan allowed the IRP team the flexibility to implement a program for divesting this equipment in an effective and timely manner. Specific plan components included:

- Organization
- Schedule Management
- Cost Management
- Risk Management
- Reporting

To maximize the overall recovery amount, the IRP team evaluated various approaches to marketing and selling available assets. The company assessed the total inventory of the CR3 unit, developed a listing of these assets and evaluated the marketability of each asset. The plan also required the company to assess any potential use for these assets within Duke Energy.

3.2 Listed Bid Event Approach for Disposition

In the spring of 2014, the IRP team conducted a series of specialized listed bid events for certain EPU assets. The events were online offerings that advertised equipment to targeted potential electric industry buyers. These included resources such as industry websites and industry publications. Offers were handled through a closed bid process. The items and events were offered throughout the industry via targeted marketing and industry-focused websites. Marketing included print advertisements in trade publications, and on industry websites.

The IRP team managed these events with coordination from Duke Energy Corporate Procurement. Concurrently, the IRP group hosted similar bid events for non-EPU CR3 assets. As shown on **Exhibit 4,** the company hosted 11 EPU-related bid events yielding sales revenues of $1,032,418. For the EPU assets, the company finalized four bid events during March 2014, four during April 2014, and three during May 2014. Lot groupings included EPU-related items such as storage equipment, cooling tower components, construction tools, and motors.

Company Initiated Listed Bid Events
CR3 EPU Assets
2014

Asset	Cost	Sale Amount	Month Sold
Tent, Lighting, Structural Members	[redacted]	[redacted]	March 2014
3500 HP Motors—(3) Lube Oil Skids—(2)	[redacted]	[redacted]	March 2014
Tent with tools and materials	[redacted]	[redacted]	March 2014
Fire Cabinets—(8)	[redacted]	[redacted]	March 2014
Gantry Crane	[redacted]	[redacted]	April 2014
Cooling Tower (all)	[redacted]	[redacted]	April 2014
Sealand-(1)	[redacted]	[redacted]	April 2014
Sealand-(4)	[redacted]	[redacted]	April 2014
Relief Valves	[redacted]	[redacted]	May 2014
Relief Valves	[redacted]	[redacted]	May 2014
AKPD 5 stage Pumps—(34)	[redacted]	[redacted]	May 2014
Total	**$15,341,111**	**$1,032,418**	**11 Bid Events**

Exhibit 4 *Source: Data Request 1.5*

IRP management states that leading up to these bid events, the team organized and grouped items for maximum bid interest and value. Management stated that when determining the order of items to list, the company considered the logistics of how and where the assets were housed on the site. This approach allowed the company to move larger items off-site first and free-up space on the site.

One large asset sold through this process was the Cooling Tower equipment. The company received several bids for this equipment, and accepted the highest bid for the entire lot. This equipment was one of the largest assets sold, and a portion of the proceeds were credited back through the NCRC.

Prior to initiating the listed bid events, the IRP team provided a listing of assets for internal distribution within Duke Energy. The IRP team was able to transfer four assets within the company using this process. The sale and proceeds comported with the requirement to transfer the assets at book value, as shown in **Exhibit 5** which details these transactions.

Transfers to Duke Energy Affiliates CR3 EPU Assets 2014			
Asset	**Cost**	**Sale Amount**	**Month Sold**
Blade Vibration Sensor and Sensor Adapter	[redacted]	[redacted]	February 2014
Sealand—two	[redacted]	[redacted]	April 2014
Gang Boxes—(2) Fire Safe Chest Carts—(5) Various tools	[redacted]	[redacted]	April 2014
Gang Boxes—(4) Carts—(4) Various tools	[redacted]	[redacted]	April 2014
Total	**$36,336**	**$35,972**	**4 Events**

Exhibit 5 *Source: Data Request 1.5*

3.3 Public Auction Approach for Disposition

In mid-2014, the company made the decision to shift its approach from a listed bid event process to a public auction for the remaining EPU and non-EPU assets. Management states its rationale for this decision was the challenge and cost of working the high volume of equipment through the bid event process. Management states that substantial additional resources would be needed to fully process all the equipment through the listed bid event approach. The company believed that the additional costs for hiring resources for this disposal method would negatively impact any additional revenue obtained through this approach.

In March 2014, Southern California Edison conducted a public auction of its non-nuclear assets from its San Onofre Nuclear Generating Station. DEF sent representatives to this event to assess its success and determine whether this approach would be a viable option for its remaining CR3 assets. After reviewing the process and discussions with Southern California Edison, DEF believed this approach was viable, and that the event garnered enough public interest to support the effort. The IRP team made a proposal that the company use the one-time, public auction approach for the remaining assets. This recommendation was presented and approved by senior management. Commission audit staff believes the decision to shift from a listed bid event approach to a public auction was reasonable.

The company issued a Request for Proposals to twelve large and small auction groups. Proposals were received from five auction companies and two finalists were brought in for on-site presentations. Management states the company chose to limit the number of potential vendors due to the specialized nature of conducting a large-scale industrial auction. DEF states that these

auction companies had experience in large-industrial based auctions, and demonstrated successful marketing to buyers interested in industrial equipment. The contract executed with the selected vendor specified the auction approach and the budget. According to DEF, compensation for expenses and commissions were in keeping with standard investment recovery practices.

A factor in selecting the chosen vendor was its global marketing presence. One asset—the EPU-related Low Pressure turbines—was potentially the highest value sale opportunity, and DEF believed that there was potential for a sale to an overseas company. The selected vendor proposed and used a mix of printed advertising in both industry publications and flyers at industry conferences, targeted calls to potential buyers, social media to industry groups, and general advertising to the public and non-industry bidders such as salvage dealers. DEF believes that this marketing effort reached a global 100,000 potential bidders. Commission audit staff believes the company's justifications for selecting this vendor were reasonable.

The auction was held September 24 through 26, 2014, with bids accepted via the Internet and phone. The auction was a sell-all event with no price reserves on lots. DEF reserved the right to reject the final bid only if the company believed that the sale price was below the cost of removal from the unit or site.

In total, the auction included 100 bidders, and the company sold 50 lots/groupings of EPU-assets. The total collected for these items was approximately $90,500. The original cost for these assets was approximately $5,229,212, not including the original cost for the NUS Rapid Cool Down System equipment which was not broken out separately in its contract.

Several large installed items offered did not sell through the closed-bid or public auction process. For this equipment, the company made the decision in January 2015 to discontinue sales efforts and to abandon in-place during decommissioning. This equipment is highly-specialized with limited marketability and the salvage value would not support the cost for removal. These assets and their original value are shown in **Exhibit 6**.

Major Installed EPU-Assets to be Abandoned In Place

Equipment	Value
Stator Core and Rewound Generator Rotor	[redacted]
Feedwater Heat Exchangers	
Belly Drain Heat Exchangers	
Isophase Bus Duct Cooling Skid	
Moisture Separator Reheaters	

Exhibit 6 *Source: Data Request 3.1*

3.4 EPU Siemens Components Disposition

Certain Siemens componets did not sell during the auction. These are one-of-a-kind specialized components with limited marketability. In one case, [redacted] The details of this were

discussed in the Commission audit report in the Docket No. 120009-EI. [redacted] DEF made the decision to list the equipment in the auction, in hopes of selling the entire component set.

[redacted] The equipment and components [redacted] are shown in **Exhibit 7** and are currently installed or housed in the CR3 unit.

Remaining EPU-Equipment Considered for Disposition	
Components	**Original Equipment Cost**
High Pressure Turbine and Equipment (uninstalled)	[redacted]
Turbine Lubricating Oil Cooler Tube Bundles	[redacted]
Siemens Exciter (installed)	[redacted]
Siemens Hydrogen Cooler (installed)[1]	[redacted]
Siemens Low Pressure Turbine Rotors, Blades, Cylinders, and parts (uninstalled)	[redacted]

Exhibit 7 *Source: Data Request 3.2*

[redacted]

The company is in the process of closing out its Investment Recovery Program for CR3. The company will continue to maintain the remaining Siemens equipment [redacted]. The company will continue to maintain monthly maintenance and administrative costs for the EPU project. The company believes the project will be closed in fall 2015, with costs continuing through that time.

[1] The cost provided for the Hydrogen Cooler is a subset of the overall Generator work. The company estimated the amount attributed for this equipment.

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DEF's Responses to Staff's First Set of Interrogatories (Nos. 1-11)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 69
PARTY: STAFF RE: DUKE ENERGY FLORIDA (DEF)
DESCRIPTION: Mark TeagueThomas G.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear cost recovery clause.	DOCKET NO. 150009-EI
	DATED: June 8, 2015

DUKE ENERGY FLORIDA, INC.'S RESPONSES TO STAFF'S FIRST SET OF INTERROGATORIES NOS. (1-11)

Duke Energy Florida, Inc. ("DEF") responds to Staff's First Set of Interrogatories (Nos. 1-11), as follows:

INTERROGATORIES

1. CR3 EPU Project: Witness Teague, at pages 4 and 5 of the May 1, 2015 testimony, discusses the Company's determination that it was (or may be) cost effective to abandon certain equipment in place and salvage the equipment through the general decommissioning process of Crystal River Unit 3. Beginning on page 11, witness Teague explains that in March of 2015 the Company established a decommissioning transition organization and approved the "CR3 Investment Recovery Closeout and Long-Term SAFETOR Asset Recovery Plan."

   a. Please explain how, if at all, the Company plans to transfer the affected EPU plant balance to the decommissioning process.

RESPONSE:

The EPU plant balance is handled separately through the NCRC. The Company does not plan to transfer the affected EPU plant balance to the decommissioning process. The cost to decommission/dismantle any EPU assets that were not sold, transferred or salvaged will be paid from the trust.

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b. Please explain how, if at all, any of the Company's CR3 EPU unrecovered investment balance is affected by the Company's March 2015 decisions regarding non-CR3 EPU assets.

RESPONSE:

The Company's CR3 EPU unrecovered investment balance is not affected by the Company's March 2015 decisions regarding non-CR3 EPU assets.

c. Please explain how, if at all, the Company's collection of CR3 EPU unrecovered investment balance is affected by the Company's March 2015 decisions regarding non-CR3 EPU assets.

RESPONSE:

The Company's collection of CR3 EPU unrecovered investment balance is not affected by the Company's March 2015 decisions regarding non-CR3 EPU assets.

2. CR3 EPU Project Net 2014 True-up: Witness Foster's March 1, 2015 Exhibit TGF-2, page 3 of 12 identifies a true-up amount for 2014 of ($1,070,629). Witness Foster's May 1, 2015 Exhibit TGF-4, page 4 identifies an estimated true-up amount for 2015 of ($857,612). The sum of these true-up amounts totals ($1,928,241). However, on page 3 of Witness Foster's May 1, 2015 Exhibit TGF-4 the true-up amounts for prior periods is shown as ($2,075,578). Please explain why there is a difference in these representations of the total true-up amounts and identify the components that result in the difference.

RESPONSE:

The $2,075,578 over recovery shown in Exhibit TGF-4 of the May 1, 2015 filing is the correct amount of the projected 2016 beginning balance over recovered position. The $1,928,241 identified in the question is the sum of the 2014 and 2015 period over/under recovery, but leaves out the impact of prior period true-ups. A discussion of where this can be seen follows:

The $1,070,629 amount identified on line 24 in Witness Foster's March 1, 2015 Exhibit TGF-2 is the current period over-recovered amount for 2014 and is exclusive of the remaining unamortized ending balance of the over/under recovery from prior periods. The net unamortized amount of the prior period in 2014 is a $524,698 over recovery. The total net over-recovered position for DEF at year-end 2014 is $1,595,326 and can be seen by summing the ending balances of lines 3e, 12 and 24. This balance is appropriately carried forward in Witness Foster's May 1, 2015 Exhibit TGF-4, page 4 in the 2015 beginning balances of line 3e and line 12. This amount is amortized in 2015 by the over/under amount projected for 2015 shown in lines 3f and 13 leaving a year end prior period over recovery of $1,217,966.

The $857,612 amount identified is the current period over-recovered estimated true-up amount for 2015. On page 3 of Witness Foster's May 1, 2015 Exhibit TGF-4 the true-up amounts for prior periods shows $2,075,578 as the prior period over recovery for the purpose of calculating the 2016 revenue requirement. The sum of $857,612 (2015 current period estimated over recovery) and $1,217,966 (2015 unamortized prior period over recovery) is $2,075,578.

3. CR3 EPU Project Net 2014 True-up: Witness Foster's May 1, 2014 Exhibit TGF-5, page 4 of 16 filed in Docket No. 140009-EI, supports an estimated $155,210 variance for collection during 2015. Please describe how the $155,210 is adjusted from Duke's current calculation of its final over/under recovery true-up calculations and provide citations to where the adjustment(s) is(are) recognized in the Company's schedules. If the amount is not adjusted from the Company's petition, please explain why.

RESPONSE:

The $155,210 is the correct amount of the current period under-recovered estimated true-up amount for 2014, and can be seen as part of the amounts of DEF's current calculations, broken-out below. The unamortized amount of the prior period was an over-recovery of $437,905 in 2014. The total net over-recovered position for DEF at year-end 2014 presented was $282,695.

The total amount being amortized in 2015 is an over-recovery of $369,487 and can be seen in Witness Foster's May 1, 2015 Exhibit TGF-4, page 4 in the beginning balances of lines 3f, 13, and 19. The $369,487 was also presented in Witness Foster's May 1, 2014 Exhibit TGF-5, page 5 of 16 filed in Docket No. 140009-EI and can be seen by summing lines 3f, 11, and 15. There were a few adjustments presented in Docket No. 140009-EI that explain the $86,792 difference between the 2014 ending balance of $282,695 and the 2015 beginning balance shown as $369,487; the adjustments are identified in Docket No. 140009-EI Appendix A (page 7) in TGF-5 filed May 1, 2014 and on page 18 in Witness Foster's May 1, 2014 Testimony.

Figures below represent the true-up amounts, and their respective components including adjustments

2014 Estimated / Actual Net of Recoveries and Collections

- **($282,695) ((Presented in May 1, 2014 – (TGF-5) on page 4 line 3e, 8,12 & 18)**
  - ($437,905) (prior period over-recovery : 2013)
    - ($213,124) **Line 3e**
    - ($224,782) **Line 12**
  - $155,210 (current period over-recovery : 2014)
    - $337,785 **Line 8**
    - ($182,574) **Line 18**

- **($369,487) ((Presented in May 1, 2014 – (TGF-5) on page 3, 2015 Rev Requirement Summary))**

- $29,497 Line 3f **(Presented in May 1, 2014 – (TGF-5) on page 5)**
  - ($213,124) cited above
  - $337,785 cited above
  - ($87,291) Period-end Adjustment (cited on Page 7 TGF-5 Filed May 1, 2014)
  - ($7,873) Period-end Adjustment (cited on Page 7 TGF-5 Filed May 1, 2014)

- ($406,857) Line 11 **(Presented in May 1, 2014 – (TGF-5) on page 5)**
  - ($182,574) cited above
  - ($224,782) cited above
  - $499 Period-end Adjustment (cited on Page 7 TGF-5 Filed May 1, 2014)

- $7,783 Line 15 **(Presented in May 1, 2014 – (TGF-5) on page 5)**
  Period-end Adjustment (cited on Page 7 TGF-5 Filed May 1, 2014)

- ($369,487) **(Presented in May 1, 2015 – (TGF-4) on page 4)**
  - $29,497 Line 3f cited above
  - ($406,857) Line 13 cited above
  - $7,783 Line 19 cited above

4. Levy Project Net 2014 True-up: Witness Foster's May 1, 2014 Exhibit TGF-4, page 4 of 15 filed in Docket No. 140009-EI, supports an estimated $7,999,738 variance for collection during 2015. Please describe how the $7,999,738 is adjusted from Duke's current calculation of its final over/under recovery true-up calculations and provide citations to where the adjustment(s) is (are) recognized in the Company's schedules. If the amount is not adjusted from the Company's petition, please explain why.

RESPONSE:

The amounts included in Exhibit TGF-4 of Witness Foster's May 1, 2014 testimony supported the finding in Commission Order No. PSC-14-0617-FOF-EI, which found that for Levy, the Commission should approve an amount that reflects the fixed monthly rates for the different rate classes as contained within the 2013 Settlement Agreement. The estimated amount shown in Docket No. 140009 was ~$104 million. In the Capacity Docket, DEF applied these rates to develop the revenue requirements that were included in capacity rates for 2015. This generated an estimated $106 million. As such, DEF has applied the amounts consistent with the capacity filing rates as revenues collected for Levy from January – April of 2015.

For the above reasons, the total collections for Levy for 2015 were approved to be $105,927,535 and were not the $103,991,141 as originally estimated in Docket No. 140009. DEF's 2015 May 1 filing in Exhibit TGF-3 Appendix A (page 2 of 3), attached to Witness Foster's testimony, presented the breakout of the application of the $105,927,535 and applied the actual amount of the over/under recovered position, not the estimated amount of $7,999,738. This can be seen in Exhibit TGF-3 on lines 6f and 15 on page 4 and on lines 6f and 13 on page 10. Exhibit TGF-3 page 9, Appendix A (page 1 of 3), shows the components of these lines: ($11,381,632) and ($179,385), respectively. In this manner, DEF has appropriately reflected the approved revenues for 2015 in its 2015 filings.

5. Levy Project 2015-2016 Scenarios: Witness Foster, beginning on page 14 of the May 1, 2015 testimony, discusses an estimate of 2016 revenue requirements supported by the calculations shown in Exhibit TGF-3. For purposes of this question, please provide the response for each requested scenario in the same format as redacted pages 3, 4, 5 and 8 of TGF-3 of witness Foster's May 2015 testimony.

a. Scenario A: Pages 3, 4, 5, and 8 of TGF-3 are revised as necessary to show the effects of assuming no revenue collection during 2016.

RESPONSE:

See attached Excel File (Confidential) bearing Bates numbers 15NC-LEVY-STAFFROG1-5a-000001 through 15NC-LEVY-STAFFROG1-5a-000017 and subject to DEF's Fourth Notice of Intent filed contemporaneously with service of this response.

In its response DEF has presented the calculations as requested, however, this is not what DEF presented in its May 1, 2015 filing for Commission approval nor do these calculations align with what DEF believes is the appropriate method to reflect Levy Nuclear Project revenue requirements for 2016 under Section 366.93(6), F.S.

b. Scenario B: Pages 3, 4, 5, and 8 of TGF-3 are revised as necessary such that the schedule for 2015 (page 4 of TFG-3), at lines 10 and 20 are the same monthly amounts for January through April as those shown in Exhibit TGF-4 attached to witness Foster's May 1, 2014 testimony and filed in the Docket No. 140009-EI. For purposes of Scenario B, also assume revenue collection occurs during calendar year 2016 as necessary and year ending 2016 uncollected investment and O&M balances are zero. Include in your response a listing of the changes to TGF-3 that result in Scenario B.

RESPONSE:

See attached Excel File (Confidential) bearing Bates numbers 15NC-LEVY-STAFFROG1-5b-000001 through 15NC-LEVY-STAFFROG1-5b-000017 and subject to DEF's Fourth Notice of Intent filed contemporaneously with service of this response.

In its response DEF has presented the calculations as requested, however, this is not what DEF presented in its May 1, 2015 filing for Commission approval nor do these calculations align with what DEF believes is the appropriate method to reflect Levy Nuclear Project revenue requirements for 2015 or 2016 under Section 366.93(6), F.S.

DEF has interpreted this request to be asking DEF to reflect collection of revenues in January – April of 2015 consistent with those estimated in Docket No. 140009. DEF does not believe this is appropriate as the Order in Docket No. 140009 approved the rates to be those approved as part of the 2013 Settlement Agreement and later, when DEF presented the NCRC revenues in the Docket No. 140001 filings, updated the revenues to be consistent with the rates approved in the 2013 Settlement Agreement as applied to the sales forecast used to set rates. These are the revenues DEF has used in its 2015 filings. To the extent the Commission finds that the revenues from the 140009 Docket are the ones that should be used, the Commission should also recognize and confirm that the same revenues for true-up purposes must be used in both the NCRC and Capacity Dockets.

This scenario (5b) reflects the treatment of the $54M deferral in the same manner as filed on May 1, 2015, where DEF would continue to accrue the carrying costs on the uncollected investment in 2015 and collect the appropriate amounts in 2016 under F.S. 366.93(6), except as referenced below.

By reflecting the changes to lines 10 and 20 for January through April 2015, DEF would have:

- **(a) Collected $36,320,475 over that period, or $118,465 less than the $36,438,940 (reported in response to question 7b). This new basis would have been based on an annual revenue requirement of approximately $103,991,142, not the $105,927,535 which was the basis of the 2015 revenue requirement reflected in DEF's May 1, 2015 filing (explained in response to question 7).**

- **(b) Increased current period 2015 revenue requirement by $2,286 (which reduces part of the over-recovery in 2016).**

- **(c) Increased current period 2016 revenue requirement by $126,753**
  (1) Decreased the prior period over-recovered amount by $120,751.

  (2) Increase 2016 period carrying cost on unrecovered investment by $6,002.

Reflecting these revenues as collected would drive a variance in the Capacity Cost Recovery Clause over-under from the reported amounts in Docket No. 140001-EI.

c. Scenario C: Pages 3, 4, 5, and 8 of TGF-3 are revised as necessary consistent with Scenario B and further modified to show the effects of assuming no revenue collection during 2016.

RESPONSE:

See attached Excel File (Confidential) bearing Bates numbers 15NC-LEVY-STAFFROG1-5c-000001 through 15NC-LEVY-STAFFROG1-5c-000017 and subject to DEF's Fourth Notice of Intent filed contemporaneously with service of this response.

In its response DEF has presented the calculations as requested, however, this is not what DEF presented in its May 1, 2015 filing for Commission approval nor do these calculations align with what DEF believes is the appropriate method to reflect Levy Nuclear Project revenue requirements under Section 366.93(6), F.S.

6. Please refer to witness Foster's May 1, 2015 Exhibit TGF-3, Appendix A, page 2 of 3. There is a reference to a 2015 "additional amortization of uncollected investment balance" of $113,366,975. Review of witness Foster's Exhibit TGF-4, at pages 5 and 9 of 15 shows a $94,038,554 amount rather than a $113,366,975 amount.

a. Please provide citations to where the $113,366,975 amount was shown in the Company's projections for 2015 filed in docket 140009-EI.

RESPONSE:

The $113,366,975 reflects DEF's application of the revenue requirements approved in Order No. PSC-14-0701-FOF-EI in Docket No. 140009-EI to the estimated sales forecast in the Capacity Docket, Docket No. 140001-EI, resulting in estimated 2015 revenue requirements of $105,927,535. The calculation of this estimated 2015 revenue requirement is described more fully in response to questions 6b and 7. Also, please see Appendix A, page 3 of 3 of Exhibit TGF-3.

b. If the $113,366,975 amount was not explicitly included in the Company's projections for 2015 filed in Docket No. 140009-EI, please explain how, if at all, use of the $113,366,975 amount is the most appropriate method to determine variances between projected and estimated 2015 Levy project costs and revenue requirements.

RESPONSE:

At the time of the May 1, 2014 filings in Docket No. 140009-EI the "additional amortization of uncollected investment balance" was calculated at $94,038,554 based on the estimated 2015 Revenue Requirement of $103,991,141.

As a result of Order No. PSC-14-0701-FOF-EI, issued on December 19, 2014 in Docket No. 140001-EI, the estimated 2015 Revenue Requirement was effectively changed from $103,991,141 to $105,927,535 (explained in response to question 4).

The calculation of the "additional amortization of uncollected investment balance" is a function of the Revenue Requirement. The "additional amortization of uncollected investment balance" was calculated at $113,366,975 based on the estimated 2015 Revenue Requirement of $105,927,535 from Order No. PSC-14-0701-FOF-EI.

7. Please refer to witness Foster's May 1, 2015 Exhibit TGF-3 page 11 of 17. The notation on the schedule states "[t]his schedule is included to support the calculation of the monthly revenue requirement for the months (January 2015-April 2015)." Also on page number 11, there is a representation that the total revenue requirement amount for the 2015 period is $105,927,535.

   a. Review of witness Foster's Exhibit TGF-4, filed in Docket No. 140009-EI, at page 9 of 15, shows a $103,991,141 amount rather than a $105,927,535 amount. Please provide citations to where the $105,927,535 amount was shown in the Company's projections for 2015 filed in Docket No. 140009-EI.

RESPONSE:

Please see DEF's response to question 6b. The estimated revenue requirement for the entire 2015 period of $105,927,535 in Exhibit TGF-3 in Appendix A on page 11 of 17 was not and could not be shown in DEF's projections for 2015 filed in Docket No. 140009-EI. The projected revenue requirement of approximately $104 million included in Exhibit TGF-4 of Witness Foster's May 1, 2014 testimony was estimated based on the fixed monthly rates for the different rate classes contained in the 2013 Settlement Agreement approved by the Commission and the Company's then current sales forecast. The estimation methodology using the fixed monthly rates for the different rate classes in the 2013 Settlement Agreement was approved by the Commission in Order No. PSC-14-0617-FOF-EI. In the Capacity Docket, Docket No. 140001-EI, DEF applied these Commission-approved rates to develop the revenue requirements that were included in capacity rates for 2015 based on the Company's then current sales forecast. This generated an estimated $106 million in revenue requirements. For these reasons, the total Commission-approved revenue requirement collections for Levy for 2015 were $105,927,535, not the $103,991,141 originally estimated revenue requirements for 2015 in Docket No. 140009.

As such, DEF has applied the amounts consistent with the capacity filing rates as revenues collected for Levy from January – April of 2015.

b. On March 2, 2015, Duke Energy Florida, Inc., filed a petition to end the Levy project fixed factors, effective May 2015. Please reconcile implementation of the termination of the collection of revenues from May through December 2015 with the statement in Exhibit TGF-3, at page 11, regarding the level of revenue requirements for 2015 totaling $105,927,535.

RESPONSE:

Please see DEF's response to question 7a above. The $105,927,535 on page 11 of 17 in Exhibit TGF-3 corresponds to line 25 on page 10 in Exhibit TGF-3. The sum of the months January through April 2015 on line 25 shows that DEF had collected $36,438,940 over that period. Consistent with Order No. PSC-15-0176-TRF-EI, DEF ended the collection of the fixed Levy factors as of May 2015 and no amount of the 2015 revenue requirement is being collected in the months May through December 2015.

c. If the $105,927,535 revenue amount was not explicitly included in the Company's projections for 2015 filed in Docket No. 140009-EI, please explain how, if at all, use of the $105,927,535 revenue amount is the most appropriate method to determine variances between projected and estimated 2015 Levy project costs and revenue requirements.

RESPONSE:

Please see DEF's responses to questions 7a and 7b.

8. Please refer to witness Foster's May 1, 2015 Exhibit TGF-3 page numbers 4, 5 and 9 of 17. On page 9, the notation indicates that the uncollected Levy project investment as of year ending 2015 is estimated to be $12,084,506. On page 4, line 6.i, the estimated net investment balance at the end of 2015 is $4,801,486. On page 5, line 6.j the 2016 beginning net investment balance is estimated to be $4,801,486. Please explain why the estimated uncollected Levy project investment, as of year ending 2015, is $12,084,506 while the associated net investment balance at the end of 2015 is $4,801,486.

RESPONSE:

The $12,084,506 represents the remaining unamortized Levy project investment, as of year ending 2015. On page 5, line 6.g the 2016 beginning Prior Period Carrying Charge Unrecovered Balance is estimated to be ($7,283,020), and represents an over-recovery of costs from prior-periods, i.e. Carrying Costs, leaving the net balance at the end of 2015 in the amount of $4,801,486.

9. Please identify all true-up amounts witness Foster includes in the "$4.1 million of prior period net over-recoveries" as stated on page 16 of the May 1, 2015 testimony. Describe in the response whether any of the amounts included in the $4.1 million net over-recovery are reversed in the calculation of the $12,084,506 amount the Company is projecting to amortize in 2016. If so, please explain why the reversal is appropriate.

RESPONSE:

The over-recovery from prior periods in the amount of $4,132,857 is made up of:

- **On page 5, line 6.g the 2016 beginning Prior Period Carrying Charge Unrecovered Balance of ($7,283,020), representing an over-recovered position.**
- **On page 5, line 13 the 2016 beginning Prior Period Unrecovered Balance of ($3,574), representing an over-recovered position.**
- **On page7, line 1.b the 2016 beginning Prior Period Carrying Charge Unrecovered Balance of $3,153,738, representing an under-recovered position.**

The Company is projecting to amortize all of these amounts in 2016 including the $12,084,506 referred to in question 8. As a result, the amounts that comprise the net over-recovery are not "reversals" against the calculation of the $12,084,506.

10. On page 5 of 15, line 5.c of Exhibit TGF-4 filed in the 140009-EI docket, the Company showed projected 2015 jurisdiction amounts of $427,394 for January and $427,394 for February without any additional charges throughout the remainder of 2015. In witness Foster's May 1, 2015 Exhibit TGF-3 page number 4, the 2015 jurisdictional amounts for January and February are $10,416 and $3,461 respectively, and the amounts in the subsequent months result in a total ($61,304).

    a. Please explain the reason, or reasons, for the variance in jurisdictional additions between the two filings.

RESPONSE:

Revising estimates provided in the Projected period to the respective Estimated/Actual period in the following year, necessarily results from the additional information obtained in the time between preparation of the projected period estimates and the actual/estimated period estimates. The 2015 projection (Exhibit TGF-4) filed in Docket No. 140009-EI on May 1, 2014 included costs for non-cash accruals for actual/estimated 2014 wind-down costs. Examples of these costs were (1) storage, insurance, and quality assurance of the completed and partially completed Levy LLE components until disposition; (2) internal Duke Energy labor to assist with disposition of the LLE; (3) estimated costs for external WEC support to gather information from its LLE suppliers and assist with disposition of the LLE; and (4) payment of final invoices for module program development work to close out DEF's relationship with Consortium member S&W under the cancelled EPC Agreement. However, some of these 2014 projected costs were not actually incurred as originally estimated, which negated the need for an accrual to be made in 2014. In Witness Foster's May 1, 2015 Exhibit TGF-3 page 4, the actual 2015 jurisdictional amounts incurred for January and February are $10,416 and $3,461 respectively. Revised estimates were made for project costs from March through December 2015, which also included an estimate of revenues for a sale of LLE that had been made, but proceeds had not yet been received by DEF.

b. Please show how the Company's filing has accounted for the variance between these projected and estimated/actual jurisdictional expenses.

RESPONSE:

The variances for estimated/actual jurisdictional expenses are appropriately reflected in Witness Foster's May 1, 2015 (Exhibit TGF-3) page 4. As more fully described above, the actual investment balances were included as part of the calculation of the revenue requirement to $105,927,535 in witness Foster's May 1, 2015 (Exhibit TGF-3) page 10.

c. If the variance between these projected and estimated/actual jurisdictional expenses is not included in the Company's estimated true-up, please explain why it believes excluding this variance is appropriate.

RESPONSE:

The variances have been explained and the appropriate amounts have been included in the Company's estimated true-up as discussed in response to question 10b above.

11. On page 5 of witness Foster's March 2, 2015 testimony a total under-recovery amount of $6,833,655 is identified as the final true-up applicable to the 2014 period for the Levy project. A $6.1 million (or $6,077,838 pursuant to the referenced schedules) amount is identified as the revenue requirement for the 2015 period inclusive of true-up effects and adjustments on page 11 of witness Foster's May 1, 2015 testimony. On page 14, a $5.5 million (or $5,466,083 pursuant to the referenced schedules) amount is identified as the revenue requirement for the 2016 period. On page 16, a total $13.5 million (or $13,459,542) revenue requirement is requested for recovery. For the Levy project, please state the Company's requested 2014 final true-up amount net of recoveries and collections during 2014 and 2015; estimated true-up amount for 2015 net of recoveries and collection during 2015; and, the projected 2016 amount. Please reconcile these amounts to $13,459,542, and provide citations to the prefiled testimony and exhibits where each of these amounts is identified.

RESPONSE:

The $6,833,654 amount is the actual current period over-recovered True-up amount for 2014 on line 24 in Witness Foster's March 1, 2015 Exhibit TGF-1, and is exclusive of the remaining unamortized ending balance of the Over/Under recovery from prior periods. The net unamortized amount of the Prior Period Over/Under in 2014 is an over-recovery of $4,727,093. The total net over-recovered position for DEF at year-end 2014 is $11,560,747.

The total net over-recovery is captured on Witness Foster's May 1, 2015 Exhibit TGF-4, page 4 in the beginning balances of line 6f and line 15. This amount is amortized over the period January through April 2015 (see response to question 4 above); leaving an over-recovery from the prior period (2014) of $7,707,165 to be refunded in 2016. The estimated under-recovered true-up amount for 2015 net of recoveries and collection during 2015 is $3,574,308; and, the 2016 projected revenue requirement (exclusive of prior period true-up activity) of $17,592,399. To sum up $13,459,542 = ($7,707,165) + $3,574,308 + $17,592,399.

Figures below represent the true-up amounts, their respective components, and revenue requirements

DEF's requested 2014 final true-up amount net of recoveries and collections during 2014 is an over-recovery of $11,560,747:

2014 Final True-up Net of Recoveries and Collections During 2014

- ($11,560,747) **((Presented in March 2, 2015 – True-up Schedule (TGF-1) on page 4))**
  - ($4,727,093) (Prior Period Over-Recovery : 2013)
    - A. ($4,647,273) **Line 6f**
    - B. ($79,819) **Line 15**
  - ($6,833,654)(Current Period Over-Recovery : 2014) **March 2, 2015 Testimony (Page 5)**
    - C. ($6,734,088) **Line 11**
    - D. ($99,566) **Line 21**

- ($11,560,747) **((Presented in May 1, 2015 – Exhibit (TGF-3) on page 4))**
  - ($11,381,362) **Line 6f**
    - ($4,647,273) cited above (A.)
    - ($6,734,088) cited above (C.)
  - ($179,385) **Line 15**
    - ($79,819) cited above (B.)
    - ($99,566) cited above (D.)

2014 Final True-up Net of Recoveries and Collections During 2015 –
((Presented in May 1, 2015 Exhibit (TGF-3) on page 4))

- ($7,707,165)
  - ($7,578,574) **Line 6f (end of period)**
    - ($11,381,362) **Line 6f (beginning of period)** cited above
    - $3,793,787 **Line 6g (sum of January through April 2015 recovery)**
  - $119,590 **Line 15 (end of period)**
    - ($179,385) **Line 15 (beginning of period)** cited above
    - $59,795 **Line 15 (sum of January through April 2015 recovery)**

2015 Estimated True-up Net of Recoveries and Collections During 2015
((Presented in May 1, 2015 Exhibit (TGF-3) on page 4 & 6))

- $3,574,380
  - $420,570
    - $304,554 **Line 11 (end of period- page 4)**
    - $116,016 **Line 21 (end of period - page 4)**
  - $3,153,738 **Line 21 (end of period - page 6)**

2016 Projected Amount
((Presented in May 1, 2015 Exhibit (TGF-3) on page 5 & 7))
((Presented in May 1, 2015 Testimony –Foster on page 14 & 16))

- $17,592,399 (2016 Revenue Requirement, exclusive of prior-Period true-ups)
  - $440,515
    - $218,252 May 1, 2015 Testimony page 14 **Line 9 (end of period- page 5)**
    - $159,263 May 1, 2015 Testimony page 14 **Line 18 (end of period- page 5)**
  - $5,067,378 May 1, 2015 Testimony page 14 **Line 7 (end of period- page 7)**
  - $12,084,506 May 1, 2015 Testimony page 16 **Line 7 (end of period- page 5)**

Reconcile these amounts to $13,459,542:
Total 2016 Revenue Requirement, including prior-Period true-ups.

- $13,459,542 **May 1, 2015 Testimony-Foster page 16 & May 1, 2015 Exhibit (TGF-3) on page 3**
  - ($7,707,165) cited above
  - $3,574,380 cited above
  - $17,592,399 cited above

AFFIDAVIT

STATE OF NORTH CAROLINA)

COUNTY OF MECKLENBURG)

I hereby certify that on this 5th day of June, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared MARK R. TEAGUE, who is personally known to me, and he acknowledged before me that he provided the responses to interrogatory number(s) 1.a., 1.b., and 1.c. from STAFF'S FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 1 - 11) in Docket No. 150009-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 5th day of June, 2015.

Mark R. Teague

Lisa S. Moore

Notary Public
State of North Carolina

My Commission Expires:
04-13-2019

LISA S. MOORE NOTARY PUBLIC GASTON COUNTY, NC

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 11th day of June, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared THOMAS G. FOSTER, who is personally known to me, and he acknowledged before me that he provided the response to interrogatory numbers 2 through 11 from STAFF'S FIRST INTERROGATORIES NOS. 1 – 11 TO DUKE ENERGY FLORIDA, INC. in Docket No. 150009-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 11 day of June, 2015.

Thomas G. Foster

Notary Public
State of Florida, at Large

Sarah Hirschman Libes
NOTARY PUBLIC
STATE OF FLORIDA
Comm# FF106231
Expires 3/23/2018

My Commission Expires:
3/23/2018

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DEF's Responses to Staff's Second Set of Interrogatories (No. 12)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 70
PARTY: STAFF RE: DUKE ENERGY FLORIDA (DEF)
DESCRIPTION: Thomas G. Foster

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear cost recovery clause.	DOCKET NO. 150009-EI
	DATED: July 2, 2015

DUKE ENERGY FLORIDA, INC.'S RESPONSES TO STAFF'S SECOND SET OF INTERROGATORIES (NO. 12)

Duke Energy Florida, Inc. ("DEF") responds to Staff's Second Set of Interrogatories (No. 12), as follows:

INTERROGATORIES

12. Is the following table an accurate representation of DEF's request for 2016 recovery of Levy Project costs and DEF's response to Staff's Interrogatory Question 5(a) concerning the impacts of not having 2016 factors set to recover DEF's Levy Project costs? If not, please provide a corrected table and explain each correction.

Impact on DEF's Requested Levy Project 2016 Amounts if Recovery is Deferred			
	"As Filed" 2016 Recovery	Deferred Recovery	2016 Impact
	(A)	(B)	(C)
Unrecovered Balance	$12,084,506	12,084,506	-
2016 Carrying Cost on Unrecovered Balance and True up amount	$ 234,809	493,169	258,360
2016 Carrying Cost on Mid-Course Adjustment	5,067,378	5,461,817	394,439
2016 Exit Costs	46,443	46,443	-
2016 Other Exit / Wind-Down Costs (including interest)	159,263	159,262	(1)
Prior period True up Amount (excluding carrying costs)	(7,283,020)	(7,283,020)	-
Prior period True up Amount (excluding interest)	(3,574)	(3,574)	-
2015 Carrying Cost on Mid-Course Adjustment	3,153,738	3,153,738	-
Total 2016 Revenue Requirement	$13,459,542	14,112,340	652,798
Estimated 1000 KWH residential bill Impact	$ 0.42	0.00	
Notes:			
2016 Year Ending Unrecovered Balance includes effects of the 2015 Mid-Course Adjustment			
(A) Source: Exhibit TGF-3			
(B) Source: DEF's response to Staff Interrogatory 5(a)			
(C) Column (B) - Column (A)			

RESPONSE:

Please see updated chart and narrative provided below:

Impact on DEF's Requested Levy Project 2016 Amounts if Recovery is Deferred			
	"As Filed" 2016 Recovery	Deferred Recovery	Impact
	(A)	(B)	(C)
Unrecovered Balance	$12,084,506	12,084,506	-
2016 Carrying Cost on Unrecovered Balance and True up amount	234,809	493,169	258,360
2016 Carrying Cost on Mid-Course Adjustment	5,067,378	5,461,817	394,439
2016 Exit Costs	46,443	46,443	-
2016 Other Exit / Wind-Down Costs (including interest)	159,263	159,262	(1)
Prior period True up Amount (excluding carrying costs)	(7,283,020)	(7,283,020)	-
Prior period True up Amount (excluding interest)	(3,574)	(3,574)	-
2015 Carrying Cost on Mid-Course Adjustment	3,153,738	3,153,738	-
Additional Revenue Requirements Resulting From Deferral	-	-	652,798
Total 2016 Revenue Requirement	$13,459,542	$0	($13,459,542)
Estimated 1000 KWH residential bill Impact	$ 0.42	$ 0.00	($0.42)
2016 Ending Balance of Unrecovered Investment Resulting from Deferred Recovery (Excluding $54M involved in WEC litigation)	$0	$14,112,340	$14,112,340
Notes:			
2016 Year Ending Unrecovered Balance includes effects of the 2015 Mid-Course Adjustment			
Source: Exhibit TGF-3			
(C) Source: DEF's response to Staff Interrogatory 5(a)			
(D) (C) Column (B) - Column (A)			
All amounts shown assume deferred collection of $54M			

DEF agrees that the figures shown in columns (A) and (B) accurately reflect the amounts provided in its original May 1, 2015 Filing and subsequent response to Staff's First Set of Interrogatories question 5(a) hypothetical 'Deferred Recovery' scenario. The calculations in column (B) do not align with what DEF believes is the appropriate method to reflect Levy Nuclear Project revenue requirements for 2016 under Section 366.93(6), F.S.

DEF generally agrees that the variances shown in column (C) are the impacts that would result in a 'Deferred Recovery' scenario. However, to clarify the results, DEF would characterize the resulting $652,798 variance as the additional amount outstanding to be recovered in a future period, as opposed to a 2016 impact. The 2016 Impact in this analysis would be the deferral of the 2016 $13,459,542 Revenue Requirement.

Additionally, the chart provided showed a Total 2016 Revenue Requirement in a 'Deferred Recovery' scenario of $14,112,340 with a bill impact of $0.00. DEF would characterize the $14,112,340 as the projected 2016 year-end unrecovered balance (exclusive of the 2015 $54M System deferral). The 2016 Revenue Requirement that would estimate the 1,000 KWH residential bill at $0.00 under the 'Deferred Recovery' scenario is $0.00.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 30 day of June, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared THOMAS G. FOSTER, who is personally known to me, and he acknowledged before me that he provided the response to interrogatory number 12 from STAFF'S SECOND INTERROGATORIES NO. 12 TO DUKE ENERGY FLORIDA, INC. in Docket No. 150009-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 30 day of June, 2015.

Thomas G. Foster

Notary Public
State of Florida, at Large

Sarah Hirschman Libes
NOTARY PUBLIC
STATE OF FLORIDA
Comm# FF106231
Expires 3/23/2018

My Commission Expires:
3/23/2018

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DEF's Responses to Staff's First Set of Interrogatories (Nos. 1-3)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 71
PARTY: STAFF RE: DUKE ENERGY FLORIDA (DEF)
DESCRIPTION: Mark TeagueThomas G.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear cost recovery clause.	DOCKET NO. 150009-EI
	DATED: June 8, 2015

DUKE ENERGY FLORIDA, INC.'S RESPONSES TO STAFF'S FIRST SET OF INTERROGATORIES NOS. (1-11)

Duke Energy Florida, Inc. ("DEF") responds to Staff's First Set of Interrogatories (Nos. 1-11), as follows:

INTERROGATORIES

1. CR3 EPU Project: Witness Teague, at pages 4 and 5 of the May 1, 2015 testimony, discusses the Company's determination that it was (or may be) cost effective to abandon certain equipment in place and salvage the equipment through the general decommissioning process of Crystal River Unit 3. Beginning on page 11, witness Teague explains that in March of 2015 the Company established a decommissioning transition organization and approved the "CR3 Investment Recovery Closeout and Long-Term SAFETOR Asset Recovery Plan."

   a. Please explain how, if at all, the Company plans to transfer the affected EPU plant balance to the decommissioning process.

RESPONSE:

The EPU plant balance is handled separately through the NCRC. The Company does not plan to transfer the affected EPU plant balance to the decommissioning process. The cost to decommission/dismantle any EPU assets that were not sold, transferred or salvaged will be paid from the trust.

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b. Please explain how, if at all, any of the Company's CR3 EPU unrecovered investment balance is affected by the Company's March 2015 decisions regarding non-CR3 EPU assets.

RESPONSE:

The Company's CR3 EPU unrecovered investment balance is not affected by the Company's March 2015 decisions regarding non-CR3 EPU assets.

c. Please explain how, if at all, the Company's collection of CR3 EPU unrecovered investment balance is affected by the Company's March 2015 decisions regarding non-CR3 EPU assets.

RESPONSE:

The Company's collection of CR3 EPU unrecovered investment balance is not affected by the Company's March 2015 decisions regarding non-CR3 EPU assets.

2. CR3 EPU Project Net 2014 True-up: Witness Foster's March 1, 2015 Exhibit TGF-2, page 3 of 12 identifies a true-up amount for 2014 of ($1,070,629). Witness Foster's May 1, 2015 Exhibit TGF-4, page 4 identifies an estimated true-up amount for 2015 of ($857,612). The sum of these true-up amounts totals ($1,928,241). However, on page 3 of Witness Foster's May 1, 2015 Exhibit TGF-4 the true-up amounts for prior periods is shown as ($2,075,578). Please explain why there is a difference in these representations of the total true-up amounts and identify the components that result in the difference.

RESPONSE:

The $2,075,578 over recovery shown in Exhibit TGF-4 of the May 1, 2015 filing is the correct amount of the projected 2016 beginning balance over recovered position. The $1,928,241 identified in the question is the sum of the 2014 and 2015 period over/under recovery, but leaves out the impact of prior period true-ups. A discussion of where this can be seen follows:

The $1,070,629 amount identified on line 24 in Witness Foster's March 1, 2015 Exhibit TGF-2 is the current period over-recovered amount for 2014 and is exclusive of the remaining unamortized ending balance of the over/under recovery from prior periods. The net unamortized amount of the prior period in 2014 is a $524,698 over recovery. The total net over-recovered position for DEF at year-end 2014 is $1,595,326 and can be seen by summing the ending balances of lines 3e, 12 and 24. This balance is appropriately carried forward in Witness Foster's May 1, 2015 Exhibit TGF-4, page 4 in the 2015 beginning balances of line 3e and line 12. This amount is amortized in 2015 by the over/under amount projected for 2015 shown in lines 3f and 13 leaving a year end prior period over recovery of $1,217,966.

The $857,612 amount identified is the current period over-recovered estimated true-up amount for 2015. On page 3 of Witness Foster's May 1, 2015 Exhibit TGF-4 the true-up amounts for prior periods shows $2,075,578 as the prior period over recovery for the purpose of calculating the 2016 revenue requirement. The sum of $857,612 (2015 current period estimated over recovery) and $1,217,966 (2015 unamortized prior period over recovery) is $2,075,578.

3. CR3 EPU Project Net 2014 True-up: Witness Foster's May 1, 2014 Exhibit TGF-5, page 4 of 16 filed in Docket No. 140009-EI, supports an estimated $155,210 variance for collection during 2015. Please describe how the $155,210 is adjusted from Duke's current calculation of its final over/under recovery true-up calculations and provide citations to where the adjustment(s) is(are) recognized in the Company's schedules. If the amount is not adjusted from the Company's petition, please explain why.

RESPONSE:

The $155,210 is the correct amount of the current period under-recovered estimated true-up amount for 2014, and can be seen as part of the amounts of DEF's current calculations, broken-out below. The unamortized amount of the prior period was an over-recovery of $437,905 in 2014. The total net over-recovered position for DEF at year-end 2014 presented was $282,695.

The total amount being amortized in 2015 is an over-recovery of $369,487 and can be seen in Witness Foster's May 1, 2015 Exhibit TGF-4, page 4 in the beginning balances of lines 3f, 13, and 19. The $369,487 was also presented in Witness Foster's May 1, 2014 Exhibit TGF-5, page 5 of 16 filed in Docket No. 140009-EI and can be seen by summing lines 3f, 11, and 15. There were a few adjustments presented in Docket No. 140009-EI that explain the $86,792 difference between the 2014 ending balance of $282,695 and the 2015 beginning balance shown as $369,487; the adjustments are identified in Docket No. 140009-EI Appendix A (page 7) in TGF-5 filed May 1, 2014 and on page 18 in Witness Foster's May 1, 2014 Testimony.

Figures below represent the true-up amounts, and their respective components including adjustments

2014 Estimated / Actual Net of Recoveries and Collections

- **($282,695) ((Presented in May 1, 2014 – (TGF-5) on page 4 line 3e, 8,12 & 18)**
  - ($437,905) (prior period over-recovery : 2013)
    - **($213,124) Line 3e**
    - **($224,782) Line 12**
  - $155,210 (current period over-recovery : 2014)
    - **$337,785 Line 8**
    - **($182,574) Line 18**

- **($369,487) ((Presented in May 1, 2014 – (TGF-5) on page 3, 2015 Rev Requirement Summary))**

- $29,497 Line 3f **(Presented in May 1, 2014 – (TGF-5) on page 5)**
  - ($213,124) cited above
  - $337,785 cited above
  - ($87,291) Period-end Adjustment (cited on Page 7 TGF-5 Filed May 1, 2014)
  - ($7,873) Period-end Adjustment (cited on Page 7 TGF-5 Filed May 1, 2014)

- ($406,857) Line 11 **(Presented in May 1, 2014 – (TGF-5) on page 5)**
  - ($182,574) cited above
  - ($224,782) cited above
  - $499 Period-end Adjustment (cited on Page 7 TGF-5 Filed May 1, 2014)

- $7,783 Line 15 **(Presented in May 1, 2014 – (TGF-5) on page 5)**
  Period-end Adjustment (cited on Page 7 TGF-5 Filed May 1, 2014)

- ($369,487) **(Presented in May 1, 2015 – (TGF-4) on page 4)**
  - $29,497 Line 3f cited above
  - ($406,857) Line 13 cited above
  - $7,783 Line 19 cited above

AFFIDAVIT

STATE OF NORTH CAROLINA)

COUNTY OF MECKLENBURG)

I hereby certify that on this 5th day of June, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared MARK R. TEAGUE, who is personally known to me, and he acknowledged before me that he provided the responses to interrogatory number(s) 1.a., 1.b., and 1.c. from STAFF'S FIRST SET OF INTERROGATORIES TO DUKE ENERGY FLORIDA, INC. (NOS. 1 - 11) in Docket No. 150009-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 5th day of June, 2015.

Mark R. Teague

Lisa S. Moore

Notary Public
State of North Carolina

My Commission Expires:
04-13-2019

LISA S. MOORE NOTARY PUBLIC GASTON COUNTY, NC

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PINELLAS)

I hereby certify that on this 11th day of June, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared THOMAS G. FOSTER, who is personally known to me, and he acknowledged before me that he provided the response to interrogatory numbers 2 through 11 from STAFF'S FIRST INTERROGATORIES NOS. 1 – 11 TO DUKE ENERGY FLORIDA, INC. in Docket No. 150009-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 11 day of June, 2015.

Thomas G. Foster

Notary Public
State of Florida, at Large

Sarah Hinschman Libes
NOTARY PUBLIC
STATE OF FLORIDA
Comm# FF106231
Expires 3/23/2018

My Commission Expires:
3/23/2018

101222887.1

PSC Order Exhibit Not moved in

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 72
PARTY: OPC
DESCRIPTION: Final Order

EXHIBIT NO. 73

DOCKET NO: 150009-EI

WITNESS: Scroggs

PARTY: Florida Power & Light Company

DESCRIPTION: Concentric Energy Advisors Update to AP1000 Project Costs (December 2014)

DOCUMENTS:

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 73
PARTY: OPC
DESCRIPTION: Concentric Energy Advisors update to AP1000 Project Cost December

Recent changes in reported AP1000 project costs include:

- FPL's overnight costs for PTN 6 & 7 (in 2014 dollars) reflect a 2.5% increase over this value from 2013, but remain unchanged since the April 2014 update.
- Scana has provided updated expectations for the rate of capital spending that will be required to complete the Summer project. For purposes of the analysis described in this memorandum, this update enables overnight cost calculations that more accurately reflect spending on the project.
- Southern Company has encountered potentially significant delays on the Vogtle project, which was noted by third party analysts and Georgia Public Service Commission Staff in November 2014. As discussed below, Southern Company has not yet updated its capital costs to include the effects of these delays on the project. As a consequence, the overnight cost calculations presented in this analysis do not included the cost impact of delays.
- Handy-Whitman escalation indices for the first half of 2014 have been added.

A summary of US AP1000 project overnight costs reflecting the latest public data appear in Table 1, below. These figures reflect total project cost estimates that were generated using FPL assumptions pertaining to on-line dates, project execution spending levels, escalation and discount rates, etc.

Table 1: Estimate of Overnight and Total Project Costs

Project	Commercial Operation Date	Overnight Costs ($2014/kW)	Projected TPC ($nominal, billions)	Notes
Scana - V.C. Summer	2018, 2019	$4,108	$13.9	Excludes transmission
Georgia Power - Vogtle	2017, 2018[1]	$4,696	$15.8	Includes transmission
Duke Energy - Levy	2024, 2025	$6,226	$21.0	Excludes transmission
FPL - Turkey Point	2022, 2023	$5,453	$18.4	Figure includes full owner's scope and cost, and includes transmission costs

Overnight Cost Estimate Revisions

V.C. Summer

In March 2009, the Public Service Commission of South Carolina ("SC PSC") approved an initial capital cost of $4.53 billion for Scana's share of two new units at the V.C. Summer Nuclear Generating Station. In November 2012, the SC PSC approved a petition for cost and schedule updates,[2] which indicated that the total capital cost estimate had risen by 0.4% to $4.55 billion ($2007). Total costs described in an update Scana filed with regulators in September 2014 indicate that the total cost estimate has not changed in the last two years.[3] However, the distribution of costs throughout the construction calendar has been updated, yielding a slightly higher overnight capital cost than was reported in Concentric Energy Advisors' April 2014 *Update to AP1000 Project Costs* memo.

[1] Does not reflect recently announced schedule delays.

[2] Public Service Commission of South Carolina. Order No. 2012-884 in Docket No. 2012-203-E. November 15, 2012.

[3] South Carolina Electric & Gas Company. V.C. Summer Nuclear Station Units 2 & 3, Quarterly Report to the South Carolina Office of Regulatory Staff, Quarter Ending December 31, 2013. February 11, 2014

According to Scana's most recent Quarterly Report to the South Carolina Office of Regulatory Staff, two future equipment milestones related to the fabrication of reactor coolant pumps have been delayed 19 to 26 months. Though a revised fully integrated project schedule has not been released, Scana received preliminary information from the Westinghouse/CB&I consortium earlier this year indicating that Unit 2 is expected to be completed in late 2018 or the first half of 2019, with Unit 3 expected 12 months later. The delay was attributed to the fabrication and delivery of structural modules from CB&I's facility in Lake Charles, Louisiana. Although these delays could affect Summer's overnight costs, they are not incorporated in Scana's reported figures, and thus, are not factored into Concentric's analysis.[4]

Vogtle

Georgia Power's 11th Vogtle Construction Monitoring ("VCM") Report describes progress on the construction of the new units throughout 2014. Neither the projected capital cost of $4.8 billion nor Georgia Power's plans for annual capital spending on the project have changed since the 9th/10th VCM Report was released in early 2014.[5] However, the project's overnight cost has increased slightly due to a change in escalation rates.

However, consultants monitoring the project for Georgia state regulators have indicated that Georgia Power will fail to meet its scheduled commercial operation dates as a result of a variety of construction milestone delays. The exact nature of these delays remains confidential. However, the consultants' testimony cites that a lack of an integrated project schedule and unexpected equipment design and fabrication problems have contributed to delays. The two nuclear reactors are currently scheduled for commercial operation at the end of 2017 and the end of 2018 respectively, but the construction monitors and regulatory staff have indicated that the schedule is likely to slip.[6] In addition, $900 million in construction costs is currently the subject of litigation between Southern Company (Georgia Power's parent company) and the Westinghouse/Stone & Webster consortium responsible for design and construction of the project. In response to new Nuclear Regulatory Commission regulations, the consortium has made a number of required changes to the original design that was the basis for the 2008 contract with Georgia Power. While these developing issues could materially affect Vogtle's overnight costs, the impact of delays and ongoing litigation has not yet been reflected in Georgia Power's reported figures. As a result, these recent challenges are not incorporated into Concentric's analysis.

In 2013, Georgia Power applied to the Internal Revenue Service for $800 million in Production Tax Credits, and on February 20, 2014, Georgia Power and the Department of Energy entered into a Loan Guarantee Agreement. The guarantee is expected to provide approximately $250 million in financing cost savings over the life of the loan. While both the tax credits and the loan guarantee represent significant cost savings opportunities for the Vogtle units, neither of these mechanisms affects the overnight capital cost of the project, which is the primary point of comparison referenced in this analysis.

Levy

A revised cost estimate for the Levy facility ("Projected Nominal Plant Costs Before AFUDC") was filed by Christopher Fallon of Duke Energy in May 2013.[7] The Levy nominal plant cost was distributed along a spend curve derived from FPL project plans through 2013, and using a generic spend curve with the same general shape through 2025. These costs were then discounted to arrive at an overnight cost in real 2007 dollars.[8]

[4] South Carolina Electric & Gas Company. Quarterly Report to the South Carolina Office of Regulatory Staff. September 2014.

[5] Georgia Power Company. Ninth/Tenth Semi-annual Vogtle Construction Monitoring Report. Docket No. 29849, February 2014.

[6] The Georgia Public Service Commission has not, however, issued any findings of fact with regard to the construction monitors' and regulatory staff's findings.

[7] Duke Energy Florida, Inc. Direct Testimony of Christopher M. Fallon, Exhibit CMF-4, page 12 of 18. May 1, 2013.

[8] Costs were discounted at Duke Energy Florida's 2013 Fixed O&M escalation rate of 2.8%.

Duke has elected not to pursue construction of the Levy project at this time, and has commenced a process to wind down the project. Duke will, however, continue its efforts to obtain a Construction and Operating License, per a Settlement Agreement with the staff of the Florida Public Service Commission. As a result, cost expectations for the project remain relevant as a point of comparison for the purpose of this analysis.

Turkey Point

FPL's overnight cost estimate and projected total project cost for the Turkey Point project represent the high end of the range presented in Steven D. Scroggs's 2014 NCRC testimony. As in recent years, the overnight figure represents an inflation adjustment of 2.5% per year over the prior year's costs.

Projected Total Project Cost

Total Project Costs are generated for each facility by incorporating assumptions FPL has used in assessing the Turkey Point project. These assumptions include overnight cost, a spend curve that is revised regularly to reflect the Company's expenditures from historical periods and any revised future plans, AFUDC and escalation rates, and commercial operation dates for the units. Applying these assumptions to the overnight cost estimates of other projects yields a range of costs that provide context for FPL's cost estimate.

FPL's 2014 high-end total cost estimate of $18.4 billion for PTN 6 & 7 is within the range of $13.9 billion to $21 billion that is generated using overnight costs from the other AP1000 projects.

Estimated Inflation

Overnight cost estimates in different dollar vintages are brought to 2013 using the Handy-Whitman "Total Plant All Steam Generation" index.[9] Handy-Whitman escalation figures are not yet available to convert figures to 2014 dollars, as the most recent figures pertain to the second half of 2013. Figures are escalated from 2013 to 2014 using Consumer Price Index ("CPI") data from the Bureau of Labor Statistics. The year-over-year escalation factors derived using the Handy-Whitman index and CPI data are captured in Table 2, below.

Table 2: Cost escalation factors

Escalation factors (Year over Year)	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Total Plant-All Steam Generation	1.004	1.009	1.006	0.998	0.923	1.034	1.014	1.033	1.019	
Total Nuclear Production Plant	1.005	0.991	0.995	1.014	0.941	1.033	1.016	1.044	1.013	
CPI (from Bureau of Labor Statistics)	1.034	1.032	1.028	1.038	0.996	1.016	1.032	1.021	1.011	1.023

[9] Handy-Whitman reports index data twice per year. Annual escalation factors are calculated by taking a weighted average of three data points:
Example: 2008 Escalation Factor = (1* January 2008 rate + 2*July 2008 rate + 1*January 2009 rate) / 4

EXHIBIT NO. 74

DOCKET NO: 150009-EI

WITNESS: Scroggs

PARTY: Florida Power & Light Company

DESCRIPTION: FPL's Response to OPC's 3rd Set of Interrogatories No. 13

(Westinghouse Price List Date)

DOCUMENTS:

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 74
PARTY: OPC
DESCRIPTION: FPL' s Response to OPC's 3rd set of IRROGS

Q.

On page 3, of Witness Scroggs Rebuttal testimony, lines 1 through 3, he states that a cost estimate "check" used the Westinghouse pricing information in 2010. Please state if the Westinghouse pricing information that was used for this "check" was based on 2009 Westinghouse pricing information. If not, please state the date of the Westinghouse pricing information that was used.

A.

The testimony indicates that the cost estimate check was conducted in 2010. The Westinghouse information was provided to FPL in 2009.

EXHIBIT NO. 75

DOCKET NO: 150009-EI

WITNESS: Steven D. Scroggs

PARTY: FPL

BRIEF TITLE OR DESCRIPTION OF THE DOCUMENT:

EPA Comments on Nuclear Regulatory Commission Draft Environmental Impact Statement for Turkey Point Units 6 & 7

PROFFERED BY: Miami

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 75
PARTY: Miami
DESCRIPTION: Scroggs/EPA Comments

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

July 17, 2015

Ms. Cindy Bladey, Chief
Rules, Announcements, and Directives Branch (RADB)
Division of Administrative Services
Office of Administration
Mailstop OWFN-12H8
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555-0001

SUBJ: EPA Review and Comments
Draft Environmental Impact Statement (DEIS)
Turkey Point Nuclear Plant, Units 6 and 7, Combined Licenses (COLs)
Miami-Dade County, Florida
CEQ No. 20150054

Dear Ms. Bladey:

Pursuant to Section 309 of the Clean Air Act (CAA) and Section 102(2)(C) of the National Environmental Policy Act (NEPA), the U.S. Environmental Protection Agency (EPA), Region 4 reviewed the Draft Environmental Impact Statement (DEIS) for the Turkey Point Nuclear Plant, Units 6 and 7, Combined Licenses (COLs), NUREG-2176. We appreciate your continued coordination and communication with us, and your reopening and extension of the public comment period for this review. The purpose of this letter is to provide our review and comments regarding the proposed project.

This DEIS is the result of Florida Power and Light Company (FPL) submitting an application to the U.S. Nuclear Regulatory Commission (NRC) for combined construction permits and operating licenses for the proposed Turkey Point Units 6 and 7. The proposed action includes construction and operation of two Westinghouse AP1000 Pressurized Water Reactors (PWRs) and ancillary facilities at the Turkey Point site, each having thermal power ratings of 3,415 MW(t).

The federal actions include the NRC's decision whether or not to issue the licenses, and the U.S. Army Corps of Engineers (USACE) decision to issue, deny, or issue with modifications a Department of the Army (DA) permit, pursuant to Section 404 of the Clean Water Act (CWA) for dredge and fill activities in Waters of the U.S., and to construct structures in navigable waters of the U.S. related to the project.

The USACE and the National Park Service (NPS) are cooperating agencies on this EIS; Biscayne National Park (BNP) and the Everglades National Park (ENP) are in proximity to the project area. The NRC's preliminary recommendation related to the environmental aspects of the project is that the COLs be issued for Units 6 and 7. This DEIS is for the licensing of the two new reactor units (Units 6 and 7), and not for issues pertaining to the existing reactor units (Units 3 and 4). However, based on our review, there are some environmental aspects of the proposed new units that relate to the existing facilities.

Based on EPA's review of the project, we rated the DEIS Preferred Alternative as Environmental Concerns (EC), Category 2-Insufficient Information. The EC-2 rating indicates that we have serious concerns, and that the document does not contain enough information needed to fully assess some of the environmental impacts that should be avoided in order to fully protect the environment. Please refer to the enclosed Summary of Rating Definitions for a detailed explanation of EPA's ratings.

EPA's concerns, associated with the alternatives analysis and the project impacts, include the following subject areas:

- Cumulative impacts to the Biscayne aquifer, an EPA-designated sole source aquifer
- Underground injection wells, karst delineation and permitting requirements
- Section 404 CWA permitting and documentation
- Impacts to Aquatic Resources of National Importance (ARNI)
- Water quality and water supply needs for the new reactors
- Numeric Nutrient Criteria within Biscayne Bay
- Migration of hypersaline effluent and radionuclides
- National Parks and aquatic preserves, species and habitats protection
- Radionuclides, nuclear waste storage and disposition
- Air quality criteria pollutants and modelling information
- Socioeconomics, Environmental Justice (EJ) outreach
- Tribal concerns, National Historic Preservation Act (NHPA) documentation
- Climate change, greenhouse gases (GHG) and sea level supporting information
- Indirect and cumulative impacts, transmission lines, alternatives analysis clarification

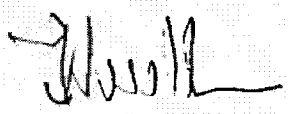
In summary, our areas of greatest concern relate to impacts on groundwater and drinking water quality, ecosystems and habitats, also including indirect and cumulative impacts. The enclosed comments state our concerns in detail, and we request that these concerns be fully addressed in the Final Environmental Impact Statement (FEIS).

The DEIS provides useful information and covers a variety of complex environmental issues related to the COL process for the proposed new units. We appreciate your coordination and outreach to us to discuss the numerous technical issues and our environmental concerns regarding this project, and your response to our request for additional review time for this DEIS.

We look forward to working with the NRC to reduce this project's impacts, and to provide environmental protection for future generations. We request that the FEIS address our concerns,

which are detailed in the enclosed comments. We are available for further discussion, and willing to work with the NRC. We look forward to reviewing the FEIS. If you have any questions, please contact Ramona McConney of my staff at 404-562-9615.

Sincerely,



Heinz J. Mueller, Chief
NEPA Program Office
Resource Conservation and Restoration Division

Enclosures: EPA Review and Comments
Summary of Rating Definitions and Follow Up Action

Cc: Alicia Williamson-Dickerson, NRC
Colonel Alan M. Dodd, USACE
Megan L. Clouser, SAJ
Bryan Faehner, NPS

EPA Review and Comments
Draft Environmental Impact Statement (DEIS)
Turkey Point Nuclear Plant, Units 6 and 7, Combined Licenses (COLs)

General

We appreciate your efforts to minimize project impacts for the proposed Units 6 and 7 by using reclaimed wastewater from the Miami-Dade Water and Sewer Department (MDWSD) treatment system as cooling water, with the alternative source being groundwater supplied from horizontal radial collector wells installed in the Biscayne Aquifer on the Turkey Point peninsula. The lateral collector wells would extend up to 900 feet from the central caisson beneath Biscayne Bay (page 3-25). We appreciate the plans to avoid releasing blowdown to surface water bodies. However, based on the EPA's review of the DEIS, there are a number of serious concerns regarding the direct, indirect and cumulative impacts of this project, and further information and clarification is needed.

Water Quality and Water Supply Concerns

Surface Water

Concerns regarding fresh water needs for Biscayne National Park (BNP), the Everglades National Park (ENP), the Comprehensive Everglades Restoration Plan (CERP), in addition to other fresh water needs in the area, need to be clarified in the Final Environmental Impact Statement (FEIS). The EPA has concerns regarding the project's fresh water supply requirements, cumulatively added to the existing fresh water needed to supply the existing Units 3 and 4, as well as for drinking water, agricultural and ecosystems in the region, in an environment already experiencing saltwater intrusion.

The Biscayne aquifer underlying the area is prone to saltwater intrusion because this area has low land-surface altitude and a low topographic gradient, and is bordered by sources of saltwater in Biscayne Bay, and, further east, by the Atlantic Ocean. Page 2-66 states that the most important factors contributing to the regional intrusion of saltwater from the ocean into the aquifer are rerouting of sheet flow to drainage canals and groundwater pumping.

Recommendations: Page 2-45 of the DEIS states that the cooling canal system/industrial wastewater facility *"... is a closed-cycle cooling system, but is not a closed hydrologic system."* EPA notes that since this is not a closed cycle hydrologic system, and therefore the FEIS should include a more in-depth discussion relating to the cumulative impacts associated with the hydrologic complex.

The FEIS should include a water balance calculation for the site that shows all the potential sources of water supplying the site, and discharges and other releases from the site under normal operating conditions. This balance should include seepages from the canal system and changes in evaporative losses (e.g., changes in thermal load due to projected completion of the conversion to synchronous condenser mode for Units 1 and 2). Additionally, the FEIS should discuss the

releases or seepages from the Industrial Waste Facility (IWF). Specifically, the FEIS should document the presence of any direct releases from the IWF to the surrounding surface waters via breaches in the berms.

Section 404 CWA Permitting

The EPA has numerous concerns regarding the analyses, data and mitigation required for the CWA Section 404 permitting application. We noted a number of details and data that need to be clarified, with additional information provided to the EPA prior to the publication of the FEIS, in order for the FEIS to meet the needs of all the project's permitting requirements.

The EPA reviewed the permit application number 2009-02417(SP-MLC) submitted to the U.S. Army Corps of Engineers (USACE) by Florida Power & Light (FPL), and responded in writing on April 9, 2015 and May 4, 2015. EPA's letters state our CWA Section 404 concerns regarding the proposed project. These comments should be considered and responded to by the project team, with further information provided in the FEIS. In addition, we identified the following concerns in the DEIS:

Section 2.2.2.3, Makeup and Potable Water Systems (pg. 2-20): Table 2-6 lists 447.80 acres of wetlands within the reclaimed water pipeline corridor, and 159.95 acres within the potable water pipeline corridor. It also states (pg.4-9) that FPL proposes to grade the disturbed portions of the corridor to the contours of the surrounding landscape and re-vegetate or return these areas to previous land uses. The EPA appreciates the effort to minimize wetland impacts by this action. The EPA is still unclear on the total extent and type of permanent impacts which will occur due to this activity. Please clarify.

Section 2.3, Water (pg. 2-26): The DEIS states that the alternate cooling water source supplied by the radial collector wells would be limited to a maximum of 60 days per year by the Florida State Conditions of Certification. The DEIS is not clear regarding what contingency plans will be implemented should the 60 day limitation be exhausted and the reclaim water supply is not available. FPL has stated that the Conditions of Certification addresses the contingency plan for emergency water allocation. Please clarify this issue with a detailed explanation of contingency plans in the FEIS.

Section 3.2.2.1, Landscape and Stormwater Drainage (pg. 3-8) : The proposed nuclear reactor Units 6 and 7, including cooling towers, makeup water reservoir, new substation and associated facilities, would be built on a filled "218 acre island" enclosed by a stabilized earth wall to the north, east, and west. A reinforced concrete wall could be constructed to the south.

The elevation within the fill island would range from 19 feet to 26 feet North American Vertical Datum of 1988. With the threat of sea level rise in the foreseeable future, the EPA has concerns on what effect this may have on the surrounding infrastructure to this created island; there are concerns that rising sea levels could potentially surround the island at some point in the future during the lifespan of this project.

Please provide information in the FEIS which would support construction of the project, considering the fact that even though the power units will be constructed on this island, the

surrounding landscape may be impacted by sea level rise or storm surges that may affect the feasibility of the project, given the project purpose.

FPL has stated that they provided substantial scientific data and testimony regarding the effects of sea level rise during the State site certification proceedings, and that the Recommended Order, adopted in the Final Order on Certification states: *"The plant design elevation accounts for more than maximum storm surge plus sea level rise. FPL has provided reasonable assurance that the project is not contrary to the public interest as it relates to the sea level rise."* The FEIS should evaluate, document and clarify the effectiveness of proposed measures to protect the facility from storm surges and rising sea level.

Section 3.2.3.4, Support and Laydown Areas (pg. 3-20): The EPA requests that the FEIS provide additional avoidance and minimization efforts by restoring wetlands associated with support and laydown areas after construction is completed.

Section 4.1.1.2, Pipelines (pg. 4-9) Table 4-3: Outlines major land use acreages for the pipelines but is not clear on the specific acres of wetlands to be impacted. Please provide more detail about wetland impacts for this activity, to be consistent with the format illustrated in Table 4-1 of the DEIS for the Turkey Point site.

Section 4.1.1.3, Access Roadways (pg. 4-9) Table 4-4: Outlines major land use acreages for access road improvement but is not clear on the specific acres of wetlands to be impacted. Please provide more detail about wetland impacts for this activity, to be consistent with the format illustrated in Table 4-1 of the DEIS for the Turkey Point site.

Section 4.1.2, Transmission-Line Corridors and Associated Areas (pg. 4-15) Tables 4-5 and 4-6: Outlines major land use acreages for transmission-line corridors and associated areas, but is not clear on the specific acres of wetlands to be impacted. Please provide more detail regarding wetland impacts for this activity, to be consistent with the format illustrated in Table 4-1 of the DEIS for the Turkey Point site.

Section 4.3.1.6, Wetland Mitigation Plan (pg.4-70): The DEIS states that FPL instituted measures during project planning to avoid and minimize impacts on wetlands to the greatest extent practicable. Proposed avoidance and minimization measures include maximizing the previously disturbed areas, while minimizing use of areas with high-quality intact wetlands. The corridor selection for the reclaimed water pipeline, portable water pipeline, and transmission facilities maximized co-location with other existing or proposed infrastructure, to limit land disturbance.

The Public Notice published by the USACE on March 13, 2015 stated that the project proposes impacts to 1000 acres of tidal and freshwater wetlands. FPL stated in their letter of May 14, 2015, addressed to USACE, that the correct number for the direct wetland impacts for the project is 710 acres, with temporary impacts to 50 acres. These include impacts to high quality, tidal mangrove wetlands.

Mangrove wetlands located within south Florida form a vital component of the estuarine and marine environment, providing a major organic detrital base to the aquatic food chains,

significant habitat for arboreal, intertidal and subtidal organisms, nesting sites, cover and foraging grounds for birds, and habitat for reptiles and mammals. Mangroves also provide protected nursery area for fishes, crustaceans, and shellfish.

Mangroves are one of the most biologically productive ecosystems in the world, also serving as storm buffers by functioning as wind breaks, and through prop root baffling of wave action. Mangrove roots stabilize shorelines and fine substrates, reducing turbidity, and enhancing water clarity. Mangroves improve water quality and clarity by filtering upland runoff, and trapping waterborne sediments and debris. The cumulative loss of this habitat has reduced overall water quality and fisheries production within the south Florida ecosystem. For these reasons, the EPA considers these mangrove wetlands to be aquatic resources of national importance (ARNI).

In addition, the proposed project would impact sawgrass marshes, which provide principal environmental values related to water quality and quantity. They serve as filter systems for water, and protect natural bodies of water from eutrophication. Numerous birds can be found in this community year-round, or for over-wintering. They also provide habitat for frogs, snails, and crayfish, which serve as food sources for larger protected animals that are found in this region. Protected animals that can be found in and around sawgrass marsh systems include the Everglades mink (*Mustela vison evergladensis*), Florida panther (*Felis concolor coryi*), snail kite (*Rostrhamus sociabilis*), wood stork (*Mycteria americana*), and American alligator (*Alligator mississippiensis*). Therefore, the EPA considers sawgrass marshes to be ARNI.

Further, the proposed project would impact submerged aquatic vegetation (SAV), which includes *Ruppia maritima, Thalassia testudinum,* and *Halodule wrightii.* Fin and shell fish commonly associated with this species include Florida crawfish, stone crab, blue crab, penaeid shrimp, sea trout, gray snapper, red drum, pinfish, mullet, and flounder. Moreover, SAV provides attachment sites for periphyton which in turn increases food value for the base of marine and estuarine food webs. SAV aids in stabilizing the shallow water submerged land which promotes water quality. SAV also performs important nutrient uptake functions, which assist in the maintenance of water quality. For these reasons, the EPA also considers SAV to be ARNI.

According to the CWA Section 404(b)(1) Guidelines, 40 CFR § 230.91(c), and the February 6, 1990, Memorandum of Agreement between the U.S. Army Corps of Engineers and the EPA regarding the Determination of Mitigation under the Clean Water Act Section 404(b)(1) Guidelines, an applicant must demonstrate avoidance and minimization of wetland impacts before compensatory mitigation can be considered. Subpart H of the CWA Section 404(b)(1) Guidelines describes several (but not all) means of minimizing impacts of an activity.

Section 4.3.1.6, Wetland Mitigation Plan (pg.70): The DEIS states that, as part of the compensatory mitigation offset projects impacts, FPL proposes to restore two parcels totaling 812 acres.

CWA 404 Permit NEPA Documentation: EPA understands that the NRC is addressing impacts of the onsite facility, and that offsite facilities, such as the transmission lines and other related facilities, will not be considered in detail for the purposes of this EIS. The EPA also understands that the USACE intends to adopt the NRC's EIS for the purposes of their CWA Section 404

permit action. However, many of the associated and connected actions, such as construction of the transmission lines, are not considered in the NRC's EIS. For the purposes of permit issuance, the USACE should state how they plan to address associated NEPA documentation for these offsite facilities, as those impacts are directly related to this project. NEPA coverage for these permit actions should be included within NRC's FEIS.

Recommendations: EPA recommends that the NRC document the USACE intentions for addressing their NEPA documentation and timing with NRC's FEIS and permit issuance. The FEIS should include a mitigation plan which details how the proposed mitigation is in compliance with the Federal Compensatory Mitigation Rule, dated April 2008.

The EPA requests that the FEIS address additional measures that can be taken to avoid and minimize onsite tidal and freshwater wetland impacts. As stated previously, the Public Notice published by the USACE stated that the project proposes impacts to 1000 acres of tidal and freshwater wetlands, and FPL stated in their response to USACE that the correct number for the direct wetland impacts for the project is 710 acres, with temporary impacts to 50 acres. Project impacts will include impacts to ARNI. The FEIS should clarify the acreage that would be impacted.

EPA understands that a benthic survey has not been completed at the FPL Turkey Point site for some years. In order to evaluate the proposed project, the FEIS should include a colored copy benthic survey of the boat basin, radial collector well locations, and the Units 6 & 7 site. The benthic survey should extend a radius of 50 feet around submerged lands of these locations. The benthic survey should include a description of the protocol used to complete the survey, sampling dates, and a map that illustrates the density and location of each SAV found at the site. The seagrass survey should be conducted between the months of June and September to ensure the survey is conducted during the active growing season. The benthic survey is necessary for the EPA to determine extent of SAV impacts that will occur by the proposed project.

The FEIS should include a wetland jurisdictional determination, so that a complete review of wetland impacts can be determined. During the wetland jurisdictional determination review, the EPA is willing to participate with that review, prior to publishing in the FEIS.

Also, the FEIS should include Uniform Mitigation Assessment Method scores (Parts 1 and 2), for the proposed impact and mitigation sites. Technical rationale for each score should also be included.

Overall, the FEIS should include updated information regarding the CWA Section 404 permitting process, and include information responsive to the concerns stated in EPA's letters to the USACE, as well as the specific concerns listed here. Impacts should be avoided to the maximum extent feasible, and unavoidable impacts should be effectively mitigated.

Numeric Nutrient Criteria (NNC)

The FEIS should include detailed information regarding impacts associated with potential exceedances of the NNC. The Florida Department of Environmental Protection (FDEP)

approved NNC water quality standards for estuaries including Biscayne Bay. However, there is no discussion in the DEIS regarding the project's potential impacts regarding the NNC and Biscayne Bay.

The NRC acknowledges the hydraulic connection between the cooling canal system (CCS)/industrial wastewater facility (IWF) and the hydrologic complex, especially during the tidal cycle (page 2-46) and states, *"Recently, the IWF has experienced algal blooms, increased water temperatures, and increases in concentrations in salinity and nutrients. The precise cause of this anomaly is not understood at this time."* However, the FEIS should further evaluate whether the overheated water in the canal, with increased nutrients due to concentrations resulting from evaporation, contributed to the formation of the algal blooms.

EPA is concerned regarding the interconnection of the IWF, Biscayne Aquifer and Biscayne Bay. NRC acknowledges this connection when it states, *"Hydraulic heads in monitoring wells near Biscayne Bay fluctuated in response to tidal cycles indicating a potential for tide-induced flow between the bay, shallow groundwater and the cooling canals in this area of the IWF"."* (page 2-68.)

On page 2-69, NRC also discusses a FPL study that examines the dynamic processes between the IWF, surface water and groundwater as it is related to water quality, but does not discuss the results of that study. NRC also discusses a required monitoring study of the IWF to evaluate the *"horizontal and vertical hydrologic exchanges with the surrounding environment"*. EPA requests that the NRC better describe the existing condition of the current operations of Units 3 and 4, and related water quality impacts, in the FEIS.

EPA also understands that the IWF is used for the existing nuclear reactors (Units 3 and 4), and that cooling water from the new units 6 and 7, will use reclaimed water from MDWSD, and the blowdown from the cooling tower will be discharged into the Boulder Zone via UIC wells.

However, the IWF will be accepting wastewater from the new reactors (Units 6 and 7), and these additional wastewater streams include excavation dewatering, stormwater run-off, muck spoil run off and drift deposition. There is a potential for these additional wastewater streams to increase nutrient loading, including nitrate, for which EPA has set a drinking water maximum contaminant level (MCL), to the underlying Biscayne Aquifer, (an Underground Source of Drinking Water under the SDWA), given the existing hydrologic connection between the IWF and groundwater.

The DEIS discusses operational surface water quality impacts associated with the IWF (page 5-19, 5.2.1.4). The DEIS individually examines the surface water quality impacts associated with excavation dewatering, stormwater discharge, muck spoil runoff and drift deposition. However, the DEIS does not holistically and additively analyze these additional stresses to the IWF. Also, the NRC does not discuss these additional wastewater stresses to the IWF and potential impacts to the underlying groundwater.

EPA acknowledges that there are no current exceedances of the NNC. However, the DEIS should evaluate the future project in the context of potential NNC impacts and possible related algal blooms beyond the IWF. EPA requests that the NRC better describe the existing condition

of the current operations of Units 3 and 4 and related water quality impacts in the FEIS and, if available, disclose the results of the FPL studies discussed in the DEIS. The EPA is concerned that the combined and additional wastewater discharges into the IWF could potentially lead to exceedances of the NNC.

Recommendations: The EPA is concerned that the proposed project could cause NNC exceedances within Biscayne Bay, and requests that more detailed information be provided in the FEIS. Specifically, EPA requests that the NRC consider the additive effects of all the wastewater being placed into the IWF. The FEIS should describe how the additional wastewater discharges to the IWF could potentially impact the Biscayne Aquifer, potentially increase NNC levels within Biscayne Bay and the potential for the algal bloom to expand beyond the IWF.

Sole source aquifer and salinity issues

The EPA has several serious concerns related to groundwater, with the paramount concern being the condition of the Biscayne Aquifer, an EPA-designated sole source aquifer serving as a drinking water resource in the south Florida area. The Biscayne aquifer has already suffered significant and unacceptable hypersalinity impacts, and the EPA is concerned that the proposed project may result in further migration of the hypersaline plume.

The estimated average rate of saltwater migration is between 525 feet per year in the northern part of the cooling canals, and 660 feet per year in the southern part, [FDEP AO OGC No. 14-0741.] Many municipal water supply systems to the west of the Turkey Point cooling water canals rely on the Biscayne aquifer, and if the hypersaline plume continues to migrate, these water supply systems could potentially need additional treatment, or alternative sources of water supply. We are concerned about the potential for additional and cumulative impacts to the sole source aquifer, in addition to the existing hypersaline impacts.

Protecting the freshwater lens in southeast Miami-Dade County is also a critical priority, since this important resource supports critical marsh wetland communities, as well as irrigation and public water supply needs. This fresh water supply is needed to preserve and restore Biscayne National Park (BNP) and Biscayne Bay, and for supporting the Comprehensive Everglades Restoration Plan (CERP).

We appreciate your efforts to minimize impacts from the proposed project by using reclaimed wastewater as cooling water. The DEIS also states that current alternative backup cooling water source plans call for saltwater supplied from horizontal radial collector wells installed in the Biscayne aquifer, between 25 and 40 feet beneath the bed of Biscayne Bay and adjacent to Biscayne National Park. The DEIS notes that the use of these wells as a backup source is limited to 60 days.

However, there are concerns that FPL could eventually require more water from the radial collector wells than currently estimated, and that FPL may need to withdraw freshwater to supply the needs of the two new reactors, in the event that adverse circumstances arise and backup water sources fail to supply sufficient quantity. The FEIS should address contingency plans in detail.

Concerns exist that future circumstances, such as draughts and/or temperature issues, may require freshwater withdrawals that could potentially impact water quantity and quality, and contribute to the risk of additional saltwater intrusion into groundwater supplies. Furthermore, there are concerns that water withdrawals from the radial collector wells could potentially contribute to increased hypersalinity.

- The DEIS states that FPL intends to place the construction dewatering water into the cooling canals. Other information indicates that dewatering water and other wastewaters generated during construction will be injected via a Class I injection well permitted by FDEP (page 4-30). This needs to be clarified in the FEIS. Estimated discharges from these waste streams would be 1200 gpm, or 1.73 mgd, of discharge into the IWF for approximately 1 year (page 3-23). The DEIS does not discuss the composition of the constituents in the wastewater. FPL also intends to drain all of the new facilities' stormwater discharge into the IWF (pages 3-8 and 3-27). On page 4-36 (4.2.3.1), NRC also states, "*Because the transport of sediment in the stormwater runoff from the disturbed area would be minimized by the use of the BMPs, and controlled by a stormwater-retention basin, the effects of offsite water quality are expected to be minor.*"

- The DEIS discusses volumes and potential pollutants of stormwater and wastewater to be placed in the IWF (page 5-19); however, the document did not discuss the types of stormwater retention basins and other best management practices (BMPs). The FDEP permit does not include information regarding possible BMPs. Additionally, FPL intends to place dewatering wastewater in the IWF as well. The NRC considered impacts of the excavation dewatering activities (4.2.3.2, page 4-37), but in relationship to inflows caused by excavation dewatering, and relationship to outflows due to the cooling canals canal seepage (mass balance).

- The DEIS individually views the surface water quality impacts associated with excavation dewatering, stormwater discharge, muck spoil run off and drift disposition, but does not holistically and additively analyze these additional stresses to the IWF. Also, the DEIS does not discuss these additional wastewater stresses to the IWF, and potential impacts to the underlying groundwater. The DEIS notes that the impacts would be minor; however, it does not discuss possible impacts related to the hypersalinity plume. The EPA is concerned that these additional wastewater activities would further stress the IWF and potentially worsen the hypersalinity plume, cumulatively and adversely impacting the Biscayne Aquifer. We note that additional waters will be added to the IWF to address the heating and hypersalinity issues, however, the extent to which the additional waters will alleviate the hypersalinity levels in the plume is unclear.

Recommendations: The FEIS should clarify whether remediation measures are planned to remedy the serious issues that exist with hypersalinity migration. Also, the FEIS should provide more detail regarding the dewatering and stormwater activities (including types of pollutants, volumes, types of BMPs and stormwater-retention basins).

EPA also recommends that the NRC consider and evaluate the additive impacts of the additional wastewater discharges (excavation dewatering, stormwater runoff activities, muck spoil runoff and drift disposition) into the IWF as a result of constructing the new reactors (Units 6 and 7), specifically as it relates to the hypersalinity plume and Biscayne aquifer and associated drinking water wells.

Underground injection of effluents

The DEIS states that blowdown water from the cooling towers, and other plant discharge effluents from proposed Units 6 and 7, would be collected in a sump and injected into the Boulder Zone, a cavernous, high-permeability South Florida geologic horizon within the Lower Floridan aquifer system. The surrounding surface water bodies would neither be directly used for the primary water supply, nor for the heat sink for the proposed Units 6 and 7. However, we have concerns regarding the potential for vertical migration of the injectate, as no adequate confining zone has been shown to exist between the injection zone and lowermost underground source of drinking water (USDW).

Several investigations by the United States Geological Survey (USGS) in southeast Florida (the latest is USGS Scientific Investigations Report 2015-5013) have shown that the limited confinement which may exist between the Lower Floridan and Upper Floridan has been reduced or eliminated by karst features and faulting. FPL has not produced any documentation to delineate karst features or faults in the Floridan which may significantly alter hydraulics of the injectate at this facility.

Further, additional data, including conducting more comprehensive aquifer testing and incorporation of karst features and fault delineation, as well as results of aquifer testing into predictive modeling, are needed to assess potential injectate impacts on USDWs. In addition to injection in the Boulder Zone creating upward gradients, the Upper Floridan is proposed to be used as a source of cooling water, also creating upward gradients from the Lower Floridan, with the potential to impact the USDWs in the area.

A petition was submitted to EPA on April 28, 2015, to designate the entire Floridan aquifer system as a Sole Source Aquifer (SSA) under 40 CFR Part 149. The area in the petition includes the Lower Floridan, which contains the Boulder Zone. Although the Boulder Zone is saline, it is hydraulically connected to fresh water zones lying above. If confinement of the overlying layer is not sufficient, the injection of effluent into the Boulder Zone could result in waste, including radionuclides, being emplaced into the lowermost USDW. EPA's review of the petition is in progress.

The MDWSD installed Class I injection wells for discharging effluent from the South District wastewater treatment plant (WWTP) into the Boulder Zone; injection began in 1983. This facility is located approximately 8 miles north of the Turkey Point facility. In 1994, MDWSD notified the Florida Department of Environmental Protection (FDEP) that ammonia and total kjeldahl nitrogen (TKN) had been found outside the injection zone in the freshwater aquifer protected by the Safe Drinking Water Act (SDWA) as a USDW. (EPA's well classification information: http://water.epa.gov/type/groundwater/uic/wells.cfm)

EPA issued consent order 4-UICC-006-95 in 1995, which became effective in 1997. This order included testing to determine whether confinement existed, as required by federal and state regulations, for Class I wells. In February 2001, the report *"Evaluation of Confining Layer Integrity Beneath the South District Wastewater Treatment Plant, Miami-Dade Water and Sewer Department, Dade County, Florida,"* by R.C. Starr, T.S. Green, and L.C. Hull was completed. The conclusions included the finding that the geologic data provided for review were not sufficient to demonstrate that the Middle Confining Unit is a competent, low hydraulic conductivity layer capable of preventing upward migrations of fluids from the Boulder Zone into the overlying underground source of drinking water. Also, the geochemical data showed that groundwater in the Upper Floridan aquifer is contaminated with treated wastewater.

Based upon EPA's review of the available scientific information and data, there is no information to show that sufficient confinement exists to meet the Underground Injection Control (UIC) regulatory requirements for Class I wells. Class I wells must meet the "No-Migration Clause" of the UIC regulations at 40 CFR § 144.12(b). Recent USGS studies indicate that karst collapse features and possibly transmissive faults exist in the subsurface in the south Florida area, and modeling for the proposed Class I wells should determine whether the proposed wells would meet the criteria in order to comply with UIC Class I permit requirements.

It is not clear whether the installation of a desalinization unit has been considered, in order to reduce or control the salinity of the water in the cooling canal system, and decrease the rate of migration of the hypersaline plume towards the water supply wells completed in the Biscayne sole source aquifer.

Recommendations: The FEIS should include more information regarding the proposed deep injection wells to be used for wastewater disposal, including the status of the permitting process of the 12 deep injection wells that are proposed, the planned timeline for permitting of these wells, and planning for surface discharge of effluents in the event that delays occur in the permitting process.

In addition, the FEIS should include information regarding subsurface karst delineation, aquifer testing and modeling that will be required to demonstrate that this project will be protective of the USDWs in the Upper Floridan. Also, the FEIS should evaluate the other alternatives that are being considered for effluent discharge. In addition, the FEIS should include details of a robust monitoring plan to ensure the protection of the Biscayne aquifer, the public drinking water supply, and prevention of migration of injectate into freshwater.

The proposed injection wells are contingent upon future issuance of applicable UIC permits, for which substantial issues will need to be addressed. More data and modeling is needed to determine whether all requirements will be met in order to issue the required permits. Since the proposed planning for disposition of blowdown/effluent is contingent upon issuance of the required permits by FDEP, alternatives will need to be developed.

Everglades National Park, Biscayne National Park and Biscayne Bay Aquatic Preserve

The EPA is concerned about the proposed project's potential impacts to the Everglades National Park (ENP), Biscayne National Park (BNP) and Biscayne Bay Aquatic Preserve (BBAP). Turkey Point is in close proximity to both the BNP and BBAP. In the Affected Environment section of the DEIS (pages 2-10 – 2-13), the NRC recognizes the unique characteristics of the ENP, BNP and BBAP, and that many of these waters are listed as Outstanding Florida Waters.

Although the DEIS generally addresses some of the issues facing these national and state protected lands, the DEIS does not specifically address potential impacts facing these fragile and vital resources. EPA is concerned that the radial collector wells (RCWs) could impact the hydrology of BNP, and potentially impact tidal cycles and inflow of freshwater towards the national parks and the aquatic preserve. The FEIS should clarify whether there will be pre and/or post construction monitoring to ensure that the RCWs are not impacting the ENP, BNP and BBAP.

EPA is concerned that the proposed projects' additional wastewater discharges to the IWF could contribute to increased salinity in the underlying Biscayne Aquifer, and increase the salinity and nutrient loading to BNP and BBAP. Also, EPA is concerned that drift deposition could impact ENP, BNP and BBAP. The NRC should provide additional details regarding these impacts, and any other project impacts to ENP, BNP and BBAP.

Recommendations: The FEIS should specifically and holistically describe impacts to the ENP, BNP and BBAP. Because these are vitally important national and regional resources, the NRC should individually and robustly address potential impacts, both construction and operational, to these public lands.

These specific impacts for the ENP, BNP and BBAP should be separately described in the Affected Environment (Chapter 2), Construction Impacts at the Turkey Point Site (Chapter 4), Operational Impacts at the Turkey Point Site (Chapter 5), and Cumulative Impacts (Chapter 7), sections of the FEIS.

Additionally, EPA recommends NRC and USACE develop a robust monitoring and adaptive management plan (in collaboration with resource agencies) to address any unforeseen future impacts to ENP, BNP and BBAP especially related to the potential operational impacts associated with the RCW. EPA recommends these commitments be reflected in the ROD.

Comprehensive Everglades Restoration Plan (CERP)

The EPA is concerned with the project's potential impacts to CERP. The CERP is a 30 year, $10-12 billion ecosystem project designed to restore the greater Everglades ecosystem. CERP is the largest ecosystem restoration project in the US, and although the Corps and the South Florida Water Management District (SFWMD) are the primary cost share partners, several other local, state, Federal agencies (including EPA), and NGOs are active partners in CERP.

A primary goal of CERP is to restore flows to the greater Everglades and Everglades National Park (ENP). One of the CERP projects is the Biscayne Bay Coastal Wetlands (BBCW) project. EPA is concerned that the proposed project will impact BBCW. In particular, L31E canal is an important part of BBCW. The DEIS states:

> *"Groundwater flow in the Biscayne aquifer is also affected by an interceptor ditch adjacent to the west side of the cooling canals and east of the L-31E Canal. Water is pumped from the interceptor ditch into the IWF cooling canals when needed to maintain a water level in the ditch that is lower than the water level in the L-31E Canal. This is designed to keep groundwater from moving westward from the interceptor ditch toward the L-31E Canal and keep cooling canal water from affecting groundwater quality to the west (FPL 2014-TN4069). However, because deeper permeable layers within the Biscayne aquifer may be isolated from hydraulic head in the ditch by lower permeability layers, it is possible that some water from the cooling canals could move to the west. As discussed in Section 2.2.3 below, monitoring by FPL indicates that hypersaline water from the cooling canals has moved west of the L31-E Canal in the deeper part of the Biscayne aquifer."*

Also, when discussing project components of the BBCW, the DEIS states, "*L-31 East Flow Way – isolation of the L-31E Canal from the major discharge canals and allowing freshwater flow through the L-31E Levee into saltwater marsh. Pump stations and culverts are to be added to facilitate freshwater discharges.*"

The FEIS should clarify whether the NRC anticipates that the proposed project will continue to use water from L31E to augment waters for the IWF, and if so, what the impacts would be to the L31N canal. Also, impacts to the Biscayne Aquifer and further movement of the saline water into Biscayne Bay should be further defined and detailed.

The SFWMD permitted FPL to continue pumping water from L31E canal into the IWF for 2 years, but there is no discussion regarding this subject in the DEIS. EPA is concerned that continued use of the L31E canal as a source of water for the cooling canal system could impact the success of the BBCW and possibly exacerbate movement of salinity through the Biscayne Aquifer.

Recommendations: The EPA recommends that the FEIS better describe the interaction between the FPL's use of L31E canals for the IWF in the existing facility, and proposed project and potential impacts to the BBCW and Biscayne Aquifer. The EPA also recommends that the FEIS discuss the 2-year SFWMD permit to pump water from the L31E canal into the IWF, and resulting impacts to BBCW and Biscayne Aquifer.

EPA also notes that, effective July 14, 2014, SFWMD updated consumptive use permitting (CUP) criteria as part of a statewide effort headed by the FDEP, and joined by all five water management districts. The FEIS should document any changes to existing or future permitting actions relative to this criteria.

Threatened and Endangered Species

The DEIS summarizes the NRC's coordination with the U.S. Fish and Wildlife Service (FWS) and state wildlife agencies in Florida. Mitigation measures include protocols and requirements for protecting the American crocodile, Smalltooth Sawfish, Nassau Grouper, manatees and sea turtles. However, unavoidable adverse impacts would include permanent loss of some onsite aquatic environments, and some disturbance of aquatic environments and potential disturbance of species. Also, there would be habitat loss and land adversely affected for resident American crocodiles (page 2-122 and Table 4-10).

Recommendations: The EPA defers to the FWS and the State wildlife agencies on these issues and agrees that the FEIS should provide updated information. Impacts should be avoided to the maximum extent feasible, and unavoidable impacts should be mitigated.

Radioactivity and Nuclear Waste

Radionuclides

Existing and historic operations at Turkey Point have resulted in radionuclides (tritium) migrating into the hydrologic complex. The DEIS discusses deep-well injection scenarios and postulated doses in Section 5.9.3.3. One of these scenarios includes postulated maximum radionuclide concentrations of tritium, strontium and cesium (page 5-108). Although the DEIS states that there would be no observable health impacts on the public from normal operation of the proposed units (page 5-109), EPA has concerns regarding potential environmental pathways and cumulative impacts related to radionuclides.

Recommendations: The FEIS should provide updated information regarding the progress with defining the extent of the tritium contamination. Updated sampling data should be included or referenced in the FEIS, with modeling information included regarding potential cumulative impacts.

Nuclear waste storage

Liquid, gaseous, and solid radioactive waste management systems would collect and treat the radioactive byproducts of operating the proposed Turkey Point Units 6 and 7, and these byproducts would be handled separately from the byproducts of existing Units 3 and 4. Spent nuclear fuel will require continued on-site storage.

Due to the uncertainty regarding future availability of a geologic repository or other away-from-reactor storage facility, on-site storage may be required for many decades, until a permanent repository is established. The DEIS notes that each nuclear island would consist of a containment building, shield building, and auxiliary building; the radwaste building would be separate from the island, approximately 36 feet above grade (page 3-19).

Recommendations: The FEIS should clarify plans regarding how the storage of spent nuclear fuel will be handled in order to prevent contamination, in the event of flooding at the site. We note that the proposed Units 6 and 7 will be elevated to provide safety from potential flooding,

however, the low sea level in this area combined with the area's history of hurricanes requires that measures to address potential flooding be thoroughly evaluated and documented.

Air Quality

Air Quality Criteria Pollutants

Section 5.7.1 discusses the potential impacts of criteria pollutants associated with operation of Units 6 and 7. The analysis indicates that the principal emissions associated with the new units are emissions of particulate matter with an aerodynamic diameter of 10 microns or less (PM10). Table 5-7 includes estimates of anticipated emissions of criteria pollutants associated with the operation of proposed units 6 and 7. Emission factors from PM10 are cited for the maximum mechanical drift from all six cooling towers. However, it is unclear what assumptions were used to estimate emissions of PM2.5.

Section 7.6.1 discusses the cumulative impacts of criteria air pollutants and indicates that the operation of Units 6 and 7 cooling towers would result in plumes and salt deposition, including "significant salt deposits" when using make-up water, with the highest concentrations occurring within the Turkey Point site, specifically including deposition on the current industrial cooling canals. Hence, the impacts of salinity of the cooling canals cannot be separated from impacts of the new units.

Potential impacts related to interactions of the Unit 6 and 7 cooling towers with the emissions from the stack of the combined-cycle generating Unit 5 were not discussed in the impacts or cumulative impacts sections. The analysis indicates that CALPUFF modelling was performed to determine the impact area, however, this analysis was not included in the appendices. Hence, it is not possible to determine if interactions between these stacks may occur. Of particular concern is the formation of PM2.5 from nitrates, ammonium, or other salts. Table 5-1, which addresses the constituent salts, does not address whether ammonium salts are present. It is not clear from the discussion whether ammonia was not present in samples from the reclaimed water facility, or whether no tests were conducted for this constituent.

Recommendations: EPA recommends that a report documenting the findings of the plume modelling be included in the FEIS appendices, including information on stack height and interaction between the emissions plumes from Units 5, 6, and 7. In addition, EPA recommends clarification of Tables 5-1 and 5-7 or related text to include assumptions used to estimate emissions of PM2.5 from the cooling towers, and the presence of ammonia or ammonium salts related to the use of reclaimed water from the sewage treatment facility.

Socioeconomics and Environmental Justice

Socioeconomics

We note the distinction in the DEIS between temporary construction impacts and longer-term operation impacts. However, since the facility's construction is likely to be underway for seven years, these impacts may be considered significant for the local communities. Issues regarding

traffic congestion, socioeconomic impacts, Environmental Justice, and other issues that directly concern the local communities, as well as operational impacts related to these matters, should be fully clarified in the FEIS, pursuant to our comments.

We understand that the NRC cannot include mitigation measures in the licenses that do not pertain to safety and security. However, the EPA encourages the project team and the applicant to continue coordinating with the communities that will be impacted by the proposed project, and to continue a comprehensive public outreach strategy to inform residents of the risks and impacts as a result of the proposed project. In particular, potential traffic impacts and emergency preparedness measures should be coordinated with local communities.

Recommendations: The EPA encourages a comprehensive public outreach strategy. This should include, but is not limited to, targeted outreach campaigns to neighbors, informational literature, and updated websites. Traffic impacts and emergency preparedness measures are particular topics that should be addressed and coordinated with local communities.

Environmental Justice (EJ)

Pursuant to Executive Order 12898, the DEIS (Section 2.6) includes demographic and impact data, including minority and low-income populations. The project team assessed the potential for disproportionately high and adverse health and environmental impacts, and concluded that there are no environmental pathways where the identified EJ populations in the 50-mile region would be likely to suffer disproportionately high and adverse environmental or health impacts as a result of the proposed project (page 10-7).

Communities may experience both benefits and burdens associated with this project, and should be involved in meaningful discussions with the project team throughout the decision-making process. We encourage the project team to continue coordinating with the communities that will be impacted by the licensing and permitting actions. Community involvement and discussion of project issues should take place throughout project planning. In particular, local communities have voiced their concerns regarding transmission line routing and potential economic impacts resulting from the location of these lines.

Demographics: The NRC includes demographic information related to minority and low income populations. The project area contains minority and low-income populations within the 50 mile project area that includes Miami-Dade County and portions of Broward, Collier, and Monroe Counties. U.S. Census data from the American Community Survey was used to evaluate minority and low-income populations prior to the identification of disproportionate impacts. Thresholds that include the 50% Criterion and the Meaningfully Greater Criterion were used to compare race and income data from the block group level to the reference population at the State. The use of these thresholds are consistent with the Council for Environmental Quality EJ Guidance.

Analyses: Based on our review, EPA has concerns regarding how the *Meaningfully Greater Criteria* was applied. The DEIS used a 20% threshold, however, the manner in which it is

applied or calculated can mean that minority or low-income populations may not be appropriately identified.

In the DEIS, 20% is simply added to the reference population (i.e., 20% threshold +42.2% minority population = 62.2% minority threshold). However, the way the threshold should be used to yield consistent benchmarks involves taking 20% of 42.2% minority population, which is 8.44, and adding that to 42.2, resulting in a benchmark of 50.64%. Using this mathematical calculation will yield consistent benchmarks that will be 20% higher than the reference population, regardless of the initial percent population value.

Meaningful engagement: Communication with minority and low-income populations and other interested individuals, community, community and organizations should consider (as appropriate) encompassing adaptive and innovative approaches to both public outreach, (i.e. disseminating relevant information) ,and participation (receiving community input), since minority populations and low-income population often experience barriers to engagement. NRC indicates that there was active phone and field consultations with various organizations and study of applicant's Environmental Report (ER) to identify affected populations and unique exposure pathways.

Recommendations: The FEIS EJ sections should include information about the outreach and participation methods to minority and low-income populations that may have limited English proficiency, particularly since migrant workers that are primarily Hispanic are located approximately 3 miles from the proposed site. In addition, the FEIS should also include a summary of any EJ comments or concerns, and the NRC's response to those comments.

EJ Impacts: The NRC's EJ analysis includes a summary of noise, air quality, water resource and traffic impacts on affected minority and low-income populations, including Native American tribes and populations that are dependent on subsistence resources. According to the DEIS, there are no disproportionate high and adverse impact to EJ populations.

Recommendations: Based on our review of the EJ section of the DEIS, it was difficult to identify the impacts to minority and low-income populations. Most of the impacts are marginalized for various reasons, including proximity. While the DEIS summarizes the impacts associated with the construction of the reactors and traffic, it is unclear whether there are other impacts that should be considered, such as impacts associated with transmission lines constructed through minority and low-income communities. The FEIS should clarify whether these and other impacts will primarily be borne by EJ communities.

Local residents should be involved in meaningful discussions with the project team throughout the decision-making process. Efforts should be made to meaningfully involve and outreach to residents near the site and with increased visibility to the facility's structures and its emissions. The project team should take community concerns regarding transmission line routing and impacts into consideration, and these concerns should be fully addressed to the extent feasible. Dialog between the project team and the communities should continue.

Tribal Coordination

Consultation

The EPA encourages government to government consultation with the Seminole Tribe of Florida and Miccosukee Tribe of Indians of Florida at all levels of decision-making. The EPA works closely with both Tribes on Everglades-related matters, and is committed to working with other federal partners to prioritize the Tribes' water quality and water management concerns.

National Historic Preservation Act (NHPA)

Historic Preservation

NRC's evaluation anticipates that indirect visual impacts on National Register-eligible buildings will occur in the transmission line corridor. Specific impacts are to be determined based on USACE impact evaluation related to transmission lines on cultural resources. FPL agreed to develop a work plan for additional cultural resources studies related to requirements for the transmission line corridors and offsite facilities.

The DEIS (Section 2.7) describes the project team's coordination with the Florida State Historic Preservation Office (SHPO) and tribes. The document concludes that the potential impact of license renewal on cultural and historic resources is minimal. The USACE is the lead federal agency for Section 106 of the National Historic Preservation Act (NHPA), and the consultation for this project is in progress.

Recommendations: Compliance with Section 106 of the National Historic Preservation Act (NHPA) should be documented as the project progresses. The FEIS should include an update regarding the mitigation measures developed in consultation with the Florida State Historic Preservation Officer (SHPO).

The FEIS should also include an update of coordination activities with the SHPOs and tribes, along with the finalized decision documents pursuant to Section 106 of the NHPA, if available. The EPA defers to the SHPOs and tribes on these issues. EPA encourages government-to-government consultation with the Seminole Tribe of Florida and Miccosukee Tribe of Indians of Florida at all levels of decision-making.

Climate Change, Greenhouse Gases (GHG), Sea Level

Climate Change and Sea Level Rise

The Turkey Point site is in a low-lying, flood-prone, (Section 2.2.1.4, p. 2-6) coastal area at or near sea level. It is often flooded by tides or freshwater runoff (Section 2.4.1.1, p. 2-74). Additionally, it is bounded by Biscayne Bay to the east, Card Sound to the south, and wetlands to the west.

Florida Power & Light proposes to build the proposed action on a filled "island" (Section 3.2.2.1, p. 3-8). This island would contain the proposed two new nuclear units' power blocks and most of the associated infrastructure: the mechanical draft cooling towers, makeup-water

reservoir, substation, underground injection control wells, and various small associated buildings. This island would be constructed on a vacant 218-acre mudflat, known as "Mud Island" (Section 4.1.1.1, pp. (4-4) – (4-6)). This 218-acre mudflat is to be excavated down to XX feet and then filled to a plant grade of 26 feet. This elevation is above the design basis flood elevation of 24.8 ft. (Section 5.11.2.4, p. 5-129).

Additionally, this land island is to be enclosed by a stabilized earth perimeter wall on the north, east, and west sides and a reinforced concrete wall on the south side (Section 3.2.2.1, p. 3-8). This land island will also be surrounded by 4,370 acres (Section 2.3.1, p. 2-42) or 5,900 acres (Section 2.2.1.6, p. 2-7) of existing man-made, unlined cooling canals of the industrial waste facility. It is unclear whether the land island will be 26 feet above these existing cooling canals.

Climate Change Adaptation: NRC's analysis of climate-change effects (Appendix I) does not consider potential climate-change impacts to the proposed action, nor subsequent impacts to the surrounding environment. Instead it documents NRC's qualitative determination of the likely changes described in Chapter 5 (operational impacts) if the environment is altered in a manner consistent with current climate-change predictions (Appendix I, p. I-1).

Recommendations: EPA recommends NRC discuss potential climate-change impacts to the facility, resulting impacts to the surrounding communities, ecosystems, infrastructure, land uses, etc., and mitigation opportunities. Additionally, EPA recommends NRC use available sea-level rise and storm-surge models to quantify impacts to the proposed action, which can facilitate identification of associated impacts to the affected environment. For example, the USACE's Sea Level Rise analysis where alternatives are evaluated using "low," "intermediate," and "high" rates of future sea level rise for both "with" and "without" project conditions.[1]

Stormwater Management Design Event: NRC states the stormwater management system for the new plant area will be designed to handle a 25-year, 72-hour design storm event (Section 3.4.2.1, p. 3-30).

Recommendations: EPA recommends NRC provided some supporting environmental information justifying the sufficiency of a 25-year, 72-hour design storm event for this facility in this area. As noted by NRC, the U.S. Global Change Research Program has determined that extreme heavy precipitation events are expected to increase in frequency and intensity. For example, an event that now occurs once in 20 years is projected to occur 2 to 3 times as often by the end of the century.

Heavy precipitation events are expected to have a 20-percent increase in the amount of precipitation falling. While the number of tropical storms occurring around the globe will decrease, those that occur will be stronger in force, yielding more Category 4 and 5 storms. Rainfall rates associated with tropical storms are expected to be greater, *"...with projected increases of about 20 percent averaged near the center of hurricanes"* (GCRP 2014-TN3472). (Appendix I, p. 1-3)

[1] Incorporating Sea Level Change in Civil Works Programs (31 December 2013) Department of the Army, U.S. Army Corps of Engineers, ER 1100-2-8162, Regulation No. 1100-2-8162, available at http://www.publications.usace.army.mil/Portals/76/Publications/EngineerRegulations/ER_1100-2-8162.pdf

Stormwater Management Cooling Canals: NRC states the stormwater runoff will be directed to the existing cooling canals of the existing industrial wastewater facility.

Recommendations: EPA recommends NRC discuss the impacts of heavy precipitation events, sea level rise, and storm surge on the existing cooling canals and their stormwater-management effectiveness and associated impacts to the affected environment. For example during the hurricane season of 2004, Hurricanes Frances and Jeanne created high-water surges of over 18 feet (Section 9.3.2.4, p. 9-70).

Reportedly, storm surge can range up to 20 feet and last a day in known extreme cases.[2] Moreover, NRC qualitatively presumes the unlined cooling canals' water-surface elevation will rise in response to sea level rise (Appendix I, p.1-5). EPA recommends that the cooling canals' water elevations be analyzed in context of sea-level rise projections and the resulting impacts assessed.

Sea Level Rise and Regional Stormwater Management: As noted by NRC, land was drained by a series of canals to support urban and agricultural development (Section 7.3.2.1, p. 7-22). The anticipated encroaching sea-level can reverse water transport by moving sea water into these canals. Thereby raising the water-surface level and decreasing stormwater storage potential within these canals. Moreover, the rising water-surface level within these canals reflects the saturation of the surrounding soils. Saturated soils are unable to store storm water. Additionally, sea level rise is expected to decrease the water elevation gradient along this canal-drainage system. Thereby reducing the capacity for gravity-driven drainage through the canal network

Recommendations: EPA recommends NRC consider the effects of sea level rise, storm surge, and extreme storm events upon the regional canal system and surrounding saturated soils and associated impacts to the proposed action. EPA recommends this analysis include the stability of the proposed 218-acre, 26-foot elevated, land island having a three-sided earthen berm. For example, FPL proposes to include the underground injection control wells within the elevated, 218-acre, land island (Section 4.1.1.1, p. 4-4).

EPA recommends NRC discuss whether these canals, UIC wells, and the four proposed radial collector wells, will act as conduits to transport ground water under the influence of sea level rise into the proposed facility. As NRC has noted, the drainage canals also provide a conduit for seawater to flow inland at high tide (Section 2.3.3.2, p. 2-66). Additionally, the analysis should include the combined effects of sea level rise combined storm surge and a heavy precipitation event.

As NRC noted (Appendix I), the U.S. Global Change Research Program rates the vulnerability of the Turkey Point area to sea-level rise as "high" to "very high," and notes an "imminent threat of increased inland flooding during heavy rain events in low-lying coastal areas such as southeastern Florida, where just inches of sea level rise will impair the capacity of stormwater drainage systems to empty into the ocean."

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[2] Miami-Dade Sea Level Rise Task Force Report and Recommendations, July 1, 2014, available at heep://www.miamidade.gov/planning/library/reports/sea-level-rise-final-report.pdf

Sea Level Rise and Land Subsidence: Prior work suggests that land subsidence rates in South Florida could be in the 0.7 to 1.8 mm per year range, with Dade County at 1.1 mm per year, which could add 7 to 18 cm (or more) to sea level rise estimates for this area through the year 2080.[3]

Recommendations: EPA recommends NRC discuss the potential impacts of filling a 218-acre mudflat, and thereby raising it to the proposed 26-foot plant grade, upon the Turkey Point area's land subsidence rate and affected environment. Additionally, EPA recommends NRC discuss this impact in context of projected sea level rise, storm surge, and extreme precipitation events. As stated earlier, the U.S. Global Change Research Program predicts the occurrence of more category 4 and 5 storms.

Sea Level Rise and Shoreline erosion: The proposed action is to be located in a low lying coastal area subject to shoreline erosion. It will impact 591 coastal acres. This includes 182 acres of mudflat, 32 acres of open water, and 89 acres of various mangrove types, sawgrass marsh, and mixed wetland hardwood (Section 4.3.1.1, pp. (4-40) – (4-42)). Additionally, the industrial wastewater facility covers another 5,600 acres along 5 miles of the Biscayne Bay shoreline (Section 2.3.1.1, p. 2-44). Moreover an existing barge-turning basin is to be enlarged by 4,356 ft^2 to accommodate large barges (Section 4.2.1.1, p. 4-27). Approximately 328 miles (40 percent) of Florida's sandy beaches are eroding enough to threaten existing developments and recreation areas.[4] According to the state Department of Environmental Protection, 485 miles of beaches (59%) already are experiencing erosion, with 387 miles experiencing "critical erosion.[5]"

Recommendations: EPA recommends NRC examine the potential for shoreline erosion impacts associated with rising sea levels, storm surges, and increasing occurrence of Category 4 and 5 storms on the proposed action and associated impacts upon the affected environment.

Climate Change and Drought impacts: As noted by NRC, climate-related changes include increased frequency and intensity of extreme weather, e.g., heavy downpours, floods, and droughts (Section 2.9.2, p. 2-208). For example, the drought of 2006 lowered the level of Lake Okeechobee to an all-time record of 8.82 foot mean sea level (Section 9.3.2.4, p. 9-70). Droughts and water shortages have the potential to increase in severity and frequency as the water demand increases in south Florida, independent of climate change effects. A minimum of one severe drought every decade can be expected.[6]

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[3] Climate Change in Coastal Areas in Florida: Sea Level Rise Estimation and Economic Analysis to Year 2080, Center for Economic Forecasting and Analysis (2008). Available at http://www.cefa.fsu.edu/content/download/47234/327898

[4] Saving Florida's VANISHING Shores, http://www.epa.gov/climatechange/Downloads/impacts-adaptation/saving_FL.pdf

[5] Florida's Resilient Coasts: A State Policy Framework for Adaptation to Climate Change, http://www.ces.fau.edu/files/projects/climate_change/Fl_ResilientCoast.pdf

[6] Droughts and Water Shortages in Central and South Florida (September 2001) SFWMD Technical Paper EMA #396 available at http://www.sfwmd.gov/portal/page/portal/pg_grp_tech_pubs/portlet_tech_pubs/ema-396.pdf

Ninety percent of South Florida has been designated as a water resource caution area.[7] These are areas that have critical water supply problems, or are projected to have these problems in the next 20 years. Chapter 62-40, F.A.C. requires reuse within these designated areas. Florida currently uses more reclaimed water (43 percent of wastewater) than any other state.

Recommendations: EPA has concerns regarding estuary and habitat impacts related to lengthy periods of droughts. In particular, the potential for increased salinity in existing brackish water habitats should be evaluated. Due to the proximity of saline, hypersaline and seawater in the area, measures to prevent increasing salinity should be addressed; in particular, brackish water species and habitat protection measures should be fully evaluated with regard to the project's impacts and potential future climate conditions.

If the proposed action needed to rely on the radial wells as the primary source of cooling water for extended periods during the project's projected life, the impacts to the near shore aquatic ecosystems should be assessed. Impacts of concern include how the volume of water required for cooling purposes and drawn from Biscayne Bay may potentially affect the salinity levels of the near shore Biscayne Bay, and the associated aquatic ecosystem. EPA recommends that this impact analysis also consider extended periods of drought, characteristic of the southeast U.S.

Greenhouse Gases (GHGs)

EPA appreciates the thorough GHG analysis in the DEIS, which evaluated the carbon dioxide (CO_2) equivalent emissions of the proposed two new nuclear power plants in context of building, operating, and decommissioning (Sections 4.7, 5.7.1, 6.1.3, and 6.3). NRC made conservative GHG-emission estimates by basing them on the most GHG-emission intensive nuclear technology (i.e., the uranium fuel cycle).

Consequently, NRC estimated the total nuclear power plant lifecycle footprint to be 10,500,000 MT CO_2e, with a 7-year preconstruction and construction phase, 40 years of operation, and 10 years of decommissioning. NRC concluded the cumulative impacts from other past, present, and reasonably foreseeable future actions on air quality resources in the geographic areas of interest would be moderate for GHGs. Additionally, NRC concluded the fossil fuel impacts, including GHG emissions, from the direct and indirect consumption of electric energy for fuel-cycle operations would be small (page 6-9).

Recommendations: EPA recommends that the NRC address the following in its FEIS:

- The GHG emissions analysis used a 40-year (Section 7.6.2, p. 7-33) operation period while the Climate Change Effect analysis (Appendix J) incorporated the license renewal which could extend operation of the two reactors another 20 years. EPA recommends NRC's GHG emissions analysis use the 60-year operation period similar to that used in Appendix J.
- Clarify what the uranium fuel cycle is, i.e., identify the activities associated with the production of electricity from nuclear reactions. This could be done effectively with a simple diagram.

[7] Florida Water Management and Adaptation in the Face of Climate Change: A White Paper On Climate Change And Florida's Water Resources November 2011, available at http://floridaclimate.org/docs/water_managment.pdf

- Whether the GHG emissions analysis in the DEIS addresses the GHG emissions associated with decommissioning the existing 2 nuclear power plants (Units 3 and 4), in addition to the new ones (Units 6 and 7). EPA recommends the decommissioning of units 3 and 4 also be included as part of the GHG cumulative-effects analysis.

Indirect and Cumulative Impacts

Indirect and Cumulative Impacts

Several potential cumulative and indirect project impacts are of particular concern at Turkey Point, particularly radionuclides in surface water and groundwater, along with hypersalinity. Also, issues related to all nuclear power plants, including spent nuclear fuel storage, transportation and disposition, and groundwater monitoring for radionuclides, will require continued monitoring as the project progresses.

The existing unlined Industrial Waste Facility (IWF)/Cooling Canal System (CCS) for Units 3 and 4 has issues regarding radionuclides and hypersalinity releases to the aquifer complex. Increasing water withdrawals from the canals, combined with additional groundwater withdrawals, could result in changing the level of the groundwater complex in the area surrounding the open interval of the withdrawal wells, eventually resulting in surface water impacts.

EPA is concerned regarding the proposed project's potential for cumulative impacts on the migration of the existing hypersaline plume, particularly since the quantity of water in the cooling water canals will increase as a result of this project. EPA is especially concerned with ensuring the protection of public drinking water wells located to the west. Therefore, as a result of the proposed changes, further migration of the hypersaline plume is expected, and there is likely to be an increase in the rate of westward migration, increasing the potential for contact with offsite wells.

EPA has concerns regarding the adjacent Biscayne Bay and the surrounding terrestrial environment, particularly that operation of additional units could potentially contribute to existing issues, and thereby increase cumulative impacts and environmental stressors. EPA has concerns that historical operating conditions at the site, combined with future construction and operation of new units, could result in increased saltwater intrusion, increased levels of radionuclides in water, and proximity of a hypersaline plume and sole source aquifer impacts.

Recommendations: The FEIS should evaluate the environmental stressors, in their entirety, on the ecosystem surrounding Turkey Point. The potential impacts of current operations, combined with future groundwater withdrawals needed for construction and operation of the facility, should be fully evaluated, and impacts should be avoided to the maximum extent feasible.

The issue of impacts on water supply wells should be thoroughly evaluated and discussed in the FEIS. The westward movement of the plume as a result of continued use of the cooling water canals should be projected through predictive modeling extending through the expected

operation of the project. The project team should explain what steps will be taken to monitor and protect drinking water supplies in the event that the hypersaline plume encounters a public water supply well.

Transmission line impacts

We have concerns regarding the proposed transmission line corridor route potentially impacting the Everglades National Park. The second and third legs of the West Preferred Corridor would traverse a landscape just east of the Everglades National Park characterized by wetlands and disturbed wetlands; a portion of the second leg would be adjacent to the eastern perimeter of the park (page 2-17).

EPA is concerned with the lack of information in the DEIS regarding the National Park Services' (NPS) DEIS (*Acquisition of Florida Power & Light Company Land in the East Everglades Expansion Area Draft Environmental Impact Statement*, January 2014). The NPS decision regarding the land exchange action will greatly influence which transmission corridor is viable.

Recommendations: The FEIS should clarify the impacts to the Everglades (particularly to the Everglades National Park) associated with the Western Preferred Corridor, and better describe the NPS land exchange DEIS. Efforts should be made to avoid impacts to the extent feasible, and to effectively mitigate impacts where they are unavoidable.

Alternatives analysis

In addition to considering the environmental effects of the proposed action, the DEIS addresses alternatives to the proposed action, including the no-action alternative, alternative siting locations, alternative energy sources, and system designs.

The Executive Summary (pg. xxxvi) states that the NRC staff eliminated several energy sources (e.g., wind, solar, geothermal, and biomass) from full consideration because they are not capable of meeting the need of the project. The EPA would prefer that the NRC evaluation consider the combining of renewable energy sources, such as wind and solar, as an alternative to meet the needs of the project.

Glades, Martin, Okeechobee, and St. Lucie were evaluated as alternative sites for nuclear stations. The NRC staff concluded that all of these alternative sites were generally comparable, and that it would be difficult to state that one site is preferable to another, from an environmental perspective. The DEIS then concludes that the Turkey Point site prevailed because *"none of the alternatives is environmentally preferable to the proposed site,"* (page xxxvii).

We also note that the proposed islands for Units 6 and 7 would be elevated 20-25 feet, in order to decrease the risk of flooding from hurricanes and other weather events that are prone to occur in this area.

Recommendations: Given the environmental concerns at the Turkey Point site, particularly regarding the Biscayne sole source aquifer, public drinking water supply well concerns,

hypersalinity and radionuclide migration issues, proximity of two national parks, Biscayne Bay Aquatic Preserve, and the issues described in EPA's Section 404 CWA comment letters in addition to the other issues detailed above, the reason for the environmental preference for the Turkey Point site is unclear.

The FEIS states that the alternative locations are generally comparable. Therefore, it is unclear why the Turkey Point site is preferred. The FEIS should further clarify and document the rationale that was used, particularly regarding evaluation of viewshed issues and operational analyses.

Also, the evacuation scenarios of the Florida Keys should be evaluated as part of the siting issues, and compared with the evacuation scenarios of the alternative sites. The Florida Keys communities are offshore, and therefore have different evacuation routes than other potential sites that do not involve offshore communities with evacuation concerns. The evacuation of offshore communities in the event of an emergency should be thoroughly considered, and should also take into account the possible impacts of hurricanes occurring in conjunction with a nuclear plant emergency.

Monitoring and Adaptive Management

EPA is concerned about the numerous environmental issues and sustainability related to the project, particularly the current operations of the IWF. The development of the hypersalinity plume, the recent uprate waiver for salinity and temperature, and pumping of water from the L31E canal and other sources to the IWF cause concern that the IWF may not be ecologically viable in the long term. EPA is concerned that the need to place additional water into the IWF in order for it to remain functional is not a long term solution, since the IWF is needed for the proposed project. EPA is particularly concerned regarding the drainage of Unit 6 and 7's construction and post-construction stormwater into the existing IWF, especially considering the numerous issues related to the current operations of the IWF.

Given these uncertainties, as well as uncertainties related to climate change (especially increases in storms and sea level rise, operations of the RCW, and possible exacerbation of the hypersalinity plume), EPA believes that a monitoring and adaptive management plan is needed to prepare for any future, unforeseen environmental issues related to the construction and operation of Units 6 and 7. Therefore, EPA requests that NRC and USACE (with resource agency collaboration) develop a robust monitoring and adaptive management plan.

Recommendations: EPA recommends that NRC and USACE develop a monitoring and adaptive management plan with collaboration from resource agencies, and other stakeholders, for inclusion in the FEIS. Further, EPA recommends NRC and USACE commit to the implementation of the monitoring and adaptive management plan in the Record of Decision (ROD).

SUMMARY OF RATING DEFINITIONS AND FOLLOW UP ACTION*

Environmental Impact of the Action

LO-Lack of Objections
The EPA review has not identified any potential environmental impacts requiring substantive changes to the proposal. The review may have disclosed opportunities for application of mitigation measures that could be accomplished with no more than minor changes to the proposal.

EC-Environmental Concerns
The EPA review has identified environmental impacts that should be avoided in order to fully protect the environment. Corrective measures may require changes to the preferred alternative or application of mitigation measures that can reduce the environmental impacts. EPA would like to work with the lead agency to reduce these impacts.

EO-Environmental Objections
The EPA review has identified significant environmental impacts that must be avoided in order to provide adequate protection for the environment. Corrective measures may require substantial changes to the preferred alternative or consideration of some other project alternative (including the no action alternative or a new alternative). EPA intends to work with the lead agency to reduce these impacts.

EU-Environmentally Unsatisfactory
The EPA review has identified adverse environmental impacts that are of sufficient magnitude that they are unsatisfactory from the standpoint of public health or welfare or environmental quality. EPA intends to work with the lead agency to reduce these impacts. If the potential unsatisfactory impacts are not corrected at the final EIS sate, this proposal will be recommended for referral to the CEQ.

Adequacy of the Impact Statement

Category 1-Adequate
The EPA believes the draft EIS adequately sets forth the environmental impact(s) of the preferred alternative and those of the alternatives reasonably available to the project or action. No further analysis or data collecting is necessary, but the reviewer may suggest the addition of clarifying language or information.

Category 2-Insufficient Information
The draft EIS does not contain sufficient information for the EPA to fully assess the environmental impacts that should be avoided in order to fully protect the environment, or the EPA reviewer has identified new reasonably available alternatives that are within the spectrum of alternatives analyzed in the draft EIS, which could reduce the environmental impacts of the action. The identified additional information, data, analyses, or discussion should be included in the final EIS.

Category 3-Inadequate
EPA does not believe that the draft EIS adequately assesses potentially significant environmental impacts of the action, or the EPA reviewer has identified new, reasonably available alternatives that are outside of the spectrum of alternatives analyzed in the draft EIS, which should be analyzed in order to reduce the potentially significant environmental impacts. EPA believes that the identified additional information, data analyses, or discussions are of such a magnitude that they should have full public review at a draft stage. EPA does not believe that the draft EIS is adequate for the purposes of the NEPA and/or Section 309 review, and thus should be formally revised and made available for public comment in a supplemental or revised draft EIS. On the basis of the potential significant impacts involved, this proposal could be a candidate for referral to the CEQ.

*From EPA Manual 1640 Policy and Procedures for the Review of the Federal Actions Impacting the Environment

EXHIBIT NO. 76

DOCKET NO: 150009-EI

WITNESS: Reed

PARTY: Florida Power & Light Company

BRIEF TITLE OR DESCRIPTION OF THE DOCUMENT:

Excerpt Southern Alliances v. Graham
(Standard of Prudence)

PROFFERED BY: Office of Public Counsel

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 76
PARTY: OPC
DESCRIPTION: Reed/Supreme Court Order

Positive
As of: August 14, 2015 3:38 PM EDT

Southern Alliance v. Graham

Supreme Court of Florida

May 2, 2013, Decided

No. SC11-2465

Reporter
113 So. 3d 742; 2013 Fla. LEXIS 886; 38 Fla. L. Weekly S 267; 2013 WL 1830919

SOUTHERN ALLIANCE FOR CLEAN ENERGY, Appellant, vs. ART GRAHAM, etc., et al., Appellees.

Prior History: [**1] An Appeal from the Florida Public Service Commission.

Core Terms

costs, preconstruction, nuclear power plant, siting, build, cost recovery, licensing, combined, nuclear, final order, power plant, gasification, integrated, plants, cycle, statutes, prudent, rates, mechanisms, activities, utility company, companies', delegates, facilities, electrical transmission, projects, requires, argues, powers, lines

Case Summary

Procedural Posture

Appellee utility companies filed petitions with the Florida Public Service Commission (PSC) seeking to recover through customer rates the preconstruction costs of their respective new nuclear power plant projects under *§ 366.93, Florida Statutes* (2010). Appellant organization opposed the petitions. The PSC granted the petitions. The alliance appealed.

Overview

The organization argued that *§ 366.93* unconstitutionally delegated legislative authority to the PSC. However, the appellate court found that establishing the subject alternative cost recovery mechanisms was simply not a "fundamental legislative task," and that, accordingly, there was no separation of powers violation. The PSC's construction of *§ 366.93* was not clearly erroneous. *Section 366.93* did not require a "final decision" to build proposed new reactors and the preconstruction costs at issue were recoverable under *§ 366.93*. The operative statutes supported the PSC's conclusion that utilities did not need to engage in siting, design, licensing, and construction simultaneously in order to satisfy *§ 366.93* and, by extension, that preconstruction activities creating an option to build could have demonstrated a utility's intent to build for cost recovery purposes under the statute. Substantial evidence supported the PSC's findings to the effect that the utility companies engaged in preconstruction activities creating an option to build the nuclear plants at issue. The PSC's order was not arbitrary and was supported by competent, substantial evidence.

Outcome

The final order was affirmed.

LexisNexis® Headnotes

Governments > Courts > General Overview

Governments > Legislation > General Overview

HN1 It is not the function of the Supreme Court of Florida to substitute its judgment for that of the legislature as to the wisdom or policy of a particular statute.

Energy & Utilities Law > Regulators > Public Utility Commissions > Ratemaking Procedures

Energy & Utilities Law > Electric Power Industry > Electric Power Rates > General Overview

Governments > Courts > General Overview

Governments > Legislation > General Overview

HN2 Authorizing recovery of preconstruction costs through customer rates in order to promote utility company investment in new nuclear power plants, even though those plants might never be built, is a policy decision for the legislature, not the Supreme Court of Florida.

Energy & Utilities Law > Regulators > Public Utility Commissions > Ratemaking Procedures

Energy & Utilities Law > Electric Power Industry > Electric Power Rates > General Overview

abdicate its constitutional lawmaking responsibility," finding to the contrary that the subject statute set forth "very specific and mandatory guidelines for the [PSC] to carry out the purpose of the legislation, and, in doing so, establishe[d] the [PSC] as a body with the appropriate expertise to evaluate the need, complex market conditions, environmental effect and other matters relating to a proposed pipeline, as well as the overall fitness of the applicant." *Id. at 944-45*. Much the same can be said in the present case. *See also AT & T Commc'ns of the S. States, Inc. v. Marks, 515 So. 2d 741, 743-44 (Fla. 1987)* (rejecting similar separation of powers claim **[**15]** where the statute at issue allowed the PSC to consider certain specified factors, as well as "[a]ny other factors that [it] considers relevant" in determining the public interest in licensing phone companies to engage in competition).

HN12 The Legislature further specified that the mechanisms shall "allow for the recovery in rates of all prudently incurred costs." *§ 366.93(2), Fla. Stat. (2010)*. SACE argues that "'prudently incurred' costs is not an objective standard which provides any real guidance for, and/or restrictions on, the [PSC's] authority to determine how far it should go in promoting utility investment in nuclear power." But ***HN13*** the companion statute to *section 366.93* illuminates by negative implication that "[p]roceeding with the construction of the nuclear or integrated gasification combined cycle power plant . . . shall not constitute or be evidence of imprudence" and that "[i]mprudence shall not include any cost increases due to events beyond the utility's control." *§ 403.519(4)(e), Fla. Stat. (2010)*; *see generally Fla. Dep't of State, Div. of Elections v. Martin, 916 So. 2d 763, 768 (Fla. 2005)* (recognizing that ***HN14*** the doctrine of *in pari materia* requires that statutes relating **[**16]** to the same subject be construed together to harmonize the statutes and give effect to legislative intent).

Moreover, ***HN15*** statutes and caselaw routinely apply the prudence standard in the PSC context. *See, e.g., § 366.82(11), Fla. Stat. (2010)* (providing that "[r]easonable and prudent unreimbursed costs projected to be incurred . . . may be added to the rates which would otherwise be charged by a utility upon approval by the [PSC]"); *§ 367.0817(3), Fla. Stat.* (2010) (providing that "[a]ll prudent costs of a reuse project **[*750]** shall be recovered in rates"); *Meadowbrook Util. Sys., Inc. v. Fla. Pub. Serv. Comm'n, 518 So. 2d 326, 327 (Fla. 1st DCA 1987)* (holding that "[h]ere the [PSC] determined that the rate case expense was prudent and we see nothing that requires us to reverse that determination").

As explained by the PSC in the present case, its "standard for determining prudence is well documented in our past Orders. That standard is '. . . what a reasonable utility manager would have done, in light of the conditions and circumstances that were known, or should [have] been known, at the time the decision was made.'" *Final Order, 2011 Fla. PUC LEXIS 392, 2011 WL 5904236, at *20*. Like the term "prudent" here, the term **[**17]** "advertising" has a fixed and definite meaning in the tax context. *In re Advisory Opinion to the Governor, 509 So. 2d 292 (Fla. 1987)*. As such, this Court in *In re Advisory Opinion* did "not believe the legislature doomed the viability of [the tax statute at issue] by failing to define such terms as 'advertising' and 'market coverage.'" *Id. at 312*; *see also Dep't of Ins. v. S.E. Volusia Hosp. Dist., 438 So. 2d 815, 819 (Fla. 1983)* (finding adequate the legislative delegation for agency to establish certain fees on "an actuarially sound basis" where "[t]he courts of Florida have found concepts of actuarial soundness to be a meaningful standard").

Furthermore, ***HN16*** "[g]iven the arcane complexities of utility rate-making, the legislature's decision to vest supervision of rates and service exclusively in the [PSC] must be respected." *Fla. Power & Light Co. v. Albert Litter Studios, Inc., 896 So. 2d 891, 896 (Fla. 3d DCA 2005)*. As this Court recognized in the similarly arcane tax context:

> ***HN17*** The specificity with which the legislature must set out statutory standards and guidelines may depend upon the subject matter dealt with and the degree of difficulty involved in articulating finite standards. **[**18]** The same conditions that may operate to make direct legislative control impractical or ineffective may also, for the same reasons, make the drafting of detailed or specific legislation for the guidance of administrative agencies impractical or undesirable. *State, Department of Citrus v. Griffin, 239 So. 2d 577 (Fla. 1970)*; *Burgess v. Florida Department of Commerce, 436 So. 2d 356 (Fla. 1st DCA 1983), review denied, 447 So. 2d 885 (Fla. 1984)*. In the context of a comprehensive taxation statute extending Florida's sales and use tax to the majority of services marketed in the state, courts cannot realistically require the legislature to dictate every conceivable application of the law down to the most minute detail. As we noted in *Microtel, Inc. v. Florida Public Service Commission, 464 So. 2d 1189, 1191 (Fla. 1985)*, the subordinate factors in complex areas such as taxation should be left to the appropriate agency having expertise and flexibility. Otherwise, the legislature would be forced to remain in perpetual session and devote a large portion of its time to regulation. *Id.*
>
> *In re Advisory Opinion, 509 So. 2d at 311-12*.

PSC Order Exhibit Not moved in

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 77
PARTY: OPC
DESCRIPTION: Final Order of PSC

EXHIBIT NO. 78

DOCKET NO: 150009-EI

WITNESS: JOHN REED

PARTY: FPL

BRIEF TITLE OR DESCRIPTION OF THE DOCUMENT:

Moody's report on U.S. export LNG projects

PROFFERED BY: FIPUG

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 78
PARTY: FIPUG
DESCRIPTION: Reed/Moody's Report on US Export LNG Project

Announcement: Moody's: Liquefied natural gas projects nixed amid lower oil prices

Global Credit Research - 07 Apr 2015

New York, April 07, 2015 -- Liquefied natural gas (LNG) suppliers are curtailing their capital budgets, amid low oil prices and a coming glut of new LNG supply from Australia and the US, Moody's Investors Service says in a new report, "Lower Oil Prices Cause Suppliers of Liquefied Natural Gas to Nix Projects."

Moody's says low LNG prices will result in the cancellation of the vast majority of the nearly 30 liquefaction projects currently proposed in the US, 18 in western Canada, and four in eastern Canada.

"The drop in international oil prices relative to US natural gas prices has wiped out the price advantage US LNG projects, reversing the wide differentials of the past four years that led Asian buyers to demand more Henry Hub-linked contracts for their LNG portfolios," says Moody's Senior Vice President Mihoko Manabe.

However, projects already under construction will continue as planned, which will lead to excess liquefaction capacity over the rest of this decade. Notably, through 2017, Australia will see new capacity come online from roughly $180 billion in investments, which will result in a 25% increase in global liquefaction capacity. Likewise, the US is poised to become a net LNG exporter after the Sabine Pass Liquefaction LLC (Ba3 stable) project goes into service in the fourth quarter of 2015.

Moody's expects Cheniere Energy's Corpus Christi project will be the likeliest project to move forward this year, since it is among the very few projects in advanced development that have secured sufficient commercial or financial backing to begin construction.

Lower oil prices will result in the deferral or cancellation of most other projects, especially this year. While some companies like Exxon Mobil Corp. (Aaa stable) can afford to be patient and wait several years until markets are more favorable, most other LNG sponsors have far less financial wherewithal, and some may be more eager to capitalize on the billions of dollars of upfront investments they have made already, sooner rather than later.

Greenfield projects on undeveloped property are much more expensive, involve more construction risk, and take longer to build than brownfield projects, which re-purpose existing LNG regasification sites. Greenfield projects are also frequently challenged by local opposition and occasionally by untested laws and regulations. Based on the public estimates of companies building new LNG liquefaction capacity, the median cost to build a US brownfield project is roughly $800 per ton of capacity, compared with the more advanced Australian greenfield projects, now estimated at around $3,400 per ton.

Through the end of the decade, Moody's expects LNG demand will grow more slowly versus supply. China will be the biggest variable and most important driver of global LNG in that timeframe. India will see rapid growth, but not be as big of a player as China. Other more mature LNG markets in Japan, South Korea and Europe, which represent the bulk of demand, will have flat growth.

The report is available to Moody's subscribers at URL:

https://www.moodys.com/researchdocumentcontentpage.aspx?docid=PBC_1002517

***

NOTE TO JOURNALISTS ONLY: For more information, please call one of our global press information hotlines: New York + 1-212-553-0376, London + 44-20-7772-5456, Tokyo + 813-5408-4110, Hong Kong + 852-3758-1350, Sydney + 61-2-9270-8141, Mexico City 001-888-779-5833, São Paulo 0800-891-2518, or Buenos Aires 0800-666-3506. You can also email us at mediarelations@moodys.com or visit our web site at www.moodys.com.

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EXHIBIT NO. 79

DOCKET NO: 150009-EI

WITNESS: Grant - Keene

PARTY: Florida Power & Light Company

BRIEF TITLE OR DESCRIPTION OF THE DOCUMENT:

FPL Responses to OPC Interrogatory Nos. 31, 32, and 34 (FERC Accounts)

PROFFERED BY: Office of Public Counsel

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 79
PARTY: OPC
DESCRIPTION: Grant Keene/FPL's Response to OPC's IRROGS 31, 32, 34

Q.
Please describe what types of costs are recorded in FERC Account 183, Preliminary Survey and Investigation Charges.

A.
FERC Account 183, Preliminary Survey and Investigation Charges, is a balance sheet account used for the recording of preliminary feasibility studies. The Code of Federal Regulations (CFR), Title 18, Part 101, provides regulatory guidance as to the type of preliminary costs incurred for project investigation and states the following: "all expenditures for preliminary surveys, plans, investigations, etc. made for the purpose of determining the feasibility of utility projects under contemplation." Generally, this account is used for larger projects under consideration, prior to management approval to move forward with a project, and prior to the company receiving a determination of need.

In addition, the CFR allows for the inclusion of "costs of studies and analyses mandated by regulatory bodies related to plant in service" in FERC Account 183.

Q.
Please explain the accounting treatment of FERC account 183 Preliminary survey and investigation costs incurred for an electric power plant that is placed into service.

A.
FPL's policy, which is consistent with the CFR, is to record costs incurred for preliminary project feasibility studies and analysis under consideration that are anticipated to be capitalized to FERC account 183. When construction commences for an electric power plant, any costs accumulated in FERC account 183 are transferred to FERC account 107, construction work in-progress (CWIP). Once construction is complete and the asset is placed into service, all CWIP charges in FERC account 107 are transferred to FERC account 101, plant in-service.

Q.

Please explain whether the Initial Assessment costs that FPL has identified in the nuclear cost recovery docket would be accounted as Preliminary Survey and Investigation charges under FERC account 183 if they are not recovered through the NCRC? If not accounted for in Account 183, please explain which in which FERC account FPL believes the Initial Assessment costs should be recorded.

A.

The Initial Assessment costs that have been identified in Docket No. 150009 should be recorded in CWIP (FERC account 107) as costs are incurred. These pre-construction costs, defined by FPSC Rule 25-6.0423, are appropriately recorded to CWIP consistent with all other Turkey Point 6 & 7 pre-construction costs incurred since the filing of FPL's need determination.

AFFIDAVIT

(Jennifer Grant-Keene)

STATE OF FLORIDA)

COUNTY OF Palm Beach)

I hereby certify that on this 23rd day of July, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Jennifer Grant-Keene, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatories numbers 31-34 and co-sponsored number 35 from OPC's third set of interrogatories to Florida Power & Light Company (Nos. 13-35) in Docket No. 150009-EI, and that the responses are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 23 day of July, 2015.

Notary Public
State of Florida, at Large

ANNETTE L. GIVENS
NOTARY PUBLIC
STATE OF FLORIDA

My Commission Expires:
March 15, 2017

PSC Order Exhibit Not moved in

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 80
PARTY: OPC
DESCRIPTION: Scroggs/Final Order approving Levy revised and restated stipulation and agreement

EXHIBIT NO. 81

DOCKET NO: 150009-EI

WITNESS: Scroggs

PARTY: Florida Power & Light Company

DESCRIPTION: Commission Staff Levy Audit June 2015

DOCUMENTS:

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

Pages 8 and 9 only

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 81
PARTY: OPC
DESCRIPTION: Commission Staff June 5th Audit Levy Pages 8, 9

Commission audit staff published previous reports in 2008 through 2014; each entitled *Review of Duke Energy Florida, Inc.'s Project Management Internal Controls for Nuclear Plant Uprate and Construction Projects.* These reports are available on the Commission website at www.floridapsc.com/publications.

1.2.2 Scope

The period of this review is January 2014 to May 2015. Staff examined the adequacy of DEF's project management and internal controls for these projects. The internal controls assessed were related to the following key areas of project activity:

- Planning
- Management and organization
- Cost and schedule controls
- Contractor selection and management
- Auditing and quality assurance

Comprehensive controls are essential for successful project management. However, adequate and comprehensive controls are ineffective if not actively emphasized by management, embraced by the organization, and subject to oversight and revision. Proper internal controls minimize risk, enhance its mitigation and management, and aid efficient, reasoned decision making.

Risk must be timely and accurately identified. Sufficient safeguards created, vetted, and in place will help prevent and mitigate risk. Prudent decision making results from well-defined processes that address identified risks, expectations, and cost. Effective communication, adherence to clear procedures, and vigilant oversight are also essential to ensure prudent project decisions.

Commission audit staff's review places primary importance on internal controls found in the Institute of Internal Auditors' *Standards for the Professional Practice of Internal Auditing* and in the *Internal Control - Integrated Framework* developed by the Committee of Sponsoring Organizations of the Treadway Commission. The framework states that an internal control should consist of five interrelated components:

- Control environment
- Risk assessment
- Control activities
- Information and communication
- Monitoring

To maximize operational effectiveness and efficiency, reliability of financial reporting, and compliance with applicable laws and regulations, all five components must be present and functioning to conclude that internal controls are effective.

1.2.3 Methodology

Initial planning, research, and data collection for this review occurred during January 2015. Additional data collection, analysis, and report writing were conducted in January through May 2015. The information compiled in this report was gathered via company responses to audit staff

document requests, onsite visits to the Crystal River Energy Complex and the DEF St. Petersburg office, and interviews with key project personnel. Audit staff also reviewed testimony, discovery, and other filings in Docket No. 150009-EI. A large volume of information was collected and analyzed by audit staff. Specific information collected from DEF included the following categories:

- Policies and procedures
- Organizational structures
- Contract requests for proposal
- Contractor bids
- Bid evaluation analyses
- Contracts
- Change orders
- Internal audit reports and quality assessment reviews

1.3 Audit Staff Observations

1.3.1 Levy Nuclear Plant

The company continues its legal dispute with Westinghouse over the cancelation of the EPC contract for the Levy plants. This has limited DEF's abilities when working to disposition the Long Lead Equipment (LLE) secured under the EPC contract. During 2014, the company worked with Westinghouse to resolve, discontinue, terminate, or sell the assets purchased through third-party vendors. Presently, the dispositions of all LLE assets, with the exception of the VFD's, were either resolved or being addressed through the EPC cancelation litigation. The remaining open item is noted in section 2.2.

It is difficult to assess the overall approach of DEF's disposition choices due to the legal issues with Westinghouse. In each case, the company was reliant on Westinghouse to be the intermediary for the dispositioning, and all the items were part of the overall contract in dispute. Prior to the cancelation of the EPC, the company made the decision to halt manufacturing of several components at its current milestone payments and negotiate a settlement for the remaining fees. In these cases the company justified its decisions through proper documentation.

The company is still working to obtain the Combined Operating License from the NRC. The application timeline has slipped due to several NRC design concerns for the AP1000. These are issues for Westinghouse to resolve; the Levy application can only be issued once the NRC approves acceptable design modifications.

1.3.2 CR3 Extended Power Uprate

The company moved forward with its planned dispositioning of the eligible CR3 assets in 2014 and 2015. This was performed using Duke Energy's corporate investment recovery guidance procedures. The completion of this effort will allow the company to work with the NRC on the decommissioning plan.

The company dispositioned CR3 equipment via internal transfers, listed bid events, and a public auction. This was in accordance with the latitude given to the recovery team through the

EXHIBIT NO. 82

DOCKET NO: 150009-EI

WITNESS: Reed

PARTY: Florida Power & Light Company

BRIEF TITLE OR DESCRIPTION OF THE DOCUMENT:

Composite Exhibit of PTN 3 & 4 EPU Costs and Contingency (Turkey Point 3 & 4 EPU Costs)

PROFFERED BY: Office of Public Counsel

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 82
PARTY: OPC
DESCRIPTION: Reed/Composite Exhibit of PTN 3,4 and contingency Turkey Point 3 and 4 EPU Costs

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for determination of need for expansion of Turkey Point and St. Lucie nuclear power plants, for exemption from Bid Rule 25-22.082, F.A.C., and for cost recovery through the Commission's Nuclear Power Plant Cost Recovery Rule, Rule 25-6.0423, F.A.C.	DOCKET NO. 070602-EI ORDER NO. PSC-07-0973-PHO-EI ISSUED: December 5, 2007

Pursuant to Notice and in accordance with Rule 28-106.209, Florida Administrative Code (F.A.C.), a Prehearing Conference was held on December 3, 2007, in Tallahassee, Florida, before Commissioner Nancy Argenziano, as Prehearing Officer.

APPEARANCES:

R. WADE LITCHFIELD, ESQUIRE, MITCH ROSS, ESQUIRE, BRYAN S. ANDERSON, ESQUIRE, and JESSICA A. CANO, ESQUIRE, 700 Universe Boulevard, Juno Beach, Florida 33408-0420
On behalf of Florida Power & Light Company.

JENNIFER S. BRUBAKER, ESQUIRE, and KATHERINE E. FLEMING, ESQUIRE, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
On behalf of the Florida Public Service Commission (Staff).

PREHEARING ORDER

I. CASE BACKGROUND

On September 17, 2007, Florida Power & Light Company (FPL) filed a petition for a determination of need for proposed nuclear power plants in Dade and St. Lucie Counties, pursuant to Section 403.519, Florida Statutes (F.S.), and Rule 25-22.080, Florida Administrative Code (F.A.C.). FPL's proposal consists of the expansion of the electric generating capacity of its existing Turkey Point and St. Lucie nuclear power plants, in Dade and St. Lucie Counties, respectively. FPL's proposed uprate would increase the power output at Turkey Point, units 3 and 4, from approximately 700 megawatts (MW) to 804 MW per unit, for a two-unit total of about 208 MW. At St. Lucie, units 1 and 2, net electrical generation per unit is expected to increase from approximately 840 MW to 943 MW, for a two-unit total of 206 MW. FPL proposes to complete the uprate to all four nuclear units during separate outages beginning in 2011 and ending in 2012.

The Commission issued a Notice of Commencement of Proceedings to the appropriate agencies, local governments, and interested persons on September 20, 2007. By Order No. PSC-

DOCUMENT NUMBER-DATE
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FPSC-COMMISSION CLERK

effective, and the Commission has approved, since the current DSM goals were approved. Additional conservation measures cannot be implemented to eliminate the need for the PTN and PSL uprates.

For purposes of analysis, FPL's forecast assumed successful contracting for and delivery of 144 MW of renewable firm capacity bid in response to its 2007 request for proposals for renewable energy, and successful extension of 143 MW of renewable firm capacity from three expiring municipal waste-to-energy contracts. There are not sufficient additional renewable energy options to mitigate the need for the 414 MW of nuclear baseload capacity that will be provided by the uprates. The table shown under Issue 1 shows the need for additional capacity even after including DSM and purchased power from renewable energy sources.

STIPULATED

ISSUE 6: Will the proposed expansion of the Turkey Point and St. Lucie Nuclear Power Plants provide the most cost-effective source of power, as this criterion is used in Section 403.519(4), Florida Statutes?

POSITION: Yes. The proposed uprates will provide the most cost-effective source of power, as this criterion is used in Section 403.519(4), Florida Statutes. The estimated nominal costs for the PTN and PSL uprates, not including construction carrying costs, are approximately $750 million and $651 million, respectively. The costs of changes to the transmission system that are needed to support the uprates are estimated at $45 million.

To fully evaluate the system impacts of the nuclear uprates, FPL developed a long-term resource plan that included the uprates ("the Plan with Nuclear Uprates") and an alternate resource plan not including the nuclear uprates ("the Plan without Nuclear Uprates"). The Plan without Nuclear Uprates represents the addition of combined-cycle (CC) units that could be sited and receive permitting approval in the relative near term. FPL also utilized three different fuel cost forecasts and four different environmental compliance cost forecasts in its economic analysis to address the impacts of uncertainty in future fuel and environmental compliance costs. Because 3 of these 12 scenarios represent a highly unlikely combination of low natural gas costs and high CO_2 environmental compliance cost, FPL used 9 scenarios in its economic analysis. FPL's analysis shows that in eight of the nine economic scenarios comparing the generating technology choices represented in the two plans, the Plan with Nuclear Uprates is the most cost effective option. The estimate is that total net savings realized by customers are expected to range from $222 million to $963 million on a cumulative present value revenue requirement basis.

FILED JUL 23, 2013
DOCUMENT NO. 04218-13
FPSC - COMMISSION CLERK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Nuclear cost recovery clause.	DOCKET NO. 130009-EI ORDER NO. PSC-13-0333-PHO-EI ISSUED: July 23, 2013

Pursuant to Notice and in accordance with Rule 28-106.209, Florida Administrative Code (F.A.C.), a Prehearing Conference was held on July 12, 2013, in Tallahassee, Florida, before Commissioner Eduardo E. Balbis, as Prehearing Officer.

APPEARANCES:

BRYAN S. ANDERSON, KENNETH R. RUBIN, and JESSICA A. CANO, ESQUIRES, Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408
On behalf of Florida Power & Light Company (FPL).

JOHN T. BURNETT, DIANNE M. TRIPLETT, and MATTHEW R. BERNIER, ESQUIRES, Duke Energy Florida, Inc., Post Office Box 14042, Saint Petersburg, Florida 33733; JAMES MICHAEL WALLS and BLAISE N. GAMBA, ESQUIRES, Carlton Fields, P.A., Post Office Box 3239, Tampa, Florida 33601-3239
On behalf of Duke Energy Florida, Inc. (DEF).

J.R. KELLY, CHARLES J. REHWINKEL, JOSEPH A. MCGLOTHLIN and ERIK L. SAYLER, ESQUIRES, Office of Public Counsel, c/o The Florida Legislature, 111 W. Madison Street, Room 812, Tallahassee, Florida 32399-1400
On behalf of the Citizens of the State of Florida (OPC).

JON MOYLE, JR., and KAREN A. PUTNAL, ESQUIRES, Moyle Law Firm, P.A., 118 North Gadsden Street, Tallahassee, Florida 32301
On behalf of the Florida Industrial Power Users Group (FIPUG).

JAMES W. BREW and F. ALVIN TAYLOR, ESQUIRES, Brickfield, Burchette, Ritts & Stone, P.C., 1025 Thomas Jefferson St., NW, Eighth Floor, West Tower, Washington, DC 20007
On behalf of White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs (PCS PHOSPHATE).

GEORGE CAVROS, ESQUIRE, 120 E. Oakland Park Boulevard, Suite 105, Fort Lauderdale, Florida, 33334
On behalf of the Southern Alliance for Clean Energy (SACE).

OPC: **FPL**

Turkey Point Units 6 & 7 Project

With respect to Turkey Point Units 6 & 7, FPL has continued to limit its activities to those necessary to pursue an operating license. At this time, the Office of Public Counsel (OPC) is not recommending any adjustments to the amounts that FPL wishes to recover from customers to sustain its conservative approach. However, in light of the amendments to Section 366.93, F.S., it appears FPL must either certify that its intent to build Turkey Point Units 6 & 7 satisfies the statutory revision or provide supplemental testimony which conforms to the revised statutory intent language. Based on the amendments to the statute, it appears that FPL must utilize its new AFUDC rate for costs after July 1, 2013.

FPL St. Lucie and Turkey Point EPU Projects

In 2007, FPL estimated the Turkey Point EPU and St. Lucie EPU projects would cost approximately $750 million and $651 million, respectively, for a combined estimated cost of approximately $1.4 billion.[2] In 2013, the Turkey Point EPU and St. Lucie EPU projects are now estimated to cost ratepayers approximately $2.2 billion and $1.2 billion, respectively. The Turkey Point EPU will be more than twice as expensive as the St. Lucie EPU on a dollars per kilowatt basis and almost three times its original $750 million estimate. Fortunately, the runaway spending on FPL's Turkey Point EPU will soon cease. The question remains, whether the St. Lucie and Turkey Point EPU projects are economically justifiable and beneficial to FPL's customers.

By Order No. PSC-09-0783-FOF-EI, the Commission indicated it has the discretion to use whatever methodology it deems appropriate to monitor the continued feasibility of a nuclear project on an annual basis.[3] That discretion applies to measuring the economics of the project and the reasonableness of the final increment of costs as the overall project, nearing completion, comes into focus. The extraordinary level of spending on the Turkey Point plant site in 2012 compels a separate appraisal of the economics of the St. Lucie and Turkey Point EPU projects to assess whether each project is economically justifiable and beneficial to FPL's customers on a standalone basis.

Utilizing information obtained from FPL, OPC witness Dr. Jacobs demonstrates that, while the St. Lucie uprate capacity is economic and beneficial, the vastly more expensive uprate capacity of the existing Turkey Point units is not.

[2] Order No. PSC-08-0021-FOF-EI, Issued January 7, 2008, at 5 (EPU Need Determination Order).
[3] Order No. PSC-09-0783-FOF-EI, issued November 19, 2009, at 14-16.

Q.
Please refer to page 32, line 6-10. At a stage of 50% design completion, what is the "expected level of uncertainty with respect to the project scope"?

A.
At a stage of 50% design completion, the level of project scope uncertainty associated with the 50% of the design that has been completed is comparatively low; however, the level of project scope uncertainty associated with the remaining 50% for which design is not completed remains relatively high.

There is no universally applicable percentage amount of uncertainty that should be applied to all projects at a 50% design completion state. FPL's non-binding cost estimate range encompasses an expected level of uncertainty with respect to project scope and project cost at the time of the submission of its testimony, which reflected a range of -0% to approximately +7%.

AFFIDAVIT

Terry Jones
(Signature of Sponsor)

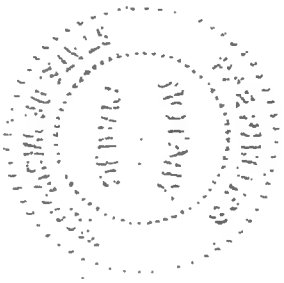
State of WI)
) ss:
County of Manitowoc

I HEREBY CERTIFY that on this 27th day of May 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Terry O. Jones who is personally known to me, and he acknowledged before me that he sponsored the answers to Interrogatory Nos. 56, and 63- 81 from the Office of Public Counsel's 7th Set of Interrogatories to Florida Power & Light Company in Docket No. 110009-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid this 27th day of May, 2011.

Rae Phillips
Notary Public - State of ~~Florida~~ Wisconsin
RP 5/27/11

Notary Stamp:



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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 110009-EI
FLORIDA POWER & LIGHT COMPANY

MAY 2, 2011

IN RE: NUCLEAR POWER PLANT COST RECOVERY
FOR THE YEARS ENDING
DECEMBER 2011 AND 2012

TESTIMONY & EXHIBITS OF:

TERRY O. JONES

COM 5
APA 1
ECR 10
GCL 1
RAD 1
SSC
ADM
OPC
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support. The majority of FPL's costs, however, will continue to flow from the many ongoing contracts introduced and reviewed in prior proceedings. Careful vendor oversight, continued use of competitive bidding when appropriate, and the application of the robust internal schedule and cost controls and internal management processes, all demonstrate that FPL's projected 2012 expenditures are reasonable.

TRUE-UP TO ORIGINAL COST AND UPDATED COST ESTIMATE RANGE

Q. Did FPL prepare a true-up of the total project costs in 2010?

A. Yes. FPL's 2010 True-up to Original schedule is included in TOJ-22.

Q. Have you prepared a current true-up of the total project costs through the current reporting period?

A. Yes. Exhibit TOJ-22 includes the 2012 TOR schedules that compare the current projections to FPL's originally filed Project costs. The 2012 TOR schedules provide information on the project costs through the end of 2013. The 2012 TOR schedules provide the best information currently available for the cost recovery period through 2013.

Q. Has FPL updated its total nonbinding cost forecast for the project?

A. Yes. Pursuant to the Commission's direction in Order No. PSC-09-0783-FOF-EI, FPL has updated its capital cost forecast. FPL has developed an updated cost forecast range for the EPU project that reflects increased scope that is necessary to support NRC regulatory requirements, power generation in

8

the uprate condition, and implementation support. The updated cost estimate range is approximately $2,324 million to $2,479 million, including transmission costs and carrying costs, as shown on NFR Schedule TOR-2.

Q. Why is FPL providing a nonbinding range instead of a single point estimate?

A. The progression of project activities over the last several years provides FPL with additional insight to revise its nonbinding cost forecast. However, the project is still in the design engineering phase and there remains an expected level of uncertainty with respect to project scope. Accordingly, it is only appropriate to provide the total project cost in terms of a range.

This approach is consistent with generally accepted project management best practices. For example, the Project Management Institute's "A Guide to the Project Management Body of Knowledge" states the following at page 161:

> The accuracy of a project estimate will increase as the project progresses through the project life cycle. For example, a project in the initiation phase could have a rough order of magnitude (ROM) estimate in the range of -50% to +100%. Later in the project, as more information is known, estimates could narrow to a range of -10% to +15%.

As activities such as final design engineering analyses, associated NRC reviews, and construction planning progress, FPL will be able to provide additional certainty to the total project cost forecast.

Q. Please describe the development of the current non-binding cost estimate range for the EPU Project.

9

A. The low end of the non-binding cost estimate range represents the current forecast, approximately $2.324 million, at this stage of the project based on the following status of tasks: i) the completion of the LAR engineering effort; ii) the approximately 95% committed costs for long lead equipment, which represents approximately $250 million of $510 million of these costs (as of March 2011); iii) the approximately 50% completion of the design modification phase of the project, which represents approximately 625,000 hours of 940,000 hours of this phase (as of April 2011); and iv) an estimate of implementation costs. The LAR analyses and design modification engineering activities have added work scope to the project. The high end of the range reflects the current forecast, an evaluation of the existing trends for weighted risks, and undefined scope. This resulted in a high end non-binding cost estimate range amount of approximately $2,479 million.

Q. Please compare the current cost estimate range of the EPU Project to the nonbinding cost estimate presented in FPL's Need Filing.

A. FPL's need filing in September 2007 for the EPU Project included a nonbinding cost estimate of $1,798 million. This initiation phase estimate was based on FPL's preliminary feasibility and scoping studies and reflected the best information available at that time. (Please note that FPL's original non-binding cost estimate included the participant's share of St. Lucie Unit 2.)

Q. Please describe the primary reasons why the current nonbinding cost estimate range is higher than the nonbinding cost estimate previously provided.

10

EXHIBIT NO. 83

DOCKET NO: 150009-EI

WITNESS: Reed

PARTY: Florida Power & Light Company

BRIEF TITLE OR DESCRIPTION OF THE DOCUMENT:

FPL Responses to OPC Interrogatory Nos. 23-30
(FOAK Responses)

PROFFERED BY: Office of Public Counsel

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 83
PARTY: OPC
DESCRIPTION: Reed/FPL Responses to OPC's IRROGS Nos. 23-30 FOAK Responses

Q.
On page 5, lines 13 through 16, Witness Reed states that "'subsequent installations will normally cost less than the first plant.'"

a. Is the assumption that a subsequent nuclear plant installation of the same design will cost less than a first installation plant based on the total capital cost for installation based on actual cost or estimated cost?

b. If this assumption is based on estimates, please explain how the estimates form the basis for this premise?

c. Is FPL's proposed AP1000 design considered a subsequent nuclear plant installation to a unit currently under construction? Is Summer or Vogtle considered to be first-of-a-kind (FOAK)? Which specific unit is considered to be FOAK?

d. Would the FPL AP 1000 nuclear units be considered a FOAK plant based on the design changes to FPL's proposed AP1000 nuclear units? If not, please explain why not?

e. Cite all examples, including cost figures, where subsequent nuclear units in the U.S. have come in at lower costs than FOAK units.

A.
a. The citation from Witness Reed's testimony (*i.e.* , page 5, lines 13 through 16) is a quote from a quality guideline published by the National Energy Technology Laboratory ("NETL"). The methodologies described in the referenced study are based on the use of actual, historical costs.

b. Not applicable, please see response to subpart (a).

c. Vogtle Units 3 & 4 have, technically, been designated the AP1000 "reference plant" for purposes of the NRC and licensing. However, the terms FOAK and NOAK refer to the ability to apply insights from early experiences with a particular technology for the benefit of later projects.

Chronologically, the PTN 6 & 7 project will follow the Summer and Vogtle projects as well as other AP1000 projects that are being completed worldwide. The FPL units will be at the front of the "second wave" of new AP1000 projects. By virtue of its position in this sequence, the Company will have the opportunity to incorporate significant lessons learned from earlier projects into its implementation of PTN 6 & 7.

d. As with all mega projects, it is likely that PTN 6 & 7 will have certain limited FOAK elements. However, given that it is using the same general technology platform as Vogtle and Summer (*i.e.* , the Westinghouse AP1000), it is Witness Reed's expectation that PTN 6 & 7 will benefit from a cost and schedule perspective by incorporating lessons learned from the preceding projects.

e. Witness Reed's testimony provides citations to industry studies that have established the benefits subsequent projects gain by virtue of following FOAK projects. Witness Reed has not undertaken an independent study to identify subsequent nuclear units in the U.S. that have come in at lower costs than FOAK units.

Q.

Please state whether witness Reed knows of any nuclear plants built in the United States that have not experienced significant cost increases over the original cost estimates to completion the plant. If yes, please name the plant, the original estimated costs and the total capital costs upon completion.

A.

In developing his rebuttal testimony, Witness Reed has not performed a study such as that described in the request. Rather, Witness Reed's rebuttal testimony discusses the cost and schedule benefits received by subsequent construction projects that follow FOAK installations.

Q.

On page 6, lines 7 through 10, Witness Reed sites a study for the proposition that between the first new nuclear plant and some subsequent plant of the same design, the study " .. estimates a learning rate of roughly 3 to 10 percent in the U.S."

a. Please explain what is meant by a 3 to 10 percent learning rate?

b. Please explain whether the "learning rate" is based on original estimated cost or actual cost to build the first nuclear plant?

A.

a. The 2004 University of Chicago study "uses a range of 3 to 10 percent for future learning rates in the U.S. nuclear construction industry, where learning rate is the percent reduction in cost resulting from doubling the number of plants built." Some of the conditions associated with determining learning rates include: the pace of reactor orders, the number of reactors built at a single site, the competitiveness of the construction market, reactor design standardization, and the impacts of regulation.

b. Because of limitations in the business proprietary data that were available to the authors of the study, the learning rates are not based on actual costs. The proportional reduction in the cost of future nuclear construction that results from engineering and construction efficiency gains with each completed plant is based on cost estimates from the DOE NP2010 program.

Q.

On page 6, lines 12 through 14, witness Reed states the first of its kind (FOAK) engineering represent roughly 11% of the total overnight capital cost estimate.

a. Please explain which overnight capital cost estimate is referred to in this part of testimony.

b. Please explain how the percent of FOAK engineering would be impacted if the cost was based on the total owner and contractor price to build the first generation APIOOO nuclear units.

c. If FOAK engineering costs are 11% of total overnight capital costs, what percentage would the remaining all other engineering costs represent? Translate these percentages into $/kw of total overnight costs including the following categories: FOAK engineering, all other engineering; equipment, materials and supplies, craft labor, owner's costs, transmission, NSSS costs and all other.

A.

a. This passage in Witness Reed's testimony refers to a University of Chicago study that uses a generic $8.84 billion overnight capital cost estimate for a two-unit plant using either the ABWR or AP1000 reactor technology.

b. The specific data required to answer this question is considered business proprietary. Therefore, the estimates used in the study were generated from the best information available, including informal communications with vendors. Mr. Reed does not believe the inclusion of owner and contractor costs would materially change the proportional cost of FOAK engineering.

c. Witness Reed has not completed an analysis of the composition of overnight costs at the level of detail that is requested in the question.

Q.
Please see page 6, line 8. What is the appropriate "n" for the Turkey Point Units 6 and 7? In the U.S., what historical units represent an "nth" plant and what were the specific, quantified savings?

A.
The NETL study Witness Reed cited in his testimony states that "the definition of the NOAK plant is somewhat arbitrary as well, although it is often taken as the fifth or higher plant." However, schedule and cost benefits available by learning from prior experience is possible regardless of which position in the sequence of construction a unit is placed after the initial unit. For example, certain major construction milestones on Vogtle Unit 4 (e.g., pouring of the concrete basemat) have benefited from the experience gained on completion of Vogtle Unit 3 and experience at the Summer site. FPL may be able to achieve significant schedule and cost savings by planning PTN 6 & 7 to reflect the lessons learned throughout the construction of the first wave of AP1000 projects.

Witness Reed has not performed a study of the specific, quantified savings from NOAK nuclear construction projects over the FOAK units.

Q.
Please refer to page 6, lines 6-20. Identify "nth of a kind" nuclear projects in the U.S. including the value of "n", the FOAK project and the percentage and quantity of savings of the "nth" plant versus the FOAK project.

A.
Witness Reed has not performed a study of the specific, quantified savings from NOAK nuclear construction projects in the U.S.

Q.
Please refer to page 3 lines, 13-20:

a. If CB&I is not the contractor for the Turkey Point Units 6 and 7 project, what other contractors would be available? Please list.

b. Is it your belief that these contractors would offer a fixed price contract? If not, why not?

c. What other contracting methods would be available?

d. What contacting method would Witness Reed recommend and why?

e. Please explain why Witness Reed believes that his recommended contracting method would be superior to a fixed price EPC contract?

A.

a. Witness Reed has not completed any assessments of the availability or suitability of any potential contractors to complete any portion of the PTN 6 & 7 Project.

b. Witness Reed does not believe that any vendor is likely to offer an economic, binding, fixed-price, EPC contract for the PTN 6 & 7 Project. The regulatory, financial, economic, and commodity risks to a vendor from entering a fixed price contract for a mega-project would almost certainly raise the cost to a level that would be unacceptable to the Company and extraordinarily disadvantageous to FPL's customers. Witness Reed believes that it is highly unlikely that any vendor would be willing to undertake a fixed price contract for a new nuclear construction project, even with a significant risk premium.

   Prior industry experience, including observations of the Vogtle and Summer projects, indicates that a commercial and contracting approach that appropriately apportions risk between the owner and the contractors of a mega-project rather than fixing the total project cost is much more likely to produce a contract that achieves the needs of both parties.

c. There are many conceivable alternatives to a fixed price contract that may ultimately be suitable for the PTN 6 & 7 Project. Potential alternatives to a fixed price approach include indexed pricing, firm pricing with fixed and indexed components, and target price models. Each of these and other models are designed to balance project-related risks among the contract counterparties rather than assign all risk to a single party.

d. Witness Reed agrees with the Company that it would be inappropriate to select a contracting strategy at this phase of the PTN 6 & 7 Project. At the earliest, the Company should begin a deliberate and methodical process of evaluating contracting options after initiating preconstruction work, as that term is used in F.S. 366.93(3)(c). Witness Reed understands that preconstruction work will not commence until after the Company receives a COL.

e. Witness Reed believes that it is too soon to determine a specific contracting approach. Please see responses to subparts (a) through (d) of this interrogatory.

Q.
Please see page 4, lines 14 -23:

a. Please explain at what "stage" Witness Reed would recommend seeking contract terms from vendors and what contracting approach would he pursue?

b. How would Witness Reed's method ensure a stable price?

c. Is Witness Reed recommending that the next phase of "preconstruction" for this project be approved before a contract price or price estimate is known?

A.

a. Please see FPL's response to OPC's Third Set of Interrogatories No. 29.

b. As explained in response to FPL's response to OPC's Third Set of Interrogatories No. 29, Witness Reed does not believe that it is appropriate for FPL to evaluate or select contracting options at this time. When, ultimately, FPL determines that it is appropriate to begin the process of obtaining contract terms from qualified vendors, the Company will undertake a methodical process of determining contracting mechanisms that will provide it with the assurance that any costs the Company will incur to develop the Project will continue to be just and reasonable. Mr. Reed does not believe that the sole or even primary criterion should be a stable price. Instead, a standard of achieving the lowest reasonable price for a project that is safe, reliable, and offers predictability would be the criteria he would focus on.

c. FPL should not seek a binding contract price for completion of any portion of the PTN 6 & 7 Project until the COL has been obtained and the Commission is prepared to authorize preconstruction activities. This can and should be done based on the best estimates of the project's price that are available at that time.

A thorough evaluation of contracting options and pricing that may be available to the Project would require that FPL commit substantial staffing and financial resources to a rigorous and involved engineering and procurement process. Based on Witness Reed's understanding of the Nuclear Cost Recovery statute, the Company would be unable to seek recovery of these costs until after it has obtained a COL and demonstrated the continued feasibility of PTN 6 & 7.

AFFIDAVIT

(John J. Reed)

STATE OF Ma)

COUNTY OF Middlesex)

I hereby certify that on this 22 day of July, 2015, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared John J. Reed, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatories numbers 23-30 from OPC's third set of interrogatories to Florida Power & Light Company (Nos. 13-35) in Docket No. 150009-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 22 day of July, 2015.

Notary Public
State of Ma. at Large

My Commission Expires:

WENDY L. PRESTON
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
April 22, 2022

EXH 84

2015 Feasibility Analyses Results for the Turkey Point 6 & 7 Project: Case # 2 Analysis - 60-Year Operating Life; Total Costs, Total Cost Differentials, and Breakeven Costs for All Fuel and Environmental Compliance Cost Scenarios in 2015$ (millions, CPVRR, 2015 - 2088)

(1)	(2)	(3)	(4)	(5) = (3) - (4)	(6)
Fuel Cost Forecast	Environmental Compliance Cost Forecast	Total Costs for Plans: Resource Plan w/ TP 6 & 7	Total Costs for Plans: Resource Plan w/o TP 6 & 7	Total Cost Difference Plan with TP 6 & 7 minus Plan without TP 6 & 7 *	Breakeven Nuclear Capital Costs ($/kW in 2015$)
High Fuel Cost	Env I	165,666	178,785	(13,119)	6,408
High Fuel Cost	Env II	177,061	191,427	(14,366)	7,018
High Fuel Cost	Env III	188,470	204,108	(15,638)	7,640
Medium Fuel Cost	Env I	149,624	161,367	(11,743)	5,734
Medium Fuel Cost	Env II	160,969	173,950	(12,982)	6,341
Medium Fuel Cost	Env III	172,319	186,565	(14,246)	6,959
Low Fuel Cost	Env I	133,349	143,709	(10,360)	5,058

*The TP 6 & 7 savings values in Column (5) also represent CPVRR breakeven capital costs for each scenario.

Note: The TP 6 & 7 non-binding cost estimate range to which the breakeven cost is compared is $3,844/kW to $5,589/kW in 2015$.

REVISED

(1)	(2)	(3)	(4)	(5) = (3) - (4)	(6)
Fuel Cost Forecast	Environmental Compliance Cost Forecast	Total Costs for Plans: Resource Plan w/ TP 6 & 7	Total Costs for Plans: Resource Plan w/o TP 6 & 7	Total Cost Difference Plan with TP 6 & 7 minus Plan without TP 6 & 7 *	Breakeven Nuclear Capital Costs ($/kW in 2015$)
High Fuel Cost	Env I	165,677	178,785	(13,108)	6,403
High Fuel Cost	Env II	177,072	191,427	(14,356)	7,013
High Fuel Cost	Env III	188,481	204,108	(15,627)	7,635
Medium Fuel Cost	Env I	149,635	161,367	(11,732)	5,729
Medium Fuel Cost	Env II	160,979	173,950	(12,971)	6,336
Medium Fuel Cost	Env III	172,330	186,565	(14,235)	6,954
Low Fuel Cost	Env I	133,359	143,709	(10,350)	5,053

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 84
PARTY:FPL
DESCRIPTION: Revised ROB-6

EXHIBIT NO. 85

DOCKET NO: 150009-EI

WITNESS:

PARTY:

BRIEF TITLE OR DESCRIPTION OF THE DOCUMENT:

Environmental Compliance Forecast High | Low

PROFFERED BY: SACE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 85
PARTY: SACE
DESCRIPTION: Sim/Environmental Compliance forecast high, low

Q.

Please refer to Witness Brown's Exhibit ROB-2, Page 2 of 4 which provides Projected Environmental Compliance Costs for the ENV II Forecast:

a. Please provide tables, similar to Witness Brown's Exhibit ROB-2, Page 2 of 4, which show the ENV I and ENV III cost forecasts used in developing the data shown in Exhibits ROB-5 and ROB-6 in FPL's economic analysis of the long-term feasibility of completing the TP Project.

b. Please explain the dramatic change in the projected environmental compliance cost for SO2 and NOx between 2014 and 2015.

A.

a. Table Staff 18a-ENV I, see Attachment No. 1, presents the requested information for the environmental cost forecast for ENV I, and Table Staff 18a-ENV III, see Attachment No. 2, presents the requested information for the environmental cost forecast for ENV III.

b. Since 2007 FPL has used environmental compliance cost projections for SO2, NOx, and CO2 in its resource planning work, including the nuclear feasibility analyses, based on values provided by the consulting firm ICF International (ICF). The changes in the SO2 and NOx costs were due to the Supreme Court's ruling in 2014 that countermanded a late 2011 District Court of Appeals in D.C. decision to stay the EPA's Cross-State Air Pollution Rule. This more recent court decision has resulted in changes in ICF's compliance cost projections for both SO2 and NOx. After discussions with ICF, FPL has incorporated new compliance cost projections into its resource planning work, including the current nuclear feasibility analyses.

Table Staff 18a-ENV III

Comparison of Key Assumptions Utilized in the 2014 and 2015 Feasibility Analyses of the Turkey Point 6 & 7 Project: Projected Environmental Compliance Costs (Env III Forecast)
(all $ values shown are in Nominal $)

	(1)	(2)	(3) = (2) - (1)
	Forecasted SO_2 Compliance Cost ($/ton)		
Selected Years	2014 Feasibility Analysis	2015 Feasibility Analysis	Change in 2015 Forecast
2027	$76	$0	($76)
2030	$82	$0	($82)
2040	$105	$0	($105)
2050	$134	$0	($134)
2060	$172	$0	($172)
2070	$220	$0	($220)
2080	$282	$0	($282)

	(1)	(2)	(3) = (2) - (1)
	Forecasted NO_x Compliance Cost ($/ton)		
Selected Years	2014 Feasibility Analysis	2015 Feasibility Analysis	Change in 2015 Forecast
2027	$685	$400	($285)
2030	$737	$400	($337)
2040	$944	$400	($544)
2050	$1,208	$400	($808)
2060	$1,547	$400	($1,147)
2070	$1,980	$400	($1,580)
2080	$2,534	$400	($2,134)

	(1)	(2)	(3) = (2) - (1)
	Forecasted CO_2 Compliance Cost ($/ton)		
Selected Years	2014 Feasibility Analysis	2015 Feasibility Analysis	Change in 2015 Forecast
2027	$15	$26	$11
2030	$21	$37	$15
2040	$64	$102	$38
2050	$154	$234	$79
2060	$321	$452	$131
2070	$448	$578	$131
2080	$573	$741	$167

Table Staff 18a-ENV I

Comparison of Key Assumptions Utilized in the 2014 and 2015 Feasibility Analyses of the Turkey Point 6 & 7 Project: Projected Environmental Compliance Costs (Env I Forecast)
(all $ values shown are in Nominal $)

	(1)	(2)	(3) = (2) - (1)
	Forecasted SO_2 Compliance Cost ($/ton)		
Selected Years	2014 Feasibility Analysis	2015 Feasibility Analysis	Change in 2015 Forecast
2027	$76	$0	($76)
2030	$82	$0	($82)
2040	$105	$0	($105)
2050	$134	$0	($134)
2060	$172	$0	($172)
2070	$220	$0	($220)
2080	$282	$0	($282)

	(1)	(2)	(3) = (2) - (1)
	Forecasted NO_x Compliance Cost ($/ton)		
Selected Years	2014 Feasibility Analysis	2015 Feasibility Analysis	Change in 2015 Forecast
2027	$685	$0	($685)
2030	$737	$0	($737)
2040	$944	$0	($944)
2050	$1,208	$0	($1,208)
2060	$1,547	$0	($1,547)
2070	$1,980	$0	($1,980)
2080	$2,534	$0	($2,534)

	(1)	(2)	(3) = (2) - (1)
	Forecasted CO_2 Compliance Cost ($/ton)		
Selected Years	2014 Feasibility Analysis	2015 Feasibility Analysis	Change in 2015 Forecast
2027	$15	$17	$3
2030	$21	$25	$3
2040	$64	$68	$4
2050	$154	$156	$1
2060	$321	$301	($20)
2070	$448	$386	($62)
2080	$573	$494	($79)

EXHIBIT NO. 86

DOCKET NO: 150009-EI

WITNESS:

PARTY:

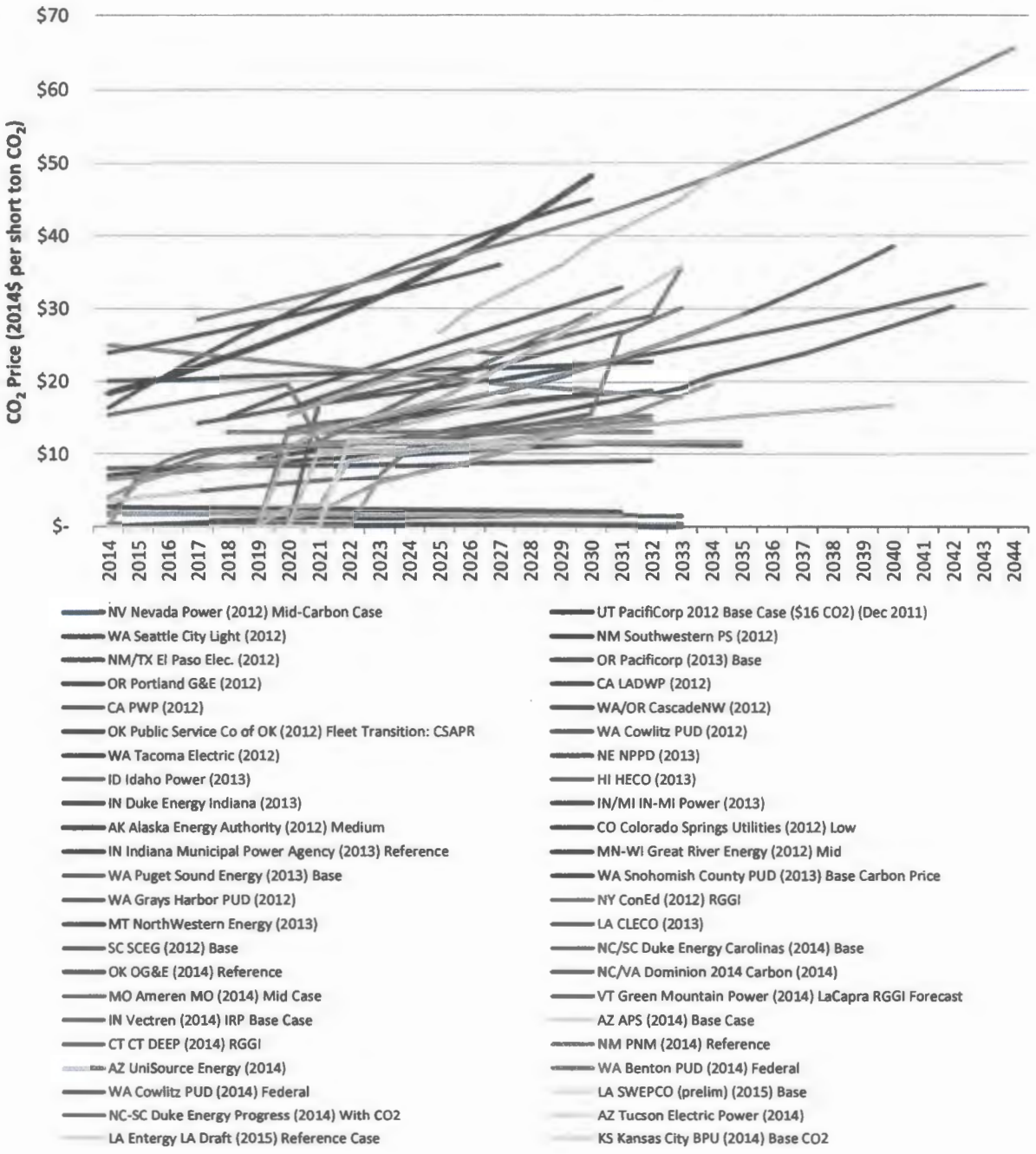
BRIEF TITLE OR DESCRIPTION OF THE DOCUMENT:

Synapse CO_2 Compliance Cost Projections

PROFFERED BY: SACE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 86
PARTY: SACE
DESCRIPTION: Synapse Co2 compliance costProjections pages 27, 31

Figure 5: Utility non-zero and non-confidential reference case forecasts from 2012-2015[50]



[50] A number of non-zero, non-confidential reference case forecasts are excluded, discussed further on page 24.

Table 4: Synapse 2015 CO_2 price projections (2014 dollars per short ton CO_2)

Year	Low Case	Mid Case	High Case
2020	$15.00	$20.00	$25.00
2021	$16.00	$21.50	$27.00
2022	$17.00	$23.00	$29.00
2023	$18.00	$24.50	$31.00
2024	$19.00	$26.00	$33.00
2025	$20.00	$27.50	$35.00
2026	$21.00	$29.00	$38.80
2027	$22.00	$30.50	$42.60
2028	$23.00	$32.00	$46.40
2029	$24.00	$33.50	$50.20
2030	$25.00	$35.00	$54.00
2031	$26.00	$37.65	$57.80
2032	$27.00	$40.30	$61.60
2033	$28.00	$42.95	$65.40
2034	$29.00	$45.60	$69.20
2035	$30.00	$48.25	$73.00
2036	$31.00	$50.90	$76.80
2037	$32.00	$53.55	$80.60
2038	$33.00	$56.20	$84.40
2039	$34.00	$58.85	$88.20
2040	$35.00	$61.50	$92.00
2041	$36.00	$64.15	$94.80
2042	$37.00	$66.80	$97.60
2043	$38.00	$69.45	$100.40
2044	$39.00	$72.10	$103.20
2045	$40.00	$74.75	$106.00
2046	$41.00	$77.40	$108.80
2047	$42.00	$80.05	$111.60
2048	$43.00	$82.70	$114.40
2049	$44.00	$85.35	$117.20
2050	$45.00	$88.00	$120.00
Levelized 2020-2050	$26.24	$41.64	$59.35

In these forecasts, the Clean Power Plan, together with other federal regulatory measures, place economic pressure on CO_2-emitting resources in the next several years, such that it is relatively more expensive to operate a high-carbon-emitting power plant. These pressures are followed later by a broader federal policy, such as cap and trade. In any state other than the RGGI region and California, we assume a zero carbon price through 2019; beginning in 2020, we expect Clean Power Plan compliance will put economic pressure on carbon-emitting power plants throughout the United States. All annual allowance prices and levelized values are reported in 2014 dollars per short ton of CO_2.

EXHIBIT NO. 87

DOCKET NO: 150009-EI

WITNESS:

PARTY:

BRIEF TITLE OR DESCRIPTION OF THE DOCUMENT:

Net fuel savings crossover

PROFFERED BY: SACE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 87
PARTY: SACE
DESCRIPTION: Sim/Net Fuel Savings Crossover

Q.
In Exhibit ROB-1 of Witness Brown's testimony, he shows approximate nominal fuel saving of $47 billion and $101 billion over the operational life of Turkey Point Units 6 & 7.

a. Please provide a spreadsheet and graph (in Excel format) showing the annual values and when the fuel saving begins to exceed the low range of the total estimated costs of the units in using nominal and cumulative present value of revenue requirement (CPVRR) calculations.

b. Please provide a spreadsheet and graph (in Excel format) showing the annual values and when the fuel saving begins to exceed the high range of the total estimated costs of the units in using nominal and CPVRR calculations.

A.
a. Table and Graph Staff-13a1, contained in Attachment No. 1, present the annual nominal net cost projections and Table and Graph Staff-13a2, contained in Attachment No. 2, present the annual CPVRR net cost projections for Turkey Point 6 & 7, assuming the low-end of the non-binding cost estimate range. The tables and graphs are projections of total cost impacts; i.e., capital, O&M, fuel, transmission, etc.

b. Table and Graph Staff-13b1, contained in Attachment No. 3, present the annual nominal net cost projections and Table and Graph Staff-13b2, contained in Attachment No. 4, present the annual CPVRR net cost projections for Turkey Point 6 & 7, assuming the high-end of the non-binding cost estimate range. The tables and graphs are projections of total cost impacts; i.e., capital, O&M, fuel, transmission, etc.

Florida Power & Light Company
Docket No. 150009-EI
Staff's Second Set of Interrogatories
Interrogatory No. 13
Attachment No. 4
Tab 2 of 2

Graph Staff-13b2 : Turkey Point 6&7 Project - Annual CPVRR Net Costs
(Assumes High End of Non-Binding Capital Cost Estimate Range)

Docket No. 150009-EI

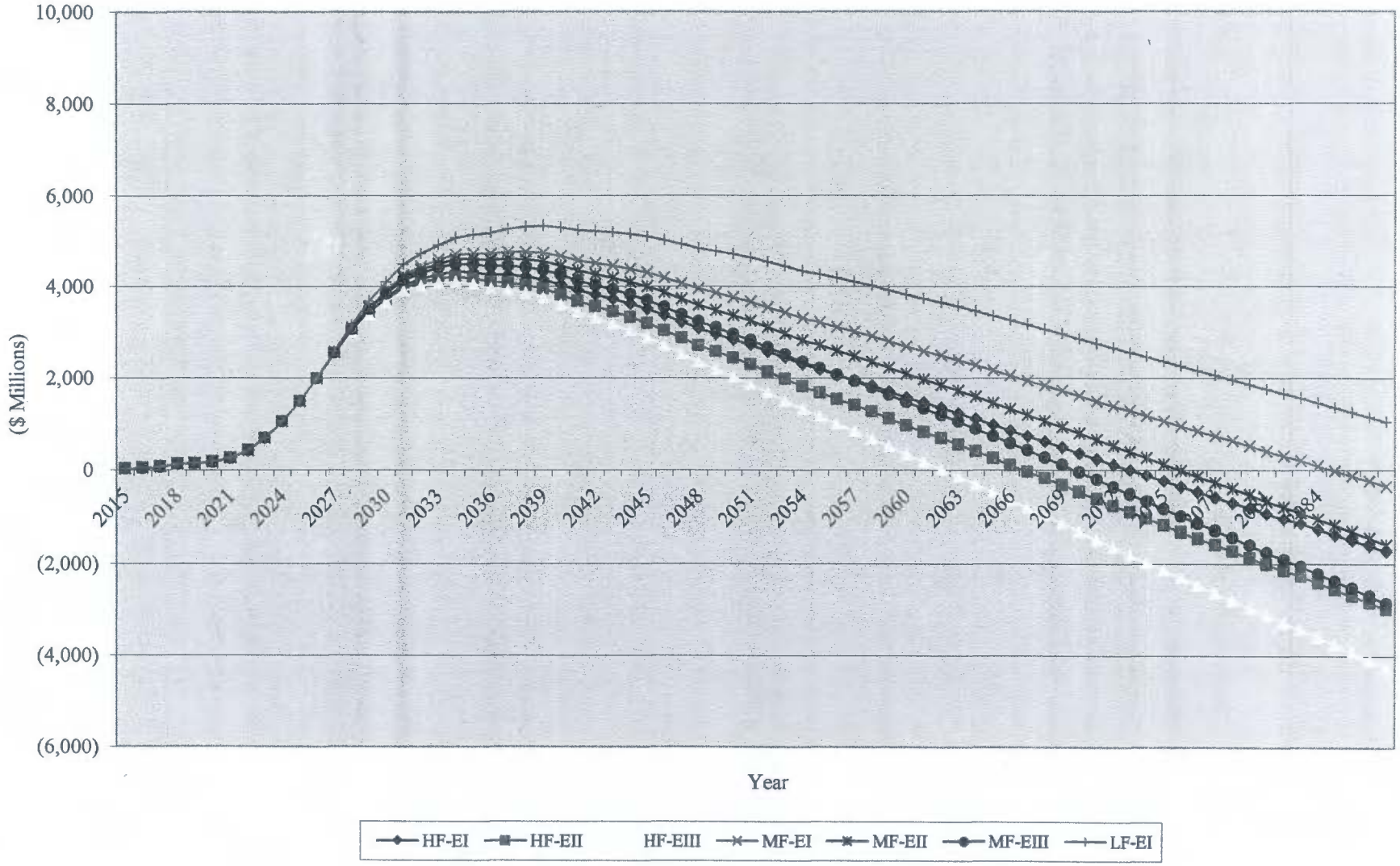


EXHIBIT NO. 88

DOCKET NO: 150009-EI

WITNESS:

PARTY:

BRIEF TITLE OR DESCRIPTION OF THE DOCUMENT:

US Census, Palm Beach County Demographics

PROFFERED BY: SACE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 88
PARTY: SACE
DESCRIPTION: US Census Palm Beach County Demographics

AMERICAN FactFinder

DP05 | ACS DEMOGRAPHIC AND HOUSING ESTIMATES

2009-2013 American Community Survey 5-Year Estimates

Supporting documentation on code lists, subject definitions, data accuracy, and statistical testing can be found on the American Community Survey website in the Data and Documentation section.

Sample size and data quality measures (including coverage rates, allocation rates, and response rates) can be found on the American Community Survey website in the Methodology section.

Although the American Community Survey (ACS) produces population, demographic and housing unit estimates, it is the Census Bureau's Population Estimates Program that produces and disseminates the official estimates of the population for the nation, states, counties, cities and towns and estimates of housing units for states and counties.

Subject	Florida				Palm Beach County, Florida
	Estimate	Margin of Error	Percent	Percent Margin of Error	Estimate
SEX AND AGE					
Total population	19,091,156	*****	19,091,156	(X)	1,339,221
Male	9,332,589	+/-1,229	48.9%	+/-0.1	648,352
Female	9,758,567	+/-1,229	51.1%	+/-0.1	690,869
Under 5 years	1,076,304	+/-540	5.6%	+/-0.1	70,607
5 to 9 years	1,084,998	+/-6,835	5.7%	+/-0.1	74,297
10 to 14 years	1,135,630	+/-6,866	5.9%	+/-0.1	76,253
15 to 19 years	1,202,527	+/-1,424	6.3%	+/-0.1	80,471
20 to 24 years	1,274,194	+/-1,639	6.7%	+/-0.1	76,590
25 to 34 years	2,349,398	+/-1,538	12.3%	+/-0.1	150,055
35 to 44 years	2,422,042	+/-1,496	12.7%	+/-0.1	164,126
45 to 54 years	2,738,571	+/-1,273	14.3%	+/-0.1	188,801
55 to 59 years	1,248,299	+/-5,980	6.5%	+/-0.1	87,040
60 to 64 years	1,159,268	+/-5,937	6.1%	+/-0.1	77,545
65 to 74 years	1,816,699	+/-1,038	9.5%	+/-0.1	136,050
75 to 84 years	1,117,145	+/-4,688	5.9%	+/-0.1	104,186
85 years and over	466,081	+/-4,700	2.4%	+/-0.1	53,200
Median age (years)	41.0	+/-0.1	(X)	(X)	43.7
18 years and over	15,084,361	+/-425	79.0%	+/-0.1	1,069,003
21 years and over	14,311,574	+/-4,419	75.0%	+/-0.1	1,020,689
62 years and over	4,082,682	+/-5,060	21.4%	+/-0.1	339,030
65 years and over	3,399,925	+/-722	17.8%	+/-0.1	293,436
18 years and over	15,084,361	+/-425	15,084,361	(X)	1,069,003
Male	7,283,572	+/-934	48.3%	+/-0.1	510,352
Female	7,800,789	+/-813	51.7%	+/-0.1	558,651
65 years and over	3,399,925	+/-722	3,399,925	(X)	293,436
Male	1,515,461	+/-430	44.6%	+/-0.1	128,032
Female	1,884,464	+/-648	55.4%	+/-0.1	165,404
RACE					

Subject	Florida				Palm Beach County, Florida
	Estimate	Margin of Error	Percent	Percent Margin of Error	Estimate
Total population	19,091,156	*****	19,091,156	(X)	1,339,221
One race	18,660,701	+/-8,574	97.7%	+/-0.1	1,312,543
Two or more races	430,455	+/-8,574	2.3%	+/-0.1	26,678
One race	18,660,701	+/-8,574	97.7%	+/-0.1	1,312,543
White	14,568,521	+/-10,462	76.3%	+/-0.1	1,015,518
Black or African American	3,056,152	+/-6,445	16.0%	+/-0.1	234,735
American Indian and Alaska Native	58,390	+/-2,655	0.3%	+/-0.1	2,363
Cherokee tribal grouping	9,460	+/-931	0.0%	+/-0.1	249
Chippewa tribal grouping	1,480	+/-392	0.0%	+/-0.1	20
Navajo tribal grouping	618	+/-239	0.0%	+/-0.1	20
Sioux tribal grouping	1,627	+/-411	0.0%	+/-0.1	20
Asian	475,905	+/-2,760	2.5%	+/-0.1	31,621
Asian Indian	130,171	+/-4,131	0.7%	+/-0.1	9,079
Chinese	81,644	+/-3,256	0.4%	+/-0.1	6,680
Filipino	89,814	+/-3,266	0.5%	+/-0.1	4,578
Japanese	13,968	+/-1,259	0.1%	+/-0.1	611
Korean	24,663	+/-1,942	0.1%	+/-0.1	1,295
Vietnamese	66,263	+/-3,833	0.3%	+/-0.1	4,652
Other Asian	69,382	+/-3,636	0.4%	+/-0.1	4,726
Native Hawaiian and Other Pacific Islander	11,258	+/-848	0.1%	+/-0.1	654
Native Hawaiian	3,318	+/-544	0.0%	+/-0.1	71
Guamanian or Chamorro	2,559	+/-744	0.0%	+/-0.1	86
Samoan	1,460	+/-535	0.0%	+/-0.1	109
Other Pacific Islander	3,921	+/-854	0.0%	+/-0.1	388
Some other race	490,475	+/-9,584	2.6%	+/-0.1	27,652
Two or more races	430,455	+/-8,574	2.3%	+/-0.1	26,678
White and Black or African American	135,715	+/-5,165	0.7%	+/-0.1	9,009
White and American Indian and Alaska Native	63,893	+/-1,967	0.3%	+/-0.1	4,046
White and Asian	72,236	+/-2,718	0.4%	+/-0.1	4,337
Black or African American and American Indian and Alaska Native	10,761	+/-1,286	0.1%	+/-0.1	678
Race alone or in combination with one or more other races					
Total population	19,091,156	*****	19,091,156	(X)	1,339,221
White	14,926,579	+/-12,084	78.2%	+/-0.1	1,037,104
Black or African American	3,262,238	+/-5,838	17.1%	+/-0.1	248,638
American Indian and Alaska Native	151,863	+/-3,445	0.8%	+/-0.1	8,059
Asian	594,578	+/-2,639	3.1%	+/-0.1	39,718
Native Hawaiian and Other Pacific Islander	32,281	+/-2,002	0.2%	+/-0.1	2,245
Some other race	586,068	+/-9,945	3.1%	+/-0.1	32,362
HISPANIC OR LATINO AND RACE					
Total population	19,091,156	*****	19,091,156	(X)	1,339,221
Hispanic or Latino (of any race)	4,369,920	+/-142	22.9%	+/-0.1	261,279
Mexican	629,945	+/-11,523	3.3%	+/-0.1	48,279
Puerto Rican	898,953	+/-12,376	4.7%	+/-0.1	36,621
Cuban	1,286,325	+/-11,921	6.7%	+/-0.1	49,359
Other Hispanic or Latino	1,554,697	+/-14,911	8.1%	+/-0.1	127,020
Not Hispanic or Latino	14,721,236	+/-142	77.1%	+/-0.1	1,077,942
White alone	10,926,354	+/-2,435	57.2%	+/-0.1	793,240
Black or African American alone	2,925,982	+/-5,068	15.3%	+/-0.1	228,074
American Indian and Alaska Native alone	40,699	+/-1,471	0.2%	+/-0.1	1,494
Asian alone	467,119	+/-2,739	2.4%	+/-0.1	31,488
Native Hawaiian and Other Pacific Islander alone	10,104	+/-729	0.1%	+/-0.1	588
Some other race alone	49,709	+/-2,874	0.3%	+/-0.1	4,723
Two or more races	301,269	+/-6,111	1.6%	+/-0.1	18,335
Two races including Some other race	21,261	+/-1,650	0.1%	+/-0.1	1,428

Subject	Florida				Palm Beach County, Florida
	Estimate	Margin of Error	Percent	Percent Margin of Error	Estimate
Two races excluding Some other race, and Three or more races	280,008	+/-6,018	1.5%	+/-0.1	16,907
Total housing units	9,003,933	+/-739	(X)	(X)	665,665

Subject	Palm Beach County, Florida		
	Margin of Error	Percent	Percent Margin of Error
SEX AND AGE			
Total population	*****	1,339,221	(X)
Male	+/-132	48.4%	+/-0.1
Female	+/-132	51.6%	+/-0.1
Under 5 years	+/-88	5.3%	+/-0.1
5 to 9 years	+/-1,331	5.5%	+/-0.1
10 to 14 years	+/-1,344	5.7%	+/-0.1
15 to 19 years	+/-124	6.0%	+/-0.1
20 to 24 years	+/-104	5.7%	+/-0.1
25 to 34 years	+/-131	11.2%	+/-0.1
35 to 44 years	+/-108	12.3%	+/-0.1
45 to 54 years	+/-122	14.1%	+/-0.1
55 to 59 years	+/-1,742	6.5%	+/-0.1
60 to 64 years	+/-1,705	5.8%	+/-0.1
65 to 74 years	+/-70	10.2%	+/-0.1
75 to 84 years	+/-1,218	7.8%	+/-0.1
85 years and over	+/-1,229	4.0%	+/-0.1
Median age (years)	+/-0.1	(X)	(X)
18 years and over	*****	79.8%	*****
21 years and over	+/-942	76.2%	+/-0.1
62 years and over	+/-1,471	25.3%	+/-0.1
65 years and over	+/-79	21.9%	+/-0.1
18 years and over	*****	1,069,003	(X)
Male	+/-87	47.7%	+/-0.1
Female	+/-89	52.3%	+/-0.1
65 years and over	+/-79	293,436	(X)
Male	+/-71	43.6%	+/-0.1
Female	+/-57	56.4%	+/-0.1
RACE			
Total population	*****	1,339,221	(X)
One race	+/-1,827	98.0%	+/-0.1
Two or more races	+/-1,827	2.0%	+/-0.1
One race	+/-1,827	98.0%	+/-0.1
White	+/-2,696	75.8%	+/-0.2
Black or African American	+/-1,698	17.5%	+/-0.1
American Indian and Alaska Native	+/-481	0.2%	+/-0.1
Cherokee tribal grouping	+/-103	0.0%	+/-0.1
Chippewa tribal grouping	+/-32	0.0%	+/-0.1
Navajo tribal grouping	+/-24	0.0%	+/-0.1
Sioux tribal grouping	+/-30	0.0%	+/-0.1
Asian	+/-803	2.4%	+/-0.1
Asian Indian	+/-971	0.7%	+/-0.1
Chinese	+/-879	0.5%	+/-0.1
Filipino	+/-712	0.3%	+/-0.1
Japanese	+/-209	0.0%	+/-0.1
Korean	+/-386	0.1%	+/-0.1
Vietnamese	+/-858	0.3%	+/-0.1
Other Asian	+/-721	0.4%	+/-0.1
Native Hawaiian and Other Pacific Islander	+/-165	0.0%	+/-0.1
Native Hawaiian	+/-63	0.0%	+/-0.1
Guamanian or Chamorro	+/-73	0.0%	+/-0.1
Samoan	+/-142	0.0%	+/-0.1

Subject	Palm Beach County, Florida		
	Margin of Error	Percent	Percent Margin of Error
Other Pacific Islander	+/-249	0.0%	+/-0.1
Some other race	+/-2,238	2.1%	+/-0.2
Two or more races	+/-1,827	2.0%	+/-0.1
White and Black or African American	+/-1,064	0.7%	+/-0.1
White and American Indian and Alaska Native	+/-668	0.3%	+/-0.1
White and Asian	+/-655	0.3%	+/-0.1
Black or African American and American Indian and Alaska Native	+/-326	0.1%	+/-0.1
Race alone or in combination with one or more other races			
Total population	*****	1,339,221	(X)
White	+/-2,657	77.4%	+/-0.2
Black or African American	+/-1,625	18.6%	+/-0.1
American Indian and Alaska Native	+/-830	0.6%	+/-0.1
Asian	+/-580	3.0%	+/-0.1
Native Hawaiian and Other Pacific Islander	+/-455	0.2%	+/-0.1
Some other race	+/-2,322	2.4%	+/-0.2
HISPANIC OR LATINO AND RACE			
Total population	*****	1,339,221	(X)
Hispanic or Latino (of any race)	*****	19.5%	*****
Mexican	+/-2,767	3.6%	+/-0.2
Puerto Rican	+/-2,145	2.7%	+/-0.2
Cuban	+/-2,539	3.7%	+/-0.2
Other Hispanic or Latino	+/-3,362	9.5%	+/-0.3
Not Hispanic or Latino	*****	80.5%	*****
White alone	+/-731	59.2%	+/-0.1
Black or African American alone	+/-1,205	17.0%	+/-0.1
American Indian and Alaska Native alone	+/-324	0.1%	+/-0.1
Asian alone	+/-823	2.4%	+/-0.1
Native Hawaiian and Other Pacific Islander alone	+/-152	0.0%	+/-0.1
Some other race alone	+/-924	0.4%	+/-0.1
Two or more races	+/-1,212	1.4%	+/-0.1
Two races including Some other race	+/-367	0.1%	+/-0.1
Two races excluding Some other race, and Three or more races	+/-1,189	1.3%	+/-0.1
Total housing units	+/-483	(X)	(X)

Data are based on a sample and are subject to sampling variability. The degree of uncertainty for an estimate arising from sampling variability is represented through the use of a margin of error. The value shown here is the 90 percent margin of error. The margin of error can be interpreted roughly as providing a 90 percent probability that the interval defined by the estimate minus the margin of error and the estimate plus the margin of error (the lower and upper confidence bounds) contains the true value. In addition to sampling variability, the ACS estimates are subject to nonsampling error (for a discussion of nonsampling variability, see Accuracy of the Data). The effect of nonsampling error is not represented in these tables.

The ACS questions on Hispanic origin and race were revised in 2008 to make them consistent with the Census 2010 question wording. Any changes in estimates for 2008 and beyond may be due to demographic changes, as well as factors including questionnaire changes, differences in ACS population controls, and methodological differences in the population estimates, and therefore should be used with caution. For a summary of questionnaire changes see http://www.census.gov/acs/www/methodology/questionnaire_changes/. For more information about changes in the estimates see http://www.census.gov/population/hispanic/files/acs08researchnote.pdf.

For more information on understanding race and Hispanic origin data, please see the Census 2010 Brief entitled, Overview of Race and Hispanic Origin: 2010, issued March 2011. (pdf format)

While the 2009-2013 American Community Survey (ACS) data generally reflect the February 2013 Office of Management and Budget (OMB) definitions of metropolitan and micropolitan statistical areas; in certain instances the names, codes, and boundaries of the principal cities shown in ACS tables may differ from the OMB definitions due to differences in the effective dates of the geographic entities.

Estimates of urban and rural population, housing units, and characteristics reflect boundaries of urban areas defined based on Census 2010 data. As a result, data for urban and rural areas from the ACS do not necessarily reflect the results of ongoing urbanization.

Source: U.S. Census Bureau, 2009-2013 5-Year American Community Survey

Explanation of Symbols:

1. An '**' entry in the margin of error column indicates that either no sample observations or too few sample observations were available to compute a standard error and thus the margin of error. A statistical test is not appropriate.
2. An '-' entry in the estimate column indicates that either no sample observations or too few sample observations were available to compute an estimate, or a ratio of medians cannot be calculated because one or both of the median estimates falls in the lowest interval or upper interval of an open-ended distribution.
3. An '-' following a median estimate means the median falls in the lowest interval of an open-ended distribution.
4. An '+' following a median estimate means the median falls in the upper interval of an open-ended distribution.
5. An '***' entry in the margin of error column indicates that the median falls in the lowest interval or upper interval of an open-ended distribution. A statistical test is not appropriate.
6. An '*****' entry in the margin of error column indicates that the estimate is controlled. A statistical test for sampling variability is not appropriate.
7. An 'N' entry in the estimate and margin of error columns indicates that data for this geographic area cannot be displayed because the number of sample cases is too small.
8. An '(X)' means that the estimate is not applicable or not available.

EXHIBIT NO. 89

DOCKET NO: 150009-EI

WITNESS: Mr. Sim

PARTY: FPL

BRIEF TITLE OR DESCRIPTION OF THE DOCUMENT:

Excerpt
FPL Response to Staff's Fourth Set of Interrogatories
Interrogatory No. 51 - Attachment No. 1

PROFFERED BY: Miami

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET: 150009-EI EXHIBIT: 89
PARTY: Miami
DESCRIPTION: Excerpt of FPL responses to Staff's 4th set of IRROGS, No. 51, Attachment

Florida Power & Light Company
Docket No. 150009-EI
Staff's Fourth Set of Interrogatories
Interrogatory No. 51
Attachment No. 1

Table Staff-51

2015 Feasibility Analyses of the Turkey Point 6 & 7 Project: CO_2 Revenue Requirements (Total Nominal and Total CPVRR) - 40-Year Operating Life (Millions, 2015-2068)

Fuel Cost Forecast	Environmental Compliance Cost Forecast	Total Nominal		Total CPVRR	
		Resource Plan w/ TP 6 & 7	Resource Plan w/o TP 6 & 7	Resource Plan w/ TP 6 & 7	Resource Plan w/o TP 6 & 7
High Fuel Cost	Env I	466,917	520,144	28,718	31,911
High Fuel Cost	Env II	583,733	650,044	35,884	39,854
High Fuel Cost	Env III	700,682	780,265	43,081	47,836
Medium Fuel Cost	Env I	466,831	519,999	28,661	31,830
Medium Fuel Cost	Env II	583,503	649,805	35,832	39,781
Medium Fuel Cost	Env III	700,129	779,771	43,020	47,762
Low Fuel Cost	Env I	466,606	519,923	28,637	31,812

2015 Feasibility Analyses of the Turkey Point 6 & 7 Project: CO_2 Revenue Requirements (Total Nominal and Total CPVRR) - 60-Year Operating Life (Millions, 2015-2088)

Fuel Cost Forecast	Environmental Compliance Cost Forecast	Total Nominal		Total CPVRR	
		Resource Plan w/ TP 6 & 7	Resource Plan w/o TP 6 & 7	Resource Plan w/ TP 6 & 7	Resource Plan w/o TP 6 & 7
High Fuel Cost	Env I	2,280,570	2,539,798	45,304	50,382
High Fuel Cost	Env II	2,851,521	3,174,707	56,624	62,943
High Fuel Cost	Env III	3,422,909	3,811,009	67,976	75,553
Medium Fuel Cost	Env I	2,280,838	2,540,179	45,251	50,305
Medium Fuel Cost	Env II	2,850,846	3,174,299	56,567	62,868
Medium Fuel Cost	Env III	3,420,438	3,809,039	67,898	75,465
Low Fuel Cost	Env I	2,279,871	2,539,915	45,220	50,285