DUKE ENERGY FLORIDA

Matthew R. Bernier
Senior Counsel
Duke Energy Florida, Inc.

August 4, 2015

VIA ELECTRONIC FILING

Ms. Carlotta Stauffer, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: *Fuel and Purchased Power Cost recovery clause with Generating Performance Incentive Factor; Docket No. 150001-EI*

Dear Ms. Stauffer:

Please find enclosed for electronic filing on behalf of Duke Energy Florida, Inc. ("DEF"), DEF'S Fuel and Capacity Cost Recovery Actual/Estimated True-Up Testimony and Schedules. The filing includes the following:

- DEF'S Petition for approval of Fuel Cost Recovery and Capacity Cost Recovery Actual/Estimated True-Up for the period January 2015 through December 2015;
- Direct Testimony of Christopher A. Menendez with Exhibit No. ___ (CAM-2); and
- Redacted Direct Testimony of Jeffrey Swartz with Redacted Exhibit No. ___ (JS-1) and Exhibit No. ___(JS-2).

Thank you for your assistance in this matter. Please feel free to call me at (850) 521-1428 should you have any questions concerning this filing.

Respectfully,

s/Matthew R. Bernier
Matthew R. Bernier
Senior Counsel
Matthew.Bernier@duke-energy.com

MRB/mw
Enclosures

Duke Energy Florida, Inc.

Docket No.: 150001

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic mail to the following this 4th day of August, 2015.

*s/Matthew R. Bernier*_______
Attorney

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchase Power	:	Docket No. 150001-EI
Cost Recovery Clause and Generating	:	
Performance Incentive Factor	:	Filed: August 04, 2015

PETITION FOR APPROVAL OF FUEL COST RECOVERY AND CAPACITY COST RECOVERY ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2015 THROUGH DECEMBER 2015

Duke Energy Florida, Inc. ("DEF") hereby petitions the Commission for approval of its actual/estimated Fuel and Purchased Power Cost Recovery True-Up of $78,731,031 over-recovery, and approval of its actual/estimated Capacity Cost Recovery true-up of $38,643,256 under-recovery for the period January 2015 through December 2015. In support of this petition, DEF states the following:

1. By Order No. PSC-99-2512-FOF-EI, dated December 22, 1999, utilities are directed to file current year estimated true-up data at least 90 days prior to each annual Fuel and Capacity Cost Recovery hearing. The hearing in this docket is scheduled for November 02 through 05, 2015.

2. The actual/estimated over-recovery of $78,731,031 in the fuel cost recovery for the period January 2015 through December 2015 was calculated in accordance with the methodology set forth in Schedule 1, attached to Order 10093, dated June 19, 1981. It is based on actual data for the period January through June 2015 and re-estimated data for the period July through December 2015. The supporting documentation is contained in the prepared direct

testimony and exhibits of DEF witness Christopher A. Menendez which is being filed together with this Petition.

3. DEF's total fuel over-recovery to be carried forward and included in the fuel factor for January through December 2016 is $78,731,031. This consists of the $67,126,064 over-recovery for 2015 increased by the final true-up over-recovery of $11,604,968 for the period ending December 2014 that was filed on March 3, 2015.

4. The actual/estimated $38,643,256 capacity under-recovery for the period January through December 2015 was calculated in accordance with the methodology set forth in Order No. 25773 dated February 24, 1992. It is based on actual data for the period January through June 2015 and re-estimated data for the period July through December 2015. The supporting documentation is contained in the prepared direct testimony and exhibits of DEF witness Christopher A. Menendez.

5. DEF's net capacity under-recovery is $38,643,256. This consists of the $24,680,810 actual/estimated under-recovery for 2015 increased by the final true-up under-recovery of $13,962,445 for the period ending December 2014 that was filed on March 3, 2015. Also included is $99,643,103 of 2015 recoverable expenses associated with the nuclear projects approved in Order No. PSC-14-0701-FOF-EI and Order No. PSC-15-0176-TRF-EI.

WHEREFORE, Duke Energy Florida, Inc. respectfully requests the Commission to approve the $78,731,031 over-recovery as the actual/estimated fuel cost recovery true-up amount for the period January through December 2015 and to approve the $38,643,256 under-recovery as the actual/estimated capacity cost recovery true-up amount for the period January through December 2015.

Respectfully,

*s/Matthew R. Bernier*_____
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DUKE ENERGY FLORIDA

DOCKET NO. 150001-EI

Fuel and Capacity Cost Recovery
Estimated/Actual True-Up Amounts
January through December 2015

DIRECT TESTIMONY OF
Christopher A. Menendez

August 4, 2015

Q. Please state your name and business address.

A. My name is Christopher A. Menendez. My business address is 299 1st Avenue North, St. Petersburg, Florida 33701.

Q. Have you previously filed testimony before this Commission in Docket No. 150001-EI?

A. Yes, I provided direct testimony on March 3, 2015.

Q: Has your job description, education, background and professional experience changed since that time?

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present, for Commission approval, Duke Energy Florida's (DEF or the Company) estimated/actual fuel and capacity cost recovery true-up amounts for the period of January through December 2015.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared Exhibit No.__ (CAM-2), which is attached to my prepared testimony, consisting of two parts. Part 1 consists of Schedules E1-B through E9, which include the calculation of the 2015 estimated/actual fuel and purchased power true-up balance and a schedule to support the capital structure components and cost rates relied upon to calculate the return requirements on all capital projects recovered through the fuel clause as required per Order No. PSC-15-0001-PCO-EI. Part 2 consists of Schedules E12-A through E12-C, which include the calculation of the 2015 estimated/actual capacity true-up balance. The calculations in my exhibit are based on actual data from January through June 2015 and estimated data from July through December 2015.

FUEL COST RECOVERY

Q. What is the amount of DEF's 2015 estimated fuel true-up balance and how was it developed?

A. DEF's estimated fuel true-up balance is an over-recovery of $78,731,031. The calculation begins with the actual under-recovered balance of $30,487,175 taken from Schedule A2, page 2 of 2, line 13, for the month of June 2015. This balance plus the estimated July through December 2015 monthly true-up calculations comprise the estimated

$78,731,031 over-recovered balance at year-end. The projected December 2015 true-up balance includes interest which is estimated from July through December 2015 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.8% per month.

Q. How does the current fuel price forecast for July through December 2015 compare with the same period forecast used in the Company's 2015 projection filing approved in Order No. PSC-14-0701-FOF-EI?

A. Natural gas costs decreased $0.47/mmbtu (9%), coal costs increased $0.17/mmbtu (5%), and light oil decreased $5.55 /mmbtu (26%).

Q. Have you made any adjustments to your estimated fuel costs for the period July through December 2015?

A. Yes, we made one adjustment totaling a net reduction of $92,851. We made an adjustment to reduce fuel costs by $92,203 (grossed up to $92,851 from retail to system) for the amortization of interest on the refund pursuant to the Revised and Restated Stipulation and Settlement Agreement approved in Order No. PSC-13-0598-FOF-EI. This adjustment is included on Schedule E1-B (sheet 2), line A5, from July – December 2015.

Q. Were there any impacts to the 2015 Estimated/Actual filing associated with the 2013 Revised and Restated Stipulation and Settlement Agreement (RRSSA)?

A. Yes. Paragraphs 6.a, 6.b, and 7.a all impact the 2015 Estimated/Actual true-up balance. Paragraph 6.a requires DEF to refund to Residential and General Service Non-Demand customers $10 million in 2015 through the Fuel Clause, allocated 94% to Residential and 6% to General Service Non-Demand. Paragraph 6.b requires DEF to refund to retail ratepayers $40 million in 2015 through the Fuel Clause. Paragraph 7.a allows DEF to increase fuel rates by $1.00/mWh, or 0.10 ₵/kWh, for the accelerated recovery of the carrying charges associated with the CR3 Regulatory Asset and requires that the increases be added to the fuel factor at secondary metering consistent with the normal fuel projection process.

Q. Have you included these impacts in your calculation of the 2015 Estimated/Actual true-up balance?

A. Yes.

Q. Please describe where the impact of paragraph 6.a is included in your schedules and how this is included in the Estimated/Actual true-up amount?

A. The 2015 Projection Filing, approved in Commission Order No. PSC-14-0701-FOF-EI, established the refund of the $10 million through a reduction in 2015 fuel rates for Residential and General Service, Non-

Demand ratepayers. The rate reduction is inherently reflected in the Jurisdictional Fuel Revenues reported in Exhibit CAM-2, Part 1, Schedule E1-B (Sheets 1 & 2) on line C.1. The refund of $10 million is shown on line C.1c. This amount is included in the 2015 fuel revenue applicable to period shown in line C.3 which is then used in the calculation of the total true-up balance (line C.13).

Q. Please describe where the impact of paragraph 6.b is included in your schedules and how this is included in the Estimated/Actual true-up amount?

A. Exhibit CAM-2, Part 1, Schedule E1-B (Sheets 1 & 2) show the refund of $40 million on line C.1a allocated evenly over the 12 month period. This amount is included in the 2015 fuel revenue applicable to period shown in line C.3 which is then used in the calculation of the total true-up balance (line C.13).

Q. Please describe where the impact of paragraph 7.a is included in your schedules and how this is included in the Estimated/Actual true-up amount?

A. Exhibit CAM-2, Part 1, Schedule E1-B (Sheets 1 & 2) show the fuel adjustment to revenue of $38 million on line C.1b. This amount is removed from the 2015 fuel revenue applicable to period shown in line C.3 which is then used in the calculation of the total true-up balance (line C.13).

Q. Does DEF expect to exceed the three-year rolling average gain on non-separated power sales in 2015?

A. Yes, DEF estimates the total gain on non-separated sales during 2015 will be $3,193,288, which exceeds the three-year rolling average of $1,739,843 by $1,453,445. Consistent with Order No. PSC-01-2371-FOF-EI, shareholders retain 20% of the gains in excess of the three-year rolling average. For 2015, this is estimated to be $290,689.

Q. On July 7, 2014, a fire occurred at the Hines Combined Cycle plant resulting in an outage. Has DEF included the replacement power costs resulting from this outage into the 2015 Estimated/Actual True-Up filing?

A. Yes, DEF incurred retail replacement power costs of approximately $18.6 million ($18.8 million system). DEF has included the Hines 2 retail replacement power costs in the 2015 Estimated/Actual True-Up balance.

Q. How did DEF calculate the replacement power costs resulting from the Hines 2 Outage?

A. To calculate the replacement power cost assuming Hines 2 had not experienced the extended outage, DEF ran a production cost simulation model for each day beginning July 7, 2014 through June 19, 2015; this process is consistent with DEF's prior replacement power calculations. DEF ran this model for each day applying the actual load conditions and fuel costs, which produced the total system cost assuming Hines 2 availability. DEF then compared the resulting "with Hines 2" system cost to the system cost calculated based on actual unit loadings (i.e., without Hines 2). The difference between the “with Hines 2” cost and the “without Hines 2” cost represents the system replacement power costs. The retail portion was calculated by applying the applicable retail jurisdictional factor to each respective month.

CAPACITY COST RECOVERY

Q. What is the amount of DEF’s 2015 estimated capacity true-up balance and how was it developed?

A. DEF’s estimated capacity true-up balance is an under-recovery of $38,643,256. The estimated true-up calculation begins with the actual under-recovered balance of $53,224,971 for the month of June 2015. This balance plus the estimated July through December 2015 monthly true-up calculations comprise the estimated $38,643,256 under-recovered balance at year-end. The projected December 2015 true-up balance includes interest which is estimated from July through December 2015 based on the average of the beginning and ending commercial paper rate applied in June. That rate is 0.8% per month.

Q. What are the primary drivers of the estimated year-end 2015 capacity under-recovery?

A. The $38,643,256 under-recovery is primarily attributable to $17,081,789 of 2015 Osprey capacity expense, which was not included in DEF’s 2015 Projection Filing because the Osprey Tolling Agreement was signed after DEF’s 2015 Projection Filing had been developed and filed, the

2014 final true-up under-recovery of $13,962,445, and other higher projected retail jurisdictional capacity costs of $5,535,621.

Q. Has DEF included the nuclear cost recovery amounts approved in Order No. PSC 14-0701-FOF-EI and Order No. PSC-15-0176-TRF-EI?

A. Yes, DEF has included $99,643,103 of 2015 recoverable expenses associated with the Levy and CR-3 Uprate projects.

Q. Does this conclude your testimony?

A. Yes.

Docket 150001-EI
Exhibit No. ____(CAM-2)
Part 1

DUKE ENERGY FLORIDA

FUEL COST RECOVERY

ESTIMATED / ACTUAL TRUE-UP

JANUARY THROUGH DECEMBER 2015

Schedule E1-B – Calculation of Estimated True-up

Schedule RRSSA – Summary of RRSSA Adjustments

Schedule E2 – Fuel Cost Recovery Clause Calculation by Month

Schedule E3 – Generating System Comparative Data

Schedule E4 – System Net Generation & Fuel Cost by Month

Schedule E5 – Inventory Analysis

Schedule E6 – Fuel Cost of Power Sold

Schedule E7 – Purchased Power

Schedule E8 – Energy Payments to Qualifying Facilities

Schedule E9 – Economy Energy Purchases

Capital Structure and Cost Rates Applied to Capital Projects
(Order No. PSC-12-0425-PAA-EU)

CALCULATION OF ESTIMATED TRUE-UP
(6 MONTHS ACTUAL, 6 MONTHS ESTIMATED)
Duke Energy Florida
Estimated for the Period of : January through December 2015

			JAN ACTUAL	FEB ACTUAL	MAR ACTUAL	APR ACTUAL	MAY ACTUAL	JUN ACTUAL	6 MONTH SUB-TOTAL
A	1	Fuel Cost of System Generation	$ 100,097,800	$ 97,550,693	$ 103,349,547	$ 112,810,811	$ 128,846,041	$ 134,240,962	$ 676,895,854
	2	Fuel Cost of Power Sold	(3,943,219)	(3,521,334)	(2,126,058)	(2,598,023)	(5,784,393)	(5,380,107)	(23,353,134)
	3	Fuel Cost of Purchased Power	7,520,849	7,910,824	10,237,409	14,882,323	12,928,988	24,457,418	77,937,812
	3a	Demand and Non-Fuel Cost of Purchased Power							-
	3b	Energy Payments to Qualified Facilities	8,990,368	8,182,122	8,070,423	9,132,303	10,888,108	10,001,969	55,265,293
	4	Energy Cost of Economy Purchases	452,250	582,968	600,426	654,836	460,058	420,572	3,171,110
	5	Adjustments to Fuel Cost	(14,256)	(21,380)	(143,979)	(17,701)	(17,248)	(16,864)	(231,427)
	6	TOTAL FUEL & NET POWER TRANSACTIONS	113,103,792	110,683,892	119,987,768	134,864,550	147,321,554	163,723,951	789,685,508
		(Sum of Lines A1 Through A5)							
B	1	Jurisdictional MWH Sales	2,654,267	2,638,626	2,812,088	2,933,622	3,114,914	3,580,025	17,733,542
	2	Non-Jurisdictional MWH Sales	30,765	17,672	21,095	27,293	40,872	40,062	177,760
	3	TOTAL SALES (Lines B1 + B2)	2,685,032	2,656,298	2,833,182	2,960,915	3,155,787	3,620,087	17,911,302
	4	Jurisdictional % of Total Sales (Line B1/B3)	98.85%	99.33%	99.26%	99.08%	98.70%	98.89%	99.01%
C	1	Jurisdictional Fuel Recovery Revenue	119,677,266	119,280,708	127,253,695	133,158,428	142,927,573	165,551,705	807,849,374
		(Net of Revenue Taxes)							
	1a	RRSSA Refund - $40M	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	20,000,000
	1b	RRSSA Fuel Adjustment	(2,654,267)	(2,638,626)	(2,812,088)	(2,933,622)	(3,114,914)	(3,580,025)	(17,733,542)
	1c	RRSSA Refund - $10M	833,333	833,333	833,333	833,333	833,333	833,333	5,000,000
	2	True-Up Provision	(6,139,350)	(6,139,350)	(6,139,350)	(6,139,350)	(6,139,350)	(6,139,350)	(36,836,100)
	2a	Incentive Provision	(185,988)	(185,988)	(185,988)	(185,988)	(185,988)	(185,988)	(1,115,928)
	3	FUEL REVENUE APPLICABLE TO PERIOD	114,864,327	114,483,410	122,282,936	128,066,135	137,653,987	159,813,009	777,163,803
		(Sum of Lines C1 Through C2a)							
	4	Fuel & Net Power Transactions (Line A6)	113,103,792	110,683,892	119,987,768	134,864,550	147,321,554	163,723,951	789,685,508
	5	Jurisdictional Total Fuel Costs & Net Power Transactions	111,968,567	110,105,025	119,161,791	133,693,280	145,481,985	161,990,807	782,401,455
		(Line A6 * Line B4 * Line Loss Multiplier)							
	6	Over/(Under) Recovery (Line C3 - Line C5)	2,895,760	4,378,385	3,121,145	(5,627,146)	(7,827,998)	(2,177,798)	(5,237,651)
	7	Interest Provision	(4,604)	(3,822)	(3,031)	(1,981)	(2,352)	(2,598)	(18,388)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	2,891,156	4,374,563	3,118,113	(5,629,126)	(7,830,350)	(2,180,396)	(5,256,039)
	9	Plus: Prior Period Balance	(62,067,235)	(62,067,235)	(62,067,235)	(62,067,235)	(62,067,235)	(62,067,235)	(62,067,235)
	10	Plus: Cumulative True-Up Provision	6,139,350	12,278,700	18,418,050	24,557,400	30,696,750	36,836,100	36,836,100
	11	Subtotal Prior Period True-up	(55,927,885)	(49,788,535)	(43,649,185)	(37,509,835)	(31,370,485)	(25,231,135)	(25,231,135)
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	($53,036,729)	(42,522,816)	($33,265,353)	($32,755,129)	($34,446,129)	($30,487,175)	($30,487,175)

CALCULATION OF ESTIMATED TRUE-UP
(6 MONTHS ACTUAL, 6 MONTHS ESTIMATED)
Duke Energy Florida
Estimated for the Period of : January through December 2015

			JUL ESTIMATED	AUG ESTIMATED	SEPT ESTIMATED	OCT ESTIMATED	NOV ESTIMATED	DEC ESTIMATED	12 MONTH PERIOD
A	1	Fuel Cost of System Generation	$ 133,700,347	$ 136,097,823	$ 126,593,806	$ 104,928,147	$ 92,423,994	$ 105,359,517	$ 1,375,999,488
	2	Fuel Cost of Power Sold	(3,094,091)	(3,019,450)	(2,848,461)	(2,645,355)	(2,066,890)	(1,256,433)	(38,283,814)
	3	Fuel Cost of Purchased Power	17,416,030	17,013,076	15,192,693	22,949,573	7,386,550	5,093,508	162,989,242
	3a	Demand and Non-Fuel Cost of Purchased Power							0
	3b	Energy Payments to Qualified Facilities	10,312,561	10,297,360	9,958,969	8,056,488	11,106,909	11,872,346	116,869,926
	4	Energy Cost of Economy Purchases	671,734	788,613	1,296,819	1,462,896	622,471	270,008	8,283,651
	5	Adjustments to Fuel Cost	(15,475)	(15,475)	(15,475)	(15,475)	(15,475)	(15,475)	(324,278)
	6	TOTAL FUEL & NET POWER TRANSACTIONS	158,991,105	161,161,947	150,178,352	134,736,273	109,457,559	121,323,471	1,625,534,215
		(Sum of Lines A1 Through A5)							
B	1	Jurisdictional MWH Sales	3,699,594	3,724,196	3,756,113	3,466,070	2,919,517	2,724,882	38,023,915
	2	Non-Jurisdictional MWH Sales	24,596	28,023	29,483	26,440	20,393	15,140	321,835
	3	TOTAL SALES (Lines B1 + B2)	3,724,190	3,752,219	3,785,596	3,492,510	2,939,910	2,740,022	38,345,749
	4	Jurisdictional % of Total Sales (Line B1/B3)	99.34%	99.25%	99.22%	99.24%	99.31%	99.45%	99.16%
C	1	Jurisdictional Fuel Recovery Revenue	170,744,713	171,885,672	173,365,900	159,914,463	134,566,793	125,540,147	1,743,867,062
		(Net of Revenue Taxes)							
	1a	RRSSA Refund - $40M	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	40,000,000
	1b	RRSSA Fuel Adjustment	(3,699,594)	(3,724,196)	(3,756,113)	(3,466,070)	(2,919,517)	(2,724,882)	(38,023,915)
	1c	RRSSA Refund - $10M	833,333	833,333	833,333	833,333	833,333	833,333	10,000,000
	2	True-Up Provision	(6,139,350)	(6,139,350)	(6,139,350)	(6,139,350)	(6,139,350)	(6,139,353)	(73,672,203)
	2a	Incentive Provision	(185,988)	(185,988)	(185,988)	(185,988)	(185,988)	(185,985)	(2,231,853)
	3	FUEL REVENUE APPLICABLE TO PERIOD	164,886,447	166,002,805	167,451,116	154,289,722	129,488,604	120,656,594	1,679,939,091
		(Sum of Lines C1 Through C2a)							
	4	Fuel & Net Power Transactions (Line A6)	158,991,105	161,161,947	150,178,352	134,736,273	109,457,559	121,323,471	1,625,534,215
	5	Jurisdictional Total Fuel Costs & Net Power Transactions	158,023,894	160,036,409	149,084,444	133,781,808	108,758,827	120,718,933	1,612,805,769
		(Line A6 * Line B4 * Line Loss Multiplier)							
	6	Over/(Under) Recovery (Line C3 - Line C5)	6,862,553	5,966,396	18,366,672	20,507,914	20,729,777	(62,339)	67,133,322
	7	Interest Provision	(1,914)	(910)	555	2,600	4,741	6,059	(7,258)
	8	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD	6,860,639	5,965,486	18,367,226	20,510,514	20,734,518	(56,280)	67,126,064
	9	Plus: Prior Period Balance	(62,067,235)	(62,067,235)	(62,067,235)	(62,067,235)	(62,067,235)	(62,067,235)	(62,067,235)
	10	Plus: Cumulative True-Up Provision	42,975,450	49,114,800	55,254,150	61,393,500	67,532,850	73,672,203	73,672,203
	11	Subtotal Prior Period True-up	(19,091,785)	(12,952,435)	(6,813,085)	(673,735)	5,465,615	11,604,968	11,604,968
	12	Regulatory Accounting Adjustment	-	-	-	-	-	-	-
	13	TOTAL TRUE-UP BALANCE	($17,487,186)	($5,382,349)	$19,124,227	$45,774,091	$72,647,959	$78,731,032	$78,731,031

COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
Duke Energy Florida
Estimated for the Period of : January through December 2015

	DOLLARS				MWH				c/KWH			
	ESTIMATED/ ACTUAL	ESTIMATED ORIGINAL	DIFFERENCE AMOUNT	DIFFERENCE %	ESTIMATED	ESTIMATED ORIGINAL	DIFFERENCE AMOUNT	DIFFERENCE %	ESTIMATED	ESTIMATED ORIGINAL	DIFFERENCE AMOUNT	DIFFERENCE %
1 Fuel Cost of System Net Generation (E3)	1,375,999,488	1,450,550,393	(74,550,905)	-5%	35,382,411	35,719,602	(337,191)	-1%	3.889	4.061	-0.172	-4%
2 Spent Nuclear Fuel Disposal Cost	0	0	-	0%	0	0	-	0%	0.000	0.000	0.000	0%
3 Coal Car Investment	0	0	-	0%			-		0.000	0.000	0.000	
4 Adjustment to Fuel Cost [1]	(324,278)	(40,353,675)	40,029,397	0%			-		0.000	0.000	0.000	
5 TOTAL COST OF GENERATED POWER	1,375,675,210	1,410,196,718	(34,521,508)	-2%	35,382,411	35,719,602	(337,191)	-1%	3.888	3.948	-0.060	-2%
6 Energy Cost of Purchased Power	162,989,242	101,841,738	61,147,504	60%	4,016,138	2,017,470	1,998,668	99%	4.058	5.048	-0.990	-20%
(Excl. Econ & Cogens) (E7)			-				-		0.000	0.000	0.000	
7 Energy Cost of Economy Purchases (E9)	8,283,651	16,351,874	(8,068,223)	-49%	178,653	356,500	(177,847)	-50%	4.637	4.587	0.050	
8 Payments to Qualifying Facilities (E8)	116,869,926	145,142,688	(28,272,762)	-19%	2,825,815	3,087,667	(261,852)	-8%	4.136	4.701	-0.565	-12%
9 TOTAL COST OF PURCHASED POWER	288,142,819	263,336,300	24,806,519	9%	7,020,606	5,461,637	1,558,969	29%	4.104	4.822	-0.717	-15%
10 TOTAL AVAILABLE MWH (LINE 5 + LINE 9)			-		42,403,017	41,181,239	1,221,778	3%	0.000	0.000	0.000	
11 Fuel Cost of Economy Sales (E6)	(5,265,948)	(4,199,152)	(1,066,796)	25%	(187,572)	(126,300)	(61,272)	49%	2.807	3.325	-0.517	-16%
11a Gain on Economy Sales (E6)	(3,193,288)	(923,813)	(2,269,475)	246%	(187,572)	(126,300)	(61,272)	49%	1.702	0.731	0.971	133%
11b Gain on Economy Sales -20% (E6)	290,689	0	290,689	0%								
12 Fuel Cost of Stratified Sales (E6)	(30,115,267)	(21,800,391)	(8,314,876)	38%	(895,498)	(550,476)	(345,022)	63%	3.363	3.960	-0.597	-15%
13 TOTAL FUEL COST AND GAINS OF POWER SALES	(38,283,814)	(26,923,356)	(11,360,458)	42%	(1,083,070)	(676,776)	(406,294)	60%	3.535	3.978	-0.443	-11%
(LINES 11 + 11a + 12)												
14 Net Inadvertent Interchange					97,864		97,864					
15 TOTAL FUEL & NET POWER TRANSACTIONS	1,625,534,215	1,646,609,662	(21,075,447)	-1%	41,417,811	40,504,463	913,348	2%	3.925	4.065	-0.141	-3%
(LINES 5 + 9 + 13 + 14)												
16 Net Unbilled					(596,118)	(93,029)	(503,089)	541%	0.000	0.000	0.000	
17 Company Use					(157,788)	(144,000)	(13,788)	10%	0.000	0.000	0.000	
18 T & D Losses					(2,318,156)	(2,242,422)	(75,734)	3%	0.000	0.000	0.000	
19 SYSTEM MWH SALES	1,625,534,215	1,646,609,662	(21,075,447)	-1%	38,345,749	38,025,012	320,737	1%	4.239	4.330	-0.091	-2%
20 Wholesale MWH Sales	(13,779,434)	(10,295,985)	(3,483,449)	34%	(321,835)	(239,422)	(82,413)	34%	4.282	4.300	-0.019	0%
21 Jurisdictional MWH Sales	1,611,754,781	1,636,313,678	(24,558,897)	-2%	38,023,915	37,785,590	238,324	1%	4.239	4.331	-0.092	-2%
21a Jurisdictional Loss Multiplier	1.00052	1.00148	(0)	0%	1.00052	1.00148	(0)	0%				
22 Jurisdictional Sales Adjusted for Line Losses	1,612,805,768	1,638,735,421	(25,929,653)	-2%	38,023,915	37,785,590	238,324	1%	4.242	4.337	-0.095	-2%
23 TRUE-UP **	62,067,235	73,672,203	(11,604,968)	-16%	38,023,915	37,785,590	238,324	1%	0.163	0.195	-0.032	-16%
24 TOTAL JURISDICTIONAL FUEL COST	1,674,873,003	1,712,407,624	(37,534,621)	-2%	38,023,915	37,785,590	238,324	1%	4.405	4.532	-0.127	-3%
25 Revenue Tax Factor	1,205,909	1,232,933	(27,025)	-2%								
26 Fuel Factor Adjusted for Taxes	1,676,078,912	1,713,640,557	(37,561,646)	-2%	38,023,915	37,785,590	238,324	1%	4.408	4.535	-0.127	-3%
27 GPIF **	2,231,853	2,231,853	-	0%	38,023,915	37,785,590	238,324	1%	0.006	0.006	0.000	-1%
28 Fuel Factor Adjusted for Taxes Including GPIF	1,678,310,765	1,715,872,410	(37,561,646)	-2%	38,023,915	37,785,590	238,324	1%	4.414	4.541	-0.127	-3%
29 FUEL FACTOR ROUNDED TO NEAREST .001 c/KWH									4.414	4.541	-0.127	-3%

* Included for Informational Purposes Only

** Calculation Based on Jurisdictional MWH Sales

[1] The $40 million retail refund required per RRSSA paragraph 6.b was treated as a reduction to fuel expense in the 2015 Original Projection. In the 2015 Estimated/Actual filing, the refund is treated as an adjustment to revenue, as shown on line C.1a of Schedule E1-B (Sheets 1&2). The difference in treatment is the primary cause of the difference amount on line 4 and 28 of the above schedule. In both filings, retail ratepayers are receiving a refund of $40 million.

Docket: 150001-EI
Exhibit: CAM-2, Part 1
Schedule: RRSSA

Duke Energy Florida
Summary of Revised and Restated Settlement Agreement (RRSSA) Adjustments
Estimated for the Period of January through December 2015

Retail:	Actual Jan-15	Actual Feb-15	Actual Mar-15	Actual Apr-15	Actual May-15	Actual Jun-15	Estimated Jul-15	Estimated Aug-15	Estimated Sep-15	Estimated Oct-15	Estimated Nov-15	Estimated Dec-15	12 Month Period	Schedule Reference	RRSSA Paragraph
1 RRSSA Refund ($40 million)	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	3,333,333	40,000,000	E1-B, line C1a	6.b.
2 RRSSA Refund ($10 million)	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	833,333	10,000,000	E1-B, line C1c	6.a.
3 Total RRSSA Refunds (Lines 2 + 3)	4,166,667	4,166,667	4,166,667	4,166,667	4,166,667	4,166,667	4,166,667	4,166,667	4,166,667	4,166,667	4,166,667	4,166,667	50,000,000		
4 Retail mWh Sales	2,654,267	2,638,626	2,812,088	2,933,622	3,114,914	3,580,025	3,699,594	3,724,196	3,756,113	3,466,070	2,919,517	2,724,882	38,023,915	E1-B, line B1	
5 RRSSA Fuel Adjustment ($/mWh)	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00	$ 1.00			7.a. / 7.a(ii)
6 Total RRSSA Fuel Adjustment to Revenue (Line 5 * 6)	(2,654,267)	(2,638,626)	(2,812,088)	(2,933,622)	(3,114,914)	(3,580,025)	(3,699,594)	(3,724,196)	(3,756,113)	(3,466,070)	(2,919,517)	(2,724,882)	(38,023,915)	E1-B, line C1b	

Duke Energy Florida
Fuel and Purchased Power Cost Recovery Clause
Estimated for the Period of : January through December 2015

			Actual Jan-15	Actual Feb-15	Actual Mar-15	Actual Apr-15	Actual May-15	Actual Jun-15	Estimated Jul-15	Estimated Aug-15	Estimated Sep-15	Estimated Oct-15	Estimated Nov-15	Estimated Dec-15	TOTAL
1	Fuel Cost of System Net Generation		$100,097,800	$97,550,693	$103,349,547	$112,810,811	$128,846,041	$134,240,962	$133,700,347	$136,097,823	$126,593,806	$104,928,147	$92,423,994	$105,359,517	$1,375,999,488
1a	Nuclear Fuel Disposal Cost		0	0	0	0	0	0	0	0	0	0	0	0	0
1b	Adjustments to Fuel Cost		(14,256)	(21,380)	(143,979)	(17,701)	(17,248)	(16,864)	(15,475)	(15,475)	(15,475)	(15,475)	(15,475)	(15,475)	(324,278)
2	Fuel Cost of Power Sold		(935,679)	(1,038,277)	(464,031)	(108,995)	(843,064)	(666,603)	(595,463)	(300,128)	(12,130)	(97,311)	(161,997)	(42,270)	(5,265,948)
2a	Gains on Power Sales		(837,732)	(1,182,638)	(109,939)	(36,526)	(295,207)	(223,362)	(106,949)	(53,904)	(2,178)	(17,478)	(29,095)	(7,592)	(2,902,599)
2b	Fuel Cost of Stratified Sales		(2,169,807)	(1,300,419)	(1,552,088)	(2,452,502)	(4,646,122)	(4,490,143)	(2,391,679)	(2,665,418)	(2,834,152)	(2,530,567)	(1,875,798)	(1,206,571)	(30,115,267)
3	Fuel Cost of Purchased Power (Excl Economy)		7,520,849	7,910,824	10,237,409	14,882,323	12,928,988	24,457,418	17,416,030	17,013,076	15,192,693	22,949,573	7,386,550	5,093,508	162,989,242
3a	Energy Payments to Qualifying Facilities		8,990,368	8,182,122	8,070,423	9,132,303	10,888,108	10,001,969	10,312,561	10,297,360	9,958,969	8,056,488	11,106,909	11,872,346	116,869,926
4	Energy Cost of Economy Purchases		452,250	582,968	600,426	654,836	460,058	420,572	671,734	788,613	1,296,819	1,462,896	622,471	270,008	8,283,651
5	Total System Fuel & Net Power Transactions		$113,103,792	$110,683,892	$119,987,768	$134,864,550	$147,321,554	$163,723,951	$158,991,105	$161,161,947	$150,178,352	$134,736,273	$109,457,559	$121,323,471	$1,625,534,215
6	Jurisdictional MWH Sold		2,654,267	2,638,626	2,812,088	2,933,622	3,114,914	3,580,025	3,699,594	3,724,196	3,756,113	3,466,070	2,919,517	2,724,882	38,023,915
7	Jurisdictional % of Total Sales		98.85%	99.33%	99.26%	99.08%	98.70%	98.89%	99.34%	99.25%	99.22%	99.24%	99.31%	99.45%	99.16%
8	Jurisdicitonal Fuel & Net Power Transactions		111,803,099	109,942,310	119,099,859	133,623,796	145,406,374	161,906,615	157,941,764	159,953,233	149,006,960	133,712,278	108,702,302	120,656,191	1,611,754,781
9	Jurisdictional Loss Multiplier		1.00148	1.00148	1.00052	1.00052	1.00052	1.00052	1.00052	1.00052	1.00052	1.00052	1.00052	1.00052	1.00052
10	Jurisdictional Fuel & Net Power Transactions		111,968,567	110,105,025	119,161,791	133,693,280	145,481,985	161,990,807	158,023,894	160,036,409	149,084,444	133,781,808	108,758,827	120,718,933	1,612,805,769
11	Adjusted System Sales	MWH	2,685,032	2,656,298	2,833,182	2,960,915	3,155,787	3,620,087	3,724,190	3,752,219	3,785,596	3,492,510	2,939,910	2,740,022	38,345,749
12	System Cost per MWH Sold	c/kwh	4.2124	4.1668	4.2352	4.5548	4.6682	4.5227	4.2691	4.2951	3.9671	3.8579	3.7232	4.4278	4.2392
13	Jurisdictional Loss Multiplier	x	1.00148	1.00148	1.00052	1.00052	1.00052	1.00052	1.00052	1.00052	1.00052	1.00052	1.00052	1.00052	1.00052
14	Jurisdictional Cost per MWH Sold	c/kwh	4.2184	4.1728	4.2375	4.5573	4.6705	4.5249	4.2714	4.2972	3.9691	3.8598	3.7252	4.4302	4.2416
15	Prior Period True-Up	+	0.1949	0.1960	0.1839	0.1763	0.1661	0.1445	0.1398	0.1389	0.1377	0.1492	0.1772	0.1898	0.1632
16	Total Jurisdictional Fuel Expense	c/kwh	4.4133	4.3688	4.4214	4.7336	4.8365	4.6693	4.4112	4.4361	4.1068	4.0090	3.9024	4.6201	4.4048
17	Revenue Tax Multiplier	x	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
18	Recovery Factor Adjusted for Taxes	c/kwh	4.4165	4.3720	4.4246	4.7370	4.8400	4.6727	4.4144	4.4393	4.1098	4.0119	3.9052	4.6234	4.4080
19	GPIF	+	0.0070	0.0070	0.0066	0.0063	0.0060	0.0052	0.0050	0.0050	0.0050	0.0054	0.0064	0.0068	0.0059
20	Total Recovery Factor (rounded .001)	c/kwh	4.423	4.379	4.431	4.743	4.846	4.678	4.419	4.444	4.115	4.017	3.912	4.630	4.414

Duke Energy Florida
Generating System Comparative Data by Fuel Type
Estimated for the Period of : January through December 2015

			Actual	Actual	Actual	Actual	Actual	Actual	
			Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Subtotal
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		0	0	0	0	0	0	0
2	LIGHT OIL		1,319,615	4,134,966	625,553	1,162,677	1,211,629	1,032,864	9,487,304
3	COAL		20,556,863	26,015,558	38,485,187	34,885,567	40,856,360	42,341,224	203,140,760
4	GAS		78,221,322	67,400,168	64,238,807	76,762,568	86,778,051	90,866,875	464,267,790
5	NUCLEAR		0	0	0	0	0	0	0
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	100,097,800	97,550,693	103,349,547	112,810,811	128,846,041	134,240,962	676,895,854
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		0	0	0	0	0	0	0
9	LIGHT OIL	0	4,405	11,319	2,376	4,324	4,285	3,451	30,160
10	COAL	0	500,728	654,980	997,082	934,801	1,035,622	1,073,428	5,196,641
11	GAS	0	2,094,706	1,768,181	1,602,145	1,952,237	2,124,314	2,341,772	11,883,355
12	NUCLEAR		0	0	0	0	0	0	0
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	2,599,838	2,434,480	2,601,603	2,891,362	3,164,221	3,418,651	17,110,156
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	0	0	0	0	0	0	0
16	LIGHT OIL	BBL	9,681	31,189	4,603	8,915	9,120	7,546	71,054
17	COAL	TON	228,326	298,466	447,186	412,463	457,388	477,254	2,321,083
18	GAS	MCF	15,871,516	13,463,049	13,349,942	15,651,678	17,368,410	18,726,081	94,430,676
19	NUCLEAR	MMBTU	0	0	0	0	0	0	0
20	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		0	0	0	0	0	0	0
22	LIGHT OIL		54,551	173,295	26,469	51,507	52,723	43,608	402,153
23	COAL		5,261,038	6,860,635	10,174,056	9,539,570	10,615,370	11,111,292	53,561,961
24	GAS		16,237,778	13,762,344	13,657,991	16,042,733	17,802,336	19,197,547	96,700,730
25	NUCLEAR		0	0	0	0	0	0	0
26	OTHER		0	0	0	0	0	0	0
27	TOTAL	MMBTU	21,553,367	20,796,274	23,858,516	25,633,810	28,470,429	30,352,447	150,664,844
	GENERATION MIX (% MWH)								
28	HEAVY OIL		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
29	LIGHT OIL		0.17%	0.47%	0.09%	0.15%	0.14%	0.10%	0.18%
30	COAL		19.26%	26.90%	38.33%	32.33%	32.73%	31.40%	30.37%
31	GAS		80.57%	72.63%	61.58%	67.52%	67.14%	68.50%	69.45%
32	NUCLEAR		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	LIGHT OIL	$/BBL	136.31	132.58	135.90	130.42	132.85	136.88	133.52
37	COAL	$/TON	90.03	87.16	86.06	84.58	89.33	88.72	87.52
38	GAS	$/MCF	4.93	5.01	4.81	4.90	5.00	4.85	4.92
39	NUCLEAR	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	LIGHT OIL		24.19	23.86	23.63	22.57	22.98	23.69	23.59
43	COAL		3.91	3.79	3.78	3.66	3.85	3.81	3.79
44	GAS		4.82	4.90	4.70	4.79	4.88	4.73	4.80
45	NUCLEAR		0.00	0.00	0.00	0.00	0.00	0.00	0.00
46	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	TOTAL	$/MMBTU	4.64	4.69	4.33	4.40	4.53	4.42	4.49
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		0	0	0	0	0	0	0
49	LIGHT OIL		12,385	15,310	11,141	11,913	12,303	12,637	13,334
50	COAL		10,507	10,475	10,204	10,205	10,250	10,351	10,307
51	GAS		7,752	7,783	8,525	8,218	8,380	8,198	8,137
52	NUCLEAR		0	0	0	0	0	0	0
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	8,290	8,542	9,171	8,866	8,998	8,878	8,806
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
56	LIGHT OIL		29.96	36.53	26.33	26.89	28.27	29.93	31.46
57	COAL		4.11	3.97	3.86	3.73	3.95	3.94	3.91
58	GAS		3.73	3.81	4.01	3.93	4.08	3.88	3.91
59	NUCLEAR		0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	TOTAL	C/KWH	3.85	4.01	3.97	3.90	4.07	3.93	3.96

Duke Energy Florida

Generating System Comparative Data by Fuel Type

Estimated for the Period of : January through December 2015

			Estimated Jul-15	Estimated Aug-15	Estimated Sep-15	Estimated Oct-15	Estimated Nov-15	Estimated Dec-15	Total
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		0	0	0	0	0	0	0
2	LIGHT OIL		284,551	171,923	327,037	330,816	366,123	368,309	11,336,063
3	COAL		40,164,847	42,243,248	39,663,073	39,973,701	22,404,520	29,914,728	417,504,877
4	GAS		93,250,949	93,682,652	86,603,696	64,623,630	69,653,351	75,076,480	947,158,548
5	NUCLEAR		0	0	0	0	0	0	0
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	133,700,347	136,097,823	126,593,806	104,928,147	92,423,994	105,359,517	1,375,999,488
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		0	0	0	0	0	0	0
9	LIGHT OIL		55	27	37	522	20	0	30,821
10	COAL		1,009,127	1,058,513	1,010,250	1,045,244	578,386	789,023	10,687,184
11	GAS		2,519,332	2,523,682	2,259,746	1,663,883	1,868,442	1,945,966	24,664,406
12	NUCLEAR		0	0	0	0	0	0	0
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	3,528,514	3,582,222	3,270,033	2,709,649	2,446,848	2,734,989	35,382,411
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	0	0	0	0	0	0	0
16	LIGHT OIL	BBL	3,143	1,782	3,475	3,362	3,990	4,032	90,838
17	COAL	TON	454,259	477,058	456,133	472,991	261,273	356,909	4,799,706
18	GAS	MCF	19,332,873	19,331,530	17,208,201	12,755,081	14,031,152	14,395,299	191,484,812
19	NUCLEAR	MMBTU	0	0	0	0	0	0	0
20	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		0	0	0	0	0	0	0
22	LIGHT OIL		18,224	10,334	20,141	19,485	23,127	23,370	516,834
23	COAL		10,739,703	11,258,527	10,733,454	11,081,959	6,077,985	8,268,036	111,721,625
24	GAS		19,332,873	19,331,530	17,208,201	12,755,081	14,031,152	14,395,299	193,754,866
25	NUCLEAR		0	0	0	0	0	0	0
26	OTHER		0	0	0	0	0	0	0
27	TOTAL	MMBTU	30,090,800	30,600,391	27,961,796	23,856,525	20,132,264	22,686,705	305,993,325
	GENERATION MIX (% MWH)								
28	HEAVY OIL		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
29	LIGHT OIL		0.00%	0.00%	0.00%	0.02%	0.00%	0.00%	0.09%
30	COAL		28.60%	29.55%	30.89%	38.58%	23.64%	28.85%	30.21%
31	GAS		71.40%	70.45%	69.11%	61.41%	76.36%	71.15%	69.71%
32	NUCLEAR		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36	LIGHT OIL	$/BBL	90.53	96.48	94.11	98.40	91.76	91.35	124.79
37	COAL	$/TON	88.42	88.55	86.96	84.51	85.75	83.82	86.99
38	GAS	$/MCF	4.82	4.85	5.03	5.07	4.96	5.22	4.95
39	NUCLEAR	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	LIGHT OIL		15.61	16.64	16.24	16.98	15.83	15.76	21.93
43	COAL		3.74	3.75	3.70	3.61	3.69	3.62	3.74
44	GAS		4.82	4.85	5.03	5.07	4.96	5.22	4.89
45	NUCLEAR		0.00	0.00	0.00	0.00	0.00	0.00	0.00
46	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	TOTAL	$/MMBTU	4.44	4.45	4.53	4.40	4.59	4.64	4.50
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		0	0	0	0	0	0	0
49	LIGHT OIL		331,345	382,741	544,351	37,328	1,156,350	0	16,769
50	COAL		10,643	10,636	10,625	10,602	10,509	10,479	10,454
51	GAS		7,674	7,660	7,615	7,666	7,510	7,398	7,856
52	NUCLEAR		0	0	0	0	0	0	0
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	8,528	8,542	8,551	8,804	8,228	8,295	8,648
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		0.00	0.00	0.00	0.00	0.00	0.00	0.00
56	LIGHT OIL		517.37	636.75	883.88	63.37	1,830.62	0.00	36.78
57	COAL		3.98	3.99	3.93	3.82	3.87	3.79	3.91
58	GAS		3.70	3.71	3.83	3.88	3.73	3.86	3.84
59	NUCLEAR		0.00	0.00	0.00	0.00	0.00	0.00	0.00
60	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	TOTAL	C/KWH	3.79	3.80	3.87	3.87	3.78	3.85	3.89

Docket No. 150001-EI

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Jul-15

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	0	0	0	0.00	0	0	NUCLEAR	0 MMBTU		0	0	0.00
2	CRYSTAL RIVER	1	375	105,775	37.9	86.45	59.8	10,538	COAL	45,290 TONS	24.61	1,114,664	4,905,383	4.64
3	CRYSTAL RIVER	2	494	193,890	52.8	97.76	53.6	10,758	COAL	84,750 TONS	24.61	2,085,836	9,030,242	4.66
4	CRYSTAL RIVER	4	722	365,541	68.0	95.16	71.5	10,600	COAL	166,635 TONS	23.25	3,874,835	13,466,312	3.68
5	CRYSTAL RIVER	5	700	343,921	66.0	92.58	71.3	10,655	COAL	157,584 TONS	23.25	3,664,368	12,762,910	3.71
6	ANCLOTE	1	501	0	0.0	94.35	0.0	0	HEAVY OIL	0 BBLS		0	0	0.00
7	ANCLOTE	2	510	0	0.0	97.45	0.0	0	HEAVY OIL	0 BBLS		0	0	0.00
8	SUWANNEE	1	30	0	0.0	99.03	0.0	0	HEAVY OIL	0 BBLS	0	0	0	0.00
9	SUWANNEE	2	30	0	0.0	98.06	0.0	0	HEAVY OIL	0 BBLS	0	0	0	0.00
10	SUWANNEE	3	71	0	0.0	97.74	0.0	0	HEAVY OIL	0 BBLS	0	0	0	0.00
11	ANCLOTE	1	501	138,975	37.3	0.00	42.7	10,422	GAS	1,448,364 MCF	1.00	1,448,364	7,076,786	5.09
12	ANCLOTE	2	510	160,955	42.4	0.00	43.2	10,522	GAS	1,693,586 MCF	1.00	1,693,586	8,016,232	4.98
13	AVON PARK	1-2	49	9	0.0	91.77	0.0	16,111	GAS	145 MCF	1.00	145	1,050	11.67
14	BARTOW	1-4	177	16	0.0	90.48	0.0	14,688	GAS	235 MCF	1.00	235	1,129	7.06
15	BARTOW CC	1	1,159	762,359	88.4	96.13	92.0	7,280	GAS	5,549,791 MCF	1.00	5,549,791	26,659,589	3.50
16	DEBARY	1-10	645	541	0.1	96.48	11.2	12,998	GAS	7,032 MCF	1.00	7,032	33,780	6.24
17	HIGGINS	1-4	113	3	0.0	93.63	0.0	17,000	GAS	51 MCF	1.00	51	244	8.13
18	HINES CC	1-4	1,912	1,297,037	91.2	95.51	23.3	7,117	GAS	9,231,340 MCF	1.00	9,231,340	44,344,684	3.42
19	INT CITY	1-14	987	8,776	1.2	95.41	7.1	12,983	GAS	113,941 MCF	1.00	113,941	562,678	6.41
20	SUWANNEE	1	52	52	0.1	95.81	0.0	13,173	GAS	685 MCF	1.00	685	105,700	203.27
21	SUWANNEE	2	50	0	0.0	100.00	0.0	0	GAS	0 MCF		0	103,681	0.00
22	SUWANNEE	3	51	24,771	65.3	98.39	66.8	12,332	GAS	305,482 MCF	1.00	305,482	1,269,901	5.13
23	TIGER BAY CC	1	204	93,222	61.4	89.68	99.8	7,238	GAS	674,716 MCF	1.00	674,716	3,241,140	3.48
24	UNIV OF FLA. CC	1	46	32,616	95.3	97.42	97.8	9,428	GAS	307,505 MCF	1.00	307,505	1,834,355	5.62
25	AVON PARK	1-2	49	0	0.0	91.77	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
26	BARTOW	1-4	177	0	0.0	90.48	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
27	BAYBORO	1-4	174	0	0.0	93.95	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
28	DEBARY	1-10	645	38	0.1	96.48	89.8	16,526	LIGHT OIL	107 BBLS	5.87	628	14,928	39.28
29	HIGGINS	1-4	113	0	0.0	93.63	0.0	0	LIGHT OIL	0 BBLS	0	0	0	0.00
30	OTHER		0	0	0.0	95.51	0.0	0	LIGHT OIL	0 BBLS	0	0	0	0.00
31	INT CITY	1-14	987	13	1.2	95.41	0.0	14,769	LIGHT OIL	33 BBLS	5.82	192	5,046	38.82
32	RIO PINAR	1	12	0	0.0	95.81	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
33	SUWANNEE	1-3	153	0	0.0	98.06	0.0	0	LIGHT OIL	0 BBLS		0	0	0.00
34	TURNER	1-4	149	4	0.0	71.29	0.0	17,000	LIGHT OIL	12 BBLS	5.67	68	1,313	32.83
35	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	2,991 BBLS	5.80	17,336	263,264	0.00
36	TOTAL			3,528,514								30,090,800	133,700,347	3.79

Duke Energy Florida

System Net Generation and Fuel Cost

Estimated for the Period of: Aug-15

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	0	0	0	0.00	0	0	NUCLEAR	0	MMBTU		0	0	0.00
2	CRYSTAL RIVER	1	375	150,433	53.9	93.87	59.8	10,537	COAL	64,955	TONS	24.40	1,585,109	6,832,016	4.54
3	CRYSTAL RIVER	2	494	195,431	53.2	95.84	54.8	10,755	COAL	86,129	TONS	24.40	2,101,806	9,003,280	4.61
4	CRYSTAL RIVER	4	722	347,376	64.7	90.32	71.6	10,599	COAL	158,510	TONS	23.23	3,681,819	12,855,474	3.70
5	CRYSTAL RIVER	5	700	365,273	70.1	97.74	71.8	10,649	COAL	167,464	TONS	23.23	3,889,793	13,552,478	3.71
6	ANCLOTE	1	501	0	0.0	96.60	0.0	0	HEAVY OIL	0	BBLS		0	0	0.00
7	ANCLOTE	2	510	0	0.0	99.07	0.0	0	HEAVY OIL	0	BBLS		0	0	0.00
8	SUWANNEE	1	30	0	0.0	99.03	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
9	SUWANNEE	2	30	0	0.0	97.07	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
10	SUWANNEE	3	71	0	0.0	98.06	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
11	ANCLOTE	1	501	156,811	42.1	0.00	42.9	10,361	GAS	1,624,697	MCF	1.00	1,624,697	7,751,038	4.94
12	ANCLOTE	2	510	136,723	36.0	0.00	45.1	10,559	GAS	1,443,697	MCF	1.00	1,443,697	7,054,550	5.16
13	AVON PARK	1-2	49	0	0.0	92.10	0.0	0	GAS	0	MCF		0	212	0.00
14	BARTOW	1-4	177	12	0.0	89.44	0.0	14,417	GAS	173	MCF	1.00	173	835	6.96
15	BARTOW CC	1	1,159	786,349	91.2	99.35	91.8	7,283	GAS	5,726,989	MCF	1.00	5,726,989	27,633,816	3.51
16	DEBARY	1-10	645	295	0.1	95.81	11.9	13,003	GAS	3,836	MCF	1.00	3,836	18,510	6.27
17	HIGGINS	1-4	113	26	0.0	93.79	0.0	16,308	GAS	424	MCF	1.00	424	2,046	7.87
18	HINES CC	1-4	1,912	1,281,353	90.1	96.23	23.1	7,115	GAS	9,116,454	MCF	1.00	9,116,454	43,988,632	3.43
19	INT CITY	1-14	987	7,454	1.0	95.07	7.0	13,020	GAS	97,048	MCF	1.00	97,048	482,019	6.47
20	SUWANNEE	1	52	21	0.1	96.45	0.0	13,000	GAS	273	MCF	1.00	273	104,020	495.33
21	SUWANNEE	2	50	0	0.0	99.35	0.0	0	GAS	0	MCF		0	99,256	0.00
22	SUWANNEE	3	51	24,798	65.4	99.35	66.6	12,297	GAS	304,931	MCF	1.00	304,931	1,272,868	5.13
23	TIGER BAY CC	1	204	97,116	64.0	89.68	99.6	7,254	GAS	704,466	MCF	1.00	704,466	3,399,183	3.50
24	UNIV OF FLA. CC	1	46	32,724	95.6	97.74	97.9	9,429	GAS	308,542	MCF	1.00	308,542	1,875,667	5.73
25	AVON PARK	1-2	49	0	0.0	92.10	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
26	BARTOW	1-4	177	0	0.0	89.44	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
27	BAYBORO	1-4	174	0	0.0	93.06	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
28	DEBARY	1-10	645	12	0.1	95.81	0.0	20,917	LIGHT OIL	43	BBLS	5.84	251	9,231	76.93
29	HIGGINS	1-4	113	0	0.0	93.79	0.0	0	LIGHT OIL	0	BBLS	0	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0	0	0	0.00
31	INT CITY	1-14	987	12	1.0	95.07	0.0	15,750	LIGHT OIL	32	BBLS	5.91	189	5,053	42.11
32	RIO PINAR	1	12	0	0.0	98.06	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
33	SUWANNEE	1-3	153	3	0.0	98.39	0.0	16,333	LIGHT OIL	8	BBLS	6.13	49	5,103	170.10
34	TURNER	1-4	149	0	0.0	72.26	0.0	0	LIGHT OIL	0	BBLS		0	272	0.00
35	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	1,699	BBLS	5.79	9,845	152,264	0.00
36	TOTAL			3,582,222									30,600,391	136,097,823	3.80

Docket No. 150001-EI

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Sep-15

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	0	0	0	0.00	0	0	NUCLEAR	0	MMBTU		0	0	0.00
2	CRYSTAL RIVER	1	375	132,629	49.1	89.67	59.9	10,535	COAL	57,710	TONS	24.21	1,397,294	5,761,784	4.34
3	CRYSTAL RIVER	2	494	190,527	53.6	96.02	55.4	10,743	COAL	84,537	TONS	24.21	2,046,844	8,360,698	4.39
4	CRYSTAL RIVER	4	722	344,039	66.2	91.00	72.7	10,581	COAL	156,749	TONS	23.22	3,640,143	12,755,115	3.71
5	CRYSTAL RIVER	5	700	343,055	68.1	94.00	72.4	10,637	COAL	157,137	TONS	23.22	3,649,173	12,785,476	3.73
6	ANCLOTE	1	501	0	0.0	93.57	0.0	0	HEAVY OIL	0	BBLS		0	0	0.00
7	ANCLOTE	2	510	0	0.0	96.45	0.0	0	HEAVY OIL	0	BBLS		0	0	0.00
8	SUWANNEE	1	30	0	0.0	98.33	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
9	SUWANNEE	2	30	0	0.0	97.95	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
10	SUWANNEE	3	71	0	0.0	96.00	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
11	ANCLOTE	1	501	150,531	41.7	0.00	42.6	10,366	GAS	1,560,454	MCF	1.00	1,560,454	7,549,097	5.01
12	ANCLOTE	2	510	102,803	28.0	0.00	43.6	10,545	GAS	1,084,107	MCF	1.00	1,084,107	5,676,577	5.52
13	AVON PARK	1-2	49	0	0.0	92.33	0.0	0	GAS	0	MCF		0	212	0.00
14	BARTOW	1-4	177	9	0.0	89.17	0.0	14,778	GAS	133	MCF	1.00	133	665	7.39
15	BARTOW CC	1	1,159	673,304	80.7	96.33	83.7	7,288	GAS	4,906,807	MCF	1.00	4,906,807	24,539,359	3.64
16	DEBARY	1-10	645	12	0.0	95.40	0.0	13,750	GAS	165	MCF	1.00	165	825	6.88
17	HIGGINS	1-4	113	13	0.0	93.83	0.0	16,846	GAS	219	MCF	1.00	219	1,096	8.43
18	HINES CC	1-4	1,912	1,194,597	86.8	96.53	22.3	7,096	GAS	8,477,392	MCF	1.00	8,477,392	42,396,158	3.55
19	INT CITY	1-14	987	2,537	0.4	95.87	6.6	13,166	GAS	33,401	MCF	1.00	33,401	172,842	6.81
20	SUWANNEE	1	52	10	0.0	96.33	0.0	14,200	GAS	142	MCF	1.00	142	107,374	1073.74
21	SUWANNEE	2	50	0	0.0	99.67	0.0	0	GAS	0	MCF		0	103,191	0.00
22	SUWANNEE	3	51	23,525	64.1	99.67	66.8	12,303	GAS	289,435	MCF	1.00	289,435	1,241,109	5.28
23	TIGER BAY CC	1	204	93,505	63.7	89.33	99.6	7,248	GAS	677,735	MCF	1.00	677,735	3,389,410	3.62
24	UNIV OF FLA. CC	1	46	18,900	57.1	97.22	97.8	9,429	GAS	178,211	MCF	1.00	178,211	1,425,781	7.54
25	AVON PARK	1-2	49	0	0.0	92.33	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
26	BARTOW	1-4	177	0	0.0	89.17	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
27	BAYBORO	1-4	174	3	0.0	92.33	0.0	16,000	LIGHT OIL	8	BBLS	6.00	48	784	26.13
28	DEBARY	1-10	645	16	0.0	95.40	0.0	18,125	LIGHT OIL	50	BBLS	5.80	290	9,888	61.80
29	HIGGINS	1-4	113	0	0.0	93.83	0.0	0	LIGHT OIL	0	BBLS	0	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0	0	0	0.00
31	INT CITY	1-14	987	12	0.4	95.87	0.0	15,917	LIGHT OIL	33	BBLS	5.79	191	5,118	42.65
32	RIO PINAR	1	12	0	0.0	99.00	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
33	SUWANNEE	1-3	153	6	0.0	98.56	0.0	16,333	LIGHT OIL	17	BBLS	5.76	98	5,815	96.92
34	TURNER	1-4	149	0	0.0	71.25	0.0	0	LIGHT OIL	0	BBLS		0	272	0.00
35	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	3,367	BBLS	5.80	19,514	305,160	0.00
36	TOTAL			3,270,033									27,961,796	126,593,806	3.87

Duke Energy Florida

System Net Generation and Fuel Cost

Estimated for the Period of: Oct-15

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	0	0	0	0.00	0	0	NUCLEAR	0	MMBTU		0	0	0.00
2	CRYSTAL RIVER	1	375	119,708	42.9	91.94	60.6	10,527	COAL	52,427	TONS	24.04	1,260,141	4,854,889	4.06
3	CRYSTAL RIVER	2	494	195,751	53.3	97.44	54.3	10,763	COAL	87,658	TONS	24.04	2,106,941	8,002,360	4.09
4	CRYSTAL RIVER	4	722	373,497	69.5	92.26	75.4	10,543	COAL	169,912	TONS	23.17	3,937,595	13,829,235	3.70
5	CRYSTAL RIVER	5	700	356,288	68.4	94.67	74.6	10,602	COAL	162,994	TONS	23.17	3,777,282	13,287,217	3.73
6	ANCLOTE	1	501	0	0.0	96.73	0.0	0	HEAVY OIL	0	BBLS		0	0	0.00
7	ANCLOTE	2	510	0	0.0	87.10	0.0	0	HEAVY OIL	0	BBLS		0	0	0.00
8	SUWANNEE	1	30	0	0.0	61.66	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
9	SUWANNEE	2	30	0	0.0	98.89	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
10	SUWANNEE	3	71	0	0.0	96.33	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
11	ANCLOTE	1	501	160,738	43.1	0.00	43.1	10,351	GAS	1,663,740	MCF	1.00	1,663,740	7,526,899	4.68
12	ANCLOTE	2	510	0	0.0	0.00	0.0	0	GAS	0	MCF		0	916,860	0.00
13	AVON PARK	1-2	49	60	0.2	92.74	0.0	16,117	GAS	967	MCF	1.00	967	6,186	10.31
14	BARTOW	1-4	177	377	0.3	90.08	27.3	13,920	GAS	5,248	MCF	1.00	5,248	26,635	7.06
15	BARTOW CC	1	1,159	371,640	43.1	86.77	46.2	7,289	GAS	2,708,843	MCF	1.00	2,708,843	13,747,833	3.70
16	DEBARY	1-10	645	1,825	0.4	96.45	12.5	12,917	GAS	23,573	MCF	1.00	23,573	119,636	6.56
17	HIGGINS	1-4	113	306	0.4	94.76	27.1	15,592	GAS	4,771	MCF	1.00	4,771	24,214	7.91
18	HINES CC	1-4	1,912	1,040,354	73.1	91.70	23.0	7,180	GAS	7,469,595	MCF	1.00	7,469,595	37,909,448	3.64
19	INT CITY	1-14	987	7,011	1.0	93.85	7.4	12,914	GAS	90,537	MCF	1.00	90,537	459,490	6.55
20	SUWANNEE	1	52	765	2.0	96.77	66.9	14,299	GAS	10,939	MCF	1.00	10,939	164,988	21.57
21	SUWANNEE	2	50	545	1.5	99.68	38.9	15,604	GAS	8,504	MCF	1.00	8,504	145,691	26.73
22	SUWANNEE	3	51	24,056	63.4	100.00	68.0	12,317	GAS	296,305	MCF	1.00	296,305	1,295,270	5.38
23	TIGER BAY CC	1	204	25,642	16.9	88.89	100.6	7,165	GAS	183,724	MCF	1.00	183,724	932,430	3.64
24	UNIV OF FLA. CC	1	46	30,564	89.3	62.10	97.9	9,434	GAS	288,335	MCF	1.00	288,335	1,348,050	4.41
25	AVON PARK	1-2	49	0	0.0	92.74	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
26	BARTOW	1-4	177	9	0.3	90.08	0.0	13,222	LIGHT OIL	21	BBLS	5.67	119	1,936	21.51
27	BAYBORO	1-4	174	3	0.0	92.66	0.0	16,000	LIGHT OIL	8	BBLS	6.00	48	781	26.03
28	DEBARY	1-10	645	190	0.4	96.45	52.1	13,489	LIGHT OIL	442	BBLS	5.80	2,563	45,532	23.96
29	HIGGINS	1-4	113	0	0.0	94.76	0.0	0	LIGHT OIL	0	BBLS	0	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0	0	0	0.00
31	INT CITY	1-14	987	258	1.0	93.85	0.0	12,818	LIGHT OIL	571	BBLS	5.79	3,307	62,169	24.10
32	RIO PINAR	1	12	0	0.0	98.39	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
33	SUWANNEE	1-3	153	62	0.1	98.82	2.4	14,290	LIGHT OIL	153	BBLS	5.79	886	24,485	39.49
34	TURNER	1-4	149	0	0.0	71.77	0.0	0	LIGHT OIL	0	BBLS		0	272	0.00
35	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	2,167	BBLS	5.80	12,562	195,641	0.00
36	TOTAL			2,709,649									23,856,525	104,928,147	3.87

Docket No. 150001-EI

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Nov-15

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	0	0	0	0.00	0	0	NUCLEAR	0	MMBTU		0	0	0.00
2	CRYSTAL RIVER	1	376	23,068	8.5	90.00	28.1	11,154	COAL	10,778	TONS	23.87	257,303	1,133,435	4.91
3	CRYSTAL RIVER	2	500	77,195	21.4	93.55	33.7	11,049	COAL	35,728	TONS	23.87	852,907	3,361,113	4.35
4	CRYSTAL RIVER	4	732	366,217	69.5	95.67	72.6	10,404	COAL	164,725	TONS	23.13	3,810,245	13,461,153	3.68
5	CRYSTAL RIVER	5	712	111,906	21.8	91.00	72.1	10,344	COAL	50,042	TONS	23.13	1,157,530	4,448,819	3.98
6	ANCLOTE	1	517	0	0.0	98.60	0.0	0	HEAVY OIL	0	BBLS		0	0	0.00
7	ANCLOTE	2	521	0	0.0	0.00	0.0	0	HEAVY OIL	0	BBLS		0	0	0.00
8	SUWANNEE	1	30	0	0.0	66.67	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
9	SUWANNEE	2	30	0	0.0	24.25	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
10	SUWANNEE	3	73	0	0.0	100.00	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
11	ANCLOTE	1	517	153,140	41.1	0.00	41.1	10,108	GAS	1,547,960	MCF	1.00	1,547,960	6,979,158	4.56
12	ANCLOTE	2	521	21,948	5.9	0.00	50.8	10,303	GAS	226,120	MCF	1.00	226,120	1,871,568	8.53
13	AVON PARK	1-2	69	0	0.0	93.17	0.0	0	GAS	0	MCF		0	212	0.00
14	BARTOW	1-4	228	0	0.0	90.33	0.0	0	GAS	0	MCF		0	0	0.00
15	BARTOW CC	1	1,279	463,782	50.4	45.00	52.1	7,137	GAS	3,310,221	MCF	1.00	3,310,221	16,514,395	3.56
16	DEBARY	1-10	785	374	0.1	96.50	0.0	12,439	GAS	4,652	MCF	1.00	4,652	23,209	6.21
17	HIGGINS	1-4	129	0	0.0	93.25	0.0	0	GAS	0	MCF		0	0	0.00
18	HINES CC	1-4	2,204	1,166,374	73.5	75.60	20.5	7,034	GAS	8,204,143	MCF	1.00	8,204,143	40,929,732	3.51
19	INT CITY	1-14	1,186	2,297	0.3	73.23	7.4	12,289	GAS	28,228	MCF	1.00	28,228	145,410	6.33
20	SUWANNEE	1	67	13,708	28.4	96.00	28.4	14,612	GAS	200,300	MCF	1.00	200,300	923,879	6.74
21	SUWANNEE	2	66	12,950	27.3	99.67	28.9	14,691	GAS	190,250	MCF	1.00	190,250	885,653	6.84
22	SUWANNEE	3	67	0	0.0	99.67	0.0	0	GAS	0	MCF		0	146,445	0.00
23	TIGER BAY CC	1	225	0	0.0	30.00	0.0	0	GAS	0	MCF		0	0	0.00
24	UNIV OF FLA. CC	1	47	33,869	100.1	91.33	102.1	9,427	GAS	319,278	MCF	1.00	319,278	1,233,690	3.64
25	AVON PARK	1-2	69	0	0.0	93.17	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
26	BARTOW	1-4	228	0	0.0	90.33	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
27	BAYBORO	1-4	231	0	0.0	94.92	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
28	DEBARY	1-10	785	10	0.1	96.50	0.0	19,700	LIGHT OIL	34	BBLS	5.79	197	8,395	83.95
29	HIGGINS	1-4	129	0	0.0	93.25	0.0	0	LIGHT OIL	0	BBLS	0	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0	0	0	0.00
31	INT CITY	1-14	1,186	6	0.3	73.23	0.0	16,500	LIGHT OIL	17	BBLS	5.82	99	3,670	61.17
32	RIO PINAR	1	16	0	0.0	99.00	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
33	SUWANNEE	1-3	200	2	0.0	98.44	0.0	15,000	LIGHT OIL	5	BBLS	6.00	30	480	24.00
34	TURNER	1-4	199	2	0.0	70.67	0.0	18,500	LIGHT OIL	6	BBLS	6.17	37	850	42.50
35	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	3,928	BBLS	5.80	22,764	352,728	0.00
36	TOTAL			2,446,848									20,132,264	92,423,994	3.78

Docket No. 150001-EI

Duke Energy Florida
System Net Generation and Fuel Cost
Estimated for the Period of: Dec-15

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	0	0	0	0.00	0	0	NUCLEAR	0	MMBTU		0	0	0.00
2	CRYSTAL RIVER	1	376	26,053	9.3	93.87	27.3	11,199	COAL	12,293	TONS	23.74	291,780	1,266,238	4.86
3	CRYSTAL RIVER	2	500	60,066	16.1	66.02	25.8	11,428	COAL	28,921	TONS	23.74	686,455	2,747,611	4.57
4	CRYSTAL RIVER	4	732	331,220	60.8	89.35	68.0	10,441	COAL	149,770	TONS	23.09	3,458,372	12,314,116	3.72
5	CRYSTAL RIVER	5	712	371,684	70.2	29.35	74.8	10,308	COAL	165,925	TONS	23.09	3,831,429	13,586,763	3.66
6	ANCLOTE	1	517	0	0.0	96.77	0.0	0	HEAVY OIL	0	BBLS		0	0	0.00
7	ANCLOTE	2	521	0	0.0	54.79	0.0	0	HEAVY OIL	0	BBLS		0	0	0.00
8	SUWANNEE	1	30	0	0.0	100.00	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
9	SUWANNEE	2	30	0	0.0	100.00	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
10	SUWANNEE	3	73	0	0.0	0.73	0.0	0	HEAVY OIL	0	BBLS	0	0	0	0.00
11	ANCLOTE	1	517	94,098	24.5	0.00	24.7	10,586	GAS	996,161	MCF	1.00	996,161	4,696,060	4.99
12	ANCLOTE	2	521	7,106	1.8	0.00	68.2	10,668	GAS	75,806	MCF	1.00	75,806	918,003	12.92
13	AVON PARK	1-2	69	0	0.0	93.39	0.0	0	GAS	0	MCF		0	212	0.00
14	BARTOW	1-4	228	0	0.0	88.87	0.0	0	GAS	0	MCF		0	0	0.00
15	BARTOW CC	1	1279	793,194	83.4	48.39	86.1	7,109	GAS	5,638,632	MCF	1.00	5,638,632	29,530,420	3.72
16	DEBARY	1-10	785	77	0.0	95.61	0.0	13,078	GAS	1,007	MCF	1.00	1,007	5,274	6.85
17	HIGGINS	1-4	129	0	0.0	92.74	0.0	0	GAS	0	MCF		0	0	0.00
18	HINES CC	1-4	2,204	983,294	60.0	82.83	21.5	7,057	GAS	6,939,090	MCF	1.00	6,939,090	36,341,126	3.70
19	INT CITY	1-14	1,186	1,727	0.2	81.01	8.1	12,343	GAS	21,316	MCF	1.00	21,316	115,023	6.66
20	SUWANNEE	1	67	6,875	13.8	96.45	28.5	14,600	GAS	100,372	MCF	1.00	100,372	548,647	7.98
21	SUWANNEE	2	66	6,843	13.9	100.00	28.8	14,680	GAS	100,456	MCF	1.00	100,456	549,600	8.03
22	SUWANNEE	3	67	12,524	25.1	99.35	50.0	12,119	GAS	151,776	MCF	1.00	151,776	756,186	6.04
23	TIGER BAY CC	1	225	5,322	3.2	0.00	98.6	7,823	GAS	41,635	MCF	1.00	41,635	218,049	4.10
24	UNIV OF FLA. CC	1	47	34,906	99.8	97.74	102.2	9,427	GAS	329,048	MCF	1.00	329,048	1,397,880	4.00
25	AVON PARK	1-2	69	0	0.0	93.39	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
26	BARTOW	1-4	228	0	0.0	88.87	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
27	BAYBORO	1-4	231	0	0.0	93.79	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
28	DEBARY	1-10	785	0	0.0	95.61	0.0	0	LIGHT OIL	0	BBLS		0	5,320	0.00
29	HIGGINS	1-4	129	0	0.0	92.74	0.0	0	LIGHT OIL	0	BBLS	0	0	0	0.00
30	OTHER		0	0	0.0	0.00	0.0	0	LIGHT OIL	0	BBLS	0	0	0	0.00
31	INT CITY	1-14	1,186	0	0.0	81.01	0.0	0	LIGHT OIL	0	BBLS		0	2,142	0.00
32	RIO PINAR	1	16	0	0.0	97.42	0.0	0	LIGHT OIL	0	BBLS		0	0	0.00
33	SUWANNEE	1-3	200	0	0.0	98.60	0.0	0	LIGHT OIL	0	BBLS	0	0	0	0.00
34	TURNER	1-4	199	0	0.0	70.73	0.0	0	LIGHT OIL	0	BBLS		0	272	0.00
35	OTHER & START UP		-	0	-	0.00	0.0	0	LIGHT OIL	4,032	BBLS	5.80	23,370	360,575	0.00
36	TOTAL			2,734,989									22,686,705	105,359,517	3.85

Duke Energy Florida
Inventory Analysis
Estimated for the Period of : January through December 2015

			Act	Act	Act	Act	Act	Act	
	HEAVY OIL		Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Subtotal
1	PURCHASES:								
2	UNITS	BBL	0	0	0	0	0	0	0
3	UNIT COST	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	AMOUNT	$	0	0	0	0	0	0	0
5	BURNED:								
6	UNITS	BBL	0	0	0	0	0	0	0
7	UNIT COST	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	AMOUNT	$	0	0	0	0	0	0	0
9	ENDING INVENTORY:								
10	UNITS	BBL	0	0	0	0	0	0	
11	UNIT COST	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	
12	AMOUNT	$	(2,206)	(2,206)	(2,206)	(2,206)	(2,206)	(2,206)	
	LIGHT OIL								
13	PURCHASES:								
14	UNITS	BBL	0	171	0	9,804	5,129	0	15,104
15	UNIT COST	$/BBL	0.00	1744.52	0.00	115.65	201.02	0.00	218.64
16	AMOUNT	$	544,738	298,313	26,863	1,133,816	1,031,008	267,622	3,302,359
17	BURNED:								
18	UNITS	BBL	9,681	31,189	4,603	8,915	9,120	7,546	71,054
19	UNIT COST	$/BBL	136.31	132.58	135.90	130.42	132.85	136.88	133.52
20	AMOUNT	$	1,319,615	4,134,966	625,553	1,162,677	1,211,629	1,032,864	9,487,304
21	ENDING INVENTORY:								
22	UNITS	BBL	1,020,493	989,475	984,872	985,760	981,769	974,224	
23	UNIT COST	$/BBL	116.71	116.49	116.43	116.30	116.58	116.70	
24	AMOUNT	$	119,103,289	115,266,636	114,667,945	114,639,084	114,458,463	113,693,222	
	COAL								
25	PURCHASES:								
26	UNITS	TON	284,975	275,167	368,576	404,722	419,359	336,786	2,089,585
27	UNIT COST	$/TON	87.18	80.84	87.84	77.65	86.11	79.49	83.16
28	AMOUNT	$	24,844,396	22,244,197	32,375,261	31,427,373	36,112,710	26,770,157	173,774,093
29	BURNED:								
30	UNITS	TON	228,326	298,466	447,186	412,463	457,388	477,254	2,321,083
31	UNIT COST	$/TON	90.03	87.16	86.06	84.58	89.33	88.72	87.52
32	AMOUNT	$	20,556,863	26,015,558	38,485,187	34,885,567	40,856,360	42,341,224	203,140,760
33	ENDING INVENTORY:								
34	UNITS	TON	1,275,860	1,252,560	1,173,951	1,166,211	1,128,182	987,715	
35	UNIT COST	$/TON	95.17	93.93	95.02	92.68	91.60	88.86	
36	AMOUNT	$	121,425,759	117,654,397	111,544,471	108,086,276	103,342,626	87,771,559	
	GAS								
37	BURNED:								
38	UNITS	MCF	15,871,516	13,463,049	13,349,942	15,651,678	17,368,410	18,726,081	94,430,676
39	UNIT COST	$/MCF	4.93	5.01	4.81	4.90	5.00	4.85	4.92
40	AMOUNT	$	78,221,322	67,400,168	64,238,807	76,762,568	86,778,051	90,866,875	464,267,790
	NUCLEAR								
41	BURNED:								
42	UNITS	MMBTU	0	0	0	0	0	0	0
43	UNIT COST	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	AMOUNT	$	0	0	0	0	0	0	0

Duke Energy Florida
Inventory Analysis
Estimated for the Period of : January through December 2015

			Est	Est	Est	Est	Est	Est	
	HEAVY OIL		Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	Total
1	PURCHASES:								
2	UNITS	BBL	0	0	0	0	0	0	0
3	UNIT COST	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	AMOUNT	$	0	0	0	0	0	0	0
5	BURNED:								
6	UNITS	BBL	0	0	0	0	0	0	0
7	UNIT COST	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
8	AMOUNT	$	0	0	0	0	0	0	0
9	ENDING INVENTORY:								
10	UNITS	BBL	0	0	0	0	0	0	
11	UNIT COST	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	
12	AMOUNT	$	0	0	0	0	0	0	
	LIGHT OIL								
13	PURCHASES:								
14	UNITS	BBL	3,143	1,782	3,475	3,362	3,990	4,032	34,888
15	UNIT COST	$/BBL	90.53	96.48	94.11	98.40	91.76	91.35	147.65
16	AMOUNT	$	284,551	171,923	327,037	330,816	366,123	368,309	5,151,118
17	BURNED:								
18	UNITS	BBL	3,143	1,782	3,475	3,362	3,990	4,032	90,838
19	UNIT COST	$/BBL	90.53	96.48	94.11	98.40	91.76	91.35	124.79
20	AMOUNT	$	284,551	171,923	327,037	330,816	366,123	368,309	11,336,063
21	ENDING INVENTORY:								
22	UNITS	BBL	974,224	974,224	974,224	974,224	974,224	974,224	
23	UNIT COST	$/BBL	90.53	96.48	94.11	98.40	91.76	91.35	
24	AMOUNT	$	88,196,499	93,993,132	91,684,221	95,863,642	89,394,794	88,995,362	
	COAL								
25	PURCHASES:								
26	UNITS	TON	454,259	477,058	456,133	472,991	261,273	356,909	4,568,208
27	UNIT COST	$/TON	88.42	88.55	86.96	84.51	85.75	83.82	84.97
28	AMOUNT	$	40,164,847	42,243,248	39,663,073	39,973,701	22,404,520	29,914,728	388,138,210
29	BURNED:								
30	UNITS	TON	454,259	477,058	456,133	472,991	261,273	356,909	4,799,706
31	UNIT COST	$/TON	88.42	88.55	86.96	84.51	85.75	83.82	86.99
32	AMOUNT	$	40,164,847	42,243,248	39,663,073	39,973,701	22,404,520	29,914,728	417,504,877
33	ENDING INVENTORY:								
34	UNITS	TON	987,715	987,715	987,715	987,715	987,715	987,715	
35	UNIT COST	$/TON	88.42	88.55	86.96	84.51	85.75	83.82	
36	AMOUNT	$	87,332,180	87,461,669	85,886,857	83,474,363	84,697,944	82,786,419	
	GAS								
37	BURNED:								
38	UNITS	MCF	19,332,873	19,331,530	17,208,201	12,755,081	14,031,152	14,395,299	191,484,812
39	UNIT COST	$/MCF	4.82	4.85	5.03	5.07	4.96	5.22	4.95
40	AMOUNT	$	93,250,949	93,682,652	86,603,696	64,623,630	69,653,351	75,076,480	947,158,548
	NUCLEAR								
41	BURNED:								
42	UNITS	MMBTU	0	0	0	0	0	0	0
43	UNIT COST	$/MMBTU	0.00	0.00	0.00	0.00	0.00	0.00	0.00
44	AMOUNT	$	0	0	0	0	0	0	0

Duke Energy Florida
Fuel Cost of Power Sold
Estimated for the Period of : January through December 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
				MWH		C/KWH				REFUNDABLE
		TYPE	TOTAL	WHEELED	MWH	(A)	(B)	TOTAL $	TOTAL	GAIN ON
MONTH	SOLD TO	&	MWH	FROM	FROM	FUEL	TOTAL	FOR	COST	POWER
		SCHED	SOLD	OTHER	OWN	COST	COST	FUEL ADJ	$	SALES
				SYSTEMS	GENERATION			(6) x (7)(A)	(6) x (7)(B)	$
Jan-15	ECONSALE	--	34,442		34,442	2.717	5.149	935,679	1,773,411	837,732
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	53,713		53,713	4.040	4.040	2,169,807	2,169,807	0
	TOTAL		88,155		88,155	3.523	4.473	3,105,487	3,943,219	837,732
Feb-15	ECONSALE	--	36,493		36,493	2.845	6.278	1,038,277	2,291,046	1,252,770
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(70,132)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	36,569		36,569	3.556	3.556	1,300,419	1,300,419	0
	TOTAL		73,062		73,062	3.201	4.916	2,338,696	3,591,466	1,182,638
Mar-15	ECONSALE	--	17,772		17,772	2.611	3.384	464,031	601,455	137,423
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(27,485)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	46,265		46,265	3.355	3.355	1,552,088	1,552,088	0
	TOTAL		64,037		64,037	3.148	3.363	2,016,119	2,153,543	109,939
Apr-15	ECONSALE	--	4,350		4,350	2.506	3.555	108,994	154,651	45,657
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(9,131)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	81,809		81,809	2.998	2.998	2,452,502	2,452,502	0
	TOTAL		86,159		86,159	2.973	3.026	2,561,497	2,607,154	36,526
May-15	ECONSALE	--	22,337		22,337	3.774	5.426	843,064	1,212,072	369,008
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(73,802)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	131,637		131,637	3.529	3.529	4,646,122	4,646,122	0
	TOTAL		153,974		153,974	3.565	3.805	5,489,187	5,858,195	295,207
Jun-15	ECONSALE	--	21,583		21,583	3.089	4.382	666,603	945,805	279,203
Act	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(55,841)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	124,876		124,876	3.596	3.596	4,490,143	4,490,143	0
	TOTAL		146,459		146,459	3.521	3.712	5,156,745	5,435,948	223,362
Jan	ECONSALE	--	136,977		136,977	2.962	5.095	4,056,648	6,978,441	2,921,793
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Jun-15	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(236,390)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	474,869		474,869	3.498	3.498	16,611,082	16,611,082	0
	TOTAL		611,846		611,846	3.378	3.855	20,667,730	23,589,523	2,685,403

Duke Energy Florida
Fuel Cost of Power Sold
Estimated for the Period of : January through December 2015

(1) MONTH	(2) SOLD TO	(3) TYPE & SCHED	(4) TOTAL MWH SOLD	(5) MWH WHEELED FROM OTHER SYSTEMS	(6) MWH FROM OWN GENERATION	(7) C/KWH (A) FUEL COST	(7) C/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ (6) x (7)(A)	(9) TOTAL COST $ (6) x (7)(B)	(10) REFUNDABLE GAIN ON POWER SALES $
Jul-15	ECONSALE	--	25,725		25,725	2.315	2.834	595,463	729,149	133,686
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(26,737)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	76,691		76,691	3.119	3.119	2,391,679	2,391,679	0
	TOTAL		102,416		102,416	2.917	3.047	2,987,142	3,120,828	106,949
Aug-15	ECONSALE	--	9,505		9,505	3.158	3.866	300,128	367,508	67,380
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(13,476)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	84,336		84,336	3.160	3.160	2,665,418	2,665,418	0
	TOTAL		93,841		93,841	3.160	3.232	2,965,546	3,032,926	53,904
Sep-15	ECONSALE	--	590		590	2.056	2.517	12,130	14,853	2,723
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(545)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	87,574		87,574	3.236	3.236	2,834,152	2,834,152	0
	TOTAL		88,164		88,164	3.228	3.231	2,846,282	2,849,005	2,178
Oct-15	ECONSALE	--	5,030		5,030	1.935	2.369	97,311	119,158	21,847
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(4,369)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	78,433		78,433	3.226	3.226	2,530,567	2,530,567	0
	TOTAL		83,463		83,463	3.149	3.175	2,627,878	2,649,725	17,478
Nov-15	ECONSALE	--	7,970		7,970	2.033	2.489	161,997	198,366	36,369
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(7,274)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	58,418		58,418	3.211	3.211	1,875,798	1,875,798	0
	TOTAL		66,388		66,388	3.070	3.124	2,037,795	2,074,164	29,095
Dec-15	ECONSALE	--	1,775		1,775	2.381	2.916	42,270	51,760	9,490
Est	ECONOMY	C	0		0	0.000	0.000	0	0	0
	EXCESS GAIN	--	0		0	0.000	0.000	0	0	(1,898)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	35,177		35,177	3.430	3.430	1,206,571	1,206,571	0
	TOTAL		36,952		36,952	3.380	3.405	1,248,841	1,258,331	7,592
Jan-15	ECONSALE	--	187,572		187,572	2.807	4.510	5,265,947	8,459,235	3,193,288
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Dec-15	EXCESS GAIN	--	0		0	0.000	0.000	0	(290,689)	(290,689)
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	895,498		895,498	3.363	3.363	30,115,267	30,115,267	0
	TOTAL		1,083,070		1,083,070	3.267	3.535	35,381,214	38,283,813	2,902,599

Duke Energy Florida
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January through December 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH			C/KWH		TOTAL $
		TYPE	TOTAL	FOR	MWH	MWH	(A)	(B)	FOR
MONTH	NAME OF	&	MWH	OTHER	FOR	FOR	FUEL	TOTAL	FUEL ADJ
	PURCHASE	SCHEDULE	PURCHASED	UTILITIES	INTERRUPTIBLE	FIRM	COST	COST	(7) x (8)(B)
Jan-15	OTHER	--	0			0	0.000	0.000	0
Act	Osprey (Calpine)	--	151,343			151,343	3.617	3.617	5,474,550
	SHADY HILLS	--	1,209			1,209	5.599	5.599	67,691
	SOCO Franklin	--	44,900			44,900	4.043	4.043	1,815,108
	SOCO Scherer	--	1,722			1,722	6.407	6.407	110,330
	Vandolah (NSG)	--	(3)			(3)	(1772.326)	(1772.326)	53,170
	TOTAL		199,171	0	0	199,171	3.776	3.776	7,520,849
Feb-15	OTHER	--	0			0	0.000	0.000	0
Act	Osprey (Calpine)	--	131,775			131,775	3.488	3.488	4,596,551
	SHADY HILLS	--	8,309			8,309	5.515	5.515	458,257
	SOCO Franklin	--	72,950			72,950	3.426	3.426	2,499,278
	SOCO Scherer	--	2,628			2,628	3.455	3.455	90,793
	Vandolah (NSG)	--	5,214			5,214	5.101	5.101	265,944
	TOTAL		220,876	0	0	220,876	3.582	3.582	7,910,824
Mar-15	OTHER	--	0			0	0.000	0.000	0
Act	Osprey (Calpine)	--	177,775			177,775	3.853	3.853	6,850,392
	SHADY HILLS	--	6,522			6,522	(6.414)	(6.414)	(418,347)
	SOCO Franklin	--	130,696			130,696	2.973	2.973	3,886,142
	SOCO Scherer	--	0			0	0.000	0.000	(289,568)
	Vandolah (NSG)	--	2,327			2,327	8.973	8.973	208,791
	TOTAL		317,320	0	0	317,320	3.226	3.226	10,237,409
Apr-15	OTHER	--	0			0	0.000	0.000	0
Act	Osprey (Calpine)	--	96,459			96,459	3.697	3.697	3,566,347
	SHADY HILLS	--	47,369			47,369	6.437	6.437	3,048,959
	SOCO Franklin	--	148,109			148,109	2.873	2.873	4,255,505
	SOCO Scherer	--	0			0	0.000	0.000	0
	Vandolah (NSG)	--	59,577			59,577	6.733	6.733	4,011,512
	TOTAL		351,514	0	0	351,514	4.234	4.234	14,882,323
May-15	OTHER	--	0			0	0.000	0.000	0
Act	Osprey (Calpine)	--	167,052			167,052	2.552	2.552	4,262,691
	SHADY HILLS	--	40,150			40,150	3.882	3.882	1,558,754
	SOCO Franklin	--	134,886			134,886	3.074	3.074	4,146,964
	SOCO Scherer	--	8,312			8,312	3.122	3.122	259,486
	Vandolah (NSG)	--	49,022			49,022	5.510	5.510	2,701,093
	TOTAL		399,422	0	0	399,422	3.237	3.237	12,928,988
Jun-15	OTHER	--	0			0	0.000	0.000	0
Act	Osprey (Calpine)	--	198,730			198,730	5.697	5.697	11,321,890
	SHADY HILLS	--	14,347			14,347	17.746	17.746	2,546,050
	SOCO Franklin	--	166,704			166,704	2.926	2.926	4,877,656
	SOCO Scherer	--	15,925			15,925	2.904	2.904	462,459
	Vandolah (NSG)	--	62,147			62,147	8.447	8.447	5,249,364
	TOTAL		457,853	0	0	457,853	5.342	5.342	24,457,418
Jan-15	OTHER	--	0			0	0.000	0.000	0
THRU	Osprey (Calpine)	--	923,134			923,134	3.908	3.908	36,072,422
Jun-15	SHADY HILLS	--	117,906			117,906	6.159	6.159	7,261,363
	SOCO Franklin	--	698,245			698,245	3.076	3.076	21,480,652
	SOCO Scherer	--	28,587			28,587	2.216	2.216	633,500
	Vandolah (NSG)	--	178,284			178,284	7.006	7.006	12,489,874
	TOTAL		1,946,156	0	0	1,946,156	4.005	4.005	77,937,812

Duke Energy Florida
Purchased Power
(Exclusive of Economy & QF Purchases)
Estimated for the Period of : January through December 2015

(1) MONTH	(2) NAME OF PURCHASE	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR OTHER UTILITIES	(6) MWH FOR INTERRUPTIBLE	(7) MWH FOR FIRM	(8) C/KWH (A) FUEL COST	(8) C/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJ (7) x (8)(B)
Jul-15	OTHER	--	0			0	0.000	0.000	0
Est	Osprey (Calpine)	--	206,179			206,179	4.118	4.118	8,490,816
	SHADY HILLS	--	13,412			13,412	6.018	6.018	807,186
	SOCO Franklin	--	157,839			157,839	3.098	3.098	4,890,287
	SOCO Scherer	--	11,125			11,125	3.950	3.950	439,416
	Vandolah (NSG)	--	50,625			50,625	5.508	5.508	2,788,325
	TOTAL		439,180	0	0	439,180	3.966	3.966	17,416,030
Aug-15	OTHER	--	0			0	0.000	0.000	0
Est	Osprey (Calpine)	--	197,671			197,671	4.156	4.156	8,214,276
	SHADY HILLS	--	12,740			12,740	6.092	6.092	776,147
	SOCO Franklin	--	154,910			154,910	3.130	3.130	4,848,341
	SOCO Scherer	--	12,584			12,584	3.893	3.893	489,921
	Vandolah (NSG)	--	47,914			47,914	5.603	5.603	2,684,391
	TOTAL		425,819	0	0	425,819	3.995	3.995	17,013,076
Sep-15	OTHER	--	0			0	0.000	0.000	0
Est	Osprey (Calpine)	--	187,328			187,328	4.229	4.229	7,922,763
	SHADY HILLS	--	7,523			7,523	6.108	6.108	459,527
	SOCO Franklin	--	154,580			154,580	3.129	3.129	4,837,475
	SOCO Scherer	--	10,820			10,820	3.914	3.914	423,502
	Vandolah (NSG)	--	26,746			26,746	5.793	5.793	1,549,426
	TOTAL		386,997	0	0	386,997	3.926	3.926	15,192,693
Oct-15	OTHER	--	0			0	0.000	0.000	0
Est	Osprey (Calpine)	--	217,196			217,196	4.368	4.368	9,487,774
	SHADY HILLS	--	33,021			33,021	5.819	5.819	1,921,348
	SOCO Franklin	--	147,750			147,750	3.157	3.157	4,664,484
	SOCO Scherer	--	19,500			19,500	3.815	3.815	743,992
	Vandolah (NSG)	--	109,045			109,045	5.623	5.623	6,131,975
	TOTAL		526,512	0	0	526,512	4.359	4.359	22,949,573
Nov-15	OTHER	--	0			0	0.000	0.000	0
Est	Osprey (Calpine)	--	53,728			53,728	4.113	4.113	2,210,088
	SHADY HILLS	--	4,644			4,644	6.069	6.069	281,826
	SOCO Franklin	--	91,395			91,395	3.584	3.584	3,275,377
	SOCO Scherer	--	9,701			9,701	3.845	3.845	373,022
	Vandolah (NSG)	--	21,527			21,527	5.789	5.789	1,246,237
	TOTAL		180,995	0	0	180,995	4.081	4.081	7,386,550
Dec-15	OTHER	--	0			0	0.000	0.000	0
Est	Osprey (Calpine)	--	87,568			87,568	4.280	4.280	3,747,799
	SHADY HILLS	--	1,039			1,039	6.538	6.538	67,934
	SOCO Franklin	--	17,457			17,457	5.987	5.987	1,045,190
	SOCO Scherer	--	1,926			1,926	4.020	4.020	77,424
	Vandolah (NSG)	--	2,489			2,489	6.234	6.234	155,161
	TOTAL		110,479	0	0	110,479	4.610	4.610	5,093,508
Jan-15	OTHER	--	0			0	0.000	0.000	0
THRU	Osprey (Calpine)	--	1,872,804			1,872,804	4.066	4.066	76,145,938
Dec-15	SHADY HILLS	--	190,285			190,285	6.083	6.083	11,575,331
	SOCO Franklin	--	1,422,176			1,422,176	3.167	3.167	45,041,806
	SOCO Scherer	--	94,243			94,243	3.375	3.375	3,180,777
	Vandolah (NSG)	--	436,630			436,630	6.194	6.194	27,045,389
TOTAL			4,016,138	0	0	4,016,138	4.058	4.058	162,989,242

Duke Energy Florida
Energy Payments to Qualifying Facilities
Estimated for the Period of : January through December 2015

(1) MONTH	(2) NAME OF PURCHASE	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR OTHER UTILITIES	(6) MWH FOR INTERRUPTIBLE	(7) MWH FOR FIRM	(8) C/KWH (A) ENERGY COST	(8) C/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJ (7) x (8)(A)
Jan-15 Act	QUAL. FACILITIES	COGEN	215,828			215,828	4.166	13.049	8,990,368
Feb-15 Act	QUAL. FACILITIES	COGEN	197,519			197,519	4.142	14.373	8,182,122
Mar-15 Act	QUAL. FACILITIES	COGEN	198,690			198,690	4.062	14.236	8,070,423
Apr-15 Act	QUAL. FACILITIES	COGEN	202,744			202,744	4.504	14.431	9,132,303
May-15 Act	QUAL. FACILITIES	COGEN	240,185			240,185	4.533	12.971	10,888,108
Jun-15 Act	QUAL. FACILITIES	COGEN	233,158			233,158	4.290	12.979	10,001,969
Jul-15 Est	QUAL. FACILITIES	COGEN	266,567			266,567	3.869	11.052	10,312,561
Aug-15 Est	QUAL. FACILITIES	COGEN	266,558			266,558	3.863	11.046	10,297,360
Sep-15 Est	QUAL. FACILITIES	COGEN	257,986			257,986	3.860	11.282	9,958,969
Oct-15 Est	QUAL. FACILITIES	COGEN	204,175			204,175	3.946	13.324	8,056,488
Nov-15 Est	QUAL. FACILITIES	COGEN	265,424			265,424	4.185	11.399	11,106,909
Dec-15 Est	QUAL. FACILITIES	COGEN	276,981			276,981	4.286	11.199	11,872,346
TOTAL	QUAL. FACILITIES	COGEN	2,825,815			2,825,815	4.136	12.457	116,869,926

Duke Energy Florida
Economy Energy Purchases
Estimated for the Period of : January through December 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL MWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jan-15	ECONPURCH	--	7,108	2.395	2.395	170,255	3.782	268,846	98,591
Act	SEPA	--	6,341	4.447	4.447	281,995	4.447	281,995	0
	TOTAL		13,449	3.363	3.363	452,250	4.096	550,841	98,591
Feb-15	ECONPURCH	--	1,086	15.968	15.968	173,413	4.089	44,407	(129,007)
Act	SEPA	--	9,224	4.440	4.440	409,555	4.440	409,555	0
	TOTAL		10,310	5.654	5.654	582,968	4.403	453,961	(129,007)
Mar-15	ECONPURCH	--	6,816	6.225	6.225	424,304	3.785	258,009	(166,295)
Act	SEPA	--	3,941	4.468	4.468	176,122	4.468	176,122	0
	TOTAL		10,757	5.581	5.581	600,426	4.036	434,131	(166,295)
Apr-15	ECONPURCH	--	6,471	5.727	5.727	370,608	4.314	279,130	(91,477)
Act	SEPA	--	6,937	4.097	4.097	284,228	4.097	284,228	0
	TOTAL		13,408	4.884	4.884	654,836	4.202	563,359	(91,477)
May-15	ECONPURCH	--	2,594	13.284	13.284	344,575	4.625	119,975	(224,601)
Act	SEPA	--	2,891	3.995	3.995	115,483	3.995	115,483	0
	TOTAL		5,485	8.388	8.388	460,058	4.293	235,457	(224,601)
Jun-15	ECONPURCH	--	605	33.774	33.774	204,330	3.761	22,753	(181,577)
Act	SEPA	--	5,299	4.081	4.081	216,243	4.081	216,243	0
	TOTAL		5,904	7.124	7.124	420,572	4.048	238,996	(181,577)
Jan-15	ECONPURCH	--	24,680	6.837	6.837	1,687,485	4.02	993,120	(694,365)
THRU	SEPA	--	34,633	4.284	4.284	1,483,625	4.28	1,483,625	0
Jun-15									
	TOTAL		59,313	5.346	5.346	3,171,110	4.176	2,476,745	(694,365)

Duke Energy Florida
Economy Energy Purchases
Estimated for the Period of : January through December 2015

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL MWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jul-15	ECONPURCH	--	10,022	5.177	5.177	518,864	6.409	642,344	123,480
Est	SEPA	--	3,397	4.500	4.500	152,870	4.500	152,870	0
	TOTAL		13,419	5.006	5.006	671,734	5.926	795,214	123,480
Aug-15	ECONPURCH	--	13,683	4.646	4.646	635,743	5.865	802,468	166,725
Est	SEPA	--	3,397	4.500	4.500	152,870	4.500	152,870	0
	TOTAL		17,080	4.617	4.617	788,613	5.593	955,338	166,725
Sep-15	ECONPURCH	--	29,115	3.946	3.946	1,148,881	5.171	1,505,467	356,586
Est	SEPA	--	3,288	4.499	4.499	147,938	4.499	147,938	0
	TOTAL		32,403	4.002	4.002	1,296,819	5.103	1,653,405	356,586
Oct-15	ECONPURCH	--	33,148	3.952	3.952	1,310,026	5.208	1,726,236	416,210
Est	SEPA	--	3,397	4.500	4.500	152,870	4.500	152,870	0
	TOTAL		36,545	4.003	4.003	1,462,896	5.142	1,879,106	416,210
Nov-15	ECONPURCH	--	11,553	4.107	4.107	474,533	5.034	581,610	107,077
Est	SEPA	--	3,288	4.499	4.499	147,938	4.499	147,938	0
	TOTAL		14,841	4.194	4.194	622,471	4.916	729,548	107,077
Dec-15	ECONPURCH	--	1,655	7.078	7.078	117,138	5.558	91,979	(25,159)
Est	SEPA	--	3,397	4.500	4.500	152,870	4.500	152,870	0
	TOTAL		5,052	5.345	5.345	270,008	4.847	244,849	(25,159)
Jan-15	ECONPURCH	--	123,856	4.758	4.758	5,892,670	5.121	6,343,224	450,554
THRU	SEPA	--	54,797	4.363	4.363	2,390,981	4.363	2,390,981	0
Dec-15									
	TOTAL		178,653	4.637	4.637	8,283,651	4.889	8,734,205	450,554

Capital Structure and Cost Rates Applied to Capital Projects
Duke Energy Florida
Estimated for the Period of : January through June 2015

	Adjusted Retail $000's	Ratio	Cost Rate	Weighted Cost
Common Equity	$ 4,101,842	48.36%	10.50%	5.08%
Preferred Stock	-	0.00%	0.00%	0.00%
Long Term Debt	3,174,547	37.42%	5.22%	1.95%
Short Term Debt	79,303	0.93%	1.22%	0.01%
Customer Deposits - Active	157,817	1.86%	2.25%	0.04%
Customer Deposits - Inactive	1,181	0.01%	0.00%	0.00%
Deferred Tax	1,114,885	13.14%	0.00%	0.00%
Deferred Tax (FAS 109)	(148,097)	-1.75%	0.00%	0.00%
ITC	1,246	0.01%	0.00%	0.00%
	8,482,724	100.00%		7.08%

Total Debt	2.00%
Total Equity	5.08%

* May 2014 DEF Surveillance Report capital structure and cost rates.
* Reference: Docket Nos. 120001-EG, 120002-EI, 120007-EI, PSC Order No. 12-0425-PAA-EU, page 8
* Included for Informational purposes only. DEF 2014 Actual/Estimated True-up Filing does not currently include a capital return component

Capital Structure and Cost Rates Applied to Capital Projects
Duke Energy Florida
Estimated for the Period of : July through December 2015

	Adjusted Retail $000's	Ratio	Cost Rate	Weighted Cost
Common Equity	$ 4,681,853	48.76%	10.50%	5.12%
Preferred Stock	-	0.00%	0.00%	0.00%
Long Term Debt	3,672,596	38.25%	5.19%	1.98%
Short Term Debt	(90,568)	-0.94%	0.17%	0.00%
Customer Deposits - Active	182,163	1.90%	2.31%	0.04%
Customer Deposits - Inactive	1,306	0.01%	0.00%	0.00%
Deferred Tax	1,318,615	13.73%	0.00%	0.00%
Deferred Tax (FAS 109)	(164,391)	-1.71%	0.00%	0.00%
ITC	498	0.01%	0.00%	0.00%
	9,602,073	100.00%		7.15%

Total Debt	2.03%
Total Equity	5.12%

* May 2015 DEF Surveillance Report capital structure and cost rates.
* Reference: Docket Nos. 120001-EG, 120002-EI, 120007-EI, PSC Order No. 12-0425-PAA-EU, page 8
* Included for Informational purposes only. DEF 2014 Actual/Estimated True-up Filing does not currently include a capital return component

Docket 150001-EI
Exhibit No. ____(CAM-2)
Part 2

DUKE ENERGY FLORIDA

CAPACITY COST RECOVERY

ESTIMATED / ACTUAL TRUE-UP

JANUARY THROUGH DECEMBER 2015

Schedule E12-A – Purchased Power Capacity Cost (Projected)

Schedule E12-B – Purchased Power Capacity Cost (Re-Projected)

Schedule E12-C – Variance Analysis (Re-projected vs. Projected)

Duke Energy Florida
Calculation of Projected Capacity Costs
For the Year 2015 - As filed on 08/22/14 in Docket 140001-EI

Docket No. 150001-EI
Exhibit__CAM-2, Part 2
Schedule E12-A
Page 1 of 1

		EST Jan-15	EST Feb-15	EST Mar-15	EST Apr-15	EST May-15	EST Jun-15	EST Jul-15	EST Aug-15	EST Sep-15	EST Oct-15	EST Nov-15	EST Dec-15	TOTAL
1	**Base Production Level Capacity Costs**													
2	Auburndale Power Partners, L.P. (AUBRDLFC)	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Auburndale Power Partners, L.P. (AUBSET)	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Lake County (LAKCOUNT)	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Lake Cogen Limited (LAKORDER)	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Metro-Dade County (METRDADE)	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Orange Cogen (ORANGECO)	3,073,960	3,073,960	3,073,960	3,073,960	3,073,960	3,073,960	3,073,960	3,073,960	3,073,960	3,073,960	3,073,960	3,073,960	36,887,520
8	Orlando Cogen Limited (ORLACOGL)	4,143,450	4,143,450	4,143,450	4,143,450	4,143,450	4,143,450	4,143,450	4,143,450	4,143,450	4,143,450	4,143,450	4,143,450	49,721,400
9	Pasco County Resource Recovery (PASCOUNT)	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	18,930,840
10	Pinellas County Resource Recovery (PINCOUNT)	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	45,063,630
11	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	5,815,550	5,815,550	5,815,550	5,815,550	5,815,550	5,815,550	5,815,550	5,815,550	5,815,550	5,815,550	5,815,550	5,815,550	69,786,600
12	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	782,100	782,100	782,100	782,100	782,100	782,100	782,100	782,100	782,100	782,100	782,100	782,100	9,385,200
13	Southern Scherer	1,744,736	1,744,736	1,744,736	1,744,736	1,744,736	1,744,736	1,744,736	1,744,736	1,744,736	1,744,736	1,744,736	1,744,736	20,936,826
14	Subtotal - Base Level Capacity Costs	20,892,668	20,892,668	20,892,668	20,892,668	20,892,668	20,892,668	20,892,668	20,892,668	20,892,668	20,892,668	20,892,668	20,892,668	250,712,016
15	Base Production Jurisdictional Responsibility	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	
16	Base Level Jurisdictional Capacity Costs	19,406,155	19,406,154	19,406,154	19,406,154	19,406,154	19,406,155	19,406,155	19,406,155	19,406,155	19,406,155	19,406,155	19,406,155	232,873,854
17	**Intermediate Production Level Capacity Costs**													
18	Southern Franklin	3,185,168	3,185,168	3,185,168	3,185,168	3,185,168	3,185,168	3,185,168	3,185,168	3,185,168	3,185,168	3,185,168	3,185,168	38,222,016
19	Schedule H Capacity Sales - NSB & RCID	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(14,792)	(177,504)
20	Subtotal - Intermediate Level Capacity Costs	3,170,376	3,170,376	3,170,376	3,170,376	3,170,376	3,170,376	3,170,376	3,170,376	3,170,376	3,170,376	3,170,376	3,170,376	38,044,512
21	Intermediate Production Jurisdictioinal Responsibility	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	
22	Intermediate Level Jurisdictional Capacity Costs	2,304,958	2,304,958	2,304,958	2,304,958	2,304,959	2,304,958	2,304,958	2,304,958	2,304,958	2,304,958	2,304,958	2,304,958	27,659,502
23	**Peaking Production Level Capacity Costs**													
24	Chattahoochee	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Shady Hills Power Company LLC	1,953,774	1,953,774	1,395,553	1,353,895	1,895,453	3,853,393	3,853,393	3,853,393	1,798,250	1,353,895	1,353,895	1,953,774	26,572,441
26	Vandolah (NSG)	2,790,705	2,806,375	2,011,337	1,988,952	2,712,358	5,592,925	5,576,136	5,531,366	2,647,069	1,949,778	1,994,548	2,806,375	38,407,924
27	Subtotal - Peaking Level Capacity Costs	4,744,480	4,760,149	3,406,890	3,342,847	4,607,811	9,446,318	9,429,529	9,384,759	4,445,319	3,303,673	3,348,443	4,760,149	64,980,364
28	Peaking Production Jurisdictional Responsibility	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	
29	Peaking Level Jurisdictional Capacity Costs	4,551,095	4,566,125	3,268,025	3,206,592	4,419,996	9,061,286	9,045,181	9,002,236	4,264,127	3,169,015	3,211,960	4,566,125	62,331,765
30	**Other Capacity Costs**													
31	Retail Wheeling	(52,200)	(31,444)	(9,046)	(9,316)	(53,353)	(907)	(20,159)	(13,483)	(114)	(270)	(8,964)	(7,158)	(206,415)
32	Other Jurisdictional Capacity Costs	(52,200)	(31,444)	(9,046)	(9,316)	(53,353)	(907)	(20,159)	(13,483)	(114)	(270)	(8,964)	(7,158)	(206,415)
33	**Total Capacity Costs (line 16+22+29+32)**	26,210,007	26,245,793	24,970,091	24,908,389	26,077,757	30,771,492	30,736,135	30,699,866	25,975,126	24,879,859	24,914,109	26,270,080	322,658,705
34	Estimated/Actual True-Up Provision - Jan - Dec 2014													16,991,240
35	**Total Capacity Costs w/ True-Up**													339,649,944
36	Revenue Tax Multiplier													1.00072
37	**Total Recoverable Capacity Costs**													339,894,492
38	**Nuclear Cost Recovery Clause**													169,131,698
39	Revenue Tax Multiplier													1.00072
40	**Total Recoverable Nuclear Costs**													169,253,473
41	**Total Recoverable Capacity & Nuclear Costs (line 37+40)**													509,147,965

Duke Energy Florida
Calculation of Estimated/Actual True-up
For the Year 2015

Docket No. 150001-EI
Exhibit__CAM-2, Part 2
Schedule E12-B

		ACT Jan-15	ACT Feb-15	ACT Mar-15	ACT Apr-15	ACT May-15	ACT Jun-15	EST Jul-15	EST Aug-15	EST Sep-15	EST Oct-15	EST Nov-15	EST Dec-15	TOTAL
1	**Base Production Level Capacity Costs**													
2	Orange Cogen (ORANGECO)	3,108,487	3,266,545	3,266,545	3,266,545	3,266,545	3,266,545	3,073,960	3,073,960	3,073,960	3,073,960	3,073,960	3,073,960	37,884,974
3	Orlando Cogen Limited (ORLACOGL)	4,390,316	4,602,317	4,594,986	4,491,065	4,619,448	4,619,448	4,143,450	4,143,450	4,143,450	4,143,450	4,143,450	4,143,450	52,178,278
4	Pasco County Resource Recovery (PASCOUNT)	1,483,270	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	1,577,570	18,836,540
5	Pinellas County Resource Recovery (PINCOUNT)	3,530,828	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	3,755,303	44,839,155
6	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	5,999,259	6,306,018	6,306,018	6,306,018	6,306,018	6,287,309	5,815,550	5,815,550	5,815,550	5,815,550	5,815,550	5,815,550	72,403,940
7	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	661,873	698,574	715,513	729,448	741,070	754,330	782,100	782,100	782,100	782,100	782,100	782,100	8,993,409
8	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Southern - Scherer	1,750,402	1,787,399	1,756,170	1,757,178	1,824,402	3,375,058	1,744,736	1,744,736	1,744,736	1,744,736	1,744,736	1,744,736	22,719,024
10	Calpine Osprey	1,405,950	1,465,539	1,443,650	1,443,650	1,443,650	1,443,650	1,405,950	1,405,950	1,405,950	1,405,950	1,405,950	1,405,950	17,081,789
11	Subtotal - Base Level Capacity Costs	22,330,384	23,459,265	23,415,755	23,326,778	23,534,006	25,079,213	22,298,618	22,298,618	22,298,618	22,298,618	22,298,618	22,298,618	274,937,109
12	Base Production Jurisdictional Responsibility	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	92.885%	
13	Base Level Jurisdictional Capacity Costs	20,741,577	21,790,139	21,749,724	21,667,078	21,859,562	23,294,827	20,712,071	20,712,071	20,712,071	20,712,071	20,712,071	20,712,071	255,375,335
14	**Intermediate Production Level Capacity Costs**													
15	Southern - Franklin	3,119,543	3,290,615	3,174,459	3,182,635	3,179,430	2,251,554	3,185,168	3,185,168	3,185,168	3,185,168	3,185,168	3,185,168	37,309,244
16	Schedule H Capacity Sales - NSB	(14,792)	(14,792)	(14,792)	(14,792)	(16,080)	(16,080)	(16,080)	(16,080)	(16,080)	(16,080)	(16,080)	(16,080)	(187,808)
17	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Subtotal - Intermediate Level Capacity Costs	3,104,751	3,275,823	3,159,667	3,167,843	3,163,350	2,235,474	3,169,088	3,169,088	3,169,088	3,169,088	3,169,088	3,169,088	37,121,436
19	Intermediate Production Jurisdictional Responsibility	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	72.703%	
20	Intermediate Level Jurisdictional Capacity Costs	2,257,247	2,381,621	2,297,173	2,303,117	2,299,850	1,625,256	2,304,022	2,304,022	2,304,022	2,304,022	2,304,022	2,304,022	26,988,397
21	**Peaking Production Level Capacity Costs**													
22	Chattahoochee	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Vandolah (RRI)	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Shady Hills Power Company LLC	1,410,076	1,646,992	1,406,900	1,440,840	1,912,680	3,888,000	3,887,109	3,887,109	1,813,984	1,365,741	1,365,741	1,970,869	25,996,042
25	Vandolah (NSG)	2,932,374	2,895,800	1,886,774	1,947,064	2,800,877	5,785,668	5,554,010	5,509,420	2,636,711	1,942,223	1,986,813	2,795,377	38,673,111
26	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Subtotal - Peaking Level Capacity Costs	4,342,450	4,542,793	3,293,674	3,387,903	4,713,557	9,673,668	9,441,119	9,396,529	4,450,696	3,307,964	3,352,554	4,766,247	64,669,152
28	Peaking Production Jurisdictional Responsibility	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	95.924%	
29	Peaking Level Jurisdictional Capacity Costs	4,165,452	4,357,629	3,159,424	3,249,812	4,521,433	9,279,369	9,056,299	9,013,526	4,269,285	3,173,131	3,215,904	4,571,974	62,033,238
30	**Other Capacity Costs**													
31	Retail Wheeling	(44,982)	(109,006)	(31,099)	(4,143)	(42,143)	(19,211)	(43,542)	(16,088)	(999)	(8,514)	(13,490)	(3,004)	(336,221)
32	Other Jurisdictional Capacity Costs	(44,982)	(109,006)	(31,099)	(4,143)	(42,143)	(19,211)	(43,542)	(16,088)	(999)	(8,514)	(13,490)	(3,004)	(336,221)
33	**Subtotal Jurisd Capacity Costs (Line 13+20+29+32)**	27,119,295	28,420,383	27,175,221	27,215,864	28,638,702	34,180,241	32,028,850	32,013,531	27,284,380	26,180,711	26,218,507	27,585,063	344,060,749
34	**Nuclear Cost Recovery Clause Costs (net of tax)**													
35	Levy Costs 1	9,215,650	9,145,040	9,074,430	9,003,820	-	-	-	-	-	-	-	-	36,438,940
36	CR3 Uprate Costs	5,442,716	5,412,634	5,382,366	5,352,099	5,321,833	5,291,141	5,260,871	5,208,780	5,178,331	5,148,065	5,117,797	5,087,530	63,204,163
37	**Total NCRC Costs - Order No. PSC-14-0701-FOF-EI**	14,658,366	14,557,674	14,456,796	14,355,919	5,321,833	5,291,141	5,260,871	5,208,780	5,178,331	5,148,065	5,117,797	5,087,530	99,643,103
38	**Total Jurisdictional Capacity Costs (Line 33+37)**	41,777,661	42,978,057	41,632,018	41,571,783	33,960,535	39,471,382	37,289,721	37,222,312	32,462,711	31,328,775	31,336,304	32,672,593	443,703,852
39	**Capacity Revenues**													
40	Capacity Cost Recovery Revenues (net of tax) 1	35,474,797	35,917,927	38,743,786	38,282,459	33,024,082	37,697,540	39,548,662	39,811,654	40,152,847	37,052,286	31,209,639	29,128,994	436,044,671
41	Prior Period True-Up Provision Over/(Under) Recovery	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(1,415,937)	(16,991,240)
42	**Current Period Revenues (net of tax)**	34,058,861	34,501,991	37,327,849	36,866,522	31,608,145	36,281,603	38,132,725	38,395,717	38,736,910	35,636,349	29,793,702	27,713,057	419,053,431
43	**True-Up Provision**													
44	True-Up Provision - Over/(Under) Recov (Line 42-38)	(7,718,800)	(8,476,066)	(4,304,169)	(4,705,260)	(2,352,390)	(3,189,779)	843,004	1,173,405	6,274,199	4,307,574	(1,542,602)	(4,959,536)	(24,650,420)
45	Interest Provision for the Month	(2,831)	(3,263)	(3,661)	(2,932)	(3,568)	(4,187)	(2,039)	(1,935)	(1,628)	(1,399)	(1,404)	(1,545)	(30,390)
46	Current Cycle Balance - Over/(Under)	(7,721,631)	(16,200,960)	(20,508,790)	(25,216,982)	(27,572,940)	(30,766,906)	(29,925,940)	(28,754,471)	(22,481,899)	(18,175,724)	(19,719,730)	(24,680,810)	(24,680,810)
47	Prior Period Balance - Over/(Under) Recovered	(30,953,685)	(30,953,685)	(30,953,685)	(30,953,685)	(30,953,685)	(30,953,685)	(30,953,685)	(30,953,685)	(30,953,685)	(30,953,685)	(30,953,685)	(30,953,685)	(30,953,685)
48	Prior Period Cumulative True-Up Collected/(Refunded)	1,415,937	2,831,873	4,247,810	5,663,747	7,079,683	8,495,620	9,911,557	11,327,493	12,743,430	14,159,367	15,575,303	16,991,240	16,991,240
49	Prior Period True-up Balance - Over/(Under)	(29,537,749)	(28,121,812)	(26,705,875)	(25,289,939)	(23,874,002)	(22,458,065)	(21,042,129)	(19,626,192)	(18,210,255)	(16,794,319)	(15,378,382)	(13,962,445)	(13,962,445)
50	**Net Capacity True-up Over/(Under) (Line 46+49)**	($37,259,380)	($44,322,772)	($47,214,666)	($50,506,921)	($51,446,942)	($53,224,971)	($50,968,069)	($48,380,663)	($40,692,155)	($34,970,043)	($35,098,112)	($38,643,256)	($38,643,256)

1 Per Order No. PSC-15-0176-TRF-EI, DEF terminated the Levy Fixed Charge beginning May 2015.

Duke Energy Florida
Calculation of Estimated/Actual Capacity Costs
For the Year 2015

Docket No. 150001-EI
Exhibit__CAM-2, Part 2
Schedule E12-B
Page 2 of 2

Contract Data:

	Name	Start Date	Expiration Date	Type	Purchase/Sale	MW
1	Orlando Cogen Limited (ORLACOGL)	Sep-93	Dec-23	QF	Purch	115.00
2	Orange Cogen (ORANGECO)	Jul-95	Dec-25	QF	Purch	74.00
3	Pasco County Resource Recovery (PASCOUNT)	Jan-95	Dec-24	QF	Purch	23.00
4	Pinellas County Resource Recovery (PINCOUNT)	Jan-95	Dec-24	QF	Purch	54.75
5	Polk Power Partners, L. P. (MULBERY/ROYSTER)	Aug-94	Aug-24	QF	Purch	115.00
6	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	Aug-94	Dec-23	QF	Purch	39.60
7	Florida Power Development	May-14	May-34	QF	Purch	60.00
8	Southern - Franklin	Jun-10	May-16	Other	Purch	350.00
9	Southern Wholesale - Scherer 3	Jun-10	May-16	Other	Purch	73.00
10	Schedule H Capacity - New Smyrna Beach	Nov-85	see note (1)	Other	Sale	1.00
11	Chattahoochee	Jan-03	Dec-17	Other	Purch	5.25
12	Vandolah (NSG)	Jun-12	May-27	Other	Puch	655.00
13	Shady Hills Tolling Agreement	Apr-07	Apr-24	Other	Purch	515.00
14	Calpine Osprey	Oct-14	Dec-16	Other	Purch	599.00

(1) The New Smyrna Beach (NSB) Schedule H contract is in effect until cancelled by either Duke Energy Florida or NSB upon 1 year's written notice.

Duke Energy Florida
Variance Analysis
For the Year 2015

Docket No. 150001-EI
Exhibit__CAM-2, Part 2
Schedule E12-C

		Re-Projection Total	Original Projection Total	Variance Total
1	**Capacity Revenues**			
2	Capacity Cost Recovery Revenues (net of tax)	$436,044,671	$508,781,643	($72,736,972)
3	Prior Period True-Up Provision Over/(Under) Recovery	(16,991,240)	(16,991,240)	0
4	**Current Period Revenues (net of tax)**	419,053,431	491,790,403	(72,736,972)
5				
6	**Capacity Costs**			
7	**Base Production Level Capacity Costs**			
8	Orange Cogen (ORANGECO)	37,884,974	36,887,520	997,454
9	Orlando Cogen Limited (ORLACOGL)	52,178,278	49,721,400	2,456,878
10	Pasco County Resource Recovery (PASCOUNT)	18,836,540	18,930,840	(94,300)
11	Pinellas County Resource Recovery (PINCOUNT)	44,839,155	45,063,630	(224,475)
12	Polk Power Partners, L.P. (MULBERRY/ROYSTER)	72,403,940	69,786,600	2,617,340
13	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	8,993,409	9,385,200	(391,791)
14	Southern - Sherer	22,719,024	20,936,826	1,782,197
15	Calpine Osprey	17,081,789	0	17,081,789
16	Subtotal - Base Level Capacity Costs	274,937,109	250,712,016	24,225,093
17	Base Production Jurisdictional Responsibility	92.885%	92.885%	0.000%
18	Base Level Jurisdictional Capacity Costs	255,375,335	232,873,854	22,501,481
19				
20	**Intermediate Production Level Capacity Costs**			
21	Southern - Franklin	37,309,244	38,222,016	(912,772)
22	Schedule H Capacity Sales - NSB & RCID	(187,808)	(177,504)	(10,304)
23	Subtotal - Intermediate Level Capacity Costs	37,121,436	38,044,512	(923,076)
24	Intermediate Production Jurisdictional Responsibility	72.703%	72.703%	0.000%
25	Intermediate Level Jurisdictional Capacity Costs	26,988,397	27,659,502	(671,104)
26				
27	**Peaking Production Level Capacity Costs**			
28	Chattahoochee	0	0	0
29	Vandolah (RRI)	0	0	0
30	Shady Hills Power Company LLC	25,996,042	26,572,441	(576,399)
31	Vandolah (NSG)	38,673,111	38,407,924	265,187
32	Subtotal - Peaking Level Capacity Costs	64,669,152	64,980,364	(311,212)
33	Peaking Production Jurisdictional Responsibility	95.924%	95.924%	0.000%
34	Peaking Level Jurisdictional Capacity Costs	62,033,238	62,331,765	(298,527)
35				
36	**Other Capacity Costs**			
37	Retail Wheeling	(336,221)	(206,415)	(129,805)
38	Other Jurisdictional Capacity Costs	(336,221)	(206,415)	(129,805)
39				
40	**Subtotal Jurisdictional Capacity Costs (Line 18+25+34+38)**	344,060,749	322,658,705	21,402,044
41				
42	**Nuclear Cost Recovery Clause Costs**			
43	Levy Costs	36,438,940	105,927,535	(69,488,595)
44	CR3 Uprate Costs	63,204,163	63,204,163	0
45	**Total NCRC Costs - Order No. PSC-14-0701-FOF-EI**	99,643,103	169,131,698	(69,488,595)
46				
47	**Total Jurisdictional Capacity Costs (Line 40+45)**	443,703,852	491,790,403	(48,086,551)
48				
49	**True-Up Provision**			
50	True-Up Provision - Over/(Under) Recov (Line 4-47)	(24,650,420)	0	(24,650,420)
51	Interest Provision for the Month	(30,390)	0	(30,390)
52	Current Cycle Balance - Over/(Under)	(24,680,810)	0	(24,680,810)
53				
54	Prior Period Balance - Over/(Under) Recovered	(30,953,685)	(16,991,240)	(13,962,445)
55	Prior Period Cumulative True-Up Collected/(Refunded)	16,991,240	16,991,240	0
56	Prior Period True-up Balance - Over/(Under)	(13,962,445)	0	(13,962,445)
57				
58	**Net Capacity True-up Over/(Under) (Line 52+56)**	($38,643,255)	$0	($38,643,255)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF

JEFFREY SWARTZ

ON BEHALF OF

DUKE ENERGY FLORIDA

DOCKET NO. 150001-EI

AUGUST 4, 2015

Q. By whom are you employed and in what capacity?

A. I am employed by Duke Energy Florida ("DEF" or the "Company") as Vice President – Fossil/Hydro Operations Florida.

Q. What are your responsibilities in that position?

A. As Vice President of DEF's Fossil/Hydro organization, my responsibilities include overall leadership and strategic direction of DEF's power generation fleet. My major duties and responsibilities include strategic and tactical planning to operate and maintain DEF's non-nuclear generation fleet; generation fleet project and additions recommendations; major maintenance programs; outage and project management; retirement of generation facilities; asset allocation; workforce planning and staffing; organizational alignment and design; continuous business improvements; retention and inclusion; succession planning; and oversight of hundreds of employees and hundreds of millions of dollars in assets and capital and operating budgets.

Q. Please describe your educational background and professional experience.

A. I earned a Bachelor of Science degree in Mechanical Engineering from the United States Naval Academy 1985. I have 14 years of power plant and production experience in various managerial and executive positions within Duke Energy managing Fossil Steam Operations, Combustion Turbine Operations and Nuclear Plant Operations. While at Duke Energy I have managed new unit projects from construction to operations, and I have extensive contract negotiation and management experience. My prior experience also includes nuclear engineering and operations experience in the United States Navy and project management, engineering, supervisory and management experience with a pulp, paper and chemical manufacturing company.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Commission with information related to the Hines Unit 2 forced outage that occurred on July 7, 2014, including background information on the event that led to the outage, an explanation of DEF's responsive actions, a presentation of DEF's root cause analysis and findings, an explanation of insurance coverage, and an explanation of DEF's reasonable and prudent restoration actions.

Q. Please provide a summary of your testimony.

A. On July 7, 2014, a mechanical failure occurred at the Hines Energy Center ("HEC"), specifically Power Block 2 ("Hines 2"), resulting in a forced outage that concluded when the unit was brought back on-line on June 19, 2015. DEF performed a Root Cause Analysis ("RCA") that determined the cause of the failure was separation of the High Pressure-Intermediate Pressure ("HP-IP") coupling resulting from the failure of the HP-IP coupling bolts. After investigation, the root cause analysis team ("RCA Team") determined that the HP-IP coupling bolts failed due to being improperly tightened by the Original Equipment Manufacturer ("OEM"), Siemens, after the March 2011 50,000-hour inspection. This failure was caused by events beyond DEF's control, and DEF could not have reasonably prevented the subsequent damage from occurring.

After the fire, DEF created a Restoration Team to oversee returning Hines 2 to service. As a result of the Restoration Team's aggressive and efficient oversight, DEF returned Hines 2 to service in a timely manner, minimizing the length and cost of the outage. DEF's actions prior to and in the wake of the Hines 2 event were reasonable and prudent.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the DEF RCA Report, attached as Exhibit No. __ (JS-1). I am also sponsoring a composite exhibit consisting of a timeline detailing major project restoration milestones and photographs of significant restoration events as Exhibit No. __(JS-2).

Q: Is the RCA considered confidential by the Company?

A: Yes. The RCA and portions of my testimony discussing the RCA's findings are confidential because DEF's rights under its insurance policies covering Hines 2 have been subrogated to its insurers. In order to protect those subrogated rights and therefore DEF's and its insurers' competitive business interests, this information has been treated by the Company as proprietary confidential business information and has not been made publicly available.

Q. Please summarize the events leading up to the Hines 2 event.

A. On July 7, 2014, the Hines 2 Steam Turbine suddenly and unexpectedly tripped offline. Site personnel heard a deep, loud rumbling sound near Hines 2 followed by a fire on the west side of the Steam Turbine enclosure. The fire spread to the third elevation of the enclosure and migrated to the east side, igniting the generator inlet air filter structure. In response to the spreading fire, station personnel shut down the associated combustion turbines and ancillary equipment. All personnel were evacuated and accounted for. Emergency personnel responded to the event and site personnel took additional precautions including a fire watch through the evening to monitor for any secondary ignition. There were no injuries associated with this event.

Q. What actions did DEF take in response to the fire and resulting forced outage?

A. The Company took three primary actions in the wake of the event: a root cause team was established to investigate the incident and prepare a root cause analysis; a restoration team was formed to bring the unit back on-line; and DEF began the process of making a claim with its insurers.

Q. Please describe the process DEF followed to ascertain the root cause of the event.

A. DEF created a RCA Team consisting of internal experts to investigate and determine the root cause of the event. The RCA Team consisted of six individuals with expertise in engineering, operations and process, and human performance.

Following industry standard procedures, the RCA Team employed specific tools used to determine potential root cause(s) including: interviews, event and causal factor review ("E&CF"), flawed barrier analysis, change analysis, component analysis, visual inspections of the equipment, photographs taken following the event, engineering calculations and measurements, and detailed review of outage reports and maintenance logs.

REDACTED

Q. Please describe the RCA Team's conclusions.

A. The DEF RCA Team determined that the root cause of the Hines 2 failure and ensuing forced outage was the separation of the HP-IP coupling resulting from the failure of the HP-IP coupling bolts. The coupling failed over time due to improper reassembly during the 2011 outage which was performed by the OEM. [redacted]

REDACTED

The RCA Team reviewed the 50,000 hour inspection performed in March 2011 and discovered that the [redacted]. If the bolts were properly tightened, a one-time axial, non-vibrational force of 1,540,000 pounds would have been required to break all bolts simultaneously. Neither the RCA Team nor the OEM have been able to establish a mechanism that could produce a force of this magnitude other than the failure mechanism described above, thereby confirming the RCA conclusion.

Q. Did the RCA Team consider alternative potential root causes?

A. Yes, the RCA Team evaluated L-0 Blade failure as a potential cause, but that theory was ultimately rejected.

REDACTED

Q. Why did the RCA Team reject the L-0 Blade failure theory?

A. During this event, the Hines 2 Steam Turbine experienced a complete failure of the 42-inch titanium, last stage (L-0) LP turbine blade row as well as significant other turbine, generator, and site damage. Because of this fact and due to past industry failures in some L-0 blades in other non-Duke Energy plants, DEF examined an L-0 blade failure as a potential root cause. During the RCA investigation, however, DEF discovered [redacted]

REDACTED

[redacted] As mentioned above, both the RCA Team and OEM have been unable to create a scenario that would yield the amount of force necessary to break all of the bolts after L-0 blade failure had the HP-IP coupling bolts been properly tightened, further indicating that the HP-IP bolts failed prior to L-0 blade failure. Thus, DEF reasonably concluded that it appears to be physically impossible for an L-0 blade failure to be the cause of the event. The root cause report that is Exhibit No. __ (JS-1) to my testimony provides further detail on how the RCA conclusion was investigated.

Q. Does DEF carry insurance on Hines 2?

A. Yes, DEF carries insurance that covers some of the costs associated with the restoration at Hines 2, but that insurance does not cover replacement fuel costs. Currently, the insurance industry does not offer a reasonably priced replacement fuel cost product, and unlike the mutual insurance company created to provide coverage for replacement power in the event of nuclear outages (Nuclear Electric Insurance Limited ("NEIL")), there is no utility industry collective that provides insurance for replacement power for fossil plant outages. The costs DEF incurred to restore the unit that are covered by DEF's various insurance policies are not at issue in this docket, and any claims that may arise against the OEM as a result of the Hines 2 event are subrogated to DEF's insurers.

At issue in this docket are the replacement power costs incurred as a result of the Hines 2 event. The total replacement power costs are reasonable and were prudently incurred in response to the Hines 2 outage. The calculation of those costs is discussed in detail in Mr. Menendez's testimony.

Q. What restoration process did DEF follow to bring Hines 2 back into service?

A. DEF first established a Restoration Team of internal experts to assess the level of damage and formulate a strategy for bringing the unit back online. The team was charged with determining what equipment could be repaired and/or refurbished and what equipment needed to be replaced, developing a project schedule and cost estimate, and overseeing the work required to bring the unit back into service in a reasonable and prudent timeframe and within the proposed cost estimates.

The Restoration Team developed a schedule of major milestones to minimize the recovery time, including milestones such as safety training for the RCA and Recovery Teams, beginning and completing the RCA, beginning and completing the equipment assessment, beginning reassembly, and finally returning the unit to service. A copy of a general restoration milestone timeline and photographs of key restoration activities are included as Exhibit No. __ (JS-2) to my testimony.

Q. Has Hines 2 returned to service?

A. Yes, the Unit was returned to service on June 19, 2015.

Q. Please provide a summary of the activities that needed to take place to return the unit to service.

A. Immediately after the fire, station personnel surveyed the affected area and safely secured the site. Site personnel started environmental remediation to contain and clean up oil spilled from the event, ultimately removing and replacing 2100 tons of dirt and rock. An assessment team of DEF subject matter experts ("SME") surveyed the entire power block to outline visible repairs. Their recommendations were:

1. Hire the OEM to rebuild the turbine, generator and associated auxiliary equipment;
2. Engineering assessment and replacing of the damaged steam turbine pedestal;
3. Remove and replace entire runs of damaged cables, instrumentation, and controls;
4. Fully test the station's generator step up ("GSU") transformers, iso-phase bus ducts, and repair as necessary;
5. Evaluate the steam turbine high energy piping and hangers for deformation and weld failures;
6. Retube the condenser (approximately 14,000 tubes) and its expansion joint;
7. Rebuild the damaged water treatment lab testing/repairing/replacing the lab equipment;
8. Properly lay up the combustion turbines and the heat recovery steam generator ("HRSG");
9. Replace the damaged steam turbine enclosures and associated structural members;

10. Evaluate current fire protection system and bring to current new requirements; and
11. Perform a "new plant start up" using the Duke Plant Major Construction Division.

The project team set up an integrated schedule, which included OEM shop activities across the world, to minimize any work flow or critical path issues. This schedule was based around the OEM's three phase repair plan: Phase I - demolition to August 31, 2014; Phase II - shop manufacturing and repair of components – September 2014 – May 2015; Phase III - field assembly and startup of the turbine generator January 2015 – June 2015.

In the first phase of the recovery plan, the steam turbine weather enclosure was safely removed with the removal of the turbine taking precedent. That work was slowed by the extensive internal damage found and the desire to salvage as many components as possible. Concurrently, the restoration team worked on removing damaged cabling and ongoing detailed component assessments. The cable replacement effort entailed removing approximately 211,789 linear feet of cable that affected numerous components throughout the power block.

Once demolition and environmental remediation was complete, the restoration team focused on procurement and scope development as work packages were handed over from the SME assessment team. Work continued on cable removals as well as removal of damaged components, and contractors started on iso-phase inspection, generator/GSU testing, condenser repairs and an engineering assessment of the damaged steam turbine pedestal.

In the last quarter of 2014, work continued on the unit's condenser, and all the internal tubing was removed. Assessment of the damaged steam turbine pedestal was completed and an engineered work scope was prepared which allowed concrete demolition to begin. Plans were finalized and equipment was procured to place the combustion turbines and HRSG in a preserved state. The combustion turbines, HRSG and generator were placed on an atmospheric climate control for preservation, and work continued on steam turbine pedestals, condenser structural repairs, auxiliary piping and conduit/cable installation.

In the first quarter of 2015, OEM teams began to mobilize concentrating on piping demolition and fabrication within their scope and re-assembly of the generator. The engineered steam turbine pedestal restoration was completed ahead of schedule and turned over to the OEM to begin the precision re-assembly of the steam turbine pedestal bearing supports and turbine alignment. Structural repairs of the condenser and re-tubing were completed. Additionally, the generator rotor was installed and initial alignments completed. OEM crews commenced reestablishment of turbine auxiliary piping, installing the bearing pedestals with instrumentation, and the HP turbine assembly. The Duke Energy commissioning team commenced start up activities with steam piping cleanliness air blows and the staging of the equipment / piping for the HRSG chemical cleaning.

In the second quarter of 2015, damaged conduit and cable work was completed and the commissioning team entered start-up mode commencing with the HRSG chemical cleaning, lube oil and hydraulic control piping flushes, the operational function testing of associated station equipment and instrumentation, and controls calibrations. The steam turbine weather enclosure structural framing was set and acoustic panels arrived, and the OEM installed the IP/LP turbine and completed installation of the steam turbine valves, hi-pressure steam piping, and piping supports and hangers. Additionally, upon the completion of the post-outage start up procedure, the combustion turbines were started, functionally checked, and synchronized to the electrical grid in anticipation of steam turbine unit testing.

In June 2015, the commissioning team completed all electrical testing and instrumentation checks. On June 9, a steam turbine vacuum was established and steam purity checks were completed on June 15. Upon completion of the commissioning team's checklist and start up plan, the steam turbine was rolled to full load and synchronized to the electrical grid on June 18, and the power block was returned to the DEF Energy Control Center for dispatch on June 19, 2015 at 07:13.

Q. Could DEF have reasonably prevented the event and the ensuing outage at Hines 2?

A. No, the event and resulting outage were caused by circumstances beyond DEF's reasonable control, as demonstrated by the RCA. DEF was not at fault.

Q. Did DEF act reasonably and prudently to restore Hines 2 to service in a timely fashion?

A. Yes, DEF took reasonable and prudent steps to develop a restoration team and guiding processes to restore Hines 2 to service. The restoration team followed those processes and Hines 2 was successfully brought back on line in a timely manner.

Q. Does that conclude your testimony?

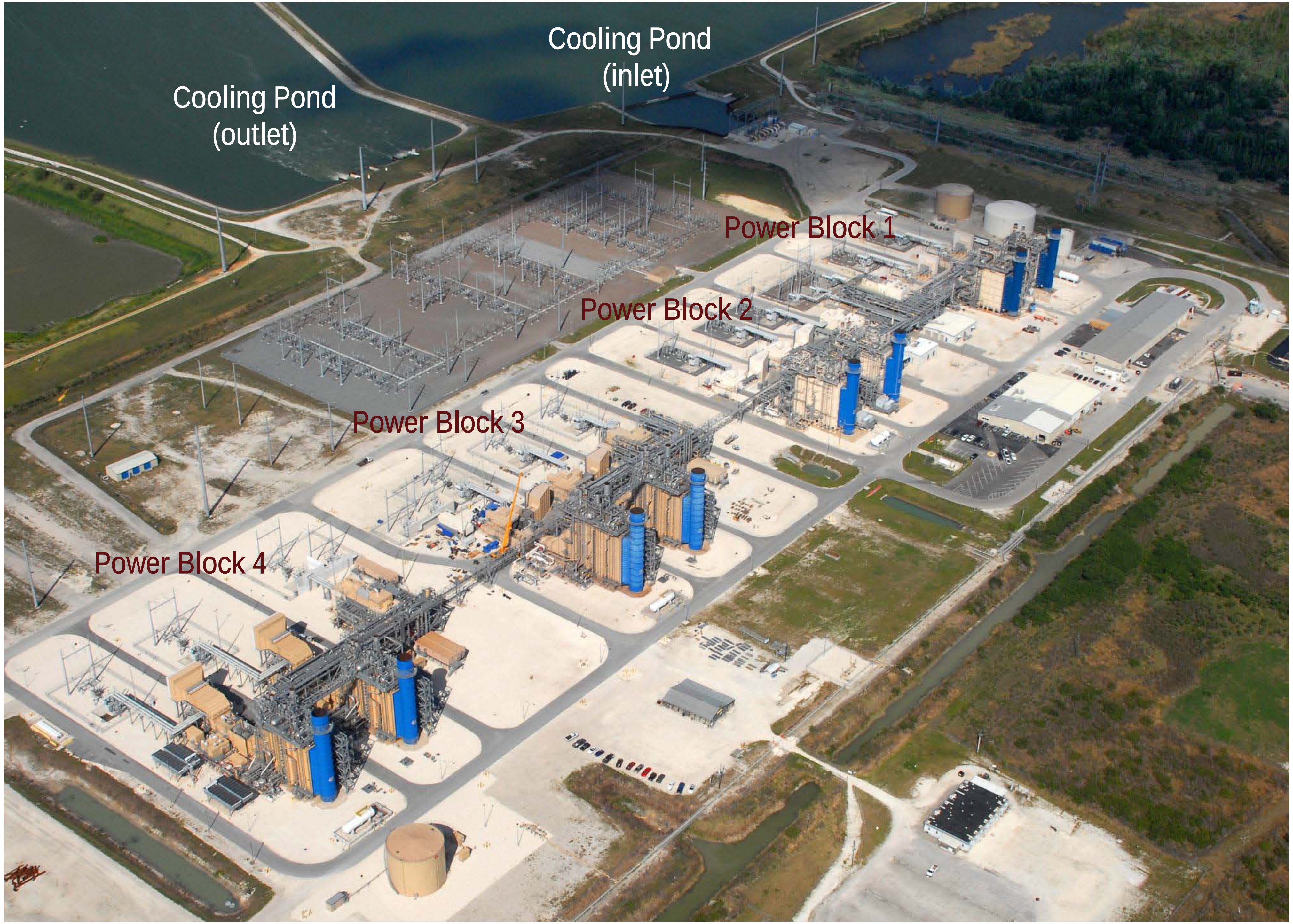
A. Yes.

Duke Energy Florida, Inc.
Docket No. 150001
Witness J. Swartz
Exhibit No. ___(JS-1)
61 pages

REDACTED

DEF’s Root Cause analysis Report
Hines PB2 HP Steam Turbine Evene
7/7/14
Final Report
(61 PAGES)

Background



DUKE ENERGY®

Background

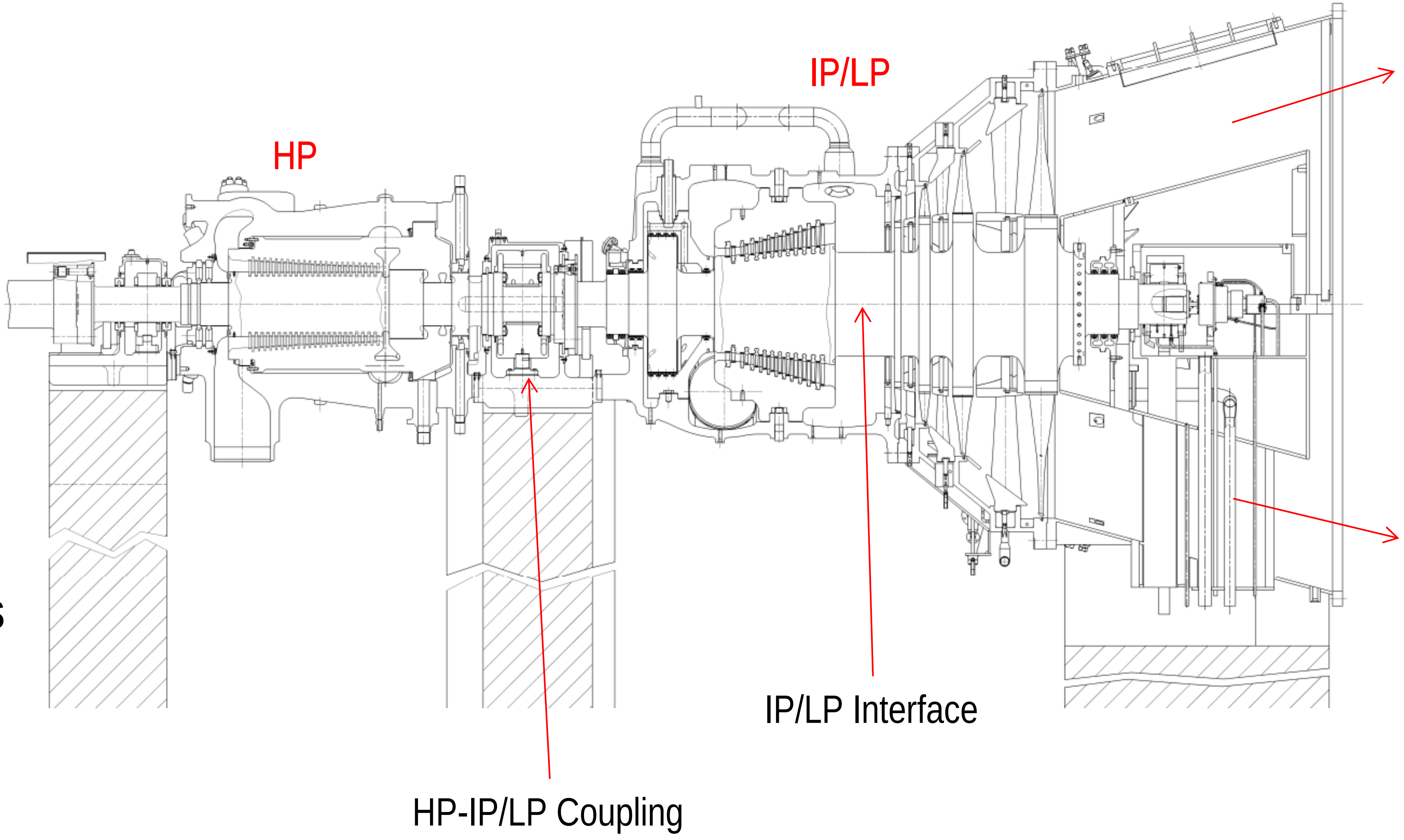
- Power Block 1 (2x1) ~500MW
  - CTGs are Siemens-Westinghouse W501FC+
  - STG is Westinghouse 2326RT2
  - Commissioned April 1999
- Power Block 2 (2x1) ~530 MW
  - CTGs are Siemens W501FD2
  - STG is Siemens HE
  - Commissioned December 2003
- Power Block 3 (2x1) ~530 MW
  - CTGs are Westinghouse W501FD2
  - STG is Siemens HE
  - Commissioned November 2005
- Power Block 4 (2x1) ~510 MW
  - CTGs are General Electric 7FA+e
  - STG is GE D11
  - Commissioned April 2007

DUKE ENERGY®

Normal Operations

PB2 Nameplate Data

- Two (2) STG-5000F CTGs
  - 187 MW each
- One (1) Siemens HE STG
  - 188 MW
  - 23-stage HP section
  - 11-stage IP section
  - 3-stage LP section
- Two (2) NEM three-pressure, unfired HRSGs
  - HP: ~1800 psig/1040 F ~420 kpph
  - IP: ~400 psig/600 F ~80 kpph
  - LP: ~80 psig/500 F ~90 kpph



Event Description

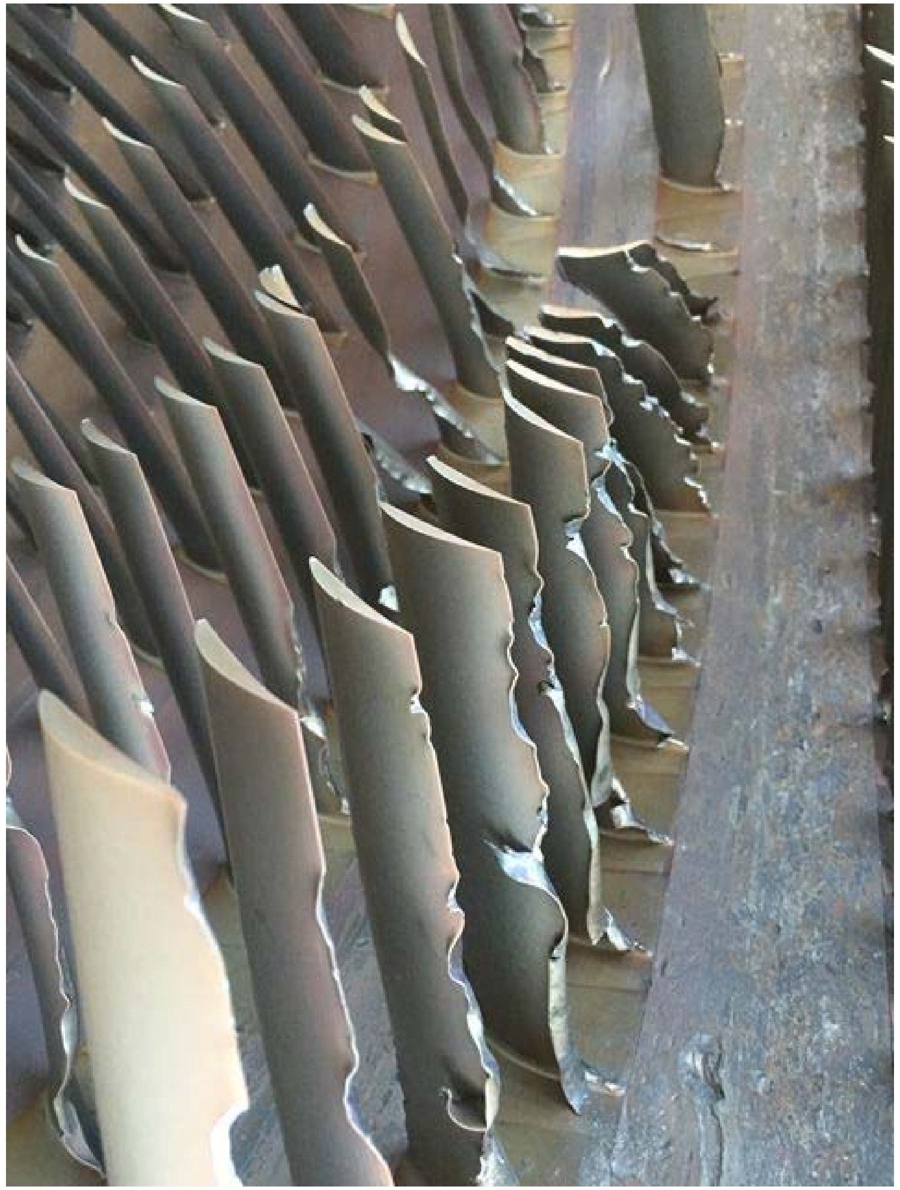
- Structural and piping damage

Event Description

- Cable and piping damage

Event Description

- Missing entire 8th stage blade row (IP)
- Various other blades missing or damaged



DUKE ENERGY®

Event Description

- HP Stop/Control Valve bonnet and stem failure
- IP Stop/Control Valve damaged
- HP/IP Piping "hammered"

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Event Description

- Damaged stationary diaphragms/vanes

Event Description

- Catastrophic failure of HP-IP/LP coupling
- MAD 12 bearing severly damaged
- All bearing pedestals compromised

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Event Description

- Collateral Condenser Tube and Hotwell Damage

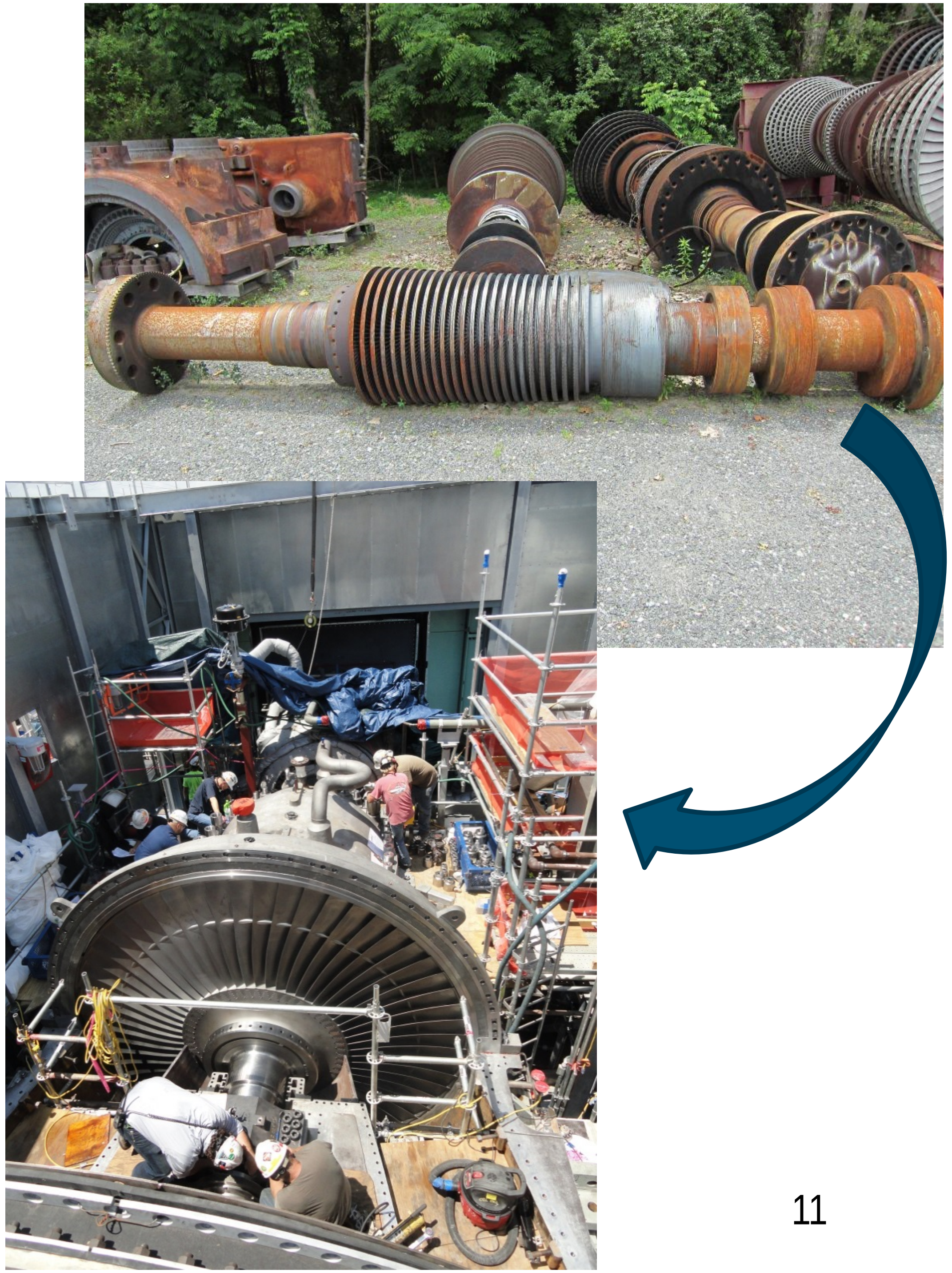
Project Details

- Restoration broken into 3 Phases:

- Phase I = Assessment/Removal/Tear-down
  - July 2014 – September 2014

- Phase II = Parts Manufacturing
  - Project Planning/Engineering/Contracts: September 2014 – January 2015
  - Equipment Repairs/Fabrication: October 2014 – May 2015
  - Work performed by OEM

- Phase III = Re-installation and Commissioning
  - Project Reassembly: September 2014 – June 2015
  - Project Commissioning: February 2015 – June 2015



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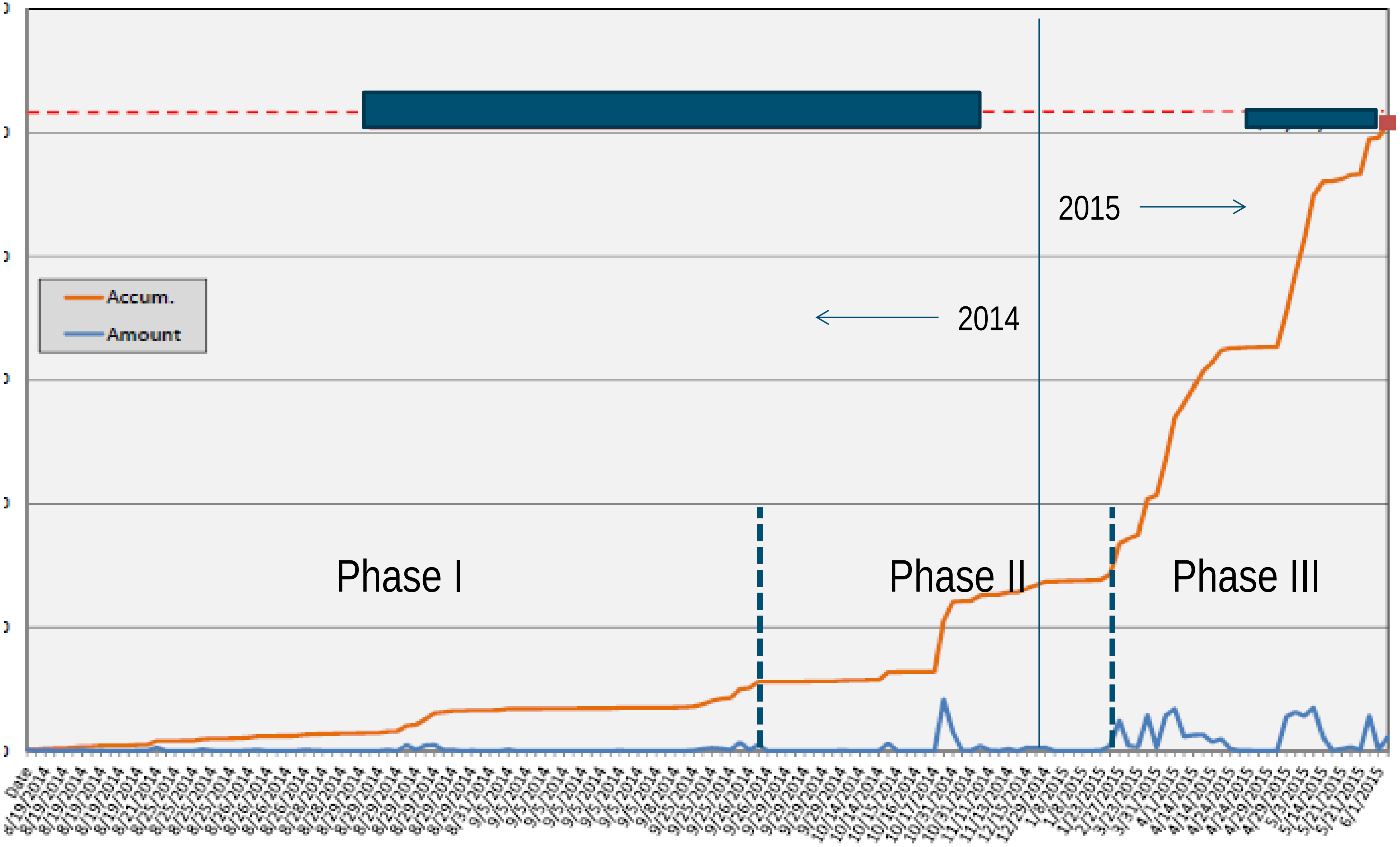
Project Details

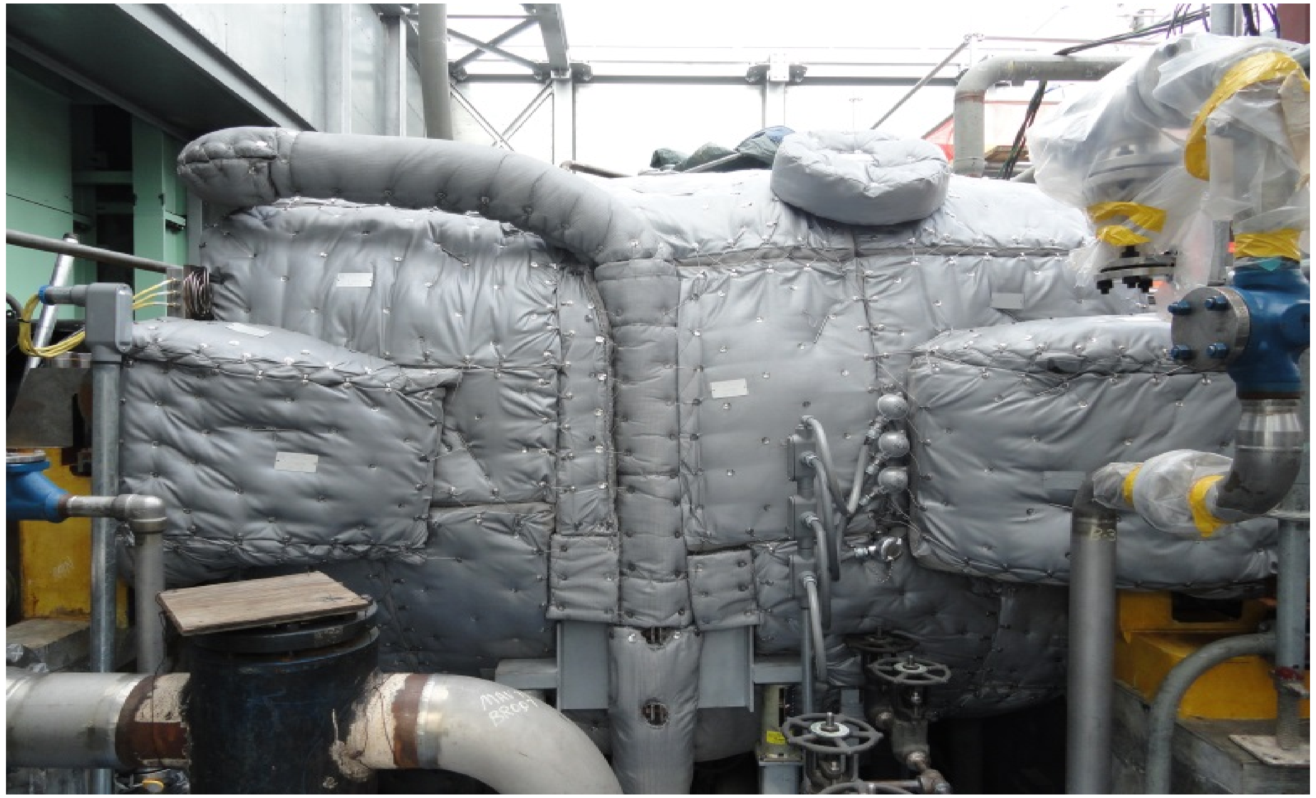
- Project Schedule



Project Details

- New HP Turbine Rotor
  - New HP Rotor

Before



After

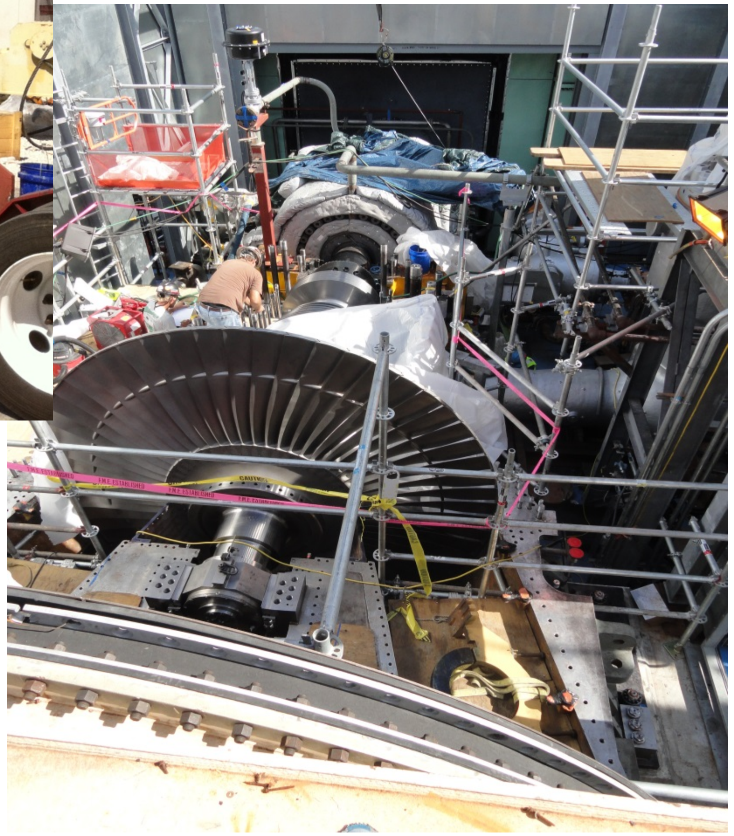
Project Details

- Refurbished IP-LP Rotor
  - New IP Rotor
  - Re-used LP Rotor

Old IP

New on site

Installed



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Project Details

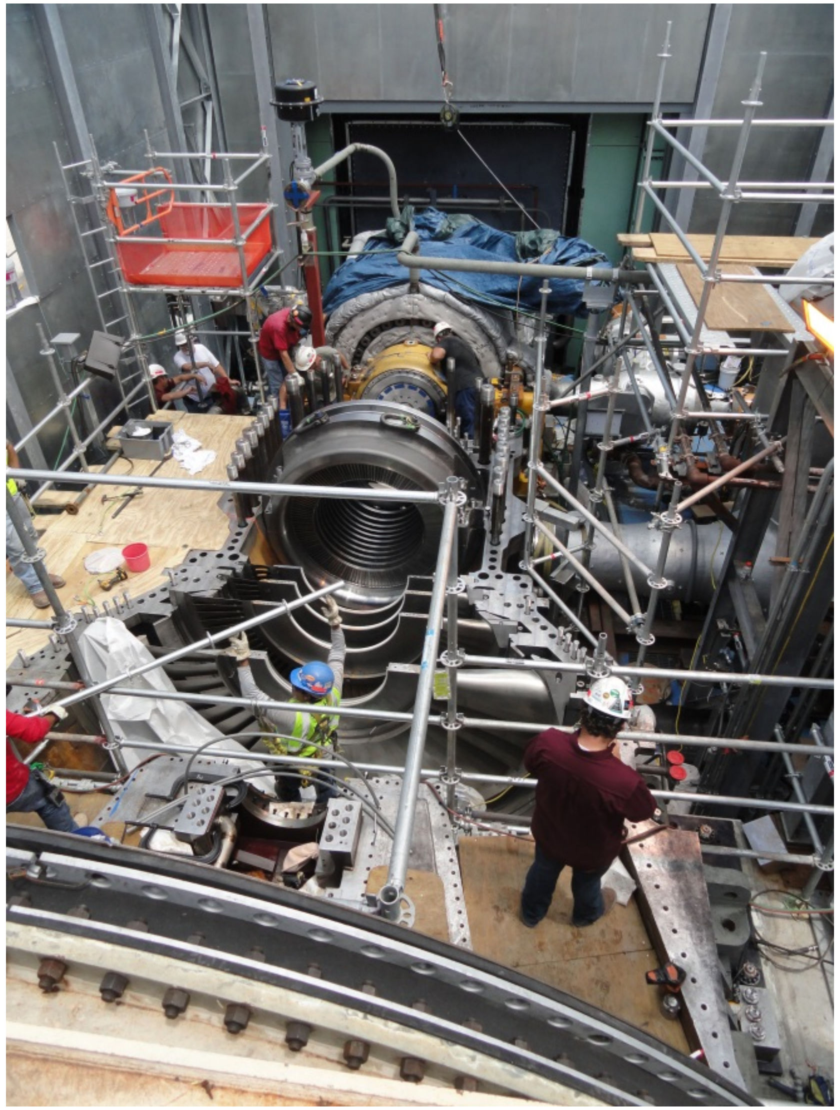
- New Steam Turbine Enclosure

Before

After

Project Details

- Steam Turbine Re-assembly

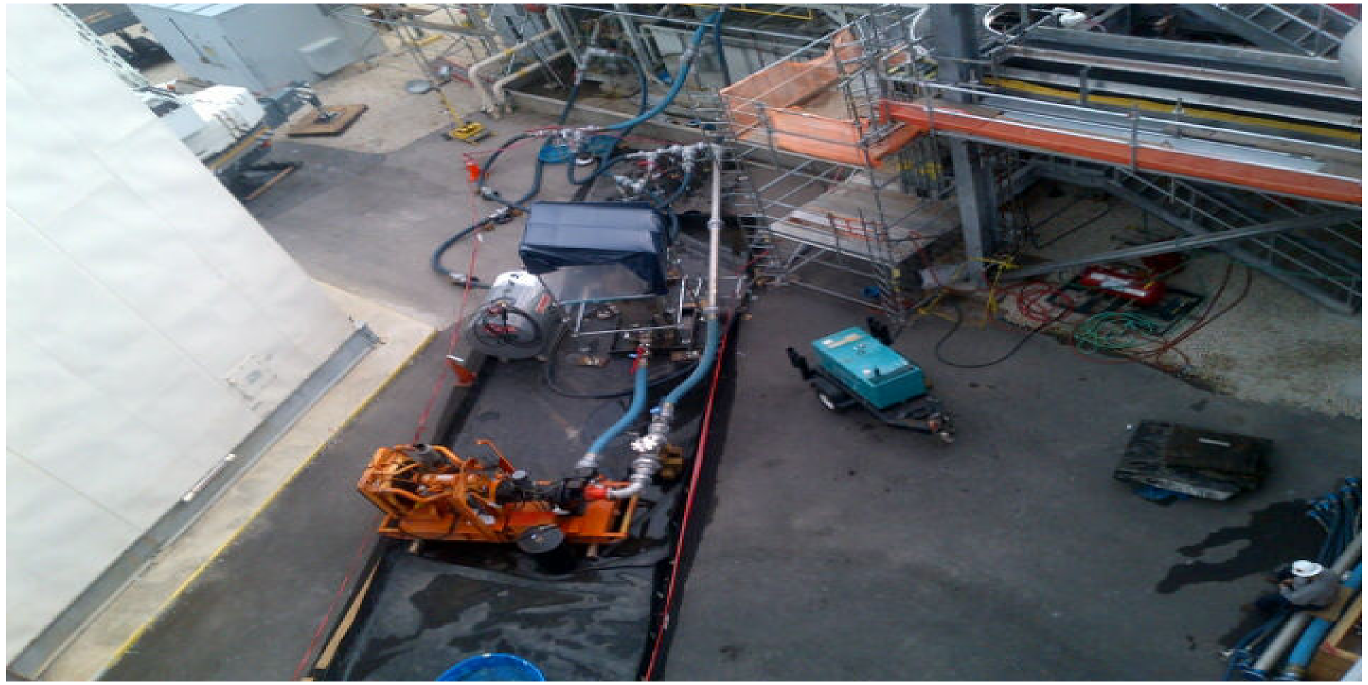


Project Details

- Diffuser Cover

Project Details

- Commissioning Activities
  - Lube Oil Flushes
  - STG Piping Air Blows
  - HRSG Chem Clean
  - CTG Test Fires
  - Steam Purity Checks



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