FPL

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September 4, 2012

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COMMISSION CLERK

-VIA HAND DELIVERY –

Ms. Ann Cole, Director
Division of the Commission Clerk and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: Docket No. 120015-EI

Dear Ms. Cole:

Enclosed for filing on behalf of Florida Power & Light Company ("FPL") is the original and five (5) copies of its responses to Staff's First Data Request dated August 23, 2012. Please note that FPL's response to Data Request No. 5 will be delivered tomorrow, pursuant to our agreement with Staff.

Please contact me at 561-304-5639 if you or your staff have any questions regarding this filing.

Sincerely,

Kenneth L. Adams for
John T. Butler

COM ____
AFD 1
APA 1
ECO ____
ENG 1
GCL 1
IDM 1
TEL ____
CLK ____

Enclosure
cc: Counsel for Parties of Record (w/encl.)

DOCUMENT NUMBER-DATE
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FPSC-COMMISSION CLERK

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by hand delivery to the Clerk, and electronic delivery to the Parties, this 4th day of September, 2012, to the following:

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By: Lynne A. Adams
for John T. Butler

AFFIDAVIT

(Renae B. Deaton)

State of Florida)

County of Palm Beach)

I hereby certify that on this 30th day of August, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Renae B. Deaton, who is personally known to me, and she acknowledged before me that she sponsored the answers to Request Nos. 5, 14, 15, and 16 and co-sponsored the answer to Request Nos. 1 and 4 from Staff's First Set of Data Request to Florida Power & Light Company in Docket No. 120015-EI, and that the responses are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 30th day of August, 2012.

Traci D. Goldwire
Notary Public, State of Florida

Notary Stamp:

NOTARY PUBLIC STATE OF FLORIDA
TRACI D. GOLDWIRE
Notary Public - State of Florida
My Comm. Expires Jul 31, 2015
Commission # EE 117539

AFFIDAVIT

(Joseph A. Ender)

State of Florida)

County of Palm Beach)

I hereby certify that on this 30th day of August, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Joseph A. Ender, who is personally known to me, and he acknowledged before me that he sponsored the answer to Request No. 13 from Staff's First Set of Data Request to Florida Power & Light Company in Docket No. 120015-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 30th day of August, 2012.

Notary Public, State of Florida

Notary Stamp:

NOTARY PUBLIC STATE OF FLORIDA
TRACI D. GOLDWIRE
Notary Public - State of Florida
My Comm. Expires Jul 31, 2015
Commission # EE 117539

AFFIDAVIT

Ui Ousdahl

(Kim Ousdahl)

State of Florida)

County of Palm Beach)

I hereby certify that on this 30th day of August, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Kim Ousdahl, who is personally known to me, and she acknowledged before me that she sponsored the answers to Request Nos. 6 and 8 and co-sponsored Response Nos. 3 and 4 from Staff's First Set of Data Request to Florida Power & Light Company in Docket No. 120015-EI, and that the responses are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 30th day of August, 2012.

Traci D. Goldwire

Notary Public, State of Florida

Notary Stamp:

NOTARY PUBLIC STATE OF FLORIDA
TRACI D. GOLDWIRE
Notary Public - State of Florida
My Comm. Expires Jul 31, 2015
Commission # EE 117539

AFFIDAVIT

Korel M. Dubin

(Korel M. Dubin)

State of Florida)

County of Palm Beach)

I hereby certify that on this 30th day of August, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Korel M. Dubin, who is personally known to me, and she acknowledged before me that she sponsored the answers to Request Nos. 2 and 7 and co-sponsored the answer to Request No. 1 from Staff's First Set of Data Request to Florida Power & Light Company in Docket No. 120015-EI, and that the responses are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 30th day of August, 2012.

Traci D. Goldwire

Notary Public, State of Florida

Notary Stamp:

NOTARY PUBLIC STATE OF FLORIDA

TRACI D. GOLDWIRE
Notary Public - State of Florida
My Comm. Expires Jul 31, 2015
Commission # EE 117539

AFFIDAVIT

(Gerard J. Yupp)

State of Florida)

County of Palm Beach)

I hereby certify that on this 30th day of August, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Gerard J. Yupp, who is personally known to me, and he acknowledged before me that he sponsored the answers to Request Nos. 9, 10, 11 and 12 from Staff's First Set of Data Request to Florida Power & Light Company in Docket No. 120015-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 30th day of August, 2012.

Notary Public, State of Florida

Notary Stamp:

MARITZA MIRANDA-WISE
MY COMMISSION # DD 870958
EXPIRES: May 30, 2013
Bonded Thru Notary Public Underwriters

AFFIDAVIT

(Daisy Iglesias)

State of Florida)

County of Palm Beach)

I hereby certify that on this 30th day of August, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Daisy Iglesias, who is personally known to me, and she acknowledged before me that she co-sponsored the answer to Request No. 3 from Staff's First Set of Data Request to Florida Power & Light Company in Docket No. 120015-EI, and that the responses are true and correct based on her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 30th day of August, 2012.

Notary Public, State of Florida

Notary Stamp: NOTARY PUBLIC STATE OF FLORIDA
Notary Public State of Florida
Lily A Rodriguez
My Commission DD854399
Expires 02/13/2013

AFFIDAVIT

(Thomas R. Koch)

State of Florida)

County of Palm Beach)

I hereby certify that on this 30th day of August, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Thomas R. Koch, who is personally known to me, and he acknowledged before me that he co-sponsored the answer to Request No. 1 from Staff's First Set of Data Request to Florida Power & Light Company in Docket No. 120015-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 30th day of August, 2012.

Notary Public, State of Florida

Notary Stamp: NOTARY PUBLIC STATE OF FLORIDA
Notary Public State of Florida
Lily A Rodriguez
My Commission DD854399
Expires 02/13/2013

AFFIDAVIT

(Ken Getchell)

State of Florida)

County of Palm Beach)

I hereby certify that on this 30th day of August, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Ken Getchell, who is personally known to me, and he acknowledged before me that he co-sponsored the answer to Request No. 1 from Staff's First Set of Data Request to Florida Power & Light Company in Docket No. 120015-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 30th day of August, 2012.

Notary Public, State of Florida

Notary Stamp:

DORIS B. HUGUET
Notary Public - State of Florida
My Comm. Expires Jul 29, 2013
Commission # DD 912276
Bonded Through National Notary Assn.

Q.
Please refer to paragraph 3(b) of the Stipulation and Settlement.

a. For both the proposed CILC and CDR programs, please provide the assumptions and results of a participant test, rate impact measure test, and total resource cost test. All three tests should be performed using the credits as proposed in FPL's 2012 rate filing and the proposed settlement dated August 15, 2012.

b. For both the proposed CILC and CDR programs, please provide an estimate of the total dollars of credits that will be charged to the energy conservation cost recovery clause using the credits as proposed in FPL's 2012 rate filing and the proposed settlement dated August 15, 2012.

c. In its original petition, FPL requested a $5 minimum late payment fee. Please explain in detail the rationale for increasing that to $6 in the stipulation, and what are the additional revenues resulting from a $6 minimum late payment fee (when compared to the $5 fee)?

d. What is the relationship between the Economic Development rider and the enumerated changes listed on paragraph 3(b)(ii) concerning the adjustments to the demand and energy charges for commercial rates, the demand credits and the relationship between the non-fuel energy and demand charges for the CILC rate?

e. What adjustments were made to accommodate the increased CILC credit since the CILC rate schedule has no stated credit in the tariff?

f. Under the stipulation, does the CILC rate remain closed to new customers? If not, what is the rationale for opening this rate to new load?

g. If the intent is to reopen the CILC rate, how many additional customers does FPL expect to take service under the rate and what is the impact on other customers (base or cost recovery clauses) of reopening this rate?

h. Is it correct that the only "credits" to be adjusted under the GBRA increases are the Curtailable credit and the transformation rider?

i. Does the language in paragraph 3(a), which says the proposed rates are "based on the billing determinants, cost of service allocations and rate design in the MFRs accompanying the 2012 Rate Petition," mean that the rates are based on the use of the 12 CP and 1/13th average demand cost allocation methodology without the incorporation of the Minimum Distribution Methodology?

A.

a. Please see the table below which summarizes the results of the requested preliminary cost-effectiveness screening tests for the CDR and CILC programs. Also included, in Attachment No. 1 to this request, are the relevant pages from FPL's model runs for each program consisting of the input page showing the assumptions and the individual pages for each of the preliminary cost-effectiveness screening tests.

	E-RIM	E-TRC	Participant
Commercial/Industrial Demand Reduction (CDR)			
2012 Rate Filing	4.12	124.91	Infinite
Proposed Settlement	2.69	124.91	Infinite
Commercial/Industrial Load Control (CILC)			
2012 Rate Filing	3.07	123.59	Infinite
Proposed Settlement	2.00	123.59	Infinite

For each program, moving to the higher incentive levels proposed in the Settlement Agreement remains cost effective under the RIM test, which correctly accounts for all DSM-related impacts to electric rates including incentive payments and unrecovered revenue requirements. Because the TRC does not account for incentive payments (or unrecovered revenue requirements), the TRC test ratios are not changed by the higher incentive levels. Because there are no participant out-of-pocket costs with either program, the cost-effectiveness results for the Participant test in all cases are "Infinite."

For the CDR program analyses, all the assumptions and results for the 2012 Rate Filing are the same as those provided in FPL's response to Staff's First Set of Interrogatories in Docket 120002-EG on June 28, 2012. The Proposed Settlement scenario uses these same assumptions, adjusting only for the proposed higher incentive level.

However, because the CILC program is closed to new participants, the standard cost-effectiveness testing perspective (which is based on evaluating future incremental participation) was not applied. In order to respond to Staff's request, FPL instead examined all of the currently enrolled participants (approximately 497 MW at the generator) in a case in which all CILC participants remain on the program at the proposed higher incentive levels, and compared it to a case in which the program was discontinued. Removing this large amount of MWs alters the in-service date of FPL's next avoided unit; therefore, the CILC programs are compared to a 2017 avoided unit as opposed to a 2019 avoided (as was used in the analyses of the CDR program). All other assumptions for the CILC program analyses, except for the proposed higher incentive level and the in-service date of the avoided unit, are also identical to those used in response to Staff's First Set of Interrogatories in Docket 120002-EG as mentioned above in regard to analyses of the CDR program.

b. Please see the table below for FPL's estimates of the total credits (i.e., for all projected participants) associated with CILC and CDR, consistent with the assumptions used in the rate filing and proposed settlement.

	2013 Total Credits (000's)	
	2012 Rate Filing	Proposed Settlement
CILC	$25,197	$39,308
CDR	$10,301	$16,070

c. As addressed by Witness Deaton in her direct testimony (pages 15-16), FPL proposed in its original filing to charge the greater of 1.5% or $5 in order to encourage timely payment by customers. The late payment fee is not a cost-based rate, but rather is designed to incent better payment behavior by late-paying customers for the benefit of all other customers. Thus, support for a $5 or a $6 rate is based on the same rationale. Other industries use late payment charges greater than $10 to encourage customers to pay on time; some other Florida utilities charge a much higher fee than FPL proposes, such as City of Miramar Utilities at $15.00 and Lee County Electric Cooperative at $10.00 for residential customers.

The additional revenues associated with moving from the $5 minimum to a $6 minimum are approximately $10.6 million. We make an assumption that the number of late payments will reduce from current projections as the intended result of a higher fee. In this case, we have assumed that approximately six percent, or about $600,000, will not be realized due to such behavioral changes. To the extent it is under-estimated, FPL is at-risk of not recovering the projected revenues.

d. There is no direct relationship and no change is intended in the Economic Development Riders. The referenced section of the Agreement reads as follows: "(ii) consistent with FPL's recently approved Economic Development Rider and to promote further economic development and job creation." This reference is intended to reflect that an important benefit of the stipulation and settlement agreement energy and demand charges for business and commercial rates as well as the CILC and CDR credits is to further support business and commercial customers in their respective efforts to support the economy, which was also the goal of FPL's Economic Development Riders.

e. The current CILC credits were increased 56%. The increased credits reduced the amount of revenues to be recovered from CILC customers through base rates. The CILC rates were set to recover the revenue increase shown on Line 1 of Exhibit A. Also, see Attachment No. 2 to this request showing the derivation of the rates for each rate schedule.

f. Yes, it remains closed.

g. Not applicable. Please see FPL's response to subpart (f).

h. No. As with the GBRA previously in effect under the 2005 settlement agreement, the CDR credit is increased as well as the CS and TR credits.

i. Yes. There is no change in the cost of service methodology, only a change in the allocation of certain costs as part of a settlement, which will provide economic benefit to a broad range of commercial customers, including virtually all of FRF's constituents.

INPUT DATA – PART 1 CONTINUED
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: CDR

2012 Rate Filing

I. PROGRAM DEMAND SAVINGS & LINE LOSSES

(1) CUSTOMER kW REDUCTION AT METER	1.00	kW
(2) GENERATOR kW REDUCTION PER CUSTOMER	1.32515	kW
(3) kW LINE LOSS PERCENTAGE	7.94	%
(4) GENERATOR kWh REDUCTION PER CUSTOMER	8.11	kWh ****
(5) kWh LINE LOSS PERCENTAGE	6.24	%
(6) GROUP LINE LOSS MULTIPLIER	1.00	
(7) CUSTOMER kWh INCREASE AT METER	0.38	kWh ****

II. ECONOMIC LIFE & K FACTORS

(1) STUDY PERIOD FOR THE CONSERVATION PROGRAM	37	YEARS
(2) GENERATOR ECONOMIC LIFE	30	YEARS
(3) T&D ECONOMIC LIFE	35	YEARS
(4) K FACTOR FOR GENERATION	1.58562	
(5) K FACTOR FOR T & D	1.55564	

III. UTILITY & CUSTOMER COSTS

	(1) UTILITY NON RECURRING COST PER CUSTOMER	***	$/CUST
	(2) UTILITY RECURRING COST PER CUSTOMER	***	$/CUST
	(3) UTILITY COST ESCALATION RATE	***	%**
	(4) CUSTOMER EQUIPMENT COST	***	$/CUST
	(5) CUSTOMER EQUIPMENT ESCALATION RATE	***	%**
	(6) CUSTOMER O & M COST	***	$/CUST/YR
	(7) CUSTOMER O & M COST ESCALATION RATE	***	%**
*	(8) INCREASED SUPPLY COSTS	***	$/CUST/YR
*	(9) SUPPLY COSTS ESCALATION RATES	***	%**
*	(10) UTILITY DISCOUNT RATE	7.29	%
*	(11) UTILITY AFUDC RATE	6.69	%
*	(12) UTILITY NON RECURRING REBATE/INCENTIVE	***	$/CUST
*	(13) UTILITY RECURRING REBATE/INCENTIVE	***	$/CUST
*	(14) UTILITY REBATE/INCENTIVE ESCALATION RATE	***	%

IV. AVOIDED GENERATOR AND T&D COSTS

(1) BASE YEAR	2012	
(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	2019	
(3) IN-SERVICE YEAR FOR AVOIDED T&D	2015-2019	
(4) BASE YEAR AVOIDED GENERATING COST	776.56	$/kW
(5) BASE YEAR AVOIDED TRANSMISSION COST	149.48	$/kW
(6) BASE YEAR DISTRIBUTION COST	39.32	$/kW
(7) GEN, TRAN & DIST COST ESCALATION RATE	3.00	%**
(8) GENERATOR FIXED O & M COST	109.68	$/kW/YR
(9) GENERATOR FIXED O&M ESCALATION RATE	2.50	%**
(10) TRANSMISSION FIXED O & M COST	3.28	$/kW
(11) DISTRIBUTION FIXED O & M COST	1.14	$/kW
(12) T&D FIXED O&M ESCALATION RATE	2.50	%**
(13) AVOIDED GEN UNIT VARIABLE O & M COSTS	0.058	CENTS/kWh
(14) GENERATOR VARIABLE O&M COST ESCALATION RATE	2.50	%**
(15) GENERATOR CAPACITY FACTOR	55%	** (In-service year)
(16) AVOIDED GENERATING UNIT FUEL COST	4.69	CENTS PER kWh** (In-service year)
(17) AVOIDED GEN UNIT FUEL COST ESCALATION RATE	8.70	%**

V. NON-FUEL ENERGY AND DEMAND CHARGES

(1) NON FUEL COST IN CUSTOMER BILL	***	CENTS/kWh
(2) NON-FUEL COST ESCALATION RATE	***	%
(3) DEMAND CHARGE IN CUSTOMER BILL	***	$/kW/MO
(4) DEMAND CHARGE ESCALATION RATE	***	%

* SUPPLEMENTAL INFORMATION NOT SPECIFIED IN WORKBOOK
** VALUE SHOWN IS FOR FIRST YEAR ONLY (VALUE VARIES OVER TIME)
*** PROGRAM COST CALCULATION VALUES ARE SHOWN ON PAGE 2
**** THIS IS A LOAD SHIFTING PROGRAM. VALUE SHOWN IN ITEM (4) IS ANNUAL KWH/CUST SHIFTED AWAY FROM PEAK HRS. VALUE SHOWN IN ITEM (7) IS ANNUAL KWH/CUST THAT IS PAID BACK DURING OFF-PEAK.

RATE IMPACT TEST
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: CDR

2012 Rate Filing

(1) YEAR	(2) INCREASED SUPPLY COSTS $(000)	(3) UTILITY PROGRAM COSTS $(000)	(4) INCENTIVES $(000)	(5) REVENUE LOSSES $(000)	(6) OTHER COSTS $(000)	(7) TOTAL COSTS $(000)	(8) AVOIDED GEN UNIT & FUEL BENEFITS $(000)	(9) AVOIDED T&D BENEFITS $(000)	(10) REVENUE GAINS $(000)	(11) OTHER BENEFITS $(000)	(12) TOTAL BENEFITS $(000)	(13) NET BENEFITS $(000)	(14) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
2012	0	16	376	3	0	395	3	0	0	0	3	(394)	(394)
2013	0	36	1,126	7	0	1,170	9	609	0	0	618	(552)	(909)
2014	0	55	1,869	11	0	1,935	16	1,211	0	0	1,227	(708)	(1,524)
2015	0	76	2,611	16	0	2,703	22	1,814	0	0	1,836	(866)	(2,225)
2016	0	97	3,353	21	0	3,471	30	2,463	0	0	2,513	(958)	(2,948)
2017	0	119	4,096	30	0	4,244	44	3,093	0	0	3,138	(1,106)	(3,726)
2018	0	142	4,838	43	0	5,023	59	3,708	0	0	3,766	(1,256)	(4,550)
2019	0	146	5,209	48	0	5,403	29,009	4,259	0	(11)	33,256	27,853	12,467
2020	0	149	5,209	50	0	5,409	25,795	4,149	0	(17)	29,927	24,518	26,428
2021	0	153	5,209	53	0	5,415	26,048	4,041	0	(17)	30,073	24,657	39,514
2022	0	157	5,209	55	0	5,421	28,237	3,937	0	(12)	32,163	26,742	52,741
2023	0	161	5,209	55	0	5,425	29,332	3,837	0	(958)	32,212	26,786	65,090
2024	0	165	5,209	58	0	5,432	27,724	3,741	0	(1,091)	30,374	24,942	75,807
2025	0	169	5,209	61	0	5,439	24,571	3,646	0	(1,270)	26,947	21,508	84,420
2026	0	173	5,209	63	0	5,445	24,788	3,553	0	(1,464)	26,877	21,432	92,419
2027	0	178	5,209	65	0	5,452	24,408	3,461	0	(1,698)	26,170	20,719	99,627
2028	0	182	5,209	67	0	5,458	25,535	3,369	0	(1,924)	26,980	21,523	106,605
2029	0	187	5,209	68	0	5,464	25,960	3,278	0	(2,194)	27,044	21,580	113,126
2030	0	191	5,209	71	0	5,471	26,064	3,187	0	(2,509)	26,742	21,271	119,117
2031	0	196	5,209	73	0	5,478	27,383	3,097	0	(2,831)	27,648	22,170	124,937
2032	0	201	5,209	76	0	5,486	29,656	3,007	0	(3,195)	29,468	23,982	130,805
2033	0	206	5,209	83	0	5,497	28,216	2,919	0	(3,620)	27,515	22,018	135,825
2034	0	211	5,209	86	0	5,506	29,205	2,837	0	(4,060)	27,982	22,476	140,602
2035	0	216	5,209	88	0	5,514	30,662	2,763	0	(4,529)	28,896	23,382	145,234
2036	0	222	5,209	95	0	5,526	29,858	2,696	0	(5,069)	27,485	21,959	149,288
2037	0	227	5,209	98	0	5,534	31,234	2,637	0	(5,619)	28,251	22,717	153,197
2038	0	233	5,209	101	0	5,543	31,820	2,586	0	(6,229)	28,176	22,633	156,827
2039	0	239	5,209	105	0	5,553	32,147	2,544	0	(6,891)	27,800	22,248	160,152
2040	0	245	5,209	108	0	5,562	33,259	2,508	0	(7,589)	28,178	22,617	163,303
2041	0	251	5,209	112	0	5,571	33,210	2,476	0	(8,358)	27,327	21,756	166,128
2042	0	257	5,209	115	0	5,581	32,909	2,444	0	(9,191)	26,162	20,581	168,618
2043	0	264	5,209	119	0	5,592	33,724	2,394	0	(10,065)	26,052	20,461	170,926
2044	0	270	5,209	124	0	5,603	34,024	2,346	0	(11,013)	25,356	19,753	173,003
2045	0	277	5,209	130	0	5,616	34,503	2,299	0	(12,019)	24,783	19,168	174,881
2046	0	284	5,209	136	0	5,628	35,288	2,255	0	(13,099)	24,444	18,815	176,599
2047	0	291	5,209	142	0	5,641	35,908	2,213	0	(14,249)	23,872	18,231	178,151
2048	0	298	5,209	148	0	5,655	36,100	2,175	0	(15,482)	22,792	17,137	179,510
NOM.	0	6,939	174,539	2,786	0	184,264	896,760	103,567	0	(156,270)	844,058	659,793	
NPV	0	1,897	54,898	672	0	57,468	223,606	36,356	0	(22,984)	236,978	179,510	

Discount Rate 7.29 %

Benefit/Cost Ratio (Col(12) / Col(7)) : 4.12

page 9

PSC FORM CE 2.3
PAGE 1 OF 1

TOTAL RESOURCE COST TEST
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: CDR

2012 Rate Filing

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
YEAR	INCREASED SUPPLY COSTS $(000)	UTILITY PROGRAM COSTS $(000)	PARTICIPANT PROGRAM COSTS $(000)	OTHER COSTS $(000)	TOTAL COSTS $(000)	AVOIDED GEN UNIT BENEFITS $(000)	AVOIDED T&D BENEFITS $(000)	PROGRAM FUEL SAVINGS $(000)	OTHER BENEFITS $(000)	TOTAL BENEFITS $(000)	NET BENEFITS $(000)	CUMULATIVE DISCOUNTED NET BENEFITS $(000)
2012	0	18	0	0	18	0	0	3	0	3	(14)	(14)
2013	0	36	0	0	36	0	609	9	0	618	582	528
2014	0	55	0	0	55	0	1,211	16	0	1,227	1,172	1,546
2015	0	76	0	0	76	0	1,814	22	0	1,836	1,761	2,971
2016	0	97	0	0	97	0	2,483	30	0	2,513	2,416	4,795
2017	0	119	0	0	119	0	3,093	44	0	3,138	3,019	6,918
2018	0	142	0	0	142	0	3,708	59	0	3,766	3,624	9,293
2019	0	146	0	0	146	28,933	4,259	76	(11)	33,256	33,111	29,522
2020	0	149	0	0	149	25,710	4,149	86	(17)	29,927	29,777	46,478
2021	0	153	0	0	153	25,972	4,041	77	(17)	30,073	29,920	62,356
2022	0	157	0	0	157	28,157	3,937	80	(12)	32,163	32,006	78,187
2023	0	161	0	0	161	29,253	3,837	79	(958)	32,212	32,051	92,963
2024	0	165	0	0	165	27,634	3,741	90	(1,091)	30,374	30,209	105,943
2025	0	169	0	0	169	24,464	3,646	106	(1,270)	26,947	26,778	116,667
2026	0	173	0	0	173	24,686	3,553	102	(1,464)	26,877	26,704	126,634
2027	0	178	0	0	178	24,304	3,461	104	(1,698)	26,170	25,993	135,677
2028	0	182	0	0	182	25,430	3,369	105	(1,924)	26,980	26,798	144,365
2029	0	187	0	0	187	25,854	3,278	106	(2,194)	27,044	26,857	152,481
2030	0	191	0	0	191	25,957	3,187	107	(2,509)	26,742	26,551	159,960
2031	0	196	0	0	196	27,372	3,097	110	(2,831)	27,648	27,452	167,166
2032	0	201	0	0	201	29,549	3,007	107	(3,195)	29,468	29,267	174,326
2033	0	206	0	0	206	28,103	2,919	112	(3,620)	27,515	27,309	180,554
2034	0	211	0	0	211	29,092	2,837	113	(4,060)	27,982	27,771	186,456
2035	0	216	0	0	216	30,556	2,763	105	(4,529)	28,896	28,680	192,137
2036	0	222	0	0	222	29,741	2,696	117	(5,069)	27,485	27,263	197,170
2037	0	227	0	0	227	31,126	2,637	107	(5,619)	28,251	28,024	201,992
2038	0	233	0	0	233	31,712	2,586	108	(6,229)	28,176	27,943	206,474
2039	0	239	0	0	239	32,035	2,544	112	(6,891)	27,800	27,562	210,594
2040	0	245	0	0	245	33,153	2,508	107	(7,589)	28,178	27,933	214,485
2041	0	251	0	0	251	33,100	2,476	110	(8,358)	27,327	27,076	218,007
2042	0	257	0	0	257	32,795	2,444	114	(9,191)	26,162	25,905	221,136
2043	0	264	0	0	264	33,617	2,394	106	(10,065)	26,052	25,789	224,045
2044	0	270	0	0	270	33,913	2,346	111	(11,013)	25,356	25,086	226,682
2045	0	277	0	0	277	34,393	2,299	110	(12,019)	24,783	24,507	229,083
2046	0	284	0	0	284	35,180	2,255	108	(13,099)	24,444	24,160	231,289
2047	0	291	0	0	291	35,802	2,213	106	(14,249)	23,872	23,581	233,296
2048	0	298	0	0	298	35,990	2,175	110	(15,482)	22,792	22,494	235,081
NOM	0	6,939	0	0	6,939	893,486	103,567	3,275	(156,270)	844,058	837,119	
NPV	0	1,897	0	0	1,897	222,701	36,356	905	(22,984)	236,978	235,081	

Discount Rate: 7.29 %

Benefit/Cost Ratio (Col(11) / Col(6)) : 124.91

PARTICIPANT COSTS AND BENEFITS
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: CDR

2012 Rate Filing

(1) YEAR	(2) SAVINGS IN PARTICIPANTS BILLS $(000)	(3) TAX CREDITS $(000)	(4) UTILITY REBATES $(000)	(5) OTHER BENEFITS $(000)	(6) TOTAL BENEFITS $(000)	(7) CUSTOMER EQUIPMENT COSTS $(000)	(8) CUSTOMER O&M COSTS $(000)	(9) OTHER COSTS $(000)	(10) TOTAL COSTS $(000)	(11) NET BENEFITS $(000)	(12) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
2012	3	0	378	0	381	0	0	0	0	381	381
2013	8	0	1,126	0	1,135	0	0	0	0	1,135	1,438
2014	14	0	1,869	0	1,882	0	0	0	0	1,882	3,074
2015	20	0	2,611	0	2,631	0	0	0	0	2,631	5,203
2016	25	0	3,353	0	3,379	0	0	0	0	3,379	7,753
2017	36	0	4,096	0	4,131	0	0	0	0	4,131	10,658
2018	52	0	4,838	0	4,889	0	0	0	0	4,889	13,863
2019	58	0	5,209	0	5,267	0	0	0	0	5,267	17,081
2020	61	0	5,209	0	5,270	0	0	0	0	5,270	20,082
2021	64	0	5,209	0	5,273	0	0	0	0	5,273	22,880
2022	67	0	5,209	0	5,276	0	0	0	0	5,276	25,490
2023	67	0	5,209	0	5,276	0	0	0	0	5,276	27,922
2024	70	0	5,209	0	5,279	0	0	0	0	5,279	30,190
2025	74	0	5,209	0	5,283	0	0	0	0	5,283	32,306
2026	76	0	5,209	0	5,285	0	0	0	0	5,285	34,278
2027	78	0	5,209	0	5,287	0	0	0	0	5,287	36,118
2028	80	0	5,209	0	5,289	0	0	0	0	5,289	37,833
2029	82	0	5,209	0	5,291	0	0	0	0	5,291	39,432
2030	85	0	5,209	0	5,294	0	0	0	0	5,294	40,923
2031	88	0	5,209	0	5,297	0	0	0	0	5,297	42,315
2032	92	0	5,209	0	5,301	0	0	0	0	5,301	43,610
2033	100	0	5,209	0	5,309	0	0	0	0	5,309	44,821
2034	104	0	5,209	0	5,313	0	0	0	0	5,313	45,950
2035	107	0	5,209	0	5,316	0	0	0	0	5,316	47,003
2036	114	0	5,209	0	5,323	0	0	0	0	5,323	47,986
2037	118	0	5,209	0	5,327	0	0	0	0	5,327	48,902
2038	122	0	5,209	0	5,331	0	0	0	0	5,331	49,757
2039	126	0	5,209	0	5,335	0	0	0	0	5,335	50,555
2040	130	0	5,209	0	5,339	0	0	0	0	5,339	51,299
2041	134	0	5,209	0	5,343	0	0	0	0	5,343	51,992
2042	139	0	5,209	0	5,348	0	0	0	0	5,348	52,640
2043	144	0	5,209	0	5,352	0	0	0	0	5,352	53,243
2044	150	0	5,209	0	5,359	0	0	0	0	5,359	53,807
2045	156	0	5,209	0	5,365	0	0	0	0	5,365	54,332
2046	163	0	5,209	0	5,372	0	0	0	0	5,372	54,823
2047	171	0	5,209	0	5,380	0	0	0	0	5,380	55,281
2048	178	0	5,209	0	5,387	0	0	0	0	5,387	55,708
NOM	3,357	0	174,539	0	177,896	0	0	0	0	177,896	
NPV	810	0	54,898	0	55,708	0	0	0	0	55,708	

In Service of Gen Unit: 2019
Discount Rate: 7.29 %
Benefit/Cost Ratio (Col(6) / Col(10)): Infinite

INPUT DATA -- PART 1 CONTINUED
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: CDR

Proposed Settlement

I. PROGRAM DEMAND SAVINGS & LINE LOSSES

(1) CUSTOMER kW REDUCTION AT METER	1.00 kW
(2) GENERATOR kW REDUCTION PER CUSTOMER	1.32515 kW
(3) kW LINE LOSS PERCENTAGE	7.94 %
(4) GENERATOR kWh REDUCTION PER CUSTOMER	8.11 kWh ****
(5) kWh LINE LOSS PERCENTAGE	6.24 %
(6) GROUP LINE LOSS MULTIPLIER	1.00
(7) CUSTOMER kWh INCREASE AT METER	0.38 kWh ****

II. ECONOMIC LIFE & K FACTORS

(1) STUDY PERIOD FOR THE CONSERVATION PROGRAM	37 YEARS
(2) GENERATOR ECONOMIC LIFE	30 YEARS
(3) T&D ECONOMIC LIFE	35 YEARS
(4) K FACTOR FOR GENERATION	1.58562
(5) K FACTOR FOR T & D	1.55564

III. UTILITY & CUSTOMER COSTS

	(1) UTILITY NON RECURRING COST PER CUSTOMER	*** $/CUST
	(2) UTILITY RECURRING COST PER CUSTOMER	*** $/CUST
	(3) UTILITY COST ESCALATION RATE	*** %**
	(4) CUSTOMER EQUIPMENT COST	*** $/CUST
	(5) CUSTOMER EQUIPMENT ESCALATION RATE	*** %**
	(6) CUSTOMER O & M COST	*** $/CUST/YR
	(7) CUSTOMER O & M COST ESCALATION RATE	*** %**
*	(8) INCREASED SUPPLY COSTS	*** $/CUST/YR
*	(9) SUPPLY COSTS ESCALATION RATES	*** %**
*	(10) UTILITY DISCOUNT RATE	7.29 %
*	(11) UTILITY AFUDC RATE	6.69 %
*	(12) UTILITY NON RECURRING REBATE/INCENTIVE	*** $/CUST
*	(13) UTILITY RECURRING REBATE/INCENTIVE	*** $/CUST
*	(14) UTILITY REBATE/INCENTIVE ESCALATION RATE	*** %

IV. AVOIDED GENERATOR AND T&D COSTS

(1) BASE YEAR	2012
(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	2019
(3) IN-SERVICE YEAR FOR AVOIDED T&D	2015-2019
(4) BASE YEAR AVOIDED GENERATING COST	776.56 $/kW
(5) BASE YEAR AVOIDED TRANSMISSION COST	149.48 $/kW
(6) BASE YEAR DISTRIBUTION COST	39.32 $/kW
(7) GEN, TRAN & DIST COST ESCALATION RATE	3.00 %**
(8) GENERATOR FIXED O & M COST	109.68 $/kW/YR
(9) GENERATOR FIXED O&M ESCALATION RATE	2.50 %**
(10) TRANSMISSION FIXED O & M COST	3.28 $/kW
(11) DISTRIBUTION FIXED O & M COST	1.14 $/kW
(12) T&D FIXED O&M ESCALATION RATE	2.50 %**
(13) AVOIDED GEN UNIT VARIABLE O & M COSTS	0.058 CENTS/kWh
(14) GENERATOR VARIABLE O&M COST ESCALATION RATE	2.50 %**
(15) GENERATOR CAPACITY FACTOR	55% ** (in-service year)
(16) AVOIDED GENERATING UNIT FUEL COST	4.69 CENTS PER kWh** (in-service year)
(17) AVOIDED GEN UNIT FUEL COST ESCALATION RATE	8.70 %**

V. NON-FUEL ENERGY AND DEMAND CHARGES

(1) NON FUEL COST IN CUSTOMER BILL	*** CENTS/kWh
(2) NON-FUEL COST ESCALATION RATE	*** %
(3) DEMAND CHARGE IN CUSTOMER BILL	*** $/kW/MO
(4) DEMAND CHARGE ESCALATION RATE	*** %

* SUPPLEMENTAL INFORMATION NOT SPECIFIED IN WORKBOOK
** VALUE SHOWN IS FOR FIRST YEAR ONLY (VALUE VARIES OVER TIME)
*** PROGRAM COST CALCULATION VALUES ARE SHOWN ON PAGE 2
**** THIS IS A LOAD SHIFTING PROGRAM. VALUE SHOWN IN ITEM (4) IS ANNUAL KWH/CUST SHIFTED AWAY FROM PEAK HRS. VALUE SHOWN IN ITEM (7) IS ANNUAL KWH/CUST THAT IS PAID BACK DURING OFF-PEAK.

Florida Power & Light Company
Docket No. 120015-EI
Staff's First Data Request
Request No. 1
Attachment No. 1
Page 6 of 16

RATE IMPACT TEST
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: CDR

Proposed Settlement

(1) YEAR	(2) INCREASED SUPPLY COSTS $(000)	(3) UTILITY PROGRAM COSTS $(000)	(4) INCENTIVES $(000)	(5) REVENUE LOSSES $(000)	(6) OTHER COSTS $(000)	(7) TOTAL COSTS $(000)	(8) AVOIDED GEN UNIT & FUEL BENEFITS $(000)	(9) AVOIDED T&D BENEFITS $(000)	(10) REVENUE GAINS $(000)	(11) OTHER BENEFITS $(000)	(12) TOTAL BENEFITS $(000)	(13) NET BENEFITS $(000)	(14) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
2012	0	18	589	3	0	609	3	0	0	0	3	(606)	(606)
2013	0	36	1,757	7	0	1,800	9	609	0	0	618	(1,182)	(1,708)
2014	0	55	2,915	11	0	2,982	16	1,211	0	0	1,227	(1,754)	(3,233)
2015	0	76	4,073	16	0	4,164	22	1,814	0	0	1,836	(2,328)	(5,177)
2016	0	97	5,230	21	0	5,348	30	2,483	0	0	2,513	(2,835)	(7,256)
2017	0	119	6,388	30	0	6,537	44	3,093	0	0	3,138	(3,399)	(9,647)
2018	0	142	7,546	43	0	7,731	59	3,708	0	0	3,766	(3,965)	(12,245)
2019	0	146	8,125	48	0	8,319	29,009	4,259	0	(11)	33,256	24,937	2,990
2020	0	149	8,125	50	0	8,325	25,795	4,149	0	(17)	29,927	21,602	15,290
2021	0	153	8,125	53	0	8,331	26,048	4,041	0	(17)	30,073	21,741	26,828
2022	0	157	8,125	55	0	8,337	28,237	3,937	0	(12)	32,163	23,826	38,613
2023	0	161	8,125	55	0	8,341	29,332	3,837	0	(958)	32,212	23,870	49,618
2024	0	165	8,125	58	0	8,348	27,724	3,741	0	(1,091)	30,374	22,026	59,082
2025	0	169	8,125	61	0	8,355	24,571	3,646	0	(1,270)	26,947	18,593	66,527
2026	0	173	8,125	63	0	8,361	24,788	3,553	0	(1,464)	26,877	18,516	73,438
2027	0	178	8,125	65	0	8,368	24,408	3,461	0	(1,698)	26,170	17,803	79,631
2028	0	182	8,125	67	0	8,374	25,535	3,369	0	(1,924)	26,980	18,607	85,664
2029	0	187	8,125	68	0	8,380	25,960	3,278	0	(2,194)	27,044	18,654	91,304
2030	0	191	8,125	71	0	8,387	26,064	3,187	0	(2,509)	26,742	18,355	96,474
2031	0	196	8,125	73	0	8,394	27,382	3,097	0	(2,831)	27,648	19,254	101,528
2032	0	201	8,125	76	0	8,402	29,656	3,007	0	(3,195)	29,468	21,066	106,682
2033	0	206	8,125	83	0	8,414	28,216	2,919	0	(3,620)	27,515	19,102	111,038
2034	0	211	8,125	86	0	8,432	29,205	2,837	0	(4,060)	27,982	19,560	115,195
2035	0	216	8,125	88	0	8,430	30,662	2,763	0	(4,529)	28,896	20,466	119,249
2036	0	222	8,125	95	0	8,442	29,858	2,696	0	(5,069)	27,485	19,043	122,764
2037	0	227	8,125	98	0	8,451	31,234	2,637	0	(5,619)	28,251	19,801	126,172
2038	0	233	8,125	101	0	8,459	31,820	2,586	0	(6,229)	28,176	19,717	129,334
2039	0	239	8,125	105	0	8,469	32,147	2,544	0	(6,891)	27,800	19,332	132,229
2040	0	245	8,125	108	0	8,478	33,259	2,508	0	(7,589)	28,178	19,700	134,968
2041	0	251	8,125	112	0	8,487	33,210	2,476	0	(8,358)	27,327	18,840	137,414
2042	0	257	8,125	115	0	8,497	32,909	2,444	0	(9,191)	26,162	17,665	139,552
2043	0	264	8,125	119	0	8,508	33,734	2,394	0	(10,065)	26,052	17,545	141,531
2044	0	270	8,125	124	0	8,520	34,024	2,346	0	(11,013)	25,356	16,837	143,301
2045	0	277	8,125	130	0	8,532	34,503	2,299	0	(12,019)	24,783	16,252	144,893
2046	0	284	8,125	136	0	8,544	35,288	2,255	0	(13,099)	24,444	15,899	146,345
2047	0	291	8,125	142	0	8,558	35,908	2,213	0	(14,249)	23,872	15,315	147,648
2048	0	298	8,125	148	0	8,571	36,100	2,175	0	(15,482)	22,792	14,221	148,776
NOM.	0	6,939	272,251	2,786	0	281,976	896,760	103,567	0	(156,270)	844,058	562,082	
NPV	0	1,897	85,632	672	0	88,201	223,606	36,356	0	(22,984)	236,978	148,776	

Discount Rate 7.29 %
Benefit/Cost Ratio (Col(12) / Col(7)) : 2.69

Florida Power & Light Company
Docket No. 120015-EI
Staff's First Data Request
Request No. 1
Attachment No. 1
Page 7 of 16

TOTAL RESOURCE COST TEST
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: CDR

Proposed Settlement

(1) YEAR	(2) INCREASED SUPPLY COSTS $(000)	(3) UTILITY PROGRAM COSTS $(000)	(4) PARTICIPANT PROGRAM COSTS $(000)	(5) OTHER COSTS $(000)	(6) TOTAL COSTS $(000)	(7) AVOIDED GEN UNIT BENEFITS $(000)	(8) AVOIDED T&D BENEFITS $(000)	(9) PROGRAM FUEL SAVINGS $(000)	(10) OTHER BENEFITS $(000)	(11) TOTAL BENEFITS $(000)	(12) NET BENEFITS $(000)	(13) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
2012	0	18	0	0	18	0	0	3	0	3	(14)	(14)
2013	0	36	0	0	36	0	609	9	0	618	582	528
2014	0	55	0	0	55	0	1,211	16	0	1,227	1,172	1,546
2015	0	76	0	0	76	0	1,814	22	0	1,836	1,761	2,971
2016	0	97	0	0	97	0	2,483	30	0	2,513	2,416	4,795
2017	0	119	0	0	119	0	3,093	44	0	3,138	3,019	6,918
2018	0	142	0	0	142	0	3,708	59	0	3,766	3,624	9,293
2019	0	146	0	0	146	28,933	4,259	76	(11)	33,256	33,111	29,522
2020	0	149	0	0	149	25,710	4,149	86	(17)	29,927	29,777	46,478
2021	0	153	0	0	153	25,972	4,041	77	(17)	30,073	29,920	62,356
2022	0	157	0	0	157	28,157	3,937	80	(12)	32,163	32,006	78,187
2023	0	161	0	0	161	29,253	3,837	79	(958)	32,212	32,051	92,963
2024	0	165	0	0	165	27,634	3,741	90	(1,091)	30,374	30,209	105,943
2025	0	169	0	0	169	24,464	3,646	106	(1,270)	26,947	26,778	116,667
2026	0	173	0	0	173	24,686	3,553	103	(1,464)	26,877	26,704	126,634
2027	0	178	0	0	178	24,304	3,461	104	(1,698)	26,170	25,993	135,677
2028	0	182	0	0	182	25,430	3,369	105	(1,924)	26,980	26,798	144,365
2029	0	187	0	0	187	25,854	3,278	106	(2,194)	27,044	26,857	152,481
2030	0	191	0	0	191	25,957	3,187	107	(2,509)	26,742	26,551	159,960
2031	0	196	0	0	196	27,272	3,097	110	(2,831)	27,648	27,452	167,166
2032	0	201	0	0	201	29,549	3,007	107	(3,195)	29,468	29,267	174,326
2033	0	206	0	0	206	28,103	2,919	112	(3,620)	27,515	27,309	180,554
2034	0	211	0	0	211	29,092	2,837	113	(4,060)	27,982	27,771	186,456
2035	0	216	0	0	216	30,556	2,763	105	(4,529)	28,896	28,680	192,137
2036	0	222	0	0	222	29,741	2,696	117	(5,069)	27,485	27,263	197,170
2037	0	227	0	0	227	31,126	2,637	107	(5,619)	28,251	28,024	201,992
2038	0	233	0	0	233	31,712	2,586	108	(6,229)	28,176	27,943	206,474
2039	0	239	0	0	239	32,035	2,544	112	(6,891)	27,800	27,562	210,594
2040	0	245	0	0	245	33,153	2,508	107	(7,589)	28,178	27,933	214,485
2041	0	251	0	0	251	33,100	2,476	110	(8,358)	27,327	27,076	218,001
2042	0	257	0	0	257	32,795	2,444	114	(9,191)	26,162	25,905	221,136
2043	0	264	0	0	264	33,617	2,394	106	(10,065)	26,052	25,789	224,045
2044	0	270	0	0	270	33,913	2,346	111	(11,013)	25,356	25,086	226,582
2045	0	277	0	0	277	34,393	2,299	110	(12,019)	24,783	24,507	229,083
2046	0	284	0	0	284	35,180	2,255	108	(13,099)	24,444	24,160	231,289
2047	0	291	0	0	291	35,802	2,213	106	(14,249)	23,872	23,581	233,296
2048	0	298	0	0	298	35,990	2,175	110	(15,482)	22,792	22,494	235,081

NOM	0	6,939	0	0	6,939	893,486	103,567	3,275	(156,270)	844,058	837,119
NPV	0	1,897	0	0	1,897	232,701	36,356	905	(22,984)	236,978	235,081

Discount Rate: 7.29 %

Benefit/Cost Ratio (Col(11) / Col(6)) : 124.91

Florida Power & Light Company
Docket No. 120015-EI
Staff's First Data Request
Request No. 1
Attachment No. 1
Page 8 of 16

PSC FORM CE 2.4
PAGE 1 OF 1

PARTICIPANT COSTS AND BENEFITS
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: CDR

Proposed Settlement

(1) YEAR	(2) SAVINGS IN PARTICIPANTS BILLS $(000)	(3) TAX CREDITS $(000)	(4) UTILITY REBATES $(000)	(5) OTHER BENEFITS $(000)	(6) TOTAL BENEFITS $(000)	(7) CUSTOMER EQUIPMENT COSTS $(000)	(8) CUSTOMER O&M COSTS $(000)	(9) OTHER COSTS $(000)	(10) TOTAL COSTS $(000)	(11) NET BENEFITS $(000)	(12) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
2012	3	0	589	0	592	0	0	0	0	592	592
2013	8	0	1,757	0	1,765	0	0	0	0	1,765	2,237
2014	14	0	2,915	0	2,929	0	0	0	0	2,929	4,781
2015	20	0	4,073	0	4,092	0	0	0	0	4,092	8,095
2016	25	0	5,230	0	5,256	0	0	0	0	5,256	12,061
2017	36	0	6,388	0	6,424	0	0	0	0	6,424	16,579
2018	52	0	7,546	0	7,598	0	0	0	0	7,598	21,559
2019	58	0	8,125	0	8,183	0	0	0	0	8,183	26,558
2020	61	0	8,125	0	8,186	0	0	0	0	8,186	31,219
2021	64	0	8,125	0	8,189	0	0	0	0	8,189	35,565
2022	67	0	8,125	0	8,192	0	0	0	0	8,192	39,617
2023	67	0	8,125	0	8,192	0	0	0	0	8,192	43,394
2024	70	0	8,125	0	8,196	0	0	0	0	8,196	46,915
2025	74	0	8,125	0	8,199	0	0	0	0	8,199	50,199
2026	76	0	8,125	0	8,201	0	0	0	0	8,201	53,260
2027	78	0	8,125	0	8,204	0	0	0	0	8,204	56,114
2028	80	0	8,125	0	8,205	0	0	0	0	8,205	58,774
2029	82	0	8,125	0	8,207	0	0	0	0	8,207	61,254
2030	85	0	8,125	0	8,210	0	0	0	0	8,210	63,567
2031	88	0	8,125	0	8,213	0	0	0	0	8,213	65,723
2032	92	0	8,125	0	8,217	0	0	0	0	8,217	67,753
2033	100	0	8,125	0	8,225	0	0	0	0	8,225	69,609
2034	104	0	8,125	0	8,229	0	0	0	0	8,229	71,357
2035	107	0	8,125	0	8,232	0	0	0	0	8,232	72,988
2036	114	0	8,125	0	8,239	0	0	0	0	8,239	74,509
2037	118	0	8,125	0	8,243	0	0	0	0	8,243	75,928
2038	122	0	8,125	0	8,247	0	0	0	0	8,247	77,250
2039	126	0	8,125	0	8,251	0	0	0	0	8,251	78,484
2040	130	0	8,125	0	8,255	0	0	0	0	8,255	79,634
2041	134	0	8,125	0	8,259	0	0	0	0	8,259	80,706
2042	139	0	8,125	0	8,264	0	0	0	0	8,264	81,706
2043	144	0	8,125	0	8,269	0	0	0	0	8,269	82,639
2044	150	0	8,125	0	8,275	0	0	0	0	8,275	83,509
2045	156	0	8,125	0	8,282	0	0	0	0	8,282	84,320
2046	163	0	8,125	0	8,288	0	0	0	0	8,288	85,077
2047	171	0	8,125	0	8,296	0	0	0	0	8,296	85,783
2048	178	0	8,125	0	8,303	0	0	0	0	8,303	86,442
NOM	3,357	0	272,251	0	275,608	0	0	0	0	275,608	
NPV	810	0	85,632	0	86,442	0	0	0	0	86,442	

In Service of Gen Unit: 2019
Discount Rate: 7.29 %
Benefit/Cost Ratio (Col(6) / Col(10)) Infinite

INPUT DATA – PART 1 CONTINUED
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: CILC 2012 Rate Filing

I. PROGRAM DEMAND SAVINGS & LINE LOSSES

(1) CUSTOMER kW REDUCTION AT METER	1.00	kW
(2) GENERATOR kW REDUCTION PER CUSTOMER	1.32515	kW
(3) kW LINE LOSS PERCENTAGE	7.94	%
(4) GENERATOR kWh REDUCTION PER CUSTOMER	8.11	kWh ****
(5) kWh LINE LOSS PERCENTAGE	6.24	%
(6) GROUP LINE LOSS MULTIPLIER	1.00	
(7) CUSTOMER kWh INCREASE AT METER	0.38	kWh ****

II. ECONOMIC LIFE & K FACTORS

(1) STUDY PERIOD FOR THE CONSERVATION PROGRAM	35	YEARS
(2) GENERATOR ECONOMIC LIFE	30	YEARS
(3) T&D ECONOMIC LIFE	35	YEARS
(4) K FACTOR FOR GENERATION	1.58554	
(5) K FACTOR FOR T & D	1.55564	

III. UTILITY & CUSTOMER COSTS

	(1) UTILITY NON RECURRING COST PER CUSTOMER	***	$/CUST
	(2) UTILITY RECURRING COST PER CUSTOMER	***	$/CUST
	(3) UTILITY COST ESCALATION RATE	***	%**
	(4) CUSTOMER EQUIPMENT COST	***	$/CUST
	(5) CUSTOMER EQUIPMENT ESCALATION RATE	***	%**
	(6) CUSTOMER O & M COST	***	$/CUST/YR
	(7) CUSTOMER O & M COST ESCALATION RATE	***	%**
*	(8) INCREASED SUPPLY COSTS	***	$/CUST/YR
*	(9) SUPPLY COSTS ESCALATION RATES	***	%**
*	(10) UTILITY DISCOUNT RATE	7.29	%
*	(11) UTILITY AFUDC RATE	6.69	%
*	(12) UTILITY NON RECURRING REBATE/INCENTIVE	***	$/CUST
*	(13) UTILITY RECURRING REBATE/INCENTIVE	***	$/CUST
*	(14) UTILITY REBATE/INCENTIVE ESCALATION RATE	***	%

IV. AVOIDED GENERATOR AND T&D COSTS

(1) BASE YEAR	2012	
(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	2017	
(3) IN-SERVICE YEAR FOR AVOIDED T&D	2015-2017	
(4) BASE YEAR AVOIDED GENERATING COST	731.98	$/kW
(5) BASE YEAR AVOIDED TRANSMISSION COST	0.00	$/kW
(6) BASE YEAR DISTRIBUTION COST	0.00	$/kW
(7) GEN, TRAN & DIST COST ESCALATION RATE	3.00	%**
(8) GENERATOR FIXED O & M COST	109.42	$/kW/YR
(9) GENERATOR FIXED O&M ESCALATION RATE	2.50	%**
(10) TRANSMISSION FIXED O & M COST	0.00	$/kW
(11) DISTRIBUTION FIXED O & M COST	0.00	$/kW
(12) T&D FIXED O&M ESCALATION RATE	2.50	%**
(13) AVOIDED GEN UNIT VARIABLE O & M COSTS	0.058	CENTS/kWh
(14) GENERATOR VARIABLE O&M COST ESCALATION RATE	2.50	%**
(15) GENERATOR CAPACITY FACTOR	55%	** (In-service year)
(16) AVOIDED GENERATING UNIT FUEL COST	4.03	CENTS PER kWh** (In-service year)
(17) AVOIDED GEN UNIT FUEL COST ESCALATION RATE	9.37	%**

V. NON-FUEL ENERGY AND DEMAND CHARGES

(1) NON FUEL COST IN CUSTOMER BILL	***	CENTS/kWh
(2) NON-FUEL COST ESCALATION RATE	***	%
(3) DEMAND CHARGE IN CUSTOMER BILL	***	$/kW/MO
(4) DEMAND CHARGE ESCALATION RATE	***	%

* SUPPLEMENTAL INFORMATION NOT SPECIFIED IN WORKBOOK
** VALUE SHOWN IS FOR FIRST YEAR ONLY (VALUE VARIES OVER TIME)
*** PROGRAM COST CALCULATION VALUES ARE SHOWN ON PAGE 2
**** THIS IS A LOAD SHIFTING PROGRAM. VALUE SHOWN IN ITEM (4) IS ANNUAL KWH/CUST SHIFTED AWAY FROM PEAK HRS. VALUE SHOWN IN ITEM (7) IS ANNUAL KWH/CUST THAT IS PAID BACK DURING OFF-PEAK.

Florida Power & Light Company
Docket No. 120015-EI
Staff's First Data Request
Request No. 1
Attachment No. 1
Page 10 of 16

RATE IMPACT TEST
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: CILC

2012 Rate Filing

(1) YEAR	(2) INCREASED SUPPLY COSTS $(000)	(3) UTILITY PROGRAM COSTS $(000)	(4) INCENTIVES $(000)	(5) REVENUE LOSSES $(000)	(6) OTHER COSTS $(000)	(7) TOTAL COSTS $(000)	(8) AVOIDED GEN UNIT & FUEL BENEFITS $(000)	(9) AVOIDED T&D BENEFITS $(000)	(10) REVENUE GAINS $(000)	(11) OTHER BENEFITS $(000)	(12) TOTAL BENEFITS $(000)	(13) NET BENEFITS $(000)	(14) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
2012	0	491	25,177	208	0	25,876	116	0	0	1	117	(25,759)	(25,759)
2013	0	503	25,197	247	0	25,948	215	0	0	3	218	(25,730)	(49,740)
2014	0	516	25,179	261	0	25,956	225	0	0	3	228	(25,728)	(72,089)
2015	0	529	25,197	265	0	25,991	220	0	0	2	222	(25,770)	(92,953)
2016	0	542	25,190	267	0	25,999	231	0	0	1	233	(25,767)	(112,396)
2017	0	556	25,190	302	0	26,047	132,280	0	0	(56)	132,224	106,177	(37,722)
2018	0	570	25,190	358	0	26,118	122,646	0	0	(78)	122,568	95,451	25,501
2019	0	584	25,190	374	0	26,147	116,304	0	0	(77)	116,226	90,079	80,534
2020	0	598	25,190	387	0	26,175	124,812	0	0	(59)	124,753	98,577	136,665
2021	0	613	25,190	408	0	26,211	114,110	0	0	(75)	114,035	87,824	188,273
2022	0	629	25,190	428	0	26,247	122,352	0	0	(57)	122,295	95,049	230,782
2023	0	644	25,190	438	0	26,272	128,352	0	0	(4,721)	123,631	97,359	275,665
2024	0	661	25,190	461	0	26,311	121,000	0	0	(5,374)	115,626	89,315	314,042
2025	0	677	25,190	480	0	26,347	122,803	0	0	(6,150)	116,653	90,306	350,207
2026	0	694	25,190	490	0	26,374	124,766	0	0	(7,025)	117,741	91,367	384,309
2027	0	711	25,190	505	0	26,406	119,560	0	0	(8,153)	111,407	85,001	413,879
2028	0	729	25,190	515	0	26,434	122,257	0	0	(9,307)	112,950	86,516	441,930
2029	0	747	25,190	527	0	26,464	126,577	0	0	(10,670)	115,907	89,443	468,959
2030	0	766	25,190	544	0	26,499	126,498	0	0	(12,207)	114,291	87,791	493,685
2031	0	785	25,190	559	0	26,533	130,592	0	0	(13,777)	116,815	90,282	517,385
2032	0	805	25,190	582	0	26,577	140,286	0	0	(15,591)	124,695	98,118	541,390
2033	0	825	25,190	625	0	26,640	134,934	0	0	(17,710)	117,224	90,585	562,046
2034	0	845	25,190	650	0	26,686	140,591	0	0	(19,893)	120,698	94,012	582,027
2035	0	867	25,190	664	0	26,721	142,222	0	0	(22,239)	119,983	93,263	600,501
2036	0	888	25,190	708	0	26,786	143,996	0	0	(24,855)	119,141	92,356	617,552
2037	0	911	25,190	730	0	26,831	148,892	0	0	(27,618)	121,274	94,444	633,803
2038	0	933	25,190	749	0	26,872	150,370	0	0	(30,626)	119,744	92,872	648,697
2039	0	957	25,190	774	0	26,920	154,307	0	0	(33,864)	120,443	93,523	662,676
2040	0	981	25,190	796	0	26,966	156,931	0	0	(37,335)	119,596	92,631	675,581
2041	0	1,005	25,190	820	0	27,015	157,810	0	0	(41,106)	116,705	89,690	687,226
2042	0	1,030	25,190	846	0	27,065	156,518	0	0	(45,194)	111,324	84,259	697,423
2043	0	1,056	25,190	872	0	27,117	161,651	0	0	(49,526)	112,126	85,008	707,011
2044	0	1,082	25,190	907	0	27,179	165,569	0	0	(54,172)	111,397	84,218	715,865
2045	0	1,109	25,190	945	0	27,244	164,986	0	0	(59,152)	105,834	78,591	723,565
2046	0	1,137	25,190	984	0	27,310	169,969	0	0	(64,477)	105,492	78,182	730,705
NOM.	0	26,976	881,629	19,677	0	926,283	4,144,948	0	0	(621,132)	3,523,816	2,595,533	
NPV	0	8,773	339,031	5,726	0	353,530	1,184,941	0	0	(100,706)	1,084,235	730,705	

Discount Rate 7.29 %

Benefit/Cost Ratio (Col(12) / Col(7)) : 3.07

Florida Power & Light Company
Docket No. 120015-EI
Staff's First Data Request
Request No. 1
Attachment No. 1
Page 11 of 16

TOTAL RESOURCE COST TEST
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: CILC

2012 Rate Filing

(1) YEAR	(2) INCREASED SUPPLY COSTS $(000)	(3) UTILITY PROGRAM COSTS $(000)	(4) PARTICIPANT PROGRAM COSTS $(000)	(5) OTHER COSTS $(000)	(6) TOTAL COSTS $(000)	(7) AVOIDED GEN UNIT BENEFITS $(000)	(8) AVOIDED T&D BENEFITS $(000)	(9) PROGRAM FUEL SAVINGS $(000)	(10) OTHER BENEFITS $(000)	(11) TOTAL BENEFITS $(000)	(12) NET BENEFITS $(000)	(13) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
2012	0	491	0	0	491	0	0	116	1	117	(374)	(374)
2013	0	503	0	0	503	0	0	215	3	218	(285)	(640)
2014	0	516	0	0	516	0	0	225	3	228	(288)	(890)
2015	0	529	0	0	529	0	0	220	2	222	(307)	(1,139)
2016	0	542	0	0	542	0	0	231	1	233	(309)	(1,373)
2017	0	556	0	0	556	132,001	0	278	(56)	132,224	131,668	91,230
2018	0	570	0	0	570	122,335	0	311	(78)	122,568	121,999	171,199
2019	0	584	0	0	584	115,928	0	375	(77)	116,226	115,642	241,850
2020	0	598	0	0	598	124,478	0	333	(59)	124,753	124,154	312,545
2021	0	613	0	0	613	113,711	0	399	(75)	114,035	113,421	372,738
2022	0	629	0	0	629	121,958	0	394	(57)	122,295	121,666	432,918
2023	0	644	0	0	644	127,963	0	389	(4,721)	123,631	122,986	489,616
2024	0	661	0	0	661	120,556	0	443	(5,374)	115,626	114,965	539,014
2025	0	677	0	0	677	122,355	0	448	(6,150)	116,653	115,976	585,459
2026	0	694	0	0	694	124,294	0	472	(7,025)	117,741	117,047	629,146
2027	0	711	0	0	711	119,083	0	477	(8,153)	111,407	110,695	667,655
2028	0	729	0	0	729	121,778	0	479	(9,307)	112,950	112,221	704,040
2029	0	747	0	0	747	126,088	0	489	(10,670)	115,907	115,159	738,840
2030	0	766	0	0	766	126,003	0	495	(12,207)	114,291	113,525	770,814
2031	0	785	0	0	785	130,090	0	502	(13,777)	116,815	116,030	801,273
2032	0	805	0	0	805	139,810	0	477	(15,591)	124,695	123,890	831,584
2033	0	825	0	0	825	134,431	0	503	(17,710)	117,224	116,400	858,127
2034	0	845	0	0	845	140,108	0	483	(19,893)	120,698	119,852	883,599
2035	0	867	0	0	867	141,730	0	492	(22,239)	119,983	119,117	907,194
2036	0	888	0	0	888	143,501	0	495	(24,855)	119,141	118,253	929,026
2037	0	911	0	0	911	148,407	0	485	(27,618)	121,274	120,364	949,737
2038	0	933	0	0	933	149,882	0	488	(30,626)	119,744	118,811	968,791
2039	0	957	0	0	957	153,792	0	515	(33,864)	120,443	119,487	986,651
2040	0	981	0	0	981	156,451	0	480	(37,335)	119,596	118,616	1,003,176
2041	0	1,005	0	0	1,005	157,304	0	506	(41,106)	116,705	115,700	1,018,199
2042	0	1,030	0	0	1,030	156,002	0	516	(45,194)	111,324	110,294	1,031,546
2043	0	1,056	0	0	1,056	161,169	0	483	(49,526)	112,126	111,070	1,044,074
2044	0	1,082	0	0	1,082	165,090	0	479	(54,172)	111,397	110,315	1,055,671
2045	0	1,109	0	0	1,109	164,480	0	506	(59,152)	105,834	104,725	1,065,932
2046	0	1,137	0	0	1,137	169,470	0	500	(64,477)	105,492	104,355	1,075,461
NOM	0	26,976	0	0	26,976	4,130,249	0	14,699	(621,132)	3,523,816	3,496,840	
NPV	0	3,773	0	0	3,773	1,180,229	0	4,712	(100,706)	1,084,235	1,075,461	

Discount Rate: 7.29 %

Benefit/Cost Ratio (Col(11) / Col(6)) : 123.59

PARTICIPANT COSTS AND BENEFITS
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: CILC

2012 Rate Filing

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
YEAR	SAVINGS IN PARTICIPANTS BILLS $(000)	TAX CREDITS $(000)	UTILITY REBATES $(000)	OTHER BENEFITS $(000)	TOTAL BENEFITS $(000)	CUSTOMER EQUIPMENT COSTS $(000)	CUSTOMER O&M COSTS $(000)	OTHER COSTS $(000)	TOTAL COSTS $(000)	NET BENEFITS $(000)	CUMULATIVE DISCOUNTED NET BENEFITS $(000)
2012	251	0	25,177	0	25,427	0	0	0	0	25,427	25,427
2013	298	0	25,197	0	25,495	0	0	0	0	25,495	49,190
2014	314	0	25,179	0	25,493	0	0	0	0	25,493	71,335
2015	320	0	25,197	0	25,517	0	0	0	0	25,517	91,994
2016	322	0	25,190	0	25,512	0	0	0	0	25,512	111,245
2017	364	0	25,190	0	25,553	0	0	0	0	25,553	129,217
2018	432	0	25,190	0	25,622	0	0	0	0	25,622	146,012
2019	450	0	25,190	0	25,640	0	0	0	0	25,640	161,676
2020	467	0	25,190	0	25,656	0	0	0	0	25,656	176,285
2021	491	0	25,190	0	25,681	0	0	0	0	25,681	189,914
2022	516	0	25,190	0	25,706	0	0	0	0	25,706	202,629
2023	528	0	25,190	0	25,717	0	0	0	0	25,717	214,485
2024	555	0	25,190	0	25,744	0	0	0	0	25,744	225,547
2025	578	0	25,190	0	25,768	0	0	0	0	25,768	235,866
2026	591	0	25,190	0	25,781	0	0	0	0	25,781	245,489
2027	608	0	25,190	0	25,798	0	0	0	0	25,798	254,463
2028	621	0	25,190	0	25,810	0	0	0	0	25,810	262,832
2029	635	0	25,190	0	25,824	0	0	0	0	25,824	270,636
2030	655	0	25,190	0	25,845	0	0	0	0	25,845	277,915
2031	673	0	25,190	0	25,863	0	0	0	0	25,863	284,704
2032	702	0	25,190	0	25,891	0	0	0	0	25,891	291,038
2033	753	0	25,190	0	25,943	0	0	0	0	25,943	296,954
2034	784	0	25,190	0	25,973	0	0	0	0	25,973	302,474
2035	801	0	25,190	0	25,990	0	0	0	0	25,990	307,623
2036	853	0	25,190	0	26,042	0	0	0	0	26,042	312,431
2037	880	0	25,190	0	26,070	0	0	0	0	26,070	316,916
2038	902	0	25,190	0	26,092	0	0	0	0	26,092	321,101
2039	933	0	25,190	0	26,122	0	0	0	0	26,122	325,005
2040	959	0	25,190	0	26,148	0	0	0	0	26,148	328,648
2041	988	0	25,190	0	26,178	0	0	0	0	26,178	332,047
2042	1,019	0	25,190	0	26,208	0	0	0	0	26,208	335,219
2043	1,050	0	25,190	0	26,240	0	0	0	0	26,240	338,179
2044	1,093	0	25,190	0	26,283	0	0	0	0	26,283	340,942
2045	1,138	0	25,190	0	26,328	0	0	0	0	26,328	343,521
2046	1,185	0	25,190	0	26,375	0	0	0	0	26,375	345,930
NOM	23,707	0	881,629	0	905,337	0	0	0	0	905,337	
NPV	6,899	0	339,031	0	345,930	0	0	0	0	345,930	

In Service of Gen Unit: 2017
Discount Rate: 7.29
Benefit/Cost Ratio (Col(6) / Col(10)): Infinite

Florida Power & Light Company
Docket No. 120015-EI
Staff's First Data Request
Request No. 1
Attachment No. 1

INPUT DATA -- PART 1 CONTINUED
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: CILC

Proposed Settlement

I. PROGRAM DEMAND SAVINGS & LINE LOSSES

(1) CUSTOMER kW REDUCTION AT METER	1.00	kW
(2) GENERATOR kW REDUCTION PER CUSTOMER	1.32515	kW
(3) kW LINE LOSS PERCENTAGE	7.94	%
(4) GENERATOR kWh REDUCTION PER CUSTOMER	8.11	kWh ****
(5) kWh LINE LOSS PERCENTAGE	6.24	%
(6) GROUP LINE LOSS MULTIPLIER	1.00	
(7) CUSTOMER kWh INCREASE AT METER	0.35	kWh ****

II. ECONOMIC LIFE & K FACTORS

(1) STUDY PERIOD FOR THE CONSERVATION PROGRAM	35	YEARS
(2) GENERATOR ECONOMIC LIFE	30	YEARS
(3) T&D ECONOMIC LIFE	35	YEARS
(4) K FACTOR FOR GENERATION	1.58554	
(5) K FACTOR FOR T & D	1.55564	

III. UTILITY & CUSTOMER COSTS

	(1) UTILITY NON RECURRING COST PER CUSTOMER	***	$/CUST
	(2) UTILITY RECURRING COST PER CUSTOMER	***	$/CUST
	(3) UTILITY COST ESCALATION RATE	***	%**
	(4) CUSTOMER EQUIPMENT COST	***	$/CUST
	(5) CUSTOMER EQUIPMENT ESCALATION RATE	***	%**
	(6) CUSTOMER O & M COST	***	$/CUST/YR
	(7) CUSTOMER O & M COST ESCALATION RATE	***	%**
*	(8) INCREASED SUPPLY COSTS	***	$/CUST/YR
*	(9) SUPPLY COSTS ESCALATION RATES	***	%**
*	(10) UTILITY DISCOUNT RATE	7.29	%
*	(11) UTILITY AFUDC RATE	6.69	%
*	(12) UTILITY NON RECURRING REBATE/INCENTIVE	***	$/CUST
*	(13) UTILITY RECURRING REBATE/INCENTIVE	***	$/CUST
*	(14) UTILITY REBATE/INCENTIVE ESCALATION RATE	***	%

IV. AVOIDED GENERATOR AND T&D COSTS

(1) BASE YEAR	2012	
(2) IN-SERVICE YEAR FOR AVOIDED GENERATING UNIT	2017	
(3) IN-SERVICE YEAR FOR AVOIDED T&D	2015-2017	
(4) BASE YEAR AVOIDED GENERATING COST	731.98	$/kW
(5) BASE YEAR AVOIDED TRANSMISSION COST	0.00	$/kW
(6) BASE YEAR DISTRIBUTION COST	0.00	$/kW
(7) GEN, TRAN & DIST COST ESCALATION RATE	3.00	%**
(8) GENERATOR FIXED O & M COST	109.42	$/kW/YR
(9) GENERATOR FIXED O&M ESCALATION RATE	2.50	%**
(10) TRANSMISSION FIXED O & M COST	0.00	$/kW
(11) DISTRIBUTION FIXED O & M COST	0.00	$/kW
(12) T&D FIXED O&M ESCALATION RATE	2.50	%**
(13) AVOIDED GEN UNIT VARIABLE O & M COSTS	0.058	CENTS/kWh
(14) GENERATOR VARIABLE O&M COST ESCALATION RATE	2.50	%**
(15) GENERATOR CAPACITY FACTOR	55%	** (In-service year)
(16) AVOIDED GENERATING UNIT FUEL COST	4.08	CENTS PER kWh** (In-service year)
(17) AVOIDED GEN UNIT FUEL COST ESCALATION RATE	9.37	%**

V. NON-FUEL ENERGY AND DEMAND CHARGES

(1) NON FUEL COST IN CUSTOMER BILL	***	CENTS/kWh
(2) NON-FUEL COST ESCALATION RATE	***	%
(3) DEMAND CHARGE IN CUSTOMER BILL	***	$/kW/MO
(4) DEMAND CHARGE ESCALATION RATE	***	%

* SUPPLEMENTAL INFORMATION NOT SPECIFIED IN WORKBOOK
** VALUE SHOWN IS FOR FIRST YEAR ONLY (VALUE VARIES OVER TIME)
*** PROGRAM COST CALCULATION VALUES ARE SHOWN ON PAGE 2
**** THIS IS A LOAD SHIFTING PROGRAM. VALUE SHOWN IN ITEM (4) IS ANNUAL KWH/CUST SHIFTED AWAY FROM PEAK HRS. VALUE SHOWN IN ITEM (7) IS ANNUAL KWH/CUST THAT IS PAID BACK DURING OFF-PEAK.

Florida Power & Light Company
Docket No. 120015-EI
Staff's First Data Request
Request No. 1
Attachment No. 1

RATE IMPACT TEST
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: CILC Proposed Settlement

(1) YEAR	(2) INCREASED SUPPLY COSTS $(000)	(3) UTILITY PROGRAM COSTS $(000)	(4) INCENTIVES $(000)	(5) REVENUE LOSSES $(000)	(6) OTHER COSTS $(000)	(7) TOTAL COSTS $(000)	(8) AVOIDED GEN UNIT & FUEL BENEFITS $(000)	(9) AVOIDED T&D BENEFITS $(000)	(10) REVENUE GAINS $(000)	(11) OTHER BENEFITS $(000)	(12) TOTAL BENEFITS $(000)	(13) NET BENEFITS $(000)	(14) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
2012	0	491	39,288	208	0	39,987	116	0	0	1	117	(39,870)	(39,870)
2013	0	503	39,308	247	0	40,059	215	0	0	3	218	(39,841)	(77,003)
2014	0	516	39,290	261	0	40,067	225	0	0	3	228	(39,839)	(111,610)
2015	0	529	39,308	265	0	40,102	220	0	0	2	222	(39,881)	(143,898)
2016	0	542	39,301	267	0	40,110	231	0	0	1	233	(39,878)	(173,590)
2017	0	556	39,301	302	0	40,158	132,280	0	0	(56)	132,224	92,066	(109,240)
2018	0	570	39,301	358	0	40,229	122,646	0	0	(78)	122,568	82,340	(55,266)
2019	0	584	39,301	374	0	40,258	116,304	0	0	(77)	116,226	75,968	(8,855)
2020	0	598	39,301	387	0	40,286	124,812	0	0	(59)	124,753	84,466	39,241
2021	0	613	39,301	408	0	40,322	114,110	0	0	(75)	114,035	73,713	78,361
2022	0	629	39,301	428	0	40,358	122,352	0	0	(57)	122,295	81,938	116,890
2023	0	644	39,301	438	0	40,383	128,352	0	0	(4,721)	123,631	83,248	157,268
2024	0	661	39,301	461	0	40,422	121,000	0	0	(5,374)	115,626	75,204	189,582
2025	0	677	39,301	480	0	40,458	122,803	0	0	(6,150)	116,653	76,195	220,095
2026	0	694	39,301	490	0	40,485	124,766	0	0	(7,025)	117,741	77,256	248,931
2027	0	711	39,301	505	0	40,517	119,560	0	0	(8,153)	111,407	70,890	273,592
2028	0	729	39,301	515	0	40,545	122,257	0	0	(9,307)	112,950	72,405	297,068
2029	0	747	39,301	527	0	40,575	126,577	0	0	(10,670)	115,907	75,332	319,832
2030	0	766	39,301	544	0	40,610	126,498	0	0	(12,207)	114,291	73,680	340,584
2031	0	785	39,301	559	0	40,644	130,592	0	0	(13,777)	116,815	76,171	360,580
2032	0	805	39,301	582	0	40,688	140,286	0	0	(15,591)	124,695	84,007	381,133
2033	0	825	39,301	625	0	40,751	134,934	0	0	(17,710)	117,224	76,474	398,571
2034	0	845	39,301	650	0	40,797	140,591	0	0	(19,893)	120,698	79,901	415,553
2035	0	867	39,301	664	0	40,832	142,222	0	0	(22,239)	119,983	79,152	431,231
2036	0	888	39,301	708	0	40,897	143,996	0	0	(24,855)	119,141	78,245	445,677
2037	0	911	39,301	730	0	40,942	148,892	0	0	(27,618)	121,274	80,333	459,500
2038	0	933	39,301	749	0	40,983	150,370	0	0	(30,626)	119,744	78,761	472,131
2039	0	957	39,301	774	0	41,031	154,307	0	0	(33,864)	120,443	79,412	484,001
2040	0	981	39,301	796	0	41,077	156,931	0	0	(37,335)	119,596	78,520	494,940
2041	0	1,005	39,301	820	0	41,126	157,810	0	0	(41,106)	116,705	75,579	504,753
2042	0	1,030	39,301	846	0	41,176	156,518	0	0	(45,194)	111,324	70,148	513,243
2043	0	1,056	39,301	872	0	41,228	161,651	0	0	(49,526)	112,126	70,897	521,239
2044	0	1,082	39,301	907	0	41,290	165,569	0	0	(54,172)	111,397	70,107	528,609
2045	0	1,109	39,301	945	0	41,355	164,986	0	0	(59,152)	105,834	64,480	534,927
2046	0	1,137	39,301	984	0	41,421	169,969	0	0	(64,477)	105,492	64,071	540,778

NOM.	0	26,976	1,375,514	19,677	0	1,422,168	4,144,948	0	0	(621,132)	3,523,816	2,101,648
NPV	0	8,773	528,958	5,726	0	543,457	1,184,941	0	0	(100,706)	1,084,235	540,778

Discount Rate 7.29 %
Benefit/Cost Ratio (Col(12) / Col(7)) : 2.00

Florida Power & Light Company
Docket No. 120015-EI
Staff's First Data Request
Request No. 1
Attachment No. 1

TOTAL RESOURCE COST TEST
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: CILC

Proposed Settlement

(1) YEAR	(2) INCREASED SUPPLY COSTS $(000)	(3) UTILITY PROGRAM COSTS $(000)	(4) PARTICIPANT PROGRAM COSTS $(000)	(5) OTHER COSTS $(000)	(6) TOTAL COSTS $(000)	(7) AVOIDED GEN UNIT BENEFITS $(000)	(8) AVOIDED T&D BENEFITS $(000)	(9) PROGRAM FUEL SAVINGS $(000)	(10) OTHER BENEFITS $(000)	(11) TOTAL BENEFITS $(000)	(12) NET BENEFITS $(000)	(13) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
2012	0	491	0	0	491	0	0	116	1	117	(374)	(374)
2013	0	503	0	0	503	0	0	215	3	218	(285)	(640)
2014	0	516	0	0	516	0	0	225	3	228	(288)	(890)
2015	0	529	0	0	529	0	0	220	2	222	(307)	(1,139)
2016	0	542	0	0	542	0	0	231	1	233	(309)	(1,373)
2017	0	556	0	0	556	132,001	0	278	(56)	132,224	131,668	91,230
2018	0	570	0	0	570	122,335	0	311	(78)	122,568	121,999	171,199
2019	0	584	0	0	584	115,928	0	375	(77)	116,226	115,642	241,850
2020	0	598	0	0	598	124,478	0	333	(59)	124,753	124,154	312,545
2021	0	613	0	0	613	113,711	0	399	(75)	114,035	113,421	372,738
2022	0	629	0	0	629	121,958	0	394	(57)	122,295	121,666	432,918
2023	0	644	0	0	644	127,963	0	389	(4,721)	123,631	122,986	489,616
2024	0	661	0	0	661	120,556	0	443	(5,374)	115,626	114,965	539,014
2025	0	677	0	0	677	122,355	0	448	(6,150)	116,653	115,976	585,459
2026	0	694	0	0	694	124,294	0	472	(7,025)	117,741	117,047	629,146
2027	0	711	0	0	711	119,083	0	477	(8,153)	111,407	110,695	667,655
2028	0	729	0	0	729	121,778	0	479	(9,307)	112,950	112,221	704,040
2029	0	747	0	0	747	126,088	0	489	(10,670)	115,907	115,159	738,840
2030	0	766	0	0	766	126,003	0	495	(12,207)	114,291	113,525	770,814
2031	0	785	0	0	785	130,090	0	502	(13,777)	116,815	116,030	801,273
2032	0	805	0	0	805	139,810	0	477	(15,591)	124,695	123,890	831,584
2033	0	825	0	0	825	134,431	0	503	(17,710)	117,224	116,400	858,127
2034	0	845	0	0	845	140,108	0	483	(19,893)	120,698	119,852	883,599
2035	0	867	0	0	867	141,730	0	492	(22,239)	119,983	119,117	907,194
2036	0	888	0	0	888	143,501	0	495	(24,855)	119,141	118,253	929,026
2037	0	911	0	0	911	148,407	0	485	(27,618)	121,274	120,364	949,737
2038	0	933	0	0	933	149,882	0	488	(30,626)	119,744	118,811	968,791
2039	0	957	0	0	957	153,792	0	515	(33,864)	120,443	119,487	986,651
2040	0	981	0	0	981	156,451	0	480	(37,335)	119,596	118,616	1,003,176
2041	0	1,005	0	0	1,005	157,304	0	506	(41,106)	116,705	115,700	1,018,199
2042	0	1,030	0	0	1,030	156,002	0	516	(45,194)	111,324	110,294	1,031,546
2043	0	1,056	0	0	1,056	161,169	0	483	(49,526)	112,126	111,070	1,044,074
2044	0	1,082	0	0	1,082	165,090	0	479	(54,172)	111,397	110,315	1,055,671
2045	0	1,109	0	0	1,109	164,480	0	506	(59,152)	105,834	104,725	1,065,932
2046	0	1,137	0	0	1,137	169,470	0	500	(64,477)	105,492	104,355	1,075,461
NOM	0	26,976	0	0	26,976	4,130,249	0	14,699	(621,132)	3,523,816	3,496,840	
NPV	0	8,773	0	0	8,773	1,180,229	0	4,712	(100,706)	1,084,235	1,075,461	

Discount Rate: 7.29 %
Benefit/Cost Ratio (Col(11) / Col(6)) : 123.59

PARTICIPANT COSTS AND BENEFITS
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: CILC

Proposed Settlement

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
YEAR	SAVINGS IN PARTICIPANTS BILLS $(000)	TAX CREDITS $(000)	UTILITY REBATES $(000)	OTHER BENEFITS $(000)	TOTAL BENEFITS $(000)	CUSTOMER EQUIPMENT COSTS $(000)	CUSTOMER O&M COSTS $(000)	OTHER COSTS $(000)	TOTAL COSTS $(000)	NET BENEFITS $(000)	CUMULATIVE DISCOUNTED NET BENEFITS $(000)
2012	251	0	39,288	0	39,538	0	0	0	0	39,538	39,538
2013	298	0	39,308	0	39,606	0	0	0	0	39,606	76,453
2014	314	0	39,290	0	39,604	0	0	0	0	39,604	110,856
2015	320	0	39,308	0	39,628	0	0	0	0	39,628	142,939
2016	322	0	39,301	0	39,623	0	0	0	0	39,623	172,839
2017	364	0	39,301	0	39,664	0	0	0	0	39,664	200,735
2018	432	0	39,301	0	39,733	0	0	0	0	39,733	226,779
2019	450	0	39,301	0	39,751	0	0	0	0	39,751	251,065
2020	467	0	39,301	0	39,767	0	0	0	0	39,767	273,709
2021	491	0	39,301	0	39,792	0	0	0	0	39,792	294,827
2022	516	0	39,301	0	39,817	0	0	0	0	39,817	314,521
2023	528	0	39,301	0	39,828	0	0	0	0	39,828	332,882
2024	555	0	39,301	0	39,855	0	0	0	0	39,855	350,007
2025	578	0	39,301	0	39,879	0	0	0	0	39,879	365,978
2026	591	0	39,301	0	39,892	0	0	0	0	39,892	380,867
2027	608	0	39,301	0	39,909	0	0	0	0	39,909	394,750
2028	621	0	39,301	0	39,921	0	0	0	0	39,921	407,694
2029	635	0	39,301	0	39,935	0	0	0	0	39,935	419,762
2030	655	0	39,301	0	39,956	0	0	0	0	39,956	431,016
2031	673	0	39,301	0	39,974	0	0	0	0	39,974	441,509
2032	702	0	39,301	0	40,002	0	0	0	0	40,002	451,296
2033	753	0	39,301	0	40,054	0	0	0	0	40,054	460,430
2034	784	0	39,301	0	40,084	0	0	0	0	40,084	468,949
2035	801	0	39,301	0	40,101	0	0	0	0	40,101	476,892
2036	853	0	39,301	0	40,153	0	0	0	0	40,153	484,305
2037	880	0	39,301	0	40,181	0	0	0	0	40,181	491,219
2038	902	0	39,301	0	40,203	0	0	0	0	40,203	497,667
2039	933	0	39,301	0	40,233	0	0	0	0	40,233	503,680
2040	959	0	39,301	0	40,259	0	0	0	0	40,259	509,289
2041	988	0	39,301	0	40,289	0	0	0	0	40,289	514,520
2042	1,019	0	39,301	0	40,319	0	0	0	0	40,319	519,400
2043	1,050	0	39,301	0	40,351	0	0	0	0	40,351	523,951
2044	1,093	0	39,301	0	40,394	0	0	0	0	40,394	528,197
2045	1,138	0	39,301	0	40,439	0	0	0	0	40,439	532,159
2046	1,185	0	39,301	0	40,486	0	0	0	0	40,486	535,857
NOM	23,707	0	1,375,514	0	1,399,222	0	0	0	0	1,399,222	
NPV	6,899	0	528,958	0	535,857	0	0	0	0	535,857	

In Service of Gen Unit:	2017
Discount Rate :	7.29
Benefit/Cost Ratio (Col(6) / Col(10))	Infinite

MFR E-14 Workpapers
Rate Class OS-2

Line No.	(1) Type of Charges	(2) Present Revenue Calculation Units		(3) Charge/Unit		(4) $ Revenue	(5)	(6) Proposed Revenue Calculation Units		(7) Charge/Unit		(8) $ Revenue	(9) Percent Increase
1	RATE SCHEDULE OS-2 - 19												
2													
3	Customer	2,229	$	97.28	$	216,837		2,229	$	103.00	$	229,587	
4	Non-Fuel Energy	12,578,957	$	0.0506	$	636,873		12,578,957	$	0.0593	$	745,681	
5													
6	**Total**				**$**	**853,710**					**$**	**975,268**	14.2%
7													
8										Increase	$	121,558	
9										Target	$	121,558	
10											$	(0)	

MFR E-14 Workpapers
Rate Class OL-1

Line No.	(1) Type of Charges	(2) Present Revenue Calculation Units	Charge/Unit	$ Revenue	(3) Proposed Revenue Calculation Units	Charge/Unit	$ Revenue	(4) Percent Increase
1	**RATE SCHEDULE OL-1 - 11**							
2								
3								
4	Total Revenue			$ 11,486,837			$ 12,703,331	10.6%
5								
6						Increase	$ 1,216,493	
7						Target	$ 1,216,486	
8							$ 8	

MFR E-14 Workpapers
Rate Class RS(T)-1

Line No.	(1) Type of Charges	(2) Units	(3) Charge/Unit	(4) $ Revenue	(5)	(6) Units	(7) Charge/Unit	(8) $ Revenue	(9) Percent Increase
		Present Revenue Calculation				Proposed Revenue Calculation			
1	RATE SCHEDULE RS-1 - 44								
2									
3	Customer	48,976,539	$ 5.90	$ 288,961,580		48,976,539	$ 7.00	$ 342,835,773	
4	Non-Fuel Energy								
5	First 1,000 kWh	35,409,639,810	$ 0.03736	$ 1,322,904,143		35,409,639,810	$ 0.04036	$ 1,429,133,063	
6	All additional kWh	17,608,833,160	$ 0.04736	$ 833,954,338		17,608,833,160	$ 0.05036	$ 886,780,838	
7	Total kWh	53,018,472,970				53,018,472,970			
8	Total			$ 2,445,820,062				$ 2,658,749,674	8.7%
9									
10	RATE SCHEDULE RST-1 - 45								
11									
12	Customer	1,956	$ 16.04	$ 31,374		1,956	$ 11.00	$ 21,516	
13	Non-Fuel Energy								
14	On Peak	1,104,823	$ 0.07930	$ 87,612		1,104,823	$ 0.12759	$ 140,964	
15	Off Peak	3,589,106	$ 0.02650	$ 95,111		3,589,106	$ 0.00712	$ 25,554	
16	Total	4,693,929		$ 214,098				$ 188,035	-12.2%
17									
18	RATE SCHEDULE RTR-1 - 48								
19									
20									
21	Customer	-		$ -			$ 11.00	$ -	
22	Non-Fuel Energy								
23	On Peak	-		$ -					
24	Off Peak	-		$ -					
25	Non-Fuel Energy								
26	First 1,000 kWh	-	$ -	$ -			$ 0.04036	$ -	
27	All additional kWh	-	$ -	$ -			$ 0.05036	$ -	
28	Total kWh								
29	Non-Fuel Energy Charges / Credits								
30	On Peak						$ 0.08391	$ -	
31	Off Peak						$ (0.03656)	$ -	
32	Total			$ -				$ -	
33									
34	TOTALS			$ 2,446,034,160				$ 2,658,937,708	
35									
36							Increase	$ 212,903,549	
37							Target Revenues	212,937,346	
38	RST/RTR revenue neutral calculation						Difference	$ (33,797)	
39	On peak class average	30.35%						0.003	
40	on-peak	1,424,558	$ 181,759						
41	off-peak	3,269,371	$ 23,278						
42	RST/RTR revenue	4,693,929	$ 205,037						
43	RS1 Average rate	0.04368							
44	Target Revenue	$ 205,031	$ (6)						
45	Adjustment		0.04829						

MFR E-14 Workpapers
Rate Class CIILC-1D

Line No.	(1) Type of Charges	(2) Present Revenue Calculation Units	(3) Charge/Unit	(4) $ Revenue	(5)	(6) Proposed Revenue Calculation Units	(7) Charge/Unit	(8) $ Revenue	(9) Percent Increase
1	RATE SCHEDULE CILC-1D - 54								
2									
3	Customer	3,972	$ 175.00	$ 695,100		3,972	$ 150.00	$ 595,800	
4	Non-Fuel Energy								
5	On Peak	754,148,919	$ 0.00646	$ 4,871,802		754,148,919	$ 0.00542	$ 4,083,716	
6	Off Peak	2,107,793,706	$ 0.00646	$ 13,616,347		2,107,793,706	$ 0.00542	$ 11,413,703	
7	Demand								
8	Max Demand	6,864,611	$ 3.17	$ 21,760,817		6,864,611	$ 3.10	$ 21,280,294	
9	Load Control On-Peak	4,807,458	$ 1.35	$ 6,490,068		4,807,458	$ 1.30	$ 6,249,695	
10	Firm On-Peak	805,340	$ 7.12	$ 5,734,021		805,340	$ 7.11	$ 5,725,967	
11	Transformation Credit	1,922,442	$ (0.24)	$ (461,386)		1,922,442	$ (0.28)	$ (538,284)	
12									
13	TOTAL			$ 52,706,769				$ 48,810,892	-7.4%
14									
15							Increase	$ (3,895,877)	
16							Target revenues	(3,895,877)	
17							Difference	-	

MFR E-14 Workpapers
Rate Class CILC-1T

Line No.	(1) Type of Charges	(2) Units		(3) Charge/Unit		(4) $ Revenue	(5)	(6) Units		(7) Charge/Unit		(8) $ Revenue	(9) Percent Increase
		Present Revenue Calculation						Proposed Revenue Calculation					
1	RATE SCHEDULE CILC-1T - 55												
2													
3	Customer	216	$	1,866.00	$	403,056		216	$	1,975.00	$	426,600	
4	Non-Fuel Energy												
5	On Peak	334,274,651	$	0.00599	$	2,002,305		334,274,651	$	0.00471	$	1,574,434	
6	Off Peak	1,007,203,091	$	0.00599	$	6,033,147		1,007,203,091	$	0.00471	$	4,743,927	
7	Demand												
8	Max Demand	512,384	$	-	$	-		512,384	$	-	$	-	
9	Load Control On-Peak	1,880,654	$	1.29	$	2,426,044		1,880,654	$	1.30	$	2,444,850	
10	Firm On-Peak	512,384	$	6.79	$	3,479,087		512,384	$	7.25	$	3,714,784	
11	Total				$	14,343,639					$	12,904,594	-10.0%
12													
13	TOTAL				$	14,343,639					$	12,904,594	
14													
15										Increase	$	(1,439,044)	
16										Target Revenues	$	(1,439,044)	
17										Difference	$	-	

MFR E-14 Workpaper
Rate Class CILC-1G

Line No.	(1) Type of Charges	(2) Present Revenue Calculation Units		(3) Charge/Unit		(4) $ Revenue	(5)	(6) Proposed Revenue Calculation Units		(7) Charge/Unit		(8) $ Revenue	(9) Percent Increase
1	RATE SCHEDULE CILC-1G - 56												
2													
3	Customer	1,248	$	122.00	$	152,256		1,248	$	100.00	$	124,800	
4	Non-Fuel Energy												
5	On Peak	47,350,221	$	0.01175	$	556,365		47,350,221	$	0.01074	$	508,541	
6	Off Peak	130,266,148	$	0.01175	$	1,530,627		130,266,148	$	0.01074	$	1,399,058	
7	Demand												
8	Max Demand	458,889	$	3.20	$	1,468,445		458,889	$	3.40	$	1,560,223	
9	Load Control On-Peak	344,050	$	1.32	$	454,146		344,050	$	1.30	$	447,265	
10	Firm On-Peak	7,514	$	6.92	$	51,997		7,514	$	7.31	$	54,927	
11	Transformation Credit	4,305	$	(0.24)	$	(1,033)		4,305	$	(0.27)	$	(1,162)	
12	Total				$	4,212,803					$	4,093,652	-2.8%
13													
14	**TOTAL**				$	**4,212,803**					$	**4,093,652**	
15													
16										Increase	$	(119,150)	
17										Target Revenues	$	(119,193)	
18										Difference	$	43	

MFR E-14 Workpapers
Rate Class GSD(T)-1

Line No.	(1) TYPE OF CHARGES	(2) PRESENT REVENUE CALCULATION UNITS	(3) CHARGE/UNIT	(4) $ REVENUE	(5	(6) PROPOSED REVENUE CALCULATION UNITS	(7) CHARGE/UNIT	(8) $ REVENUE		(9) PERCENT INCREASE		
	RATE SCHEDULE GSD-1 - 72											
1											HLFT	GSDT
2	Customer	1,206,464 $	16.44	$ 19,834,268		1,206,464	$ 18.00	$ 21,716,352	9.5%		156,096	491,652
3	Non-Fuel Energy	22,502,463,769 $	0.01401	$ 315,259,517		22,502,463,769	$ 0.01500	$ 337,536,957	7.1%		13,403,749	15,982,170
4	Demand	64,720,673 $	6.50	$ 420,684,375		64,720,673	$ 7.00	$ 453,044,711	7.7%		10,686,319	18,971,918
5	Transformation Credit	117,981 $	(0.24)	$ (28,315)		117,981	$ (0.27)	$ (31,855)	12.5%		(3,613)	(1,019)
6	Subtotal			$ 755,749,845				$ 812,266,165		7.5%	24,242,551	35,444,721
7	CDR Credit										955,846	208,968
8	Adder	565 $	570.14	$ 322,129		565	$ 75.00	$ 42,375				
9	Credit	145,011 $	(4.68)	$ (678,651)		145,011	$ (7.30)	$ (1,058,579)				
10	Total			$ 755,393,323				$ 811,249,960		7.4%		
11												
12	RATE SCHEDULE GSDT-1 - 70											
13												
14	Customer	27,314 $	22.77	$ 621,940		27,314	$ 24.00	$ 655,536			$ 208,128	
15	Non-Fuel Energy											
16	On Peak	294,667,539 $	0.03121	$ 9,196,574		294,667,539	$ 0.03440	$ 10,136,563	10.2%		8,055,176	
17	Off Peak	770,810,434 $	0.00654	$ 5,041,100		770,810,434	$ 0.00710	$ 5,472,754	8.6%		4,681,890	
18	Demand	2,710,274 $	6.50	$ 17,616,781		2,710,274	$ 7.00	$ 18,971,918	7.7%		10,424,722	
19	Transformation Credit	3,774 $	(0.24)	$ (906)		3,774	$ (0.27)	$ (1,019)			(3,613)	
20	Subtotal			$ 32,475,489				$ 35,235,752		8.5%	23,366,304	
21	CDR Credit										217,565	
22	Adder	12 $	563.58	$ 6,763		12	$ 75.00	$ 900				
23	Credit	402,992 $	(4.68)	$ (1,886,001)		402,992	$ (7.30)	$ (2,941,840)				
24	Total			$ 30,596,251				$ 32,294,813		8.5%		
25												
26	RATE SCHEDULE HLFT - 170											
27												
28	Customer	8,672.00 $	22.77	$ 197,461		8,672.00	$ 24.00	$ 208,128				655,536
29	Non-Fuel Energy - On Peak	234,162,107.00 $	0.01198	$ 2,805,262		234,162,107.00	$ 0.01218	$ 2,852,094	1.7%		26%	3,589,051
30	Non-Fuel Energy - Off Peak	659,421,165.00 $	0.00654	$ 4,312,614		659,421,165.00	$ 0.00710	$ 4,681,890	8.6%			5,472,754
31	Demand - Maximum	1,526,617.00 $	1.81	$ 2,763,177		1,526,617.00	$ 1.90	$ 2,900,572	5.0%		98%	5,149,521
32	Demand - On-Peak	1,489,246.00 $	7.83	$ 11,660,796		1,489,246.00	$ 8.40	$ 12,509,666	7.3%			22,766,302
33	Transformation Credit	13,382.00 $	(0.24)	$ (3,212)		13,382.00	$ (0.27)	$ (3,613)			80.2%	(1,019)
34	Subtotal			$ 21,736,099				$ 23,148,738		6.5%		37,632,144
35	CDR Credit											$ 2,396,391
36	Adder	1,721.00 $	570.14	$ 981,211		1,721.00	$ 75.00	$ 129,075				
37	Credit	150,628.11 $	(4.68)	$ (704,940)		150,628.11	$ (7.30)	$ (1,099,585)				
38	Total			$ 22,012,371				$ 22,178,228		0.8%		
39												
40	RATE SCHEDULE SDTR - 270											
41			Option A - GSD-1				Option A - GSD-1					
42												
43	Customer	18,431 $	22.77	$ 419,674		18,431	$ 24.00	$ 442,344				
44	Non-Fuel Energy - Seasonal On Peak	20,059,884 $	0.05627	$ 1,128,770		20,059,884	$ 0.06254	$ 1,254,545				
45	Non-Fuel Energy - Seasonal Off Peak	191,065,476 $	0.00971	$ 1,855,246		191,065,476	$ 0.01000	$ 1,910,655				
46	Non-Fuel Energy - Non-Seasonal	395,054,701 $	0.01401	$ 5,534,716		395,054,701	$ 0.01500	$ 5,925,821				
47	Demand - Seasonal On-Peak	405,665 $	7.70	$ 3,123,621		405,665	$8.20	$ 3,326,453				
48	Demand - Non-Seasonal	1,556,309 $	5.58	$ 8,684,204		1,556,309	$6.70	$ 10,427,270				
49	Transformation Credit	1,416 $	(0.24)	$ (340)		1,416	$ (0.27)	$ (382)				
50	Subtotal			$ 20,745,891				$ 23,286,705				
51	CDR Credit											
52	Adder	- $	570.14	$ -		-	$ 75.00	$ -				
53	Credit	- $	(4.68)	$ -		-	$ (7.30)	$ -				
54	Total			$ 20,745,891				$ 23,286,705		12.2%		

MFR E-14 Workpapers
Rate Class GSD(T)-1

Line No.	(1) TYPE OF CHARGES	(2) PRESENT REVENUE CALCULATION UNITS	(3) CHARGE/UNIT	(4) $ REVENUE	(5)	(6) PROPOSED REVENUE CALCULATION UNITS	(7) CHARGE/UNIT	(8) $ REVENUE	(9) PERCENT INCREASE
55									
56	RATE SCHEDULE SDTR - 370								
57			Option B - GSDT-1				Option B - GSDT-1		
58									
59	Customer	671	$ 22.77	$ 15,279		671	$ 24.00	$ 16,104	
60	Non-Fuel Energy - Seasonal On Peak	442,338	$ 0.05627	$ 24,890		442,338	$ 0.06254	$ 27,664	
61	Non-Fuel Energy - Seasonal Off Peak	3,722,252	$ 0.00971	$ 36,143		3,722,252	$ 0.01000	$ 37,223	
62	Non-Fuel Energy - Non-Seasonal On Peak	1,491,233	$ 0.03126	$ 46,616		1,491,233	$ 0.03232	$ 48,197	
63	Non-Fuel Energy - Non-Seasonal Off Peak	5,161,710	$ 0.00971	$ 50,120		5,161,710	$ 0.01000	$ 51,617	
64	Demand - Seasonal On Peak	8,779	$ 8.13	$ 71,373		8,779	$8.20	$ 71,988	
65	Demand - Non-Seasonal On Peak	23,591	$ 6.01	$ 141,782		23,591	$6.70	$ 158,060	
66	Transformation Credit	-	$ (0.24)	$ -		-	$ (0.27)	$ -	
67	Subtotal			$ 386,203				$ 410,852	
68	CDR Credit								
69	Adder	-	$ 563.58	$ -		-	$ 75.00	$ -	
70	Credit	-	$ (4.68)	$ -		-	$ (7.30)	$ -	
71	Total			$ 386,203				$ 410,852	6.4%
72									
73	TOTALS			$ 829,134,038				$ 889,420,558	
74									
75							Increase	$ 60,286,520	
76							Target	$ 60,286,649	
77							Difference	$ (129)	
78							adjustment	0.00099	
79									
80									
81	GSDT revenue neutral calculation								
82	on pk class average	29.39%	Energy Revenue						
83	on peak	313,160,134	$ 10,772,709						
84	off peak	752,317,839	$ 5,341,457						
85	total at class on-pk		$ 16,114,165						
86	total at GSD1 rates	$ 0.01500	$ 15,982,170						
87	Difference		$ 131,996						
88	adjustment		0.00319	0.10221083					
89									
90									
91	HLFT Revenue at GSD-1 rate and target Load Factor								
92	Target Load Factor	70%							
93	Average Class On-Peak %	29.39%							
94			GSD Rates						
95	accounts	8,672	$ 18.00	$156,096					
96	kW	1,489,246	$ 7.00	$10,424,722					
97	kWh	780,101,287	$0.01500	$11,701,519					
98	Total			$22,282,337					
99	HLFT Demand/Customer Revenue			$ 15,618,367					
100	Net Energy Revenue			$6,663,971					
101									
102	Adjusted Energy Charges								
103	Per Unit Energy Cost		$0.00710						
104									
105	kWh On-Peak	229,283,598	$0.01218	$2,792,674					
106	kWh Off-Peak	550,817,689	$ 0.00710	$3,910,806					
107	Total	780,101,287		$6,703,480					
108	Difference			$39,509					
109	Energy Charge Adjustment	0.00020							
110									

MFR E-14 Workpapers
Rate Class GSLD(T)-1

Line No.	(1) TYPE OF CHARGES	(2) PRESENT REVENUE CALCULATION UNITS	(3) CHARGE/UNIT	(4) $ REVENUE	(5)	(6) PROPOSED REVENUE CALCULATION UNITS	(7) CHARGE/UNIT	(8) $ REVENUE	(9) PERCENT INCREASE			
1	RATE SCHEDULE GSLD-1 - 62											
2											HLFT	GSLDT
3	Customer	16,715	$ 50.13	$ 837,923		16,715	$ 55.00	$ 919,325	10%		$ 245,685.00	702,295
4	Non-Fuel Energy	3,886,576,675	$ 0.00922	$ 35,834,237		3,886,576,675	$ 0.01056	$ 41,042,250	15%		$ 18,309,430.80	48577820.22
5	Demand	10,358,163	$ 7.60	$ 78,722,039		10,358,163	$ 8.00	$ 82,865,304	5%		$ 24,415,608.00	69036648
6	Transformation Credit	172,521	$ (0.24)	$ (41,405)		172,521	$ (0.27)	$ (46,581)	13%		$ (26,750.52)	(28,788.48)
7	Subtotal			$ 115,352,794				$ 124,780,298		8.2%	$ 42,943,973.28	118,287,975
8	CDR Credit										$ 1,324,950.95	$ 726,901.30
9	Adder	367	$ 564.07	$ 207,014		367	$ 125.00	$ 45,875				
10	Credit	144,278	$ (4.68)	$ (675,222)		144,278	$ (7.30)	$ (1,053,230)				
11	Total			$ 114,884,586				$ 123,772,943		7.7%		
12												
13	RATE SCHEDULE GSLDT-1 - 64											
14												
15	Customer	12,769	$ 50.13	$ 640,110		12,769	$ 55.00	$ 702,295	10%		245,685	
16	Non-Fuel Energy											
17	On Peak	1,292,038,884	$ 0.02047	$ 26,448,036		1,292,038,884	$ 0.01901	$ 24,561,659	-7%		$ 8,524,608	
18	Off Peak	3,308,133,485	$ 0.00426	$ 14,092,649		3,308,133,485	$ 0.00704	$ 23,289,260	65%		$ 9,049,357	
19	Demand	8,629,581	$ 7.60	$ 65,584,816		8,629,581	$ 8.00	$ 69,036,648	5%		$ 23,885,720	
20	Transformation Credit	106,624	$ (0.24)	$ (25,590)		106,624	$ (0.27)	$ (28,788)	13%		$ (26,751)	
21	Subtotal			$ 106,740,020				$ 117,561,073		10.1%	$ 41,678,619	
22	CDR Credit										$ 59,597	
23	Adder	159	$ 564.07	$ 89,687		159	$ 125.00	$ 19,875	-78%			
24	Credit	676,250	$ (4.68)	$ (3,164,851)		676,250	$ (7.30)	$ (4,936,627)	56%			
25	Total			$ 103,664,856				$ 112,644,321		8.7%		
26												
27	RATE SCHEDULE CS-1 - 73											
28												
29	Customer	340	$ 50.13	$ 17,044		340	$ 80.00	$ 27,200	60%			
30	Non-Fuel Energy	89,986,025	$ 0.00922	$ 829,671		89,986,025	$ 0.01056	$ 950,252	15%			
31	Demand	257,955	$ 7.60	$ 1,960,458		257,955	$ 8.00	$ 2,063,840	5%			
32	Transformation Credit	42,773	$ (0.24)	$ (10,266)		42,773	$ (0.27)	$ (11,549)	13%			
33	Curtailable Credit	191,512	$ (1.72)	$ (329,401)		191,512	$ (1.72)	$ (329,401)	0%			
34	Total			$ 2,467,507				$ 2,700,143		9.4%		
35												
36	RATE SCHEDULE CST-1 - 74											
37												
38	Customer	144	$ 50.13	$ 7,219		144	$ 80.00	$ 11,520	60%			
39	Non-Fuel Energy											
40	On Peak	17,173,902	$ 0.02047	$ 351,550	0.256	17,173,902	$ 0.01901	$ 326,476	-7%			
41	Off Peak	49,790,585	$ 0.00426	$ 212,108		49,790,585	$ 0.00704	$ 350,526	65%			
42	Demand	118,760	$ 7.60	$ 902,576		118,760	$ 8.00	$ 950,080	5%			
43	Transformation Credit	18,992	$ (0.24)	$ (4,558)		18,992	$ (0.27)	$ (5,128)	13%			
44	Curtailable Credit	75,974	$ (1.72)	$ (130,675)		75,974	$ (1.72)	$ (130,675)	0%			
45	Total			$ 1,338,219				$ 1,502,798		12.3%		
46												

MFR E-14 Workpapers
Rate Class GSLD(T)-1

Line No.	(1) TYPE OF CHARGES	(2) PRESENT REVENUE CALCULATION UNITS	(3) CHARGE/UNIT	(4) $ REVENUE	(5)	(6) PROPOSED REVENUE CALCULATION UNITS	(7) CHARGE/UNIT	(8) $ REVENUE		(9) PERCENT INCREASE	
47	RATE SCHEDULE HLFT - 164										
48			500 - 1,999 kW				500 - 1.999 kW				
49	Customer	4,467	$ 50.13	$ 223,931		4,467	$ 55.00	$ 245,685	10%		$ 702,295
50	Non-Fuel Energy - On Peak	448,427,551	$ 0.00546	$ 2,448,414	0.259	448,427,551	$ 0.00572	$ 2,565,006	5%		$ 7,390,482
51	Non-Fuel Energy - Off Peak	1,285,420,063	$ 0.00546	$ 7,018,394		1,285,420,063	$ 0.00572	$ 7,352,603	5%		$ 18,922,524
52	Demand - On-Peak	2,985,715	$ 7.83	$ 23,378,148		2,985,715	$ 8.50	$ 25,378,578	9%		$ 73,351,439
53	Demand - Maximum	3,051,951	$ 1.81	$ 5,524,031		3,051,951	$ 2.00	$ 6,103,902	10%		$ 17,642,044
54	Transformation Credit	98,076	$ (0.24)	$ (23,778)		99,076	$ (0.27)	$ (26,751)	13%		$ (28,788)
55	Subtotal			$ 38,569,140				$ 41,619,022		7.9%	$ 117,979,975
56	CDR Credit										$ 418,902
57	Adder	3,876	$ 564.07	$ 2,187,483		3,878	$ 125.00	$ 484,750	-78%		
58	Credit	452,785	$ (4.68)	$ (2,119,034)		452,785	$ (7.30)	$ (3,305,331)	56%		
59	Total			$ 38,837,569				$ 38,798,441		0.4%	
60											
61	RATE SCHEDULE SDTR - 264										
62			Option A - GSLD-1				Option A - GSLD-1				
63	Customer	4,703.00	$ 50.13	$ 235,781		4,703.00	$ 55.00	$ 258,665	10%		
64	Non-Fuel Energy - Seasonal On Peak	29,539,308.00	$ 0.03633	$ 1,073,163		29,539,308.00	$ 0.04267	$ 1,260,442	17%		
65	Non-Fuel Energy - Seasonal Off Peak	270,693,988.00	$ 0.00641	$ 1,735,148		270,693,988.00	$ 0.00704	$ 1,905,686	10%		
66	Non-Fuel Energy - Non-Seasonal	608,376,807.00	$ 0.00922	$ 5,609,234		608,376,807.00	$ 0.01056	$ 6,424,459	15%		
67	Demand - Seasonal On-Peak	580,937.00	$ 8.55	$ 4,967,011		580,937.00	$8.90	$ 5,170,339	4%		
68	Demand - Non-Seasonal	2,104,505.00	$ 7.26	$ 15,278,706		2,104,505.00	$7.70	$ 16,204,689	6%		
69	Transformation Credit	30,870.00	$ (0.24)	$ (7,409)		30,870.00	$ (0.27)	$ (8,335)	13%		
70	Subtotal			$ 28,891,616				$ 31,215,945		8.0%	
71	CDR Credit										
72	Adder	-	$ 564.07	$ -		-	$ 125.00	$ -	-78%		
73	Credit	-	$ (4.68)	$ -		-	$ (7.30)	$ -	56%		
74	Total			$ 28,891,616				$ 31,215,945		8.0%	
75											
76											
77	RATE SCHEDULE SDTR - 364										
78			Option B - GSLDT-1				Option B - GSLDT-1				
79	Customer	132	$ 50.13	$ 6,617		132	$ 55.00	$ 7,260	10%		
80	Non-Fuel Energy - Seasonal On Peak	953,434	$ 0.03633	$ 34,638		953,434	$ 0.04267	$ 40,683	17%		
81	Non-Fuel Energy - Seasonal Off Peak	7,228,415	$ 0.00641	$ 46,334		7,228,415	$ 0.00704	$ 50,888	10%		
82	Non-Fuel Energy - Non-Seasonal On Peak	3,856,617	$ 0.01884	$ 72,659		3,856,617	$ 0.02194	$ 84,614	16%		
83	Non-Fuel Energy - Non-Seasonal Off Peak	12,455,515	$ 0.00641	$ 79,840		12,455,515	$ 0.00704	$ 87,687	10%		
84	Demand - Seasonal On Peak	13,383	$ 8.55	$ 114,425		13,383	$ 8.90	$ 119,109	4%		
85	Demand - Non-Seasonal On Peak	34,514	$ 7.26	$ 250,572		34,514	$ 7.70	$ 265,758	6%		
86	Transformation Credit	-	$ (0.24)	$ -		-	$ (0.27)	$ -	13%		
87	Subtotal			$ 605,084				$ 655,999		8.4%	
88	CDR Credit										
89	Adder	-	$ 564.07	$ -		-	$ 125.00	$ -			
90	Credit	-	$ (4.68)	$ -		-	$ (7.30)	$ -			
91	Total			$ 605,084				$ 655,999			
92											
93	TOTALS			$ 290,489,438				$ 311,290,590		7.2%	
94											
95							Increase	$ 20,801,153			
96							Target	$ 20,800,537			
97								$ 616			
98							adjustment	0.00134			

MFR E-14 Workpapers
Rate Class GSLD(T)-1

Line No.	(1) TYPE OF CHARGES			(2) PRESENT REVENUE CALCULATION UNITS	(3) CHARGE/UNIT	(4) $ REVENUE	(5)	(6) PROPOSED REVENUE CALCULATION UNITS	(7) CHARGE/UNIT	(8) $ REVENUE	(9) PERCENT INCREASE
99	TOU revenue neutral calculation										
100	on pk class average	29.62%	Energy Revenue								
101	on peak	1,362,489,528	$ 25,900,925.93								
102	off peak	3,237,682,841	$ 22,793,287.20								
103	total at class on-pk		$ 48,694,213								
104	total at GSLD1 rates	$ 0.01056	$ 48,577,820								
105	Difference		$ 116,393								
106	adjustment		-0.00146	-0.00191							
107											
108	HLFT Revenue at GSLD-1 rate and target Load Factor										
109	Target Load Factor		70%								
110	Average Class On-Peak %		29.6%								
111											
112	accounts		4,467	$ 55.00	$245,685						
113	kW		2,985,715	$ 8.00	$23,885,720						
114	kWh		1,559,546,961	$0.01056	$16,468,616						
115	Total				$40,600,221						
116	Demand/Customer Rev				$ 31,728,165						
117	Net Energy Revenue required				$8,872,056						
118											
119											
120	Adjusted Energy Charges										
121	Per Unit Energy Cost			$0.00704							
122											
123	kWh On-Peak		461,910,170	$0.00572	$2,642,126						
124	kWh Off-Peak		1,097,636,791	$0.00572	$6,278,482						
125	Total		1,559,546,961		$8,920,609						
126	Difference				$48,552						
127	Energy Charge Adjustment		$ 0.00026								
128											

MFR E-14 Workpapers
Rate Class GSLD(T)-2

Line No.	(1) TYPE OF CHARGES	(2) PRESENT REVENUE CALCULATION UNITS	(3) CHARGE/UNIT	(4) $ REVENUE	(5)	(6) PROPOSED REVENUE CALCULATION UNITS	(7) CHARGE/UNIT	(8) $ REVENUE	(9) PERCENT INCREASE		HLFT	GSDT
1	RATE SCHEDULE GSLD-2 - 63											
2												
3	Customer	360	$ 179.19	$ 64,508		360	$ 195.00	$ 70,200	8.8%			
4	Non-Fuel Energy	435,519,559	$ 0.00861	$ 3,749,823		435,519,559	$ 0.00950	$ 4,137,436	10.3%			
5	Demand	992,416	$ 7.60	$ 7,542,362		992,416	$ 8.30	$ 8,237,053	9.2%			
6	Transformation Credit	305,470	$ (0.24)	$ (73,313)		305,470	$ (0.27)	$ (82,477)	12.5%			
7	Subtotal			$ 11,283,381				$ 12,362,212		9.6%		
8	CDR Credit											
9	Adder	118	$ 433.91	$ 51,201		118	$ 50.00	$ 5,900				
10	Credit	92,803	$ (4.68)	$ (434,317)		92,803	$ (7.30)	$ (677,461)				
11	Total			$ 10,900,265				$ 11,690,651		7.3%		
12												
13	RATE SCHEDULE GSLDT-2 - 66											
14												
15	Customer	805	$ 179.19	$ 144,248		805	$ 195.00	$ 156,975	8.8%			88,560
16	Non-Fuel Energy											
17	On Peak	264,154,502	$ 0.01512	$ 3,994,018	0.25	264,154,502	$ 0.01620	$ 4,279,303	7.1%		$	3,248,105
18	Off Peak	794,013,755	$ 0.00620	$ 4,922,885		794,013,755	$ 0.00697	$ 5,534,276	12.4%		$	4,132,739
19	Demand	1,875,663	$ 7.60	$ 14,255,039		1,875,663	$ 8.30	$ 15,568,003	9.2%		$	10,518,789
20	Transformation Credit	461,080	$ (0.24)	$ (110,659)		461,080	$ (0.27)	$ (124,492)	12.5%		$	(69,291)
21	Subtotal			$ 23,205,529				$ 25,414,085		9.5%	$	17,916,923
22	CDR Credit										$	321,713
23	Adder	137	$ 433.91	$ 59,446		137	$ 50.00	$ 6,850	-88.5%			
24	Credit	110,743	$ (4.68)	$ (518,277)		110,743	$ (7.30)	$ (808,423)	56.0%			
25	Total			$ 22,746,698				$ 24,612,492		8.2%		
26												
27	RATE SCHEDULE CS-2 - 71											
28												
29	Customer	12	$ 179.19	$ 2,150		12	$ 220.00	$ 2,640	22.8%			
30	Non-Fuel Energy	21,269,577	$ 0.00861	$ 183,131		21,269,577	$ 0.00950	$ 202,061	10.3%			
31	Demand	52,773	$ 7.60	$ 401,075		52,773	$ 8.30	$ 438,016	9.2%			
32	Transformation Credit	47,149	$ (0.24)	$ (11,316)		47,149	$ (0.27)	$ (12,730)	12.5%			
33	Curtailable Credit	30,797	$ (1.72)	$ (52,971)		30,797	$ (1.72)	$ (52,971)	0.0%			
34	Total			$ 522,070				$ 577,016		10.5%		
35												
36	RATE SCHEDULE CST-2 - 75											
37												
38	Customer	60	$ 179.19	$ 10,751		60	$ 220.00	$ 13,200	22.8%			
39	Non-Fuel Energy											
40	On Peak	11,693,389	$ 0.01512	$ 176,804		11,693,389	$ 0.01620	$ 189,433	7.1%			
41	Off Peak	45,853,089	$ 0.00620	$ 284,289		45,853,089	$ 0.00697	$ 319,596	12.4%			
42	Demand	100,200	$ 7.60	$ 761,520		100,200	$ 8.30	$ 831,660	9.2%			
43	Transformation Credit	21,941	$ (0.24)	$ (5,266)		21,941	$ (0.27)	$ (5,924)	12.5%			
44	Curtailable Credit	61,251	$ (1.72)	$ (105,352)		61,251	$ (1.72)	$ (105,352)	0.0%			
45	Total			$ 1,122,747				$ 1,242,613		10.7%		
46												

MFR E-14 Workpapers
Rate Class GSLD(T)-2

Line No.	(1) TYPE OF CHARGES	(2) PRESENT REVENUE CALCULATION UNITS	(3) CHARGE/UNIT	(4) $ REVENUE	(5)	(6) PROPOSED REVENUE CALCULATION UNITS	(7) CHARGE/UNIT	(8) $ REVENUE	(9) PERCENT INCREASE		
47	RATE SCHEDULE HLFT - 165										
48			= or > 2,000 kW				= or > 2,000 kW				
49	Customer	444 $	179.19	$ 79,560		444 $	195.00	$ 86,580	8.8%		$ 156,975
50	Non-Fuel Energy - On Peak	200,500,326 $	0.00513	$ 1,028,567	0.25	200,500,326 $	0.00526	$ 1,054,832	2.5%		$ 1,389,453
51	Non-Fuel Energy - Off Peak	592,932,462 $	0.00513	$ 3,041,744		592,932,482 $	0.00526	$ 3,118,825	2.5%		$ 4,176,512
53	Demand - On-Peak	1,267,324 $	7.83	$ 9,923,147	0.86	1,267,324 $	8.50	$ 10,772,254	8.6%		$ 15,943,136
52	Demand - Maximum	1,316,105 $	1.81	$ 2,382,150		1,316,105 $	2.00	$ 2,632,210	10.5%		$ 3,895,720
54	Transformation Credit	256,634 $	(0.24)	$ (61,592)		256,634 $	(0.27)	$ (69,291)	12.6%		$ (124,492)
55	Subtotal			$ 18,393,575				$ 17,595,209		7.3%	$ 25,437,303
56	CDR Credit										$ 23,238
57	Adder	48 $	433.91	$ 20,828		48 $	50.00	$ 2,400	-88.5%		
58	Credit	25,607 $	(4.68)	$ (119,842)		25,607 $	(7.30)	$ (186,933)	56.0%		
59	Total			$ 16,294,581				$ 17,410,676		6.8%	
60											
61	RATE SCHEDULE SDTR - 265										
62			Option A - GSLD-2				Option A - GSLD-2				
63	Customer	48 $	179.19	$ 8,601		48 $	195.00	$ 9,360	8.8%		
64	Non-Fuel Energy - Seasonal On Peak	481,009 $	0.02965	$ 14,262		481,009 $	0.03632	$ 17,470	22.5%		
65	Non-Fuel Energy - Seasonal Off Peak	6,531,880 $	0.00598	$ 39,061		6,531,880 $	0.00633	$ 41,347	5.9%		
66	Non-Fuel Energy - Non-Seasonal	28,744,878 $	0.00861	$ 247,493		28,744,878 $	0.00950	$ 273,076	10.3%		
67	Demand - Seasonal On-Peak	6,652 $	9.00	$ 59,868		6,652	$9.20	$ 61,198	2.2%		
68	Demand - Non-Seasonal	64,239 $	7.22	$ 463,808		64,239	$8.10	$ 520,336	12.2%		
69	Transformation Credit	7,866 $	(0.24)	$ (1,888)		7,866 $	(0.27)	$ (2,124)	12.5%		
70	Subtotal			$ 831,203				$ 920,664		10.8%	
71	CDR Credit										
72	Adder	- $	433.91	$ -		- $	50.00	$ -	-88.5%		
73	Credit	- $	(4.68)	$ -		- $	(7.30)	$ -	56.0%		
74	Total			$ 831,203				$ 920,664		10.8%	
75											
76	RATE SCHEDULE SDTR - 365										
77			Option B - GSLDT-2				Option B - GSLDT-2				
78	Customer	84 $	179.19	$ 16,052		84 $	195.00	$ 16,380	8.8%		
79	Non-Fuel Energy - Seasonal On Peak	1,796,591 $	0.02965	$ 53,269		1,796,591 $	0.03632	$ 65,252	22.5%		
80	Non-Fuel Energy - Seasonal Off Peak	12,743,521 $	0.00598	$ 76,206		12,743,521 $	0.00633	$ 80,666	5.9%		
81	Non-Fuel Energy - Non-Seasonal On Peak	7,929,170 $	0.01734	$ 137,492		7,929,170 $	0.02010	$ 159,376	15.9%		
82	Non-Fuel Energy - Non-Seasonal Off Peak	26,529,109 $	0.00598	$ 158,644		26,529,109 $	0.00633	$ 167,929	5.9%		
83	Demand - Seasonal On Peak	23,672 $	9.00	$ 213,048		23,672	$9.20	$ 217,782	2.2%		
84	Demand - Non-Seasonal On Peak	76,800 $	7.22	$ 554,496		76,800	$8.10	$ 622,080	12.2%		
85	Transformation Credit	44,180 $	(0.24)	$ (10,603)		44,180 $	(0.27)	$ (11,929)	12.5%		
86	Subtotal			$ 1,197,604				$ 1,317,538		10.0%	
87	CDR Credit										
88	Adder	- $	433.91	$ -		- $	50.00	$ -	-88.5%		
89	Credit	- $	(4.88)	$ -		- $	(7.30)	$ -	56.0%		
90	Total			$ 1,197,604				$ 1,317,538		10.0%	
91											
92											
93	TOTALS			$ 53,615,147				$ 57,771,650		7.8%	
94											
95							Increase	$ 4,156,503			
96							Target	$ 4,157,833			
97								$ (1,330)			
98							Adjustment	0.00089			

MFR E-14 Workpapers
Rate Class GSLD(T)-2

Line No.	(1) TYPE OF CHARGES			(2) PRESENT REVENUE CALCULATION UNITS	(3) CHARGE/UNIT	(4) $ REVENUE	(5)	(6) PROPOSED REVENUE CALCULATION UNITS	(7) CHARGE/UNIT	(8) $ REVENUE	(9) PERCENT INCREASE
99	GSLDT2 revenue neutral calculation										
100	on pk class average	26.46%	Energy Revenue		Revenue at GSLD-2 rate and target Load Factor						
101	on peak	280,028,798	4,536,467		Target Load Factor	70%					
102	off peak	778,139,459	5,423,632		Average Class On-Peak %	26.46%					
103	total at class on-pk	1,058,168,257	9,960,099								
104	total at GSLD2 energy r $	0.00950	10,052,598		accounts	444	$ 195.00	$66,580			
105	Difference		(92,500)		kW	1,287,324	$ 8.30	$10,518,789			
106	adjustment		0.00108		kWh	672,529,655	$0.00950	$6,389,032			
107					Total			$16,984,401			
108					Demand/Customer Rev			$ 13,481,044			
109					Net Energy Revenue			$3,503,357			
110											
111											
112					Adjusted Energy Charges						
113					Per Unit Energy Cost		$0.00697				
114											
115					kWh On-Peak	177,975,165	$0.00526	$936,149			
116					kWh Off-Peak	494,554,490	$0.00526	$2,601,357			
117					Total	672,529,655		$3,537,506			
118					Difference			$34,149			
119					Energy Charge Adjustment	0.00013					

MFR E-14 Workpapers
Rate Class GS(T)-1

Line No.	(1) TYPE OF CHARGES	(2) PRESENT REVENUE CALCULATION UNITS	(3) CHARGE/UNIT	(4) $ REVENUE	(5)	(6) PROPOSED REVENUE CALCULATION UNITS	(7) CHARGE/UNIT	(8) $ REVENUE	(9) PERCENT INCREASE
1	RATE SCHEDULE GS-1 - 68								
2									
3	Customer	4,965,923.00	$ 6.89	$ 34,215,209		4,965,923.00	$ 6.89	$ 34,215,209	
4	Non-Fuel Energy	5,821,874,593.00	0.04447	$ 258,898,763		5,821,874,593.00	$ 0.04447	$ 258,898,763	
5	Demand	-	$ -	$ -		-	$ -	$ -	
6	Unmetered Service Credit	10,847.00	$ (6.00)	$ (65,082)		10,847.00	$ (6.00)	$ (65,082)	
7									
8	Total			$ 293,048,891				$ 293,048,891	0.0%
9									
10	RATE SCHEDULE GST-1 - 69								
11									
12	Customer	6,988	$ 13.53	$ 94,548		6,988	$ 13.53	$ 94,548	
13	Non-Fuel Energy								
14	On Peak	5,692,420	0.08473	$ 482,319		5,692,420	$ 0.08473	$ 482,319	
15	Off Peak	17,257,229	0.02645	$ 456,454		17,257,229	$ 0.02645	$ 456,454	
16	Demand	-	$ -	$ -		-	$ -	$ -	
17		22,949,649							
18	Total			$ 1,033,320				$ 1,033,320	0.0%
19									
20	TOTALS			$ 294,082,211				$ 294,082,211	
21									
22							Increase	$ -	
23							Target	$ -	
24							Difference	$ -	
25	GST revenue neutral calculation						adjustment		
26	on pk class average	30.60%	Energy Revenue						
27	on peak kWh at class average	7,021,976	$ 594,972.06						
28	off peak kWh at class average	15,927,673	$ 421,286.94						
29	total revenue at GST	22,949,649	$ 1,016,259						
30	total at GS1 rate	0.04447	$ 1,020,571						
31	Difference		$ (4,312)						
32	adjustment		0.03684						
33									

MFR E-14 Work papers
SDTR Work paper Detail
2013 Test Year

Line No.	Description	270 370 SDTR-1	264 364 SDTR-2	265 365 SDTR-3	Total
1	Billing Units				
2					
3	kW Seasonal On-Peak	414,444	594,320	30,324	
4	kW Non-Seasonal	1,579,900	2,139,019	141,039	
5	Total	1,994,344	2,733,339	171,363	
6					
7	kWh Seasonal On-Peak	20,502,222	30,492,740	2,277,600	53,272,562
8	kWh Seasonal Off-Peak	194,787,728	277,922,403	19,275,401	491,985,532
9	kWh Non-Seasonal	395,054,701	608,376,807	28,744,878	
10	kWh Non-Seasonal On-Peak	1,491,233	3,856,617	7,929,170	
11	kWh Non-Seasonal Off-Peak	5,161,710	12,455,515	26,529,109	
12	Total Billing Units	616,997,594	933,104,082	84,756,158	
13	Summer Excess (Based on GSD/GSLD Rates)	117.84%	110.74%	111.13%	
14	Summer On-Peak Energy Ratio	10%	10%	11%	10%
15					
16		72	62	63	
17	Revenue Neutrality	GSD-1	GSLD-1	GSLD-2	
18	Proposed Customer Charge ($/kW)	$ 24.00	$ 55.00	$ 195.00	
19	Proposed Demand Charge ($/kW)	$ 7.00	$ 8.00	$ 8.30	
20	Proposed Energy Charge ($/kWh)	$0.015000	$0.010560	$0.009500	
21	On-Peak Energy	600,869,476	267,689,645	48,083,162	916,642,283
22	Off-Peak Energy	1,443,494,165	636,110,703	133,612,707	2,213,217,574
23	On-Peak Energy Ratio	29%	30%	26%	29%
24	Percent Adjustment				33%
25					
26	**Preliminary SDTR Rates**				
27	Demand Revenue	$13,960,408	$21,866,712	$1,422,313	
28	Summer Energy Revenue	$3,229,349	$3,256,864	$204,754	
29	Non-Summer Energy Revenue	$6,025,615	$6,596,715	$600,430	
30					
31	Summer Demand Charge	$8.20	$8.90	$9.20	
32	Non-Summer Demand Charge	$6.70	$7.70	$8.10	
33					
34	Summer On-Peak Energy Charge	$0.062542	$0.042668	$0.036321	
35	Summer Off-Peak Energy Charge	$0.009996	$0.007037	$0.006331	
36					
37	Non-Summer Energy Charge	$0.015000	$0.010560	$0.009500	
38	Non-Summer On-Peak Energy Charge	$0.032321	$0.021937	$0.020103	
39	Non-Summer Off-Peak Energy Charge	$0.009996	$0.007037	$0.006331	
40					
41	NOTE: PROPOSED RATES ARE PRELIMINARY AND MAY NOT BE SHOWN IN FULL PRECISION. THEY MAY NOT				
42	MATCH FINAL PROPOSED RATES OR REVENUES DUE TO ROUNDING AND OTHER ADJUSTMENTS.				
43	DOES NOT INCLUDE OPTIONAL RATES.				

MFR E-14 Workpapers
Rate Class MET

Line No.	(1) Type of Charges	(2) Present Revenue Calculation Units	(3) Charge/Unit	(4) $ Revenue	(5)	(6) Proposed Revenue Calculation Units	(7) Charge/Unit	(8) $ Revenue	(9) Percent Increase
1	**RATE SCHEDULE MET - 80**								
2									
3	Customer	312	$ 373.94	$ 116,669		312	$ 400.00	$ 124,800	
4	Non-Fuel Energy	92,698,007	$ 0.00846	$ 784,225		92,698,007	$ 0.01248	$ 1,156,871	
5	Demand	202,968	$ 9.81	$ 1,991,116		202,968	$ 10.60	$ 2,151,461	
6	Total			$ 2,892,010				$ 3,433,132	18.7%
7									
8	TOTAL			**$ 2,892,010**				**$ 3,433,132**	
9									
10							Increase	$ 541,121	
11							Target	$ 541,122	
12							difference	$ (0)	

MFR E-14 Workpapers
Rate Class SST-DST

Line No.	(1) Type of Charges	(2) Present Revenue Calculation Units	(3) Charge/Unit	(4) $ Revenue	(5)	(6) Proposed Revenue Calculation Units	(7) Charge/Unit	(8) $ Revenue	(9) Percent Increase
1	RATE SCHEDULE SST-1D - 851								
2									
3	Customer	36	$ 75.13	$ 2,705		36	$ 100.00	$ 3,600	
4	Non-Fuel Energy								
5	On Peak	9,801	$ 0.00624	$ 61		9,801	$ 0.00714	$ 70	
6	Off Peak	20,361	$ 0.00624	$ 127		20,361	$ 0.00714	$ 145	
7	Demand (1)								
8	Distribution CSD	7,629	$ 2.61	$ 19,912		7,629	$ 2.70	$ 20,598	3.45%
9	Reservation/kW	2,923	$ 0.93	$ 2,718		2,923	$ 1.07	$ 3,128	15.05%
10	Daily Demand	5,789	$ 0.44	$ 2,547		5,789	$ 0.52	$ 3,010	18.18%
11	CSD - Max On-Peak	4,706	$ 0.93	$ 4,377		4,706	$ 1.07	$ 5,035	15.05%
12	Total			$ 32,447				$ 35,587	9.7%
13									
14									
15	RATE SCHEDULE SST-2D - 852								
16									
17	Customer	-	$ 75.13	$ -		-	$ 100.00	$ -	
18	Non-Fuel Energy								
19	On Peak	-	$ 0.00624	$ -		-	$ 0.00714	$ -	
20	Off Peak	-	$ 0.00624	$ -		-	$ 0.00714	$ -	
21	Demand (1)								
22	Distribution CSD	-	$ 4.31	$ -		-	$ 2.70	$ -	
23	Reservation/kW	-	$ 0.93	$ -		-	$ 1.07	$ -	
24	Daily Demand	-	$ 0.44	$ -		-	$ 0.52	$ -	
25	CSD - Max On-Peak	-	$ 0.93	$ -		-	$ 1.07	$ -	
26	Total			$ -				$ -	
27									
28									
29	RATE SCHEDULE SST-3D - 853								
30									
31	Customer	12	$ 204.19	$ 2,450		12	$ 375.00	$ 4,500	
32	Non-Fuel Energy								
33	On Peak	2,021,909	$ 0.00624	$ 12,617		2,021,909	$ 0.00714	$ 14,436	
34	Off Peak	5,561,457	$ 0.00624	$ 34,703		5,561,457	$ 0.00714	$ 39,709	
35	Demand (1)								
36	Distribution CSD	49,172	$ 2.38	$ 117,029		49,172	$ 2.70	$ 132,764	
37	Reservation/kW	20,422	$ 0.93	$ 18,992		20,422	$ 1.07	$ 21,852	
38	Daily Demand	282,465	$ 0.44	$ 124,285		282,465	$ 0.52	$ 146,882	
39	CSD - Max On-Peak	28,750	$ 0.93	$ 26,738		28,750	$ 1.07	$ 30,763	
40	Total			$ 336,814				$ 390,905	
41									

MFR E-14 Workpapers
Rate Class SST-DST

Line No.	(1) Type of Charges	(2) Present Revenue Calculation Units	(3) Charge/Unit	(4) $ Revenue	(5)	(6) Proposed Revenue Calculation Units	(7) Charge/Unit	(8) $ Revenue	(9) Percent Increase
42	RATE SCHEDULE ISST-1(D) - 52								
43									
44	Customer	-	$ 200.00	$ -		-	$ 375.00	$ -	
45	Non-Fuel Energy								
46	On Peak	-	$ 0.00643	$ -		-	$ 0.00714	$ -	
47	Off Peak	-	$ 0.00643	$ -		-	$ 0.00714	$ -	
48	Demand (1)								
49	Distribution CSD	-	$ 2.59	$ -		-	$ 2.70	$ -	
50	Reservation/kW Firm Standby	-	$ 0.90	$ -		-	$ 1.07	$ -	
51	Reservation/kW Interruptible Standby	-	$ 0.25	$ -		-	$ 0.16	$ -	
52	Daily Demand Firm Standby	-	$ 0.41	$ -		-	$ 0.52	$ -	
53	Daily Demand Interruptible Standby	-	$ 0.10	$ -		-	$ 0.08	$ -	
54	Total			$ -				$ -	
55									
56	TOTAL			$ 369,261				$ 426,492	
57									
58							Increase	$ 57,231	
59							Target Revenu	$ 57,200	
60							Difference	$ 31	
61							Adjustment	-1.5	

MFR E-14 Workpapers
Rate Class SST-TST

Line No.	(1) Type of Charges	(2) Present Revenue Calculation Units	(3) Charge/Unit	(4) $ Revenue	(5)	(6) Proposed Revenue Calculation Units	(7) Charge/Unit	(8) $ Revenue	(9) Percent Increase
1	RATE SCHEDULE SST-1T- 85								
2									
3	Customer	156	$ 1,451.71	$ 226,467		156	$ 1,451.71	$ 226,467	
4	Non-Fuel Energy								
5	On Peak	23,828,428	$ 0.00648	$ 154,408		23,828,428	$ 0.00648	$ 154,408	
6	Off Peak	73,782,486	$ 0.00648	$ 478,111		73,782,486	$ 0.00648	$ 478,111	
7	Demand (1)								
8	Distribution CSD	1,883,436	$ -	$ -		1,883,436	$ -	$ -	
9	Reservation/kW	745,439	$ 1.10	$ 819,983		745,439	$ 1.10	$ 819,983	
10	Daily Demand	4,186,084	$ 0.32	$ 1,339,547		4,186,084	$ 0.32	$ 1,339,547	
11	CSD - Max On-Peak	1,137,997	$ 1.10	$ 1,251,797		1,137,997	$ 1.10	$ 1,251,797	
12	Total			$ 4,270,312				$ 4,270,312	0.0%
13									
14	RATE SCHEDULE ISST-1(T) - 53								
15									
16									
17	Customer	-	$ 1,891.00	$ -		-	$ 1,891.00	$ -	
18	Non-Fuel Energy								
19	On Peak	-	$ 0.00597	$ -		-	$ 0.00597	$ -	
20	Off Peak	-	$ 0.00597	$ -		-	$ 0.00597	$ -	
21	Demand (1)								
22	Distribution CSD	-	$ -	$ -		-	$ -	$ -	
23	Reservation/kW Firm Standby	-	$ 0.88	$ -		-	$ 0.88	$ -	
24	Reservation/kW Interruptible Standby	-	$ 0.23	$ -		-	$ 0.23	$ -	
25	Daily Demand Firm Standby	-	$ 0.41	$ -		-	$ 0.41	$ -	
26	Daily Demand Interruptible Standby	-	$ 0.10	$ -		-	$ 0.10	$ -	
27	Total			$ -				$ -	
28									
29	TOTALS			$ 4,270,312				$ 4,270,312	
30									
31							increase	$ -	
32							Target	$ 723,473	
33							Difference	$ (723,473)	
34							Adjustment		
35									

MFR E-14 Work papers
SST Work paper detail
2013 Test Year
(per Order 17159, Docket No. 850673-EU)

Line No.	Description		SST-T	SST-D					
1	Per Unit Customer Charge		1,476.742467	377.874661					
2	Proposed Customer Charge		$1,475.00	$375.00					
3									
4	**Demand Costs**		SST-T	SST-D			ISST -T	ISST -D	
5	Production - Steam		**151,097**	**7,821**					
6	Production - Nuclear		**580,879**	**30,932**					
7	Production - Other Power Supply		**8,112**	**446**					
8	Production - Other Production		**672,893**	**35,211**					
9	Distribution - Land & Land Rights		**0**	**3,386**					
10	Production - Curtailment Credit		**446**	**22**					
11	Distribution - Structures & Improvements		**0**	**5,768**					
12	Distribution - Overhead Conductors & Devices		**0**	**72,118**					
13	Distribution - Line Transformers		**0**	**6,221**					
14	Distribution - Poles, Towers & Fixtures		**0**	**21,218**					
15	Distribution - Station Equipment		**0**	**49,534**					
16	Distribution - Underground Conduit		**0**	**43,010**					
17	Distribution - Underground Conductors & Devices		**0**	**31,081**					
18	Transmission		**275,993**	**14,430**			0.17	0.16	Monthly
19	Total Production & Transmission		**$1,689,420**	**$92,248**			0.08	0.08	Daily
20	Avg CP Demand		**13,385**	**746**					
21	Per Unit Cost		$10.52	$10.30					
22	Adjusted for Outage Rate	10%	$ 1.05	$ 1.03					
23	Daily Demand Rate		$ 0.50	$ 0.49					
24									
25	Distribution Costs		NA	228,949					
26	CSD kW			56,801					
27	CSD Distribution unit cost			4.03					
28									
29	**Reservation/Daily Rates**		SST-T	SST-1D	SST-2D	SST-3D			
30	Loss Adjustment Factor		**1.0280343**	**1.0408441**	**1.0408441**	**1.0408441**			
31	Resulting kW Reservation Charge		**$ 1.08**	**$ 1.07**	**$ 1.07**	**$ 1.07**			
32	Resulting kW Daily Demand Rate		**$ 0.51**	**$ 0.52**	**$ 0.52**	**$ 0.51**			
33	CSD Distribution		**0**	**4.20**	**4.20**	**4.20**			
34	CSD Max on-peak		$ 1.08	$ 1.07	$ 1.07	$ 1.07			
35									
36									
37	**Energy**		**SST-T**	**SST-1D**	**SST-2D**	**SST-3D**			

MFR E-14 Work papers
SST Work paper detail
2013 Test Year
(per Order 17159, Docket No. 850673-EU)

Line No.	Description	SST-T	SST-D			
38	Loss Adjustment Factor	**1.02260666**	**1.0325**	**1.0325**	**1.0325**	
39	$/kWh	**$0.00726**	**$0.00714**	**$0.00714**	**$0.00714**	
40						
41						
42	**Energy**					
43	**Revenue Requirements**		SST-D	SST-T	SST-D	SST-T
44	Production - Steam		9,355	125,234	0.00122876	0.001283
45	Production - Nuclear		27,607	361,656	0.003626083	0.0037051
46	Production - Other Production		13,481	176,331	0.001770659	0.0018065
47	Transmission		2,175	29,421	0.000285647	0.0003014
48	Customer - Uncollectible Accounts		0	0	0	0
49	**Sub-Total Revenue Requirements**		52,618	692,641		
50	Energy kWh		7,613,528	97,610,914		
51	Energy kWh Rates				0.006911	0.007096

Note: Rate classes SST-TST and SST-DST rates are set as prescribed in Order No. 17159, Docket No. 850673-EU.

MFR E-14 Workpapers
Rate Class SL-2

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line	Type of	Present Revenue Calculation				Proposed Revenue Calculation			Percent
No.	Charges	Units	Charge/Unit	$ Revenue		Units	Charge/Unit	$ Revenue	Increase
1	RATE SCHEDULE SL-2 - 86								
2									
3									
4	**Total Revenue**			$ 1,254,377				$ 1,254,377	0.0%
5									
6							Increase	$ -	
7							Target	$ -	
8							Difference	$ -	

MFR E-14 Workpapers
Rate Class SL-1

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line	Type of	Present Revenue Calculation				Proposed Revenue Calculation			Percent
No.	Charges	Units	Charge/Unit	$ Revenue		Units	Charge/Unit	$ Revenue	Increase
1	RATE SCHEDULE SL-1 - 87								
2									
3									
4	Total Revenue			$ 70,716,672				$ 78,478,444	11.0%
5									
6							Increase	$ 7,761,772	
7							Target	$ 7,761,772	
8							Difference	$ 0	

MFR E-14 Workpapers
Rate Class GSLD(T)-3

Line No.	(1) Type of Charges	(2) Present Revenue Calculation Units	(3) Charge/Unit	(4) $ Revenue	(5)	(6) Proposed Revenue Calculation Units	(7) Charge/Unit	(8) $ Revenue	(9) Percent Increase
1	RATE SCHEDULE GSLD-3 - 91								
2									
3	Customer	-	$ 1,441.88	$ -		-	$ 1,441.88	$ -	
4	Non-Fuel Energy	-	$ 0.00640	$ -		-	$ 0.00640	$ -	
5	Demand	-	$ 6.32	$ -		-	$ 6.32	$ -	
6	Subtotal			$ -				$ -	
7	CDR Credit								
8	Adder	-	$ 2,825.46	$ -		-	$ 475.00	$ -	
9	Credit	-	$ (4.68)	$ -		-	$ (4.68)	$ -	
10	Total			$ -				$ -	
11									
12	RATE SCHEDULE GSLDT-3 - 90								
13									
14	Customer	72	$ 1,441.88	$ 103,815		72	$ 1,441.88	$ 103,815	
15	Non-Fuel Energy								
16	On Peak	51,459,583	$ 0.00739	$ 380,286		51,459,583	$ 0.00739	$ 380,286	
17	Off Peak	139,475,583	$ 0.00604	$ 842,433		139,475,583	$ 0.00604	$ 842,433	
18	Demand	361,134	$ 6.32	$ 2,282,367		361,134	$ 6.32	$ 2,282,367	
19	Subtotal			$ 3,608,901				$ 3,608,901	
20	CDR Credit								
21	Adder	-	$ 2,825.46	$ -		-	$ 475.00	$ -	
22	Credit	-	$ (4.68)	$ -		-	$ (7.30)	$ -	
23	Total			$ 3,608,901				$ 3,608,901	0.0%
24									
25	RATE SCHEDULE CS-3 - 92								
26									
27	Customer	-	$ 1,441.88	$ -		-	$ 1,466.88	$ -	
28	Non-Fuel Energy	-	$ 0.00640	$ -		-	$ 0.00640	$ -	
29	Demand	-	$ 6.32	$ -		-	$ 6.32	$ -	
30	Transformation Credit	-	$ (0.24)	$ -		-	$ (0.24)	$ -	
31	Curtailable Credit	-	$ (1.72)	$ -		-	$ (1.72)	$ -	
32	Total			$ -				$ -	

MFR E-14 Workpapers
Rate Class GSLD(T)-3

33													
34	RATE SCHEDULE CST-3 - 82												
35													
36	Customer		12	$	1,441.88	$	17,303	12	$	1,466.88	$	17,603	
37	Non-Fuel Energy												
38	On Peak		302,625	$	0.00739	$	2,236	302,625	$	0.00739	$	2,236	
39	Off Peak		8,244,974	$	0.00604	$	49,800	8,244,974	$	0.00604	$	49,800	
40	Demand		4,254	$	6.32	$	26,885	4,254	$	6.32	$	26,885	
41	Transformation Credit		-	$	(0.24)	$	-	-	$	(0.24)	$	-	
42	Curtailable Credit		-	$	(1.72)	$	-	-	$	(1.72)	$	-	
43	Total					$	96,224				$	96,524	0.3%
44													
45	TOTAL					$	3,705,125				$	3,705,425	
46													
47								Increase			$	300	
48								Target			$	300	
49								Difference			$	-	
50		$	0.00682										
51	Revenue neutral calculation												
52	on pk class average		25.94%		Energy Revenue								
53	on peak		49,525,295		365,992								
54	off peak		141,409,871		854,116								
55	total at class on-pk		190,935,166		1,220,108								
56	total at GSLD3 energy rates	$	0.00640		1,221,985								
57	Difference				1,878								
58	adjustment				-0.00135								
59													
60	GSLD3 adjustment				-0.00036								

MFR E-14 Workpapers
Rate Class GSCU

Line No.	(1) Type of Charges	(2) Present Revenue Calculation Units	(3) Charge/Unit	(4) $ Revenue	(5)	(6) Proposed Revenue Calculation Units	(7) Charge/Unit	(8) $ Revenue	(9) Percent Increase
1	RATE SCHEDULE GSCU-1 - 168								
2									
3	Customer	53,146	$ 6.00	$ 318,876		53,146	$ 12.00	$ 637,752	
4	Non-Fuel Energy	37,869,107	$ 0.03563	$ 1,349,276		37,869,107	$ 0.02808	$ 1,063,365	
5	Demand	-	$ -	$ -		-	$ -	$ -	
6	Unmetered Service Credit	-	$ -	$ -		-	$ -	$ -	
7	Total			$ 1,668,152				$ 1,701,117	2.0%
8									
9	TOTAL			$ 1,668,152				$ 1,701,117	
10									
11							Increase	$ 32,964	
12							Target	$ 32,964	
13							Difference	$ 0	

MFR E-14 Workpapers

Line No.	Transformer credit worksheet			
1	Transformer costs	Demand	$	212,881,826
2		TX Rating		63,726
3		TX Credit	$	0.28
4		Current credit		0.24
5		Increase reque	$	0.04
6		Reduction		65%
		Reduced incre		0.03
		Reduced TX c		0.27

MFR E-14 Workpapers

Demand Rate calculation

Line No.		GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3
1	E6b per unit cost				
2	Production - Steam	0.6135781	0.706096676	0.654134579	0.572111348
3	Production - Nuclear	2.423721	2.861292778	2.697928729	2.260876585
4	Production - Other Production	2.763468	3.251536899	3.064728788	2.577131405
5	Production - Other Power Supply	0.0349707	0.041537362	0.03919298	0.032636599
6	Production - Curtailment Credit	0.0017294	0.00186214	0.001729762	0.001593091
7	Transmission	1.1324203	1.332199795	1.255637933	1.056049154
8	Distribution - Land & Land Rights	0.0424082	0.050034071	0.045426039	0
9	Distribution - Structures & Improvements	0.0722855	0.085945173	0.078099208	0
10	Distribution - Station Equipment	0.6208316	0.739655293	0.672288677	0
11	Distribution - Poles, Towers & Fixtures	0.2844895	0.337546006	0.30110692	0
12	Distribution - Overhead Conductors & Devices	1.1215134	1.337093942	1.149859042	0
13	Distribution - Underground Conduit	0.5793098	0.686765743	0.611849917	0
14	Distribution - Underground Conductors & Devices	0.4523633	0.53169631	0.463829809	0
15	Distribution - Primary Capacitors and Regulators	0.0779839	0.09302405	0.084563465	0
16	Distribution - Secondary Transformers	0.4410058	0.402673338	0.284136974	0
17	**Sub-Total Unit Costs ($/Unit)**	10.662078	12.45895958	11.40451282	6.500398181
18					
19					
20					
21		GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3
22					
23	Per Unit Rounded	10.70	12.50	11.40	6.50
24	Adjustment	-3	-2	-2	0
25	Proposed Demand rates	$ 7.70	$ 10.50	$ 9.40	$ 6.50
26					
27	HLFT On Peak rate	$ 8.80	$ 10.30	$ 9.50	Production, transmission plus 1/2 distribution
28	HLFT Max Demand rate	$ 1.80	$ 2.10	$ 1.80	1/2 distribution
29		$ 10.60	$ 12.40	$ 11.30	

MFR E-14 Workpapers

CILC Demand calculation

Line No.	CILC	CILC-1D	CILC-1G	CILC-1T
1				
2	Production - Steam	3,827,175	248,684	1,675,016
3	Production - Nuclear	15,172,187	982,404	6,647,035
4	Production - Other Power Supply	219,545	14,160	96,293
5	Production - Other Production	17,245,960	1,119,092	7,550,894
6	Production - Curtailment Credit	10,511	709	4,474
7	Transmission	7,067,007	458,628	3,094,091
8	Total	43,542,386	2,823,677	19,067,803
9	Billing units	5,612,798	351,564	2,393,038
10	Firm on-peak demand	$ 7.80	$ 8.00	$ 8.00
11				
12	Distribution - Land & Land Rights	268,116	18,219	-
13	Distribution - Structures & Improvements	458,269	30,986	-
14	Distribution - Overhead Conductors & Devices	6,631,012	479,567	-
15	Distribution - Line Transformers	2,018,834	194,563	-
16	Distribution - Poles, Towers & Fixtures	1,760,608	121,937	-
17	Distribution - Station Equipment	3,939,310	266,009	-
18	Distribution - Underground Conduit	3,578,188	248,318	-
19	Distribution - Underground Conductors & Devices	2,715,130	194,254	-
20	Total Distribution	21,369,467	1,553,853	
21	Billing units	6,864,611	458,889	
22	Max Demand	$ 3.10	$ 3.40	
23				
24	Transmission	7,067,007	458,628	3,094,091
25	Billing units	5,612,798	351,564	2,393,038
26	load control on peak	$ 1.30	$ 1.30	$ 1.30
27				
28	Billing units			
29	Load Control On-Peak	4,807,458	344,050	1,880,654
30	Firm On-Peak	805,340	7,514	512,384
31	Total On-Peak	5,612,798	351,564	2,393,038
32				
33	Max Demand	6,864,611	458,889	512,384

MFR E-14 Workpapers

Customer Charge calculation

Line No.		Total Retail	CILC-1D	CILC-1G	CILC-1T
1	**Customer**				
2	**Unit Costs ($/Unit)**				
3	Transmission Pull-Offs	0.000000	0.000000	0.000000	1,272.376234
4	Distribution - Meters	0.000000	160.996521	96.886451	768.677938
5	Distribution - Installation on Customer's Premises	0.000000	0.056461	0.056544	0.000000
6					
7	Distribution - Services	0.000000	23.455799	3.032167	0.000000
8	Customer - Meter Reading	0.000000	12.876118	8.409548	13.993823
9	Customer - Collections, Service and Sales	0.000000	3.582959	3.587032	3.581049
10	Customer - Misc Serv Revs - Field Collection - Late Payment	0.000000	(52.659645)	(8.239204)	(80.916352)
11	Customer - Misc Serv Revs - Initial Connection	0.000000	0.000000	0.000000	0.000000
12	Customer - Misc Serv Revs - Connection of Existing Account	0.000000	(0.014000)	0.000000	0.000000
13	Customer - Misc Serv Revs - Reconnection	0.000000	0.000000	0.000000	0.000000
14	Customer - Misc Serv Revs - Returned Check Charges	0.000000	0.000000	0.000000	0.000000
15	Customer - Misc Serv Revs - Current Diversion	0.000000	0.000000	0.000000	0.000000
16	Customer - Misc Serv Revs - Other Billings	0.000000	(0.048860)	(0.048856)	(0.048732)
17	Customer - Misc Serv Revs - Reimbursements - Other	0.000000	0.008647	0.005504	0.000000
18	**Sub-Total Unit Costs ($/Unit)**	0.000000	148.254001	103.689185	1,977.663959
19					
20	Customer Charge		150.00	100.00	1,975.00
21					
22	Unmetered Credit				
23					
24	CDR Admin				

MFR E-14 Workpapers

Customer Charge calculation

Line No.		GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2
1	**Customer**					
2	**Unit Costs ($/Unit)**					
3	Transmission Pull-Offs	0.000000	0.000000	0.000000	0.000000	0.000000
4	Distribution - Meters	2.283670	1.945222	11.830494	44.767387	183.751076
5	Distribution - Installation on Customer's Premises	0.056840	0.056569	0.056591	0.056400	0.056401
6						
7	Distribution - Services	2.336895	2.318525	2.419331	5.375750	28.057577
8	Customer - Meter Reading	3.082943	3.747739	6.255971	8.415712	21.619853
9	Customer - Collections, Service and Sales	3.604864	3.588426	3.590557	3.580219	3.580505
10	Customer - Misc Serv Revs - Field Collection - Late Payment	(0.942908)	(0.020655)	(6.958400)	(40.802515)	(133.329948)
11	Customer - Misc Serv Revs - Initial Connection	(0.047160)	(0.000576)	(0.026229)	(0.025745)	0.000000
12	Customer - Misc Serv Revs - Connection of Existing Account	(0.185251)	0.000000	(0.094656)	(0.032111)	(0.030695)
13	Customer - Misc Serv Revs - Reconnection	(0.067369)	0.000000	(0.024093)	0.000000	0.000000
14	Customer - Misc Serv Revs - Returned Check Charges	(0.060088)	0.000000	(0.209146)	(0.470354)	0.000000
15	Customer - Misc Serv Revs - Current Diversion	(0.008407)	0.000000	(0.027398)	0.000000	0.000000
16	Customer - Misc Serv Revs - Other Billings	(0.048968)	(0.048655)	(0.048848)	(0.048545)	(0.048767)
17	Customer - Misc Serv Revs - Reimbursements - Other	0.008020	0.008014	0.007999	0.008050	0.007583
18	**Sub-Total Unit Costs ($/Unit)**	10.013082	11.594610	16.772174	20.824246	103.663587
19						
20	Customer Charge	10.00	12.00	25.00	25.00	100.00
21						
22	Unmetered Credit	(5.00)				
23						
24	CDR Admin			75.00	125.00	50.00

MFR E-14 Workpapers

Customer Charge calculation

Line No.		GSLD(T)-3	MET	OL-1	OS-2
1	**Customer**				
2	**Unit Costs ($/Unit)**				
3	Transmission Pull-Offs	1,280.257437	0.000000	0.000000	0.000000
4	Distribution - Meters	262.165190	270.170662	0.000000	54.464699
5	Distribution - Installation on Customer's Premises	0.000000	0.056425	0.000420	0.056354
6					
7	Distribution - Services	0.000000	106.015529	0.000000	37.331095
8	Customer - Meter Reading	12.135547	14.863681	0.000000	7.479937
9	Customer - Collections, Service and Sales	3.585039	3.581175	0.002601	3.577609
10	Customer - Misc Serv Revs - Field Collection - Late Payment	(59.426935)	0.000000	(0.001388)	(0.204382)
11	Customer - Misc Serv Revs - Initial Connection	0.000000	0.000000	0.000000	0.000000
12	Customer - Misc Serv Revs - Connection of Existing Account	0.000000	0.000000	0.000000	0.000000
13	Customer - Misc Serv Revs - Reconnection	0.000000	0.000000	0.000000	0.000000
14	Customer - Misc Serv Revs - Returned Check Charges	0.000000	0.000000	(0.000129)	0.000000
15	Customer - Misc Serv Revs - Current Diversion	0.000000	0.000000	0.000000	0.000000
16	Customer - Misc Serv Revs - Other Billings	(0.049169)	(0.048616)	(0.000036)	(0.048877)
17	Customer - Misc Serv Revs - Reimbursements - Other	0.000000	0.000000	0.000006	0.009246
18	**Sub-Total Unit Costs ($/Unit)**	1,498.667109	394.638856	0.001475	102.665679
19					
20	Customer Charge	1,500.00	400.00		100.00
21					
22	Unmetered Credit				
23					
24	CDR Admin	475.00			

MFR E-14 Workpapers

Customer Charge calculation

Line No.		RS(T)-1	SL-1	SL-2	SST-DST
1	**Customer**				
2	**Unit Costs ($/Unit)**				
3	Transmission Pull-Offs	0.000000	0.000000	0.000000	0.000000
4	Distribution - Meters	2.244309	0.000000	0.000000	259.491391
5	Distribution - Installation on Customer's Premises	0.056828	0.000000	0.000000	0.056523
6					
7	Distribution - Services	2.317463	0.000000	0.000000	106.963775
8	Customer - Meter Reading	0.697931	0.000000	0.000000	12.281780
9	Customer - Collections, Service and Sales	3.606052	0.000700	0.001173	3.586102
10	Customer - Misc Serv Revs - Field Collection - Late Payment	(1.021849)	(0.000586)	(0.004215)	(4.791556)
11	Customer - Misc Serv Revs - Initial Connection	(0.007101)	0.000000	0.000000	0.000000
12	Customer - Misc Serv Revs - Connection of Existing Account	(0.299631)	0.000000	0.000000	0.000000
13	Customer - Misc Serv Revs - Reconnection	(0.170457)	0.000000	0.000000	0.000000
14	Customer - Misc Serv Revs - Returned Check Charges	(0.123121)	(0.000002)	0.000000	0.000000
15	Customer - Misc Serv Revs - Current Diversion	(0.046395)	0.000000	0.000000	0.000000
16	Customer - Misc Serv Revs - Other Billings	(0.049119)	(0.000010)	(0.000016)	(0.048863)
17	Customer - Misc Serv Revs - Reimbursements - Other	0.004742	0.000002	0.000003	0.000000
18	**Sub-Total Unit Costs ($/Unit)**	7.209653	0.000105	(0.003056)	377.539152
19					
20	Customer Charge	7.00			375.00
21					
22	Unmetered Credit				
23					
24	CDR Admin				

MFR E-14 Workpapers

Customer Charge calculation

Line No.		SST-TST
1	**Customer**	
2	**Unit Costs ($/Unit)**	
3	Transmission Pull-Offs	1,375.039204
4	Distribution - Meters	252.960238
5	Distribution - Installation on Customer's Premises	0.000000
6		
7	Distribution - Services	0.000000
8	Customer - Meter Reading	11.262050
9	Customer - Collections, Service and Sales	3.623877
10	Customer - Misc Serv Revs - Field Collection - Late Payment	(166.996833)
11	Customer - Misc Serv Revs - Initial Connection	0.000000
12	Customer - Misc Serv Revs - Connection of Existing Account	0.000000
13	Customer - Misc Serv Revs - Reconnection	0.000000
14	Customer - Misc Serv Revs - Returned Check Charges	0.000000
15	Customer - Misc Serv Revs - Current Diversion	0.000000
16	Customer - Misc Serv Revs - Other Billings	(0.048863)
17	Customer - Misc Serv Revs - Reimbursements - Other	0.000000
18	**Sub-Total Unit Costs ($/Unit)**	1,475.839674
19		
20	Customer Charge	1,475.00
21		
22	Unmetered Credit	
23		
24	CDR Admin	

MFR E-14 Workpapers

Time of Use Customer Charge Calculation

Line No.	Description	RS(T)	GS(T)	GSD(T)
1	Customer Billing Units			
2	Billing Units	48,978,495	4,972,911	1,261,552
2	TOU Metering	1,956	6,988	55,088
3	Standard Metering	48,976,539	4,965,923	1,206,464
3	Total	48,978,495	4,972,911	1,261,552
4				
4	Dollars			
5	Allocation Percent	100%	100%	93%
5	Allocated Dollars	$ 109,922,884	$ 11,356,486	$ 14,924,784
6	Total Standard (from E-6b)	$ 353,117,962	$ 49,794,168	$ 21,158,970
6	Total Metering Cost (from E-6b)	$ 109,922,884	$ 11,356,486	$ 14,924,784
7	Total Non-Metering Cost (from E-6b)	$ 243,195,079	$ 38,437,681	$ 6,234,187
7				
8	Standard Metering	$ 109,910,704	$ 11,322,820	$ 13,912,397
8	TOU Metering	$ 12,179	$ 33,666	$ 1,012,387
9				
9	Total TOU	$ 21,892	$ 87,679	$ 1,284,614
10	Total Standard	$ 353,096,071	$ 49,706,488	$ 19,874,356
10				
11	Per Unit Costs			
11	Standard Metering	$ 7.21	$ 10.01	$ 16.47
12	TOU Metering	$ 11.19	$ 12.55	$ 23.32
12	Average	$ 7.21	$ 10.01	$ 16.77
13				
13	Distribution - Meters	$ 109,922,884	$ 11,356,486	$ 14,924,784

25

MFR E-14 Workpapers

Time of Use Customer Charge Calculation

Line No.	Description	RS(T)	GS(T)	GSD(T)
14	Customer - Meter Reading	$ 34,183,598	$ 15,331,203	$ 7,892,233
14				
15	Proposed Costs			
15	Standard Metering	$ 7.00	$ 10.00	$ 25.00
16	TOU Metering	$ 11.00	$ 13.00	$ 25.00

Q.

Please refer to paragraph 6 of the Stipulation and Settlement. In the next from the last sentence, the phrase "through a cost recovery clause" appears. Which cost recovery clause or clauses does this paragraph involve? As part of the answer to this question, state the cost categories that are the subject of this paragraph (cyber security, seismic and flood protection costs) and state the cost recovery clause for each category and tie each cost covered by this paragraph to a specific cost recovery clause.

A.

Paragraph 6 is (and is intended by the signatories to be) substantially identical to Paragraph 4 of the 2010 Settlement Agreement approved in Docket No. 080677-EI. In both instances, these paragraphs are intended to define the circumstances under which FPL may seek to recover costs through the various cost recovery clause mechanisms presently authorized by the Commission (i.e., fuel and purchased power cost recovery clause, capacity cost recovery clause, environmental cost recovery clause and energy conservation cost recovery clause) or that may be authorized in the future. In general, Paragraph 6 permits FPL to use cost recovery clauses to recover the types of costs that traditionally and historically have been clause recoverable, while restricting FPL's use of clause recovery for types of costs that have not previously been clause recoverable to circumstances where such costs are incurred as a result of requirements imposed by an authorized governmental entity (e.g., the U.S Nuclear Regulatory Commission) and either the Florida Legislature or this Commission has authorized the use of clause recovery for that purpose. As was the case with Paragraph 4 in the 2010 Settlement Agreement, the parenthetical reference to the types of costs that might be imposed in the future by governmental requirements is illustrative and is not intended either to define the full range of such governmental requirements that may arise or to indicate that FPL necessarily intends to seek clause recovery for such costs. FPL notes that, as discussed in the testimony of FPL witness Art Stall in this docket, there are limited costs for complying with seismic and flood-protection requirements arising out the Fukushima Daiichi event projected in the 2013 test year but FPL expects that those compliance costs may turn out to be much higher in 2013 and beyond. Accordingly, FPL's 2013 projection filing in Docket No. 120001-EI includes a request to recover through the capacity cost recovery clause any incremental increases in such compliance costs above the level included in the 2013 test year.

Q.
Refer to paragraph 7(a) of the Stipulation and Settlement.

a. Per Section 7(a) of the proposed stipulation, FPL will continue to recover the annual non-fuel revenue requirement for West County Unit 3 (WCEC 3) through the capacity cost recovery clause (capacity clause) in the manner provided in the 2010 rate case stipulation. Will FPL continue to use a 10% return on equity in the calculation of the WCEC 3 annual non-fuel revenue requirement? If not, please explain.

b. Is it correct that the WCEC 3 annual revenue requirement capital structure includes only long-term debt and common equity, excluding all other sources of capital?

c. Provide a calculation of the overall rate of return for the WCEC 3 annual revenue requirement on a pre-tax and after-tax basis for 2011, 2012 and 2013 that has been or would be included in the capacity clause.

d. Provide a calculation of the WCEC 3 jurisdictional annual revenue requirement for 2011 (actual) and 2012 (projected) that has been included for recovery in the capacity clause.

e. Based on the WCEC 3 amounts included in the 2013 projected test year (as appropriate), provide a calculation of the 2013 WCEC 3 jurisdictional annual revenue requirement that would be included for recovery in the capacity clause pursuant to Section 7 of the proposed stipulation. Please indicate if any of the amounts in the calculation are based on amounts from the need determination.

f. Please state the projected fuel savings for 2012 and 2013 and the annual non-fuel revenue requirement for West County Unit 3 for 2012 and 2013.

g. Does FPL expect the annual non-fuel revenue requirement for West County Unit 3 to exceed projected fuel savings for any year covered by this Stipulation and Settlement? Please explain.

h. Are the expenses included in the calculation of the WCEC 3 jurisdictional annual revenue requirement for recovery through the capacity clause based on actual amounts or on estimated amounts that were included in the need determination request?

i. If the WCEC 3 jurisdictional annual revenue requirement expenses are based on estimated amounts from the need determination, please provide a comparison between the actual expenses and the expenses recovered through the capacity clause for 2011 for O&M expenses, depreciation, property taxes, and income taxes.

A.

a. Pursuant to Paragraph 2 of the settlement agreement, FPL would utilize a 10.7% return on equity in the calculation of WCEC 3 annual non-fuel revenue requirements. All other WCEC 3 costs are based on need determination amounts.

b. Yes. WCEC3 annual revenue requirement capital structure includes only long term debt and common equity, and excludes all other sources of capital.

c. Please see Attachment No. 1 to this request.

d. Please see Attachment No. 2 to this request.

e. Please see Attachment No. 3 to this request.

f. The projected fuel savings for 2012 and 2013 are $190,367,000 and $133,225,000, respectively. The lower projected fuel savings for 2013 are largely due to lower projected fuel costs, which mean customers will pay less overall for fuel in 2013. For the annual non-fuel revenue requirements for WCEC 3 for 2012, see FPL's response to subpart (d). For the annual non-fuel revenue requirements for WCEC 3 for 2013, see FPL's response to subpart (e).

g. Yes. The annual non-fuel revenue requirement for WCEC 3 is expected to exceed fuel savings under the Stipulation and Settlement period.

Over its life, WCEC 3 is projected to result in significant net benefits for FPL's customers. For example, WCEC 3 was projected to result in a net benefit of at least $460 million of Current Present Value of Revenue Requirements (CPVRR) to FPL's customers compared to any resource plan that did not include WCEC 3.

h. As is also the case in FPL's 2012 rate petition, section 7(a) of the proposed stipulation would not provide for WCEC3 cost recovery to be limited to projected fuel savings. The expenses included in the calculation of the WCEC 3 jurisdictional annual non-fuel revenue requirements for recovery through FPL's capacity clause in all years are based on estimated amounts upon which FPL's need determination request was granted.

i. Throughout the term of FPL's 2010 Stipulation and Settlement Agreement, FPL is authorized to recover the lower of the annual non-fuel revenue requirements associated with WCEC 3 through FPL's capacity clause, based on need determination costs, and the amount of projected fuel savings for WCEC 3 each year. Because FPL recovered estimated annual non-fuel revenue requirements in 2011, a complete comparison of the requested information is not available. Once a plant is in service, many of the cost components are not tracked separately such as deferred taxes, operating expenses, and property taxes, however, the following amounts have been separately identified. The amount of production maintenance expense recorded in 2011 for WCEC 3 was $3,868,000. Depreciation Expense for WCEC 3, excluding common plant depreciation and dismantlement expense, was $16,329,640, and property taxes were not incurred until 2012.

WEST COUNTY UNIT 3 RATE OF RETURN
FOR 2011, 2012 AND 2013

West County Unit 3 — **As Filed In 2011 and 2012**

Capital Structure	Ratio	Cost Rate	Wtd Cost Rate	Pre Tax COC	After Tax COC
Long Term Debt	44.20%	6.43%	2.84%	2.84%	1.746%
Common Equity	55.80%	10.00%	5.58%	9.08%	5.58%
Total	100.00%		8.42%	11.93%	7.33%

West County Unit 3 — **2013 Per Proposed Settlement Agreement**

Capital Structure	Ratio	Cost Rate	Wtd Cost Rate	Pre Tax COC	After Tax COC
Long Term Debt	44.20%	6.43%	2.84%	2.84%	1.746%
Common Equity	55.80%	10.70%	5.97%	9.72%	5.97%
Total	100.00%		8.81%	12.56%	7.72%

WCEC UNIT 3
2011 REVENUE REQUIREMENTS

WCEC3 Revenue Requirement Calculation	06/01/2011 - 12/31/2011 ($000)
Jurisdictional Adjusted Rate Base	$845,832
Rate of Return on Rate Base	8.422%
Required Jurisdictional Net Operating Income	71,236
Partial Year Required Net Operating Income (7/12)	41,555
Jurisdictional Adjusted Net Operating Income (Loss)	(19,414)
Net Operating Income Deficiency (Excess)	60,968
Net Operating Income Multiplier	1.63411
2011 Revenue Requirement - First 7 Months Operation	$99,629

Note:
For 2011, the estimated fuel savings were lower than revenue requirements (approx. $96M)
Therefore, FPL collected the amount equal to the estimated fuel savings through the capacity clause in 2011.

WCEC UNIT 3
2012 REVENUE REQUIREMENTS

WCEC3 Revenue Requirement Calculation	2012 ($000)
Jurisdictional Adjusted Rate Base	$812,068
Rate of Return on Rate Base	8.422%
Required Jurisdictional Net Operating Income	68,393
Required Net Operating Income	68,393
Jurisdictional Adjusted Net Operating Income (Loss)	(33,718)
Net Operating Income Deficiency (Excess)	102,111
Net Operating Income Multiplier	1.63411
2012 Revenue Requirement	$166,861

Note:
For 2012, the estimated fuel savings were higher than revenue requirements.
Therefore, FPL collected the non-fuel revenue requirements through the capacity clause in 2012.

2011 AND 2012
WCEC3 REVENUE REQUIREMENT DATA

Capital Structure	Ratio	Cost Rate	Wtd Cost Rate	Pre Tax COC	After Tax COC
Long Term Debt	44.200%	6.430%	2.84206%	2.84206%	1.74574%
Common Equity	55.800%	10.000%	5.58000%	9.08425%	5.58000%
Total	100.000%		8.42206%	11.92631%	7.32574%

Assumptions	
Income Tax Rate	38.575%
Production Depreciation Rate	4.000%
Transmission Depreciation Rate	2.500%
Rate of Return	8.42206%

Net Plant	6/01/2011	12/31/2011	5/31/2012	12/31/2012
Production Plant	819,157,500	819,157,500	819,157,500	819,157,500
Transmission Plant	45,570,260	45,570,260	45,570,260	45,570,260
Production Reserve	0	(19,113,675)	(32,766,300)	(51,879,975)
Transmission Reserve	0	(664,566)	(1,139,257)	(1,803,823)
Deferred Taxes	9,376,790	4,664,390	(450,838)	(5,746,400)
Net Plant	874,104,550	849,613,909	830,371,366	805,297,562

	6/01/2011-12/31/2011	6/01/2011-5/31/2012	12/31/2011-12/31/2012
Average Rate Base	861,859,229	852,237,958	827,455,735
Juris Factor	0.981404	0.981404	0.981404
Juris Rate Base	845,832,095	836,389,741	812,068,369
Juris Interest Expense	14,022,782	23,770,698	23,079,470
Income Tax - Interest Expense	(5,409,288)	(9,169,547)	(8,902,906)

Operating Expenses	6/01/2011-12/31/2011	6/01/2011-5/31/2012	12/31/2011-12/31/2012
Other O&M - FOM, CAP, VOM, Prop Ins	11,041,700	19,123,583	19,396,520
Depreciation	19,778,241	33,905,557	33,905,557
Taxes Other Than Income Taxes - Prop Tax	9,079,640	15,416,761	15,209,090
Total Operating Expenses	39,899,581	68,445,901	68,511,167
Juris Operating Expenses	39,149,725	67,159,426	67,223,284
Income Tax - Operating Expenses	(15,102,006)	(25,906,749)	(25,931,382)
Other Income Taxes - Def Taxes	790,050	1,354,370	1,354,370
Juris Other Income Taxes	775,358	1,329,184	1,329,184

Juris Net Operating Income	6/01/2011-12/31/2011	6/01/2011-5/31/2012	12/31/2011-12/31/2012
Operating Expenses	(39,149,725)	(67,159,426)	(67,223,284)
Income Tax - Operating Expenses	15,102,006	25,906,749	25,931,382
Income Tax - Interest Expense	5,409,288	9,169,547	8,902,906
Other Income Taxes	(775,358)	(1,329,184)	(1,329,184)
Juris Net Operating Income	(19,413,788)	(33,412,315)	(33,718,181)

WCEC UNIT 3
2013 REVENUE REQUIREMENTS

WCEC3 Revenue Requirement Calculation	2013 ($000)
Jurisdictional Adjusted Rate Base	$769,387
Rate of Return on Rate Base	8.813%
Required Jurisdictional Net Operating Income	67,803
Required Net Operating Income	67,803
Jurisdictional Adjusted Net Operating Income (Loss)	(34,046)
Net Operating Income Deficiency (Excess)	101,849
Net Operating Income Multiplier	1.63411
2013 Revenue Requirement	$166,433

Revenue Requirement Backup Data

Capital Structure	Ratio	Cost Rate	Wtd Cost Rate	Pre Tax COC	After Tax COC
Long Term Debt	44.200%	6.430%	2.84206%	2.84206%	1.74574%
Common Equity	55.800%	10.700%	5.97060%	9.72015%	5.97060%
Total	100.000%		8.81266%	12.56221%	7.71634%

Assumptions	
Income Tax Rate	38.575%
Production Depreciation Rate	4.000%
Transmission Depreciation Rate	2.500%
Rate of Return	8 81266%

Net Plant	6/01/2011	12/31/2011	5/31/2012	12/31/2012	12/31/2013
Production Plant	819,157,500	819,157,500	819,157,500	819,157,500	819,157,500
Transmission Plant	45,570,260	45,570,260	45,570,260	45,570,260	45,570,260
Production Reserve	0	(19,113,675)	(32,766,300)	(51,879,976)	(84,646,275)
Transmission Reserve	0	(664,566)	(1,139,257)	(1,803,823)	(2,943,079)
Deferred Taxes	9,376,790	4,664,390	(450,838)	(5,746,400)	(14,504,962)
Net Plant	874,104,550	849,613,909	830,371,366	805,297,562	762,633,444

	6/01/2011-12/31/2011	6/01/2011-5/31/2012	12/31/2011-12/31/2012	1/01/2012-5/31/2012	12/31/2012-12/31/2013
Average Rate Base	861,859,229	852,237,958	827,455,735	819,157,500	783,965,503
Juris Factor	0.981404	0.981404	0.981404	0.981404	0.981404
Juris Rate Base	845,832,095	836,389,741	812,068,369	803,924,447	769,386,880
Juris Interest Expense	14,022,782	23,770,698	23,079,470	9,520,006	21,866,437
Income Tax - Interest Expense	(5,409,288)	(9,169,547)	(8,902,906)	(3,672,342)	(8,434,978)

Operating Expenses	6/01/2011-12/31/2011	6/01/2011-5/31/2012	12/31/2011-12/31/2012	1/01/2012-5/31/2012	12/31/2012-12/31/2013
Other O&M - FOM, CAP, VOM, Prop Ins	11,041,700	19,123,583	19,396,520	8,081,883	19,774,240
Depreciation	18,778,241	33,905,557	33,905,557	14,127,315	33,905,557
Taxes Other Than Income Taxes - Prop Tax	9,079,640	15,416,761	15,209,090	6,337,121	14,598,800
Total Operating Expenses	39,899,581	68,445,901	68,511,167	28,546,319	68,278,597
Juris Operating Expenses	39,149,725	67,159,426	67,223,284	28,009,702	66,994,769
Income Tax - Operating Expenses	(15,102,006)	(25,906,749)	(25,931,382)	(10,804,742)	(25,843,232)
Other Income Taxes - Def Taxes	790,050	1,354,370	1,354,370	564,320	1,354,370
Juris Other Income Taxes	775,358	1,329,184	1,329,184	553,826	1,329,184

Juris Net Operating Income	6/01/2011-12/31/2011	6/01/2011-5/31/2012	12/31/2011-12/31/2012	1/01/2012-5/31/2012	12/31/2012-12/31/2013
Operating Expenses	(39,149,725)	(67,159,426)	(67,223,284)	(28,009,702)	(66,994,769)
Income Tax - Operating Expenses	15,102,006	25,906,749	25,931,382	10,804,742	25,843,232
Income Tax - Interest Expense	5,409,288	9,169,547	8,902,908	3,672,342	8,434,978
Other Income Taxes	(775,358)	(1,329,184)	(1,329,184)	(553,826)	(1,329,184)
Juris Net Operating Income	(19,413,788)	(33,412,315)	(33,718,181)	(14,086,443)	(34,045,743)

Q.
Refer to paragraph 8(a) of the Stipulation and Settlement.

a. Per Section 8(c) of the proposed stipulation, is it correct that the capital structure to be utilized to calculate the GBRA will exclude short-term debt, preferred stock, customer deposits, deferred taxes and investment credits?

b. For both the WCEC 3 annual revenue requirement calculation and the GBRA calculation, is it correct that deferred taxes are treated as a reduction to rate base?

c. Provide a calculation of the WCEC 3 annual revenue requirement that is included in the proposed $516.5 million base rate increase in Docket No. 120015-EI.

d. For each of the three projects described in Section 8(a) of the proposed settlement, please provide the estimated revenue requirement for the first 12 months of operation. The estimated revenue requirements should also be separated by capital, fixed O&M, and variable O&M.

e. For each GBRA, why is it more appropriate to use the capital structure reflected in the MFR's for the Canaveral Step Increase than using the overall cost of capital for the 2013 test year?

f. For each GBRA, what is the difference in the revenue requirement using the capital structure reflected in the MFR's for the Canaveral Step Increase versus using the overall cost of capital for the 2013 test year?

g. What is the anticipated impact on a 1,000 kWh residential bill of the base rate increases due to the Riviera Modernization (2014)? For the Port Everglades Modernization Project (2016)?

A.
a. Yes. The capital structure to be utilized to calculate the GBRA would exclude short term debt, preferred stock, customer deposits, deferred taxes, and investment tax credits as these other sources cannot be utilized to finance the plants. For example, customer deposits cannot be expanded in order to help finance a new power plant, yet the mathematical result of utilizing an overall cost of capital for GBRA would imply that result.

b. Yes. For both the annual revenue requirements for WCEC3 and the GBRA calculation, deferred taxes are treated as a reduction to rate base.

c. As addressed during the technical hearing, FPL's MFR filing (e.g., MFR A-2) reflected the inclusion in the "Bill Under Present Rates" of WCEC 3 revenues that are currently being recovered through the capacity clause. Therefore, FPL did not include additional revenues (or identify separate revenue requirements) for WCEC3 in the proposed $516.5 million base rate increase. Please note that the tariff sheets included as Exhibit B to the proposed settlement agreement reflect continued recovery of WCEC3 through the capacity clause pursuant to paragraph 7 rather than recovery through base rates.

d. Please see Attachment No. 1 to this request for Cape Canaveral revenue requirements, Attachment No. 2 to this request for Riviera revenue requirements, and Attachment No. 3 to this request for Port Everglades revenue requirements.

e. The purpose of the Canaveral Step Increase is to recover the incremental costs associated with the first year operation of the Cape Canaveral Modernization Project. Because generation plants are long-lived assets, which typically are financed incrementally, only common equity and long-term debt should be included in the incremental capital structure. In addition, all forecasted deferred taxes related to the construction of the Cape Canaveral Modernization Project and generated during its first year of operations are appropriately included as a reduction to rate base. This approach was used to develop the revenue requirements in FPL's need determination hearings and was also consistently used to develop the incremental generation base rate adjustments associated with cost recovery for FPL's Turkey Point Unit 5, West County Unit 1, West County Unit 2 and West County Unit 3 generation plants under FPL's 2005 and 2010 Settlement Agreements, Order No. PSC-05-0902-S-EI, Docket No. 050188-EI and Order No. PSC-11-0089-S-EI, Docket No. 080677-EI, respectively.

f. An accurate comparison cannot be performed, as the 2013 overall cost of capital is not representative of what would finance the plants to which the GBRA would apply. For Cape Canaveral, the 2013 overall cost of capital is unrepresentative because the cost of financing that plant were pulled out of the 2013 test year on an incremental basis, leaving a cost of capital that, by definition, does not reflect financing Cape Canaveral. For the Riviera and Everglades plants, this mismatch would be exacerbated by the fact that the 2013 overall cost of capital would not reflect any of the approximately $2.5 billion of additional financing requirements for these plants. See response to subparts (a) and (e) above.

g. See FPL's response to Staff's First Data Request No. 5(a).

CAPE CANAVERAL FIRST YEAR REVENUE REQUIREMENTS
($000)

Cape Canaveral Revenue Requirement Calculation	FIRST YEAR OPERATIONS ($000)
Jurisdictional Adjusted Rate Base	$811,809
Rate of Return on Rate Base	8.576%
Required Jurisdictional Net Operating Income	69,621
Required Net Operating Income	69,621
Jurisdictional Adjusted Net Operating Income (Loss)	(31,833)
Net Operating Income Deficiency (Excess)	101,454
Net Operating Income Multiplier	1.63188
Revenue Requirement	$165,561

Revenue Requirement Backup Data
Cape Canaveral Power Plant

Capital Structure	Ratio	Cost Rate	Wtd Cost Rate	Pre Tax COC
Long Term Debt	39.031%	5.258%	2.052%	2.052%
Common Equity	60.969%	10.700%	6.524%	10.621%
Total	100.000%		8.576%	12.673%

Jurisdictional Rate Base - MFR B-1	811,809
Jurisdictional NOI	(31,833)

Juris Rate Base - MFR B-1	($000)	KO -16 Adj	Revised	
Plant In Service	956,492	(10,069)	946,423	
Accum Provision Depreciation	(15,557)	166	(15,391)	
Working Capital	0	0	0	
Other - Deferred Taxes	(119,610)	387	(119,223)	
Total	821,325	(9,516)	811,809	Capital

Juris NOI - MFR C-1	($000)	KO -16 Adj	Revised	
Fixed O&M	6,394		6,394	Fixed O&M
Variable O&M	4,484		4,484	Variable O&M
Property Insurance	1,249		1,249	Capital
Depreciation	31,502	(331)	31,171	Capital
Property Taxes	17,670	(212)	17,458	Capital
Payroll Taxes	286		286	
Income Taxes	(29,494)	285	(29,209)	
Total NOI	(32,092)	(258)	(31,833)	

RIVIERA FIRST YEAR REVENUE REQUIREMENTS
($000)

Riviera Revenue Requirement Calculation	FIRST YEAR OPERATIONS ($000)
Jurisdictional Adjusted Rate Base	$1,220,926
Rate of Return on Rate Base	8.576%
Required Jurisdictional Net Operating Income	104,707
Required Net Operating Income	104,707
Jurisdictional Adjusted Net Operating Income (Loss)	(40,131)
Net Operating Income Deficiency (Excess)	144,838
Net Operating Income Multiplier	1.63188
Riviera Revenue Requirement	$236,358

Revenue Requirement Backup Data
Riviera Power Plant

Capital Structure	Ratio	Cost Rate	Wtd Cost Rate	Pre Tax COC
Long Term Debt	39.031%	5.258%	2.052%	2.052%
Common Equity	60.969%	10.700%	6.524%	10.621%
Total	100.000%		8.576%	12.673%

Assumptions	
Income Tax Rate	38.575%
Production Depreciation Rate	4.000%
Transmission Depreciation Rate	2.500%
Rate of Return	8.57603%
Juris Factor - Generation	98.14000%
Juris Factor - Transmission	89.47240%
Juris Factor - Property Insurance	97.92240%

Net Plant	6/01/2014	12/31/2014	5/31/2015	12/31/2015
Other Production Plant	1,116,295,066	1,116,295,066	1,116,295,066	1,116,295,066
Transmission Plant	159,287,859	159,287,859	159,287,859	159,287,859
Other Production Reserve	0	(26,046,885)	(44,651,803)	(70,698,688)
Transmission Reserve	0	(2,322,948)	(3,982,196)	(6,305,144)
Deferred Taxes	15,643,694	6,196,447	(2,109,956)	(13,738,919)
Net Plant	1,291,226,619	1,253,409,539	1,224,838,970	1,184,840,174

Juris Net Plant	6/01/2014	12/31/2014	5/31/2015	12/31/2015
Other Production Plant	1,095,531,978	1,095,531,978	1,095,531,978	1,095,531,978
Transmission Plant	142,518,670	142,518,670	142,518,670	142,518,670
Other Production Reserve	0	(25,562,413)	(43,821,279)	(69,383,692)
Transmission Reserve	0	(2,078,397)	(3,562,967)	(5,641,364)
Deferred Taxes	15,183,400	6,013,600	(2,047,562)	(13,331,381)
Juris Net Plant	1,253,234,048	1,216,423,438	1,188,618,840	1,149,694,211

	6/01/2014-5/31/2015	12/31/2014-12/31/2015	
Average Rate Base	1,258,032,794	1,219,124,857	
Juris Factor	0.970504	0.970416	
Juris Rate Base	1,220,926,444	1,183,058,825	Capital
Juris Interest Expense	25,057,528	24,280,357	
Income Tax - Interest Expense	(9,665,941)	(9,366,148)	

Operating Expenses	6/01/2014-5/31/2015	12/31/2014-12/31/2015
Fixed O&M	7,237,474	7,237,474

Revenue Requirement Backup Data
Riviera Power Plant

Capital Structure	Ratio	Cost Rate	Wtd Cost Rate	Pre Tax COC
Variable O&M			1,078,479	1,078,479
Property Insurance			787,023	799,520
Depreciation - Other Production			44,651,803	44,651,803
Depreciation - Transmission			3,982,196	3,982,196
Taxes Other Than Income Taxes - Prop Tax			23,576,735	22,748,803
Total Operating Expenses			81,313,710	80,498,275

Juris Operating Expenses	6/01/2014-5/31/2015	12/31/2014-12/31/2015	
Fixed O&M	7,102,857	7,102,857	Fixed O&M
Variable O&M	1,058,419	1,058,419	Variable O&M
Property Insurance	770,672	782,909	Capital
Depreciation - Other Production	43,821,279	43,821,279	Capital
Depreciation - Transmission	3,562,967	3,562,967	Capital
Taxes Other Than Income Taxes - Prop Tax	22,881,327	22,075,813	Capital
Total Juris Operating Expenses	79,197,521	78,404,244	

Juris Operating Expenses	79,197,521	78,404,244
Income Tax - Operating Expenses	(30,550,444)	(30,244,437)
Other Income Taxes - Def Taxes	(1,184,945)	(1,184,945)
Juris Other Income Taxes	(1,149,994)	(1,149,890)

Juris Net Operating Income	6/01/2014-5/31/2015	12/31/2014-12/31/2015
Operating Expenses	(79,197,521)	(78,404,244)
Income Tax - Operating Expenses	30,550,444	30,244,437
Income Tax - Interest Expense	9,665,941	9,366,148
Other Income Taxes	(1,149,994)	(1,149,890)
Juris Net Operating Income	(40,131,130)	(39,943,550)

PORT EVERGLADES FIRST YEAR REVENUE REQUIREMENTS
($000)

Port Everglades Revenue Requirement Calculation	FIRST YEAR OPERATIONS ($000)
Jurisdictional Adjusted Rate Base	$1,144,824
Rate of Return on Rate Base	8.576%
Required Jurisdictional Net Operating Income	98,180
Required Net Operating Income	98,180
Jurisdictional Adjusted Net Operating Income (Loss)	(35,505)
Net Operating Income Deficiency (Excess)	133,685
Net Operating Income Multiplier	1.63188
Revenue Requirement	$218,158

Revenue Requirement Backup Data
Port Everglades Power Plant

Capital Structure	Ratio	Cost Rate	Wtd Cost Rate	Pre Tax COC
Long Term Debt	39.031%	5.258%	2.052%	2.052%
Common Equity	60.969%	10.700%	6.524%	10.621%
Total	100.000%		8.576%	12.673%

Assumptions	
Income Tax Rate	38.575%
Production Depreciation Rate	3.333%
Transmission Depreciation Rate	2.500%
Rate of Return	8.57603%
Juris Factor - Generation	98.14000%
Juris Factor - Transmission	89.47240%
Juris Factor - Property Insurance	97.92240%

Net Plant	6/01/2016	12/31/2016	5/31/2017	12/31/2017
Other Production Plant	1,150,606,224	1,150,606,224	1,150,606,224	1,150,606,224
Transmission Plant	34,160,608	34,160,608	34,160,608	34,160,608
Other Production Reserve	0	(22,372,899)	(38,353,541)	(60,726,440)
Transmission Reserve	0	(498,176)	(854,015)	(1,352,191)
Deferred Taxes	12,254,368	3,876,975	(3,557,867)	(13,966,647)
Net Plant	1,197,021,200	1,165,772,733	1,142,001,409	1,108,721,555

Juris Net Plant	6/01/2016	12/31/2016	5/31/2017	12/31/2017
Other Production Plant	1,129,204,948	1,129,204,948	1,129,204,948	1,129,204,948
Transmission Plant	30,564,316	30,564,316	30,564,316	30,564,316
Other Production Reserve	0	(21,956,763)	(37,640,165)	(59,596,928)
Transmission Reserve	0	(445,730)	(764,108)	(1,209,838)
Deferred Taxes	11,995,811	3,795,127	(3,482,725)	(13,671,491)
Juris Net Plant	1,171,765,075	1,141,161,899	1,117,882,267	1,085,291,008

	6/01/2016-5/31/2017	12/31/2016-12/31/2017	
Average Rate Base	1,169,511,305	1,137,247,144	
Juris Factor	0.978891	0.978878	
Juris Rate Base	1,144,823,671	1,113,226,454	Capital
Juris Interest Expense	23,495,642	22,847,161	
Income Tax - Interest Expense	(9,063,444)	(8,813,292)	

Operating Expenses	6/01/2016-5/31/2017	12/31/2016-12/31/2017	
Fixed O&M	10,000,000	10,000,000	Fixed O&M

Revenue Requirement Backup Data
Port Everglades Power Plant

Capital Structure	Ratio	Cost Rate	Wtd Cost Rate	Pre Tax COC	
Variable O&M			1,006,787	1,006,787	Variable O&M
Property Insurance			563,164	572,015	Capital
Depreciation - Other Production			38,353,541	38,353,541	Capital
Depreciation - Transmission			854,015	854,015	Capital
Taxes Other Than Income Taxes - Prop Tax			21,624,365	21,378,882	Capital
Total Operating Expenses			72,401,871	72,165,240	

Juris Operating Expenses	6/01/2016- 5/31/2017	12/31/2016- 12/31/2017
Fixed O&M	9,814,000	9,814,000
Variable O&M	988,061	988,061
Capital Replacement	0	0
Property Insurance	551,463	560,131
Depreciation - Other Production	37,640,165	37,640,165
Depreciation - Transmission	764,108	764,108
Taxes Other Than Income Taxes - Prop Tax	21,167,888	20,927,322
Total Juris Operating Expenses	70,925,685	70,693,786
Juris Operating Expenses	70,925,685	70,693,786
Income Tax - Operating Expenses	(27,359,583)	(27,270,128)
Other Income Taxes - Def Taxes	(1,023,452)	(1,023,452)
Juris Other Income Taxes	(1,001,848)	(1,001,835)

Juris Net Operating Income	6/01/2016- 5/31/2017	12/31/2016- 12/31/2017
Operating Expenses	(70,925,685)	(70,693,786)
Income Tax - Operating Expenses	27,359,583	27,270,128
Income Tax - Interest Expense	9,063,444	8,813,292
Other Income Taxes	(1,001,848)	(1,001,835)
Juris Net Operating Income	(35,504,505)	(35,612,201)

Q.
Please refer to Section 8(c). For each project subject to the proposed GBRA, please provide a side-by-side comparison of the return on equity and capital structure that was assumed in each project's determination of need proceeding and the capital structure and ROE being proposed in the settlement.

A.
Please see Attachment No. 1 to this request.

CAPITAL STRUCTURE COMPARISON
PROPOSED GBRA VS. NEED DETERMINATION

Cape Canaveral Project

Capital Structure	Per Proposed Settlement Agreement: Ratio	Cost Rate	Wtd Cost Rate	Per Need Determination Hearing: Ratio	Cost Rate	Wtd Cost Rate
Long Term Debt	39.03%	5.26%	2.05%	44.20%	6.600%	2.92%
Common Equity	60.97%	10.70%	6.52%	55.80%	11.750%	6.56%
Total	100.00%		8.58%	100.00%		9.47%

Riviera Project

Capital Structure	Per Proposed Settlement Agreement: Ratio	Cost Rate	Wtd Cost Rate	Per Need Determination Hearing: Ratio	Cost Rate	Wtd Cost Rate
Long Term Debt	39.03%	5.26%	2.05%	44.20%	6.600%	2.92%
Common Equity	60.97%	10.70%	6.52%	55.80%	11.750%	6.56%
Total	100.00%		8.58%	100.00%		9.47%

Port Everglades Project

Capital Structure	Per Proposed Settlement Agreement: Ratio	Cost Rate	Wtd Cost Rate	Per Need Determination Hearing: Ratio	Cost Rate	Wtd Cost Rate
Long Term Debt	39.03%	5.26%	2.05%	40.90%	5.500%	2.25%
Common Equity	60.97%	10.70%	6.52%	59.10%	10.000%	5.91%
Total	100.00%		8.58%	100.00%		8.16%

Q.

Section 8(f) describes the term of the proposed GBRA portion of the settlement. Please compare and contrast the proposed term of the GBRA described in Section 8(f) to that approved as part of the settlement approved in Docket 050045-EI and the proposal that was offered and denied in Docket No. 080677-EI. Also please provide a similar comparison and contrast to other portions of the GBRA proposal.

A.

Paragraph 6 is (and is intended by the signatories to be) substantially identical to Paragraph 17 of the 2005 Settlement Agreement that was approved in Docket No. 050045-EI, with changes only as needed to update the GBRA mechanism to current circumstances. FPL proposed in Docket No. 080677-EI that the Commission "authorize the continued use of the GBRA mechanism to reflect the revenue requirements associated with generation additions for which a determination of need has been granted …." FPL Petition for Rate Increase, dated March 18, 2009, at page 23. Thus, there was no intent that the GBRA mechanism for which FPL sought approval in Docket No. 080677-EI would differ in any respect from the provisions of the 2005 Settlement Agreement.

The only substantive update in the proposed settlement agreement to the GBRA contained in the 2005 Settlement Agreement is that the Annualized Base Revenue Requirement for the Canaveral Modernization Project will be "as reflected in the 2012 Rate Petition and accompanying MFRs" rather than using the revenue requirement specified in the need determination for that unit. FPL intends to reduce that Annualized Base Revenue Requirement to reflect the adjustment that appears as Item 18 in FPL witness Ousdahl's Exhibit KO-16 and the ROE mid-point of 10.7% provided in Paragraph 2 of the proposed settlement agreement. An ROE of 10.7% will be applied to the GBRAs for the other two units as well.

Specifically with respect to Paragraph 8(f), the term of the GBRA under the proposed settlement agreement is stated on substantially identical terms to Paragraph 17 of the 2005 Settlement Agreement. In both instances, the intent is for FPL's base rate levels, including the effects of the GBRA(s), to continue in effect after the end of the settlement term when base rates are next reset by the Commission.

Q.
Please refer to paragraph 9(b) of the Stipulation and Settlement.

a. How does FPL intend to fund dismantlement activities at the time of plant shutdown if its dismantlement reserve is flowed-back to its current customers?

b. Would FPL's proposal to flow-back its current dismantlement reserve violate the regulatory principle whereas service costs are borne by the customers who receive the benefits of investment and not passed to future a generation of customers?

c. Is FPL aware of any other investor-owned electric utility that has been allowed to flow-back fossil plant dismantlement reserves? If so, please detail.

d. Does FPL currently have a theoretical reserve surplus in its Fossil Dismantlement Reserve? If yes, what is the calculated surplus amount?

A.
In responding to this request, FPL has assumed that Staff meant to reference paragraph 10(b) of the Stipulation and Settlement instead of paragraph 9(b).

a. Future dismantlement activities will be funded through current and future dismantlement accruals determined by authorized amounts approved from dismantlement studies filed with the Commission. Authorized accruals are to be collected over the remaining life of the units to be dismantled.

b. No, it will not. FPL's recent modernization projects have allowed for the construction of new generating plants at existing plant sites and thereby defer for 30 years or more the need to incur the full cost of green field dismantlement at those sites. Therefore, a portion of its currently accrued dismantlement reserve will not be needed until much later than previously anticipated, which would appropriately accommodate the dismantlement flow-back contemplated by the proposed settlement agreement.

c. At this time, FPL has not identified other investor-owned utilities that have specifically used a flow-back of fossil plant dismantlement reserves but FPL notes that Progress Energy Florida is currently authorized to flow back a portion of the very similar reserve for cost of removal, under the settlement agreement approved in Docket No. 120022-EI.

d. FPL estimates annual dismantlement accruals when filing periodic dismantlement studies that are reviewed by the Commission. After reviewing all the evidence in FPL's 2009 Rate Case, the Commission authorized approximately $18.5 million in dismantlement annual accruals effective with 2010, and FPL continues to accrue that amount annually. During the term of the settlement, these accruals will add approximately $74 million to the dismantlement reserve. Therefore, FPL expects no more than a net $135 million reduction in the dismantlement reserve (i.e., $209 million maximum flow-back during the settlement term pursuant to Paragraph 10(b) of the proposed settlement agreement, less $74 million of accruals).

FPL has not performed a dismantlement study since 2009 and therefore, is unable to provide a precise calculation or updated estimate of the annual dismantlement accrual or any imbalances in the dismantlement reserve at this time; however, all other things equal, as indicated in response to 8(b), FPL's construction of the modernization projects will have a downward effect on the level of the accrual and any calculation of a reserve imbalance, and thus, mitigate the use of $135 million in fossil dismantlement.

Q.

Please refer to paragraph 12(a)(i) of the Stipulation and Settlement.

a. Please define the following terms: short-term wholesale sales, short-term wholesale purchases. As part of the definition, please distinguish these terms from long-term wholesale sales and purchases.

b. Are FPL's agreements to supply power to the City of Key West and Lee County Electric Cooperative a part of wholesale sales that will be affected by the provisions of paragraph 12? Please explain.

c. Are any other of FPL's long-term wholesale power supply agreements affected by the provisions of paragraph 12? Please explain.

d. How will a gain on a short-term wholesale purchase be calculated? Please provide a detailed example.

e. FPL has 2 BCF of firm gas storage at Bay Gas Storage in southern Alabama. Does FPL have any other firm gas storage?

f. FPL currently recovers the cost of gas storage - monthly storage reservation charges, fuel retention, commodity charges for injection and withdrawal, and monthly insurance charges - through the fuel cost recovery clause. In Docket No. 060392-EI, FPL represented that having firm gas storage will increase system reliability and reduce gas price volatility. How would these benefits be affected if FPL releases firm storage or sells gas in storage?

A.

a. Short-term wholesale sales and purchases refer to transactions that are one year or less in duration. Long-term wholesale sales and purchases refer to transactions that are greater than one year in duration. Separated sales are not included as part of the proposed Incentive Mechanism. For clarification, short-term wholesale sales and purchases can be firm or non-firm.

b. No. The agreements to supply power to the City of Key West and Lee County Electric Cooperative are separated sales and therefore are not part of the provisions of paragraph 12.

c. No. As stated in response to subpart (a), separated sales are not part of the Incentive Mechanism. Therefore, any existing or future separated sales are not affected by the provisions of paragraph 12. Additionally, FPL does not currently have any short-term wholesale sales (as defined in part a) that carry into 2013 and would be part of the proposed Incentive Mechanism. From the wholesale purchases side, FPL will have two existing purchased power agreements that carry into 2013. These agreements include UPS and SJRPP purchases which are long-term transactions and are not part of the proposed Incentive Mechanism.

d. The savings associated with short-term wholesale purchases will be calculated through the same methodology that FPL currently utilizes for calculating gains on short-term wholesale sales and savings on short-term wholesale purchases. FPL utilizes two applications to determine marginal (incremental) pricing for sales and purchases. Marginal pricing for transactions greater than one hour in duration is developed utilizing GenTrader software. Marginal pricing for next-hour transactions is developed utilizing a program called "Economy A" which is part of FPL's EMS system. GenTrader and "Economy A" are unit commitment programs that provide optimal system dispatch output data based on numerous inputs including fuel prices, generation parameters and load data. These programs are used to determine the projected marginal costs for each transaction under consideration. The marginal cost data for each transaction is compared to the purchase or sale price of power to determine savings or gains. The marginal cost data for all transactions is shown in aggregate for each counterparty on Schedule A6 as the "Total $ for Fuel Adjustment" and on Schedule A9 as the "Cost if Generated" in Docket No. 120001-EI. An example of the savings calculation for a short-term purchase is shown below:

> **Transaction Evaluated:**
> FPL is offered a next-day economy purchase of 100 MW from hour ending 0800 through hour ending 2300 at $35 per MWh.
> **Projected Marginal Cost:**
> FPL runs its GenTrader program to determine that its average marginal cost of generation during these hours is $55 per MWh.
> **Savings Calculation:**
> -Total cost of power = 16 hours * 100 MW * $35 per MWh = $56,000.
> -The "Cost if Generated" = 16 hours * 100 MW * $55 per MWh = $88,000.
> -FPL saves $88,000 - $56,000 = $32,000 on this transaction versus its cost of generation.

e. No. Currently, FPL only has firm natural gas storage at Bay Gas. FPL's firm gas storage agreement with Bay Gas expires at the end of March 2013. FPL has been in negotiations with several natural gas storage companies over the past several months, including Bay Gas, to address its future gas storage needs. Given its increased dependence on natural gas, FPL plans to increase its storage capability above 2 BCF moving forward.

f. FPL's primary focus is system reliability, and FPL will not engage in any activities that negatively impact system reliability. The benefits of increased system reliability and reduced gas price volatility will not be impacted if FPL releases firm storage or sells gas in storage. FPL is proposing to optimize its storage asset(s) during non-critical demand seasons when it does not plan to carry full inventory. FPL's primary intent would be to optimize, if possible, any unutilized capacity during the shoulder months. Additionally, optimization of FPL's storage capacity could potentially include the use of an Asset Management Agreement ("AMA") whereby the optimization function could be outsourced to a third party to help provide additional customer value while maintaining the current levels of system reliability and reduced volatility.

Q.
Please refer to paragraph 12(a)(ii) of the Stipulation and Settlement.

a. Currently, if FPL sells gas out of storage at a gain, is that gain credited to fuel costs? Please explain.

b. Currently, if FPL sells idle gas transportation or idle electric transmission short-term, are those sales recognized and treated for regulatory purposes? Please explain.

c. Currently, regarding delivered city-gate gas sales using existing transport, how are those sales recognized and treated for regulatory purposes?

d. Currently, regarding production (upstream) area sales, how are those sales recognized and treated for regulatory purposes?

e. Is FPL, or will FPL be, participating in the expansion of the Southeast Supply Header Pipeline and, if so, will this added pipeline capacity be part of "asset optimization" stated in paragraph 12? Please explain.

f. Under the second bullet on page 13, paragraph 12 (a) (ii) of the stipulation, (Delivered city-gate gas sales using existing Transport), to whom would FPL market the gas?

g. Under the third bullet under paragraph 12 (a) (ii) (Production (upstream) area sales), what types of entities would likely be buyers?

A.
a. Yes. If FPL sold gas out of storage at a gain, the gain would be credited to the total cost of gas inventory. At this time, FPL does not sell gas out of its storage position.

b. Yes. If FPL sold idle gas transportation, the revenue would be credited to the total cost of gas transportation during the month in which the sale occurred. Currently, FPL does not sell idle gas transportation. If FPL sells idle electric transmission, the revenue is credited to the total cost of transmission during the month in which the sale occurred. Customers receive the benefits from these types of sales through the fuel clause and/or capacity clause.

c. FPL does not currently make delivered city-gate gas sales using existing transport. When the necessity arises to sell natural gas due to an unexpected load change, FPL sells its natural gas in the production area. The revenue from this type of sale is credited to the total cost of gas during the month in which the sale occurred. A sale of delivered city-gate gas using existing transport would be treated in the same manner.

d. Please see response to subpart (c).

e. FPL has participated in several discussions regarding pipeline expansions in the southeast region, including the expansion of the Southeast Supply Header Pipeline. While any portions of FPL's pipeline capacity could be a part of "asset optimization", the capacity on upstream pipelines would typically not be idle for release even for short periods as this upstream capacity is typically flowing FPL's lowest cost gas supply. FPL could outsource all or a portion of the optimization of its upstream pipeline capacity through an Asset Management Agreement ("AMA") to help potentially provide additional customer value with no impact to system reliability or commodity costs.

f. FPL could market delivered city-gate gas to any end user that could accept the gas on the FGT or Gulfstream pipelines.

g. Generally, natural gas suppliers would be the likely buyers of production area gas sales.

Q.
Please refer to paragraph 12(a)(iii) of the Stipulation and Settlement.

a. For 2012, FPL's estimated benchmark for gains on non-separated wholesale sales for purposes of calculating the shareholder incentive is $6,763,028. In paragraph 12(a)(iii), the sharing thresholds are $36 million and $10 million. Does FPL anticipate an increase in off system wholesale sales that will contribute to reaching these thresholds? Please explain and identify and describe any anticipated increases in off-system sales.

b. Differentiate the impact on customer savings between the $36 million "Customer Savings Threshold" and the incremental $10 million "Additional Customer Savings."

c. Does the "Customer Savings Threshold" and the "Additional Customer Savings" apply to the same customer classes?

d. Does FPL anticipate new wholesale sales agreements, pipeline capacity, storage capacity, or gas sales opportunities that will contribute to reaching the thresholds in paragraph 12(a)(iii)? Please explain and identify these new activities.

e. Please refer to Order No. PSC-00-1744-PAA-EI, issued September 26, 2000. Explain how the provisions of this order governing gains on non-separated wholesale power sales (firm and non-firm) would be affected by this stipulation and settlement.

f. Are the references to paragraph 12(b)(i) correct?

A.
a. No. FPL is not projecting an increase in off-system wholesale sales. In its 2012 Actual/Estimated True-Up filed on August 1, 2012, FPL projects to finish the year with slightly over $4 million in gains on off-system wholesale sales. FPL is projecting slightly over $4.2 million in gains on off-system wholesale sales in 2013 with approximately the same volume of sales. The projections for 2013 will be filed on August 31, 2012. The current shareholder incentive approved in Order No. PSC-00-1744-PAA-EI, issued on September 26, 2000, is based solely on gains from off-system wholesale sales. The $36 million and $10 million in the new incentive proposal are the thresholds set for the combination of gains on wholesale sales, savings on wholesale purchases and gains realized through asset optimization.

b. The impact on customer savings between the $36 million and the $10 million is the same. Customers will receive 100% of the benefit up to $46 million (the combination of the $36 million and $10 million).

c. Yes.

d. FPL is not currently aware of any anticipated new wholesale sales agreements, pipeline capacity, storage capacity, or gas sales opportunities that will contribute to reaching the threshold. FPL will not enter into new pipeline capacity or storage capacity agreements for the sole purpose of contributing to the threshold. FPL will continue to evaluate and enter into agreements/transactions that benefit the reliability of fuel supply and help lower overall fuel costs for FPL's customers.

e. The shareholder incentive mechanism implemented in Order No. PSC-00-1744-PAA-EI would not apply to FPL if the Incentive Mechanism outlined in the proposed stipulation and settlement was approved. The regulatory treatment for the revenues and expenses associated with each non-separated wholesale power sale outlined in Order No. PSC-00-1744-PAA-EI would continue to be appropriate if the proposed stipulation and settlement was approved.

f. No. The correct reference should be to paragraph 12(a)(i).

Q.

Please refer to paragraph 12(b) of the Stipulation and Settlement.

a. Does variable power plant O&M costs that is incurred currently in off system wholesale sales include capital replacement parts? Please explain.

b. Regarding the O&M costs, can FPL provide an estimate of the 2013 amount?

c. Regarding the O&M costs, how will these costs be reported in the fuel clause proceeding?

d. Is it FPL's intent to recover the incremental O&M costs incurred in implementing its expanded short-term wholesale purchases and sales programs as well as the asset optimization measures, even if no gains as described in 12(a)(ii) are realized under the programs?

A.

a. FPL's 2010 test year MWh production forecast included off-system sales and therefore, variable power plant O&M costs that are currently incurred in off-system wholesale sales include capital replacement parts. To the extent that FPL's off-system sales exceed the estimated level that was included in FPL's 2010 test year MWh production forecast, FPL is not recovering the additional variable power plant O&M costs through base rates. FPL is proposing to begin recovering the incremental variable power plant O&M expenses beginning in 2013 if off-system sales exceed the assumed level included in the 2013 test year forecast.

b. FPL is projecting that its wholesale sales volume will not exceed 514,000 MWh in 2013 and therefore, the incremental variable plant O&M costs will be $0.

c. As described in paragraph 12(b)(ii), FPL will recover variable power plant O&M costs if wholesale sales exceed 514,000 MWh. To the extent this occurs, FPL will report the variable power plant O&M costs on the "Total Gains Schedule" described in paragraph 12(a)(i) that FPL will file each year as part of its Fuel Cost Recovery Final True-Up filing.

d. Yes. FPL's intent is to recover the incremental O&M costs incurred for implementing its expanded optimization program regardless of the level of gains/savings achieved.

Q.
Please prepare a schedule in the format of MFR Schedule E-1, Attachment 3 of 3, for the increases proposed under the stipulation.

A.
As requested, please see Attachment No. 1 to this request.

MFR E-1 - COST OF SERVICE STUDY
2013 AT PROPOSED RATES PER SETTLEMENT AGREEMENT
($000 WHERE APPLICABLE)

	Total Retail	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3	MET
PROJECTED ROR AT PRESENT RATES - [1]											
Total Rate Base	21,036,823	382,340	25,650	120,245	1,230,085	6,064	4,243,869	1,856,855	342,408	19,414	16,231
Operating Revenues -											
Sales of Electricity	4,266,616	73,145	5,467	23,403	304,655	1,665	860,848	311,835	57,388	4,043	2,884
Other Operating Revenues	140,637	1,470	96	265	8,780	25	19,742	7,417	1,329	43	62
Total Operating Revenues	4,407,253	74,615	5,563	23,669	313,434	1,690	880,590	319,253	58,716	4,086	2,947
Total Operating Expenses	(3,250,894)	(55,461)	(3,952)	(18,434)	(222,511)	(1,288)	(635,259)	(246,966)	(46,029)	(3,056)	(2,218)
Net Operating Income (NOI)	1,156,359	19,147	1,611	5,232	90,902	403	245,249	72,532	12,778	1,030	729
Rate of Return (ROR)	5.50%	5.01%	6.28%	4.35%	7.39%	6.64%	5.78%	3.91%	3.73%	5.30%	4.49%
Parity at Present Rates	1.000	0.911	1.142	0.792	1.344	1.208	1.051	0.711	0.679	0.965	0.817
PROPOSED INCREASES - [2]											
Base Revenues	322,341	5,511	455	2,690	0	33	62,118	24,138	4,759	1	541
Unbilled Revenues	10,661	182	15	89	0	1	2,055	798	157	0	18
Miscellaneous Service Charges	44,998	138	7	12	3,106	1	5,863	1,065	160	3	0
Total Proposed Increases	378,000	5,831	477	2,791	3,106	35	70,036	26,001	5,076	4	559
PROJECTED ROR AT PROPOSED RATES -											
Total Rate Base	21,036,823	382,340	25,650	120,245	1,230,085	6,064	4,243,869	1,856,855	342,408	19,414	16,231
Operating Revenues -											
Sales of Electricity	4,599,618	78,838	5,937	26,182	304,655	1,699	925,021	336,771	62,304	4,044	3,443
Other Operating Revenues	185,635	1,608	103	277	11,886	26	25,605	8,482	1,489	46	62
Total Operating Revenues	4,785,253	80,446	6,040	26,460	316,540	1,725	950,626	345,254	63,792	4,090	3,506
Total Operating Expenses	(3,397,259)	(57,719)	(4,137)	(19,515)	(223,714)	(1,301)	(662,377)	(257,034)	(47,995)	(3,058)	(2,434)
Net Operating Income (NOI)	1,387,994	22,720	1,903	6,942	92,805	424	288,167	88,465	15,888	1,032	1,071
Rate of Return (ROR)	6.60%	5.94%	7.42%	5.77%	7.54%	7.00%	6.79%	4.76%	4.64%	5.32%	6.60%

MFR E-1 - COST OF SERVICE STUDY
2013 AT PROPOSED RATES PER SETTLEMENT AGRE
($000 WHERE APPLICABLE)

	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
PROJECTED ROR AT PRESENT RATES - [1]							
Total Rate Base	55,140	5,373	12,364,753	351,455	4,238	1,889	10,814
Operating Revenues -							
Sales of Electricity	11,479	853	2,532,394	70,674	1,252	369	4,262
Other Operating Revenues	206	38	100,149	886	83	11	34
Total Operating Revenues	11,684	890	2,632,543	71,559	1,335	380	4,297
Total Operating Expenses	(8,762)	(676)	(1,949,528)	(53,104)	(854)	(262)	(2,534)
Net Operating Income (NOI)	2,923	214	682,796	18,454	480	118	1,762
Rate of Return (ROR)	5.30%	3.99%	5.52%	5.25%	11.33%	6.25%	16.30%
Parity at Present Rates	0.964	0.726	1.005	0.955	2.062	1.138	2.965
PROPOSED INCREASES - [2]							
Base Revenues	1,217	122	212,937	7,762	0	57	0
Unbilled Revenues	40	4	7,043	257	0	2	0
Miscellaneous Service Charges	95	0	34,234	206	91	0	17
Total Proposed Increases	1,352	126	254,214	8,225	91	59	17
PROJECTED ROR AT PROPOSED RATES -							
Total Rate Base	55,140	5,373	12,364,753	351,455	4,238	1,889	10,814
Operating Revenues -							
Sales of Electricity	12,736	979	2,752,374	78,693	1,252	428	4,262
Other Operating Revenues	301	38	134,383	1,092	174	11	51
Total Operating Revenues	13,036	1,016	2,886,757	79,784	1,426	439	4,314
Total Operating Expenses	(9,285)	(725)	(2,047,962)	(56,289)	(890)	(285)	(2,541)
Net Operating Income (NOI)	3,751	292	838,576	23,495	536	154	1,773
Rate of Return (ROR)	6.80%	5.43%	6.78%	6.68%	12.65%	8.17%	16.39%

MFR E-1 - COST OF SERVICE STUDY
2013 AT PROPOSED RATES PER SETTLEMENT AGREEMENT
($000 WHERE APPLICABLE)

	Total Retail	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3	MET
Parity at Proposed Rates	1.000	0.901	1.125	0.875	1.143	1.060	1.029	0.722	0.703	0.806	1.000

(1) Per MFR E-1 attachment No. 1
(2) Per proposed Settlement Agreement Exhibit A

Note: Totals may not add due to rounding.

MFR E-1 - COST OF SERVICE STUDY
2013 AT PROPOSED RATES PER SETTLEMENT AGRE
($000 WHERE APPLICABLE)

	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
Parity at Proposed Rates	1.031	0.822	1.028	1.013	1.917	1.238	2.484

(1) Per MFR E-1 attachment No. 1
(2) Per proposed Settlement Agreement Exhibit A

Note: Totals may not add due to rounding.

Q.
What is the impact on a 1,000 kWh residential bill, including base rates and clauses, of the stipulation in 2013? Please show all components separately.

A.
Please see FPL's response to Staff's First Data Requests No. 5(a).

Q.

Why were revised tariff sheets for the GS(T) rate schedules (Tariff sheets 8.101 and 8.103) omitted from the revised tariffs submitted with the stipulation? Is the intent to use the rates submitted in the original filing, MFR Schedule E-14, pages 4 and 5, or to simply not change the currently applicable sheets?

A.

The current GS-1 and GST-1 rate schedules are not intended to change under the settlement compared to the current tariffs.

Q.

Has FPL conducted any migration analysis on the impact of the new rates? If so, have changes in billing determinants resulted from this adjustment? If not, why not?

A.

FPL set rates to avoid migration. FPL does not expect any significant migration based on total class billing determinants and typical bill analyses.