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COMMISSION
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HEARING EXHIBITS FOR THE HEARING HELD on November 19 and 20, 2012, in DOCKET 120015-EI

Comprehensive Exhibit List for Entry into Hearing Record

Hearing I.D. #	Witness	I.D. # As Filed or Party	Exhibit Description	Entered
STAFF (DIRECT)				
649		Exhibit List	Comprehensive Exhibit List	
650		Staff's Hearing Exhibit #650	FPL's Responses to Staff's 19th Set of Interrogatories, Nos. 497-500, 504, 506, 515-517, Supplemental Response to 517, 522-523, and 528-531 *[Bates Nos. 03002-03023]*	
651		Staff's Hearing Exhibit #651	FPL's Responses to Staff's 20th Set of Interrogatories, Nos. 534-545, 547, 549-556, 558-560, 564-565, 567-568, 572-573, 576, 591-594, and 596 *[Bates Nos. 03024-03069]*	
652		Staff's Hearing Exhibit #652	FPL's Responses to Staff's 21st Set of Interrogatories, Nos. 597-606 *[Bates Nos. 03070-03081]*	
653		Staff's Hearing Exhibit #653	FPL's Responses to Staff's 22nd Set of Interrogatories, Nos. 608-612 and 617-618 *[Bates Nos. 03082-03091]*	
654		Staff's Hearing Exhibit #654	FPL's Responses to Staff's 23rd Set of Interrogatories, Nos. 619-621 *[Bates Nos. 03092-03098]*	
655		Staff's Hearing Exhibit #655	FPL's Responses to Staff's 24th Set of Interrogatories, Nos. 622-623 *[Bates Nos. 03099-03103]*	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 649
PARTY Commission Staff
DESCRIPTION Comprehensive Exhibit List
DATE

DOCUMENT NUMBER-DATE
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FPSC-COMMISSION CLERK

656		Staff's Hearing Exhibit #656	FPL's Responses to Staff's 13th Request for the Production of Documents, No. 90 **(See Staff Hearing Exhibit CD for this Excel file)** *[Bates Nos. 03104]*	
657		Staff's Hearing Exhibit #657	FPL's Responses to OPC's 16th Set of Interrogatories, Nos. 271, 275, and 278 *[Bates Nos. 03105-03112]*	
658		Staff's Hearing Exhibit #658	FIPUG's Response to Staff's 2nd Set of Interrogatories, No. 5 *[Bates Nos. 03113-03116]*	
659		Staff's Hearing Exhibit #659	FIPUG's Responses to Staff's 3rd Set of Interrogatories, Nos. 6 and 7 *[Bates Nos. 03117-03119]*	
660		Staff's Hearing Exhibit #660	SFHHA's Response to Staff's 1st Set of Interrogatories, No. 1 *[Bates Nos. 03120-03123]*	
661		Staff's Hearing Exhibit #661	SFHHA's Responses to Staff's 2nd Set of Interrogatories, Nos. 2 and 3 *[Bates Nos. 03124-03127]*	
662		Staff's Hearing Exhibit #662	FEA's Responses to Staff's 1st Set of Interrogatories, Nos. 1 and 2 *[Bates Nos. 03128-03130]*	
663		Staff's Hearing Exhibit #663	OPC's Response to Staff's 1st Set of Interrogatories, No. 1 *[Bates Nos. 03131-03134]*	
664		Staff's Hearing Exhibit #664	FRF's Response to Staff's 1st Set of Interrogatories, No. 1 *[Bates Nos. 03135-03137]*	
665		Staff's Hearing Exhibit #665	Pinecrest's Response to Staff's 1st Set of Interrogatories, No. 1 *[Bates Nos. 03138-03140]*	
666		Staff's Hearing Exhibit #666	Hendrick's Response to Staff's 1st Set of Interrogatories, No. 1 *[Bates Nos. 03141-03145]*	

SIGNATORIES TO THE SETTLEMENT AGREEMENT				
FLORIDA POWER & LIGHT (FPL) (DIRECT)				
667	Renae B. Deaton	RBD-12	FPL Bill Comparisons Under Settlement Rates – January 2012 to January 2013, June 2013	
668	Renae B. Deaton	RBD-13	FPL Bill Comparisons Under Settlement Rates vs. Rates Proposed in March 2012 MFRs- June 2013	
669	Renae B. Deaton	RBD-14	Parity of Major Rate Classes: Current and Proposed Settlement Agreement	
670	Renae B. Deaton	RBD-15	EEI Industrial Bill Comparison- January 2012	
671	Renae B. Deaton	RBD-16	Late Payment Charge Survey	
672	Sam A. Forrest	SF-1	Historical Performance of Existing Incentive Mechanism	
673	Sam A. Forrest	SF-2	Historical Performance of Power Sales Gains and Purchased Power Savings	
674	Sam A. Forrest	SF-3	Example- “Total Gains Schedule”	
675	Robert E. Barrett, Jr.	REB-9	GBRA ROE Midpoint Illustrative Example	
676	Robert E. Barrett, Jr.	REB-10	MFR A-1 Canaveral, Riviera, and Port Everglades	
677	Robert E. Barrett, Jr.	REB-11	Dismantlement Reserve - Illustrative Example of Impact of Amortization on Future Accruals	
678	Robert E. Barrett, Jr.	REB-12	Depreciation Accrual - Illustrative Example of Effect of Nuclear Plant Additions on Accrual	

FLORIDA INDUSTRIAL POWER USERS GROUP (FIPUG) (DIRECT)				
679	Jeffry Pollock	JP-15	Incremental Infrastructure Cost	
680	Jeffry Pollock	JP-16	Return on Equity	
681	Jeffry Pollock	JP-17	2013 Class Revenue Allocation	
682	Jeffry Pollock	JP-18	Cost Effectiveness	
FEDERAL EXECUTIVE AGENCIES (FEA) (DIRECT)				
683	Ryan M. Allen	RMA-1	2011 Economic Impact Analysis Patrick Air Force Base and Cape Canaveral Air Force Station	
NON-SIGNATORIES TO THE SETTLEMENT AGREEMENT				
OFFICE OF PUBLIC COUNSEL (OPC) (DIRECT)				
684	James W. Daniel	JWD-1	List of Regulatory Proceedings	
685	James W. Daniel	JWD-2	Incentive Mechanism Comparison	
686	Kevin W. O’Donnell	KWO-11	Dow Jones Utility Index	
687	Kevin W. O’Donnell	KWO-12	Federal Reserve Article	
688	Kevin W. O’Donnell	KWO-13	ROE Comparison	
689	Kevin W. O’Donnell	KWO-14	Equity Ratio Comparison	
690	Kevin W. O’Donnell	KWO-15	30-Year US Treasury Yields	
691	Donna Ramas	DR-7	Per FPL Original Revenue Requirement, Modified for Revised ROR	

692	Donna Ramas	DR-8	Per FPL Post-Hrg Revenue Requirement, Modified for Revised ROR	
JOHN W. HENDRICKS (pro se) (DIRECT)				
693	John W. Hendricks	JWH-7	Tax Efficiency in the GBRA Process	
REBUTTAL				
FPL (REBUTTAL)				
694	Sam A. Forrest	SF-4	Incentive Mechanism Comparison	
695	Sam A. Forrest	SF-5	FPL responses to Staff's 22nd Set of Interrogatories, Nos. 608 through 611	
696	Sam A. Forrest	SF-6	FPL's Natural Gas Assets	
697	Robert E. Barrett, Jr.	REB-13	Expanded OPC Witness Ramas Exhibit DR-8 - Adjusted Earned ROE	
698	Robert E. Barrett, Jr.	REB-14	Projected Capital Expenditures (2014-2016) Excluding New Generation	
699	Robert E. Barrett, Jr.	REB-15	FPL's response to OPC's Sixteenth Set of Interrogatories, Question No. 275	
700	Robert E. Barrett, Jr.	REB-16	Total Project Construction Costs for TP5 and WCEC 1&2 – Need vs. Actual	
701	Moray P. Dewhurst	MD-11	Proposed Settlement Agreement	
FIPUG (REBUTTAL)				
702	Jeffry Pollock	JP-19	Incremental Infrastructure Costs	
703	Jeffry Pollock	JP-20	Return on Equity	

704	Jeffry Pollock	JP-21	Incremental Infrastructure Cost (Errata to JP-15)	
705	Terry Deason	OPC	2005 FPL Stipulated Order (Order PSC-05-0902-S-EI)	
706	Renae B. Deaton	Thomas Saporito	The free Dictionary definition of Public Interest	
707	Ranae B. Deaton	Thomas Saporito	FPL, key customer advocacy groups ask PSC to approve proposed settlement to secure low rates for FPL customers.	
708	Jeffery Pollock	OPC	Excerpt of 7/16/09 testimony of Pollock	
709	Jeffery Pollock	OPC	Incremental infrastructure costs (originally JP-1) with columns C-G expanded	
710	Jeffery Pollock	OPC	Excerpts from last rate case, Order PSC-10-0153, in Dkts 080677 and 090130	
711	Jeffery Pollock	OPC	2013 MFR Schedules B-1 Adjusted Rate Base and C-1 Adjusted jurisdictional NOI from dkt 120015-EI	
712	Jeffery Pollock	OPC	Incremental Infrastructure costs Exhibit JP-21 (Errata to Exh 15) with colums C-G expanded	
713	Jeffery Pollock	OPC	Excertps from FPL's last rate case final order	
714	Sam Forest	FPL	2012, 10-Year Site FPL Plan (pg 95 and 96)	
715	Sam Forest	FPL	August 15th Document (pgs 12-15)	
716	Lane Kollen	FPL	Excerpt – July 2009 Testimony	
717	Lane Kollen	FPL	Excerpt - Order 10-0153-FOF-EI	

718	Lane Kollen	FPL	SFHHA Petition to intervene & order granting intervention	
719	Ranae Deaton	FPL	Sales by Rate Class	
720	Moray Dewhurst	OPC	Reports Provided by FPL in response to OPC's 14th Req. for PODs, No. 105	
721	James Daniel	OPC	Errata to Exhibit JWD-2	
722	James Daniel	FPL	Incentive Mechanism Performance 2001-2011 (3 pgs)	
723	Donna Ramas	FPL	PEF and Gulf rate increases as percentages of tatal revenue (2 pgs)	
724	John Hendricks	FPL	Excerpt from ***Joskow Incentive Regulation and its application to Electricity*** (entire article)	
725 726	Robert E. Barrett Terry Deason	FPL OPC	REB-17 3/13/12 E-mail	

650

FPL's Responses to Staff's 19th Set of Interrogatories, Nos. 497-500, 504, 506, 515-517, Supplemental Response to 517, 522-523, and 528-531

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 650
PARTY Staff's Hearing Exhibit 650
DESCRIPTION FPL's responses to Staff's 19th, Interrogatories.
DATE Bates Nos. 03002-03023

Q.
For questions 497-500, please refer to paragraph 9(b) of the Stipulation and Settlement.

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?

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

Q.
For questions 497-500, please refer to paragraph 9(b) of the Stipulation and Settlement.

Please explain in detail whether FPL's proposal to flow-back its current dismantlement reserve violates 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.

A.
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.

Q.
For questions 497-500, please refer to paragraph 9(b) of the Stipulation and Settlement.

Please explain in detail whether FPL is aware of any other investor-owned electric utility that has been allowed to flow-back fossil plant dismantlement reserves.

A.
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.

Q.
For questions 497-500, please refer to paragraph 9(b) of the Stipulation and Settlement.

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

A.
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 FPL's response to Staff's Nineteenth Set of Interrogatories No. 498, 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.
For questions 501-506, please refer to paragraph 12(a)(i) of the Stipulation and Settlement.

Please provide a detailed explanation (including examples) of how a gain on a short-term wholesale purchase will be calculated.

A.
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.

Q.
For questions 501-506, please refer to paragraph 12(a)(i) of the Stipulation and Settlement.

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.
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.
For questions 514-519, please refer to paragraph 12(a)(iii) of the Stipulation and Settlement.

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

A.
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).

Q.
For questions 514-519, please refer to paragraph 12(a)(iii) of the Stipulation and Settlement. Does the "Customer Savings Threshold" and the "Additional Customer Savings" apply to the same customer classes?

A.
Yes.

Q.

For questions 514-519, please refer to paragraph 12(a)(iii) of the Stipulation and Settlement.

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.

A.

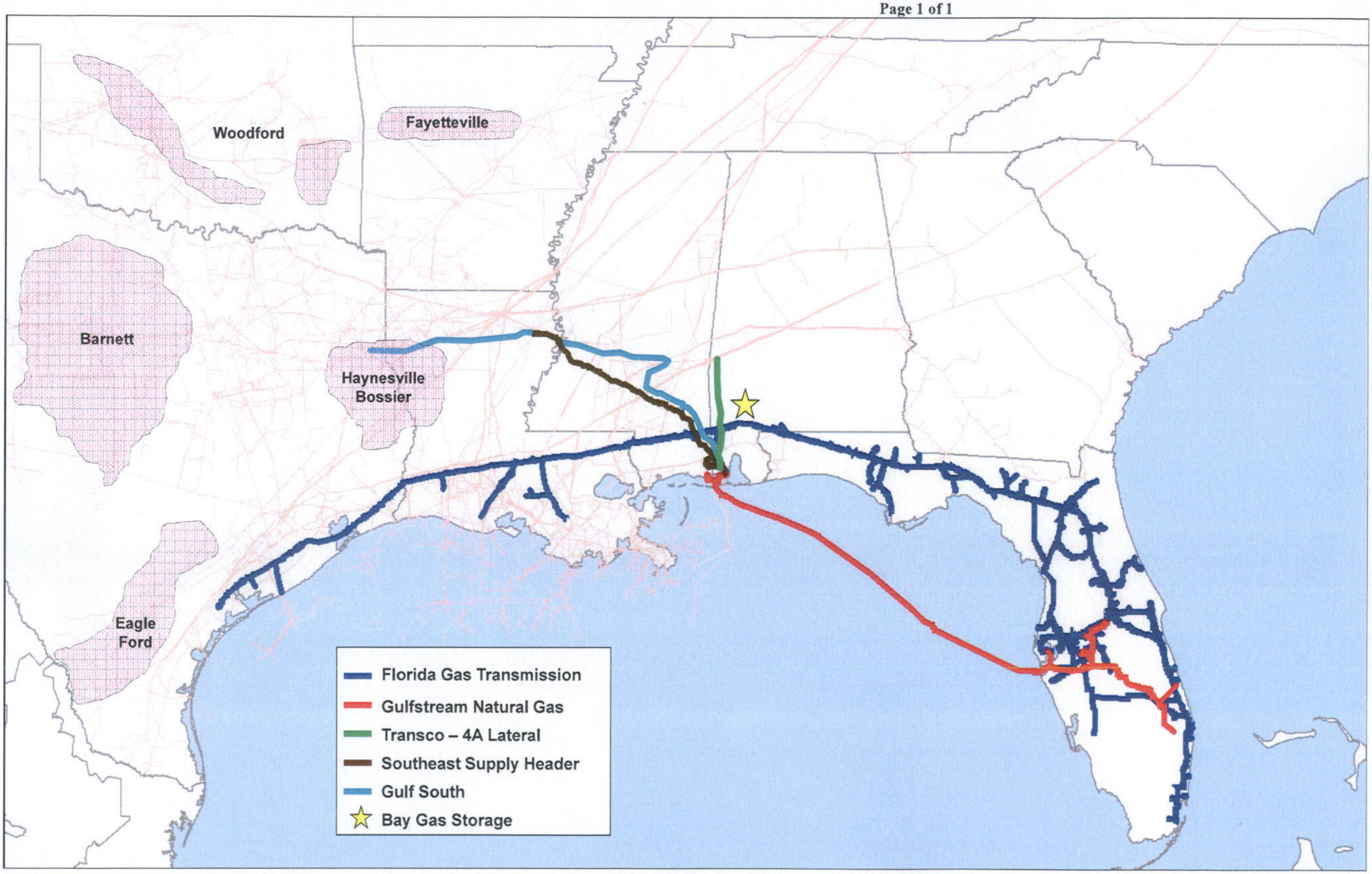
FPL is not currently aware of any anticipated new wholesale sales agreements, pipeline capacity, storage capacity, or gas sales opportunities that will contribute to reaching the threshold. FPL does not presently have any plans to enter into new agreements for the purpose of asset optimization. FPL will 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.

Q.
For questions 514-519, please refer to paragraph 12(a)(iii) of the Stipulation and Settlement.

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.

A.
As described in the original response, FPL will only enter into new agreements/transactions that benefit reliability, help lower overall fuel costs, or both. FPL consistently evaluates its natural gas requirements and considers potential transactions that could increase the reliability and/or economic benefit of its natural gas portfolio. FPL recently has entered into two new pipeline capacity agreements with Gulf South Pipeline Company ("Gulf South"). The first agreement is for seasonal firm transportation capacity from 2013 through 2017. The second agreement is associated with a Gulf South expansion and is for ten years of firm transportation capacity beginning in 2015. The primary benefits of this transportation capacity, consistent with FPL's goal, are increased reliability, receipt point diversification, and in the case of the second agreement, a new mainline interconnect with FGT. Moreover, the new pipeline capacity will allow FPL to take advantage of basis differentials in the purchase of gas for its generating fleet, and FPL expects the resulting fuel savings to help off-set the cost of the pipeline capacity agreements. It is also possible that this new transportation capacity will offer expanded asset optimization opportunities, the gains from which would benefit customers under the proposed incentive mechanism. Attachment No. 1 to this interrogatory is an exhibit showing FPL's current portfolio of natural gas assets, including the new Gulf South transportation.

Florida Power & Light Company
Docket No. 120015-EI
Staff's Nineteenth Set of Interrogatories
Interrogatory No. 517 - Supplemental
Attachment No. 1



Q.
For questions 520-523, please refer to paragraph 12(b) of the Stipulation and Settlement.

Regarding the O&M costs, please explain in detail how these costs will be reported in the fuel clause proceeding.

A.
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.

Q.
For questions 520-523, please refer to paragraph 12(b) of the Stipulation and Settlement.

Please state in detail whether it is 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.
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.
For questions 528-531, please refer to FPL's response to item 506 of Staff's Nineteenth Set of Interrogatories to Florida Power & Light. Also refer to paragraph 12(a)(ii) of the settlement and to the bullet on the Asset Management Agreement (AMA).

Please state whether the third party will be independent of FPL and Next Era Energy. Please explain and, as part of the response to this question, define "third party" as used in the stipulation and settlement.

A.
Yes. FPL intends the reference to a third party in paragraph 12(a)(ii) to be defined as an entity that is independent of FPL or NextEra Energy.

Q.
For questions 528-531, please refer to FPL's response to item 506 of Staff's Nineteenth Set of Interrogatories to Florida Power & Light. Also refer to paragraph 12(a)(ii) of the settlement and to the bullet on the Asset Management Agreement (AMA).

The AMA would allow the optimization of functions such as gas storage, gas deliveries, upstream gas purchases, gas transportation, electric transmission, and possibly other functions to be outsourced to a third party. This suggests that efficiencies would be gained with this outsourcing. Why hasn't FPL already sought to take advantage of these efficiencies and pass the benefits on to customers?

A.
FPL has had discussions with unaffiliated third parties regarding Asset Management Agreements within the past two years. Given the decrease in the volatility of natural gas prices, the overall lower level of natural gas prices, and the narrowing of basis differentials between geographic locations, to date FPL has not been able to reach commercially acceptable terms with a third party that are advantageous to FPL's customers. FPL anticipates that, if those market conditions changed in the future, however, that it may become beneficial to FPL and its customers to engage in an Asset Management Agreement.

Q.
For questions 528-531, please refer to FPL's response to item 506 of Staff's Nineteenth Set of Interrogatories to Florida Power & Light. Also refer to paragraph 12(a)(ii) of the settlement and to the bullet on the Asset Management Agreement (AMA).

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A.
FPL has had discussions with unaffiliated third parties regarding Asset Management Agreements within the past two years. Given the decrease in the volatility of natural gas prices, the overall lower level of natural gas prices, and the narrowing of basis differentials between geographic locations, to date FPL has not been able to reach commercially acceptable terms with a third party that are advantageous to FPL's customers. FPL anticipates that, if those market conditions changed in the future, however, that it may become beneficial to FPL and its customers to engage in an Asset Management Agreement.

Q.

For questions 528-531, please refer to FPL's response to item 506 of Staff's Nineteenth Set of Interrogatories to Florida Power & Light. Also refer to paragraph 12(a)(ii) of the settlement and to the bullet on the Asset Management Agreement (AMA).

In addition to the above, please refer to FPL's response to item 507 of Staff's Nineteenth Set of Interrogatories to Florida Power & Light. Why does FPL not currently sell gas out of storage for gains and credit the gain to fuel costs?

A.

Selling natural gas out of storage is not currently part of an approved optimization program and is not part of the existing incentive mechanism. FPL's opportunity to engage productively in these forms of asset optimization is still evolving, so the potential to utilize them remains untested for the most part. FPL's gas utilization has increased in recent years and its portfolio of gas transportation and storage has grown to match, offering new opportunities when these assets are not needed to serve native load to deploy them in ways that reduce fuel expenses for FPL's customers. FPL also notes that, absent an approved program and associated incentive mechanism, FPL would bear the risk for the outcome of each transaction, with no prospect for sharing in the gain. Due to this asymmetrical risk, FPL has not entered into sales of natural gas from storage.

Q.

For questions 528-531, please refer to FPL's response to item 506 of Staff's Nineteenth Set of Interrogatories to Florida Power & Light. Also refer to paragraph 12(a)(ii) of the settlement and to the bullet on the Asset Management Agreement (AMA).

In addition to the above, please refer to FPL's response to item 508 of Staff's Nineteenth Set of Interrogatories to Florida Power & Light Why does FPL not currently sell idle gas transportation and idle electric transmission and credit the gain to fuel costs?

A.

FPL does not currently sell idle gas transportation for the same reasons indicated in FPL's response to Staff's Nineteenth Set of Interrogatories No. 530.

FPL does engage in the sale of idle electric transmission. FPL owns long-term firm electric transmission service on the Southern Company system to support its UPS purchased power agreements. Under the terms of the UPS agreements, if FPL does not schedule UPS power by the day-ahead deadline defined in each agreement, FPL loses its scheduling rights for the next-day. If FPL determines that it does not require UPS power for a given day, it can re-post its electric transmission service on Southern Company's OASIS system for other entities to purchase. The revenues from any such sales of idle electric transmission capacity are credited to customers through the fuel clause and/or capacity clause.

AFFIDAVIT

Robert E Barrett Jr

(Robert E. Barrett, Jr.)

State of Florida)

County of Palm Beach)

I hereby certify that on this 17th the day of October, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Robert E. Barrett, Jr, who is personally known to me, and he acknowledged before me that he sponsored the answer to Request Nos. 476-491 and 495-500 from Staff's Nineteenth Set of Interrogatories 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 17th day of October, 2012.

Jennifer A Reklinski

Notary Public, State of Florida

Notary Stamp: Notary Public State of Florida
Jennifer A Reklinski
My Commission DD944536
Expires 02/27/2014

AFFIDAVIT

Sam A. Forrest

State of Florida)

County of Palm Beach)

I hereby certify that on this 7th day of October 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Sam A. Forrest**, who is personally known to me, and he acknowledged before me that he sponsored the answers to **Interrogatory Nos. Nos. 501-523, and 528-533**, from Staff's 19th Set of Interrogatories 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 7th day of October, 2012.

Maritza Miranda-Wise
Notary Public, State of Florida

Notary Stamp:

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

AFFIDAVIT

Sam A. Forrest

State of Florida)

County of Palm Beach)

I hereby certify that on this 24 day of November 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Sam A. Forrest**, who is personally known to me, and he acknowledged before me that he sponsored the answer to **Supplemental Interrogatory No. 517**, from Staff's 19th Set of Interrogatories to Florida Power & Light Company in Docket No. 120015-EI, and that the response is true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 24 day of November 2012.

Notary Public, State of Florida

Notary Stamp:

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

651

FPL's Responses to Staff's 20th Set of Interrogatories, Nos. 534-545, 547, 549-556, 558-560, 564-565, 567-568, 572-573, 576, 591-594, and 596

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 651
PARTY Staff's Hearing Exhibit 651
DESCRIPTION FPL's response to Staff's 20th set of
DATE Interrogatories (Bates Nos. 03024-03069)

Q.

By their omission from Appendix B of the proposed settlement agreement, please confirm that the following tariff pages remain unchanged from the currently approved tariff sheets on file:

General Service Non Demand
Thirty-eight Revised Sheet No. 8.101
Twenty-sixth Revised Sheet No. 8.103

General Service Large Demand -3
Nineteenth Revised Sheet No. 8.551
Twenty-fifth Revised Sheet No. 8.552

Traffic Signals
Thirty-fifth Revised Sheet No. 8.730

Contract Provision
Fifteenth Revised Sheet No. 10.010

A.

Yes. Note that for Tariff Sheet 10.010, using an ROE of 10.7% results in an annual facility rental rate of 23% of the installed cost of facilities, which is the same rental rate under the currently approved tariff.

Q.
What was the estimated revenue impact included in FPL's 2013 rate case for the Extended Power Uprate Systems that FPL has now filed as a separate base rate increase in Docket No. 120244-EI? In your response, please state the bill impact on a 1,000 kWh residential bill based on the estimated revenue requirement.

A.
There is no revenue impact associated with the Extended Power Uprate Systems placed in service in 2012 (2012 EPUs) included in FPL's 2013 rate case. All costs associated with the 2012 EPUs were removed from rate base and net operating income through Commission adjustments as reflected on MFR B-2 and C-2, respectively. Page 1 of Exhibit RBD-12 includes the $2.59 1000 kWh bill impact of the 2012 EPUs as presented in attachment C to FPL's Petition for Base Rate Increase for Extended Power Uprate Systems Placed in Commercial Service filed in Docket No. 120244-EI on October 1, 2012. This bill impact accounts for the EPU base rate increase only and does not take into account the fuel and environmental savings that these projects provide to FPL's customers.

Q.
What is the revenue requirement for the Extended Power Uprate Systems included in Docket 120244-EI? In your response, please state the bill impact on a 1,000 kWh residential bill based on that revenue requirement.

A.
The 12 month retail jurisdictional revenue requirement for the Extended Power Uprate Systems placed into service in 2012 is $246,047,170, including a true-up related to the 2011 base rate revenue requirement. (The original filed amount of $246,053,294 was subsequently corrected in response to a data request in Docket No. 120244-EI.) The bill impact is $2.59 on a typical 1,000 kWh monthly residential bill. This bill impact accounts for the EPU base rate increase only and does not take into account the fuel and environmental savings that these projects provide to FPL's customers.

Q.
When does FPL anticipate the filing of the final EPU System base rate increase? In your response, please state the effective date FPL anticipates for this base rate increase, and the expected base rate increase related to the uprate.

A.
FPL plans to file the final EPU System base rate increase in the third or fourth quarter of 2013 with a potential true-up filing in 2014. Rates are to be effective on the first billing cycle day of January 2014, with any true-up effective on the first billing cycle day of January 2015. FPL will not have all of the data needed to determine the expected base rate increase for assets that are placed into service in 2013 and any true-up related to the 2012 base rate revenue requirement until shortly before the filing is made.

Q.
Does FPL know of any other potential base rate increases that it plans on filing during the four year term of the stipulation and settlement agreement not already included within the agreement?

A.
No, there are no known additional base rate increases for the four year term of the stipulation and settlement agreement other than what is already included within the agreement.

Q.
For the four year term of the proposed stipulation beginning January 1, 2013, please provide the annual, total, and cumulative total revenue requirements to be collected pursuant to the proposed stipulation for the following units:

a. Canaveral Modernization Project (projected to go into service June 2013);
b. Riviera Modernization Project (projected to go into service June 2014);
c. Port Everglades Modernization Project (projected to go into service June 2016).

A.
See FPL's response to Staff's Twentieth Set of Interrogatories No. 541.

Q.
For the four year term of the proposed stipulation beginning January 1, 2013, please provide the projected annual, total, and cumulative total revenue requirements for the following units:

a. Canaveral Modernization Project (projected to go into service June 2013);
b. Riviera Modernization Project (projected to go into service June 2014);
c. Port Everglades Modernization Project (projected to go into service June 2016).

A.
See FPL's response to Staff's Twentieth Set of Interrogatories No. 541.

Q.

For the four year term of the proposed stipulation beginning January 1, 2013, please provide the annual, total, and cumulative total difference in actual revenue requirements and the revenue requirements to be collected pursuant to the proposed stipulation for the following units:

a. Canaveral Modernization Project (projected to go into service June 2013);
b. Riviera Modernization Project (projected to go into service June 2014);
c. Port Everglades Modernization Project (projected to go into service June 2016).

A.

See Attachment No. 1 for the requested revenue requirement comparison. The assumptions for the revenue requirements reflected on the attachment are consistent with the amounts reflected on FPL witness Barrett's Exhibit REB-10, which was provided along with his direct testimony on the Proposed Settlement Agreement that was filed with the Commission on October 12, 2012. The revenue requirements calculated for the GBRA increase, shown on Attachment No. 1, are the amounts the Company expects to receive over the first 12 months of the operations of each plant. However, pursuant to the terms of the Proposed Settlement Agreement, if the capital costs of any of the plants is lower than that used in calculating the first 12 month revenue requirements, the Company will lower its revenue recovery and provide refunds to customers to reflect the lower capital costs. The Company can only provide the first year revenue requirements for each plant as it does not have a forecast beyond that to allow it to properly reflect other changes to the estimated costs including additional capital expenditures or growth in plant, operating expenses, insurance, property taxes, and other related costs.

Theoretical Comparison of First Year Revenue Requirements and Projected Revenue Requirements
($ millions)

	First Year Annualized Revenue Requirements (GBRA)	Revenues to be Recovered [4]	Difference
Cape Canaveral [1]	$ 165.3	$ 165.3	$ -
Riviera [2]	236.0	236.0	$ -
Port Everglades [3]	217.9	217.9	$ -
Total	**$ 619.2**	**$ 619.2**	**$ -**

Notes:

(1) Based on the following assumptions: the revised Cape Canaveral Modernization Project costs and expenses included in the Appendix to FPL's post hearing brief filed on September 21, 2012, the as-filed, incremental capital structure, the revised long term debt cost rate as described by FPL in its post hearing brief, and the settlement ROE of 10.7%. The projected in-service date for Canaveral is June 1, 2013.

(2) Based on the following assumptions: the projected capital costs and expenses included in the Riviera Modernization project need determination filing, the as filed and revised incremental capital structure and cost rates for the Canaveral Modernization Project, and the settlement ROE of 10.7%, consistent with Paragraph 8(c) of the Proposed Settlement Agreement. The projected in-service date for Riviera is June 1, 2014.

(3) Based on the following assumptions: the projected capital costs and expenses included in the Port Everglades Modernization project need determination filing, the as filed and revised incremental capital structure and cost rates for the Canaveral Modernization Project, and the settlement ROE of 10.7%, consistent with Paragraph 8(c) of the Proposed Settlement Agreement. The projected in-service date for Port Everglades is June 1, 2016.

(4) Based on the estimated step increase base rate filed methodology which is equivalent to GBRA.

Q.
Please describe in detail the actions taken by FPL to draft, introduce, and seek sponsorship of the amendment to CS for SB 2094 filed in the Florida Senate on February 10, 2012 entitled: "366.95 Certified generation Adjustment."

A.
See FPL's Objections to Staff's Twentieth Set of Interrogatories previously filed on October 22, 2012. Notwithstanding and without waiving those objections, FPL states that it did support the amendment to CS/SB 2094 proposed during the 2012 legislative session.

Q.
Please describe in detail the action taken by the Legislature on the proposed amendment.

A.
Consistent with FPL's general objection regarding the provision of publicly available information, detail regarding the action taken by the Legislature on the proposed amendment can be located at (http://www.flsenate.gov/Session/Bill/2012/2094).

Q.

Please complete the table below showing the year in which plant additions entered commercial service, the total capital costs of each plant, and each year that a general rate proceeding was concluded.

Year		Plant addition (Name)		Plant cost ($)		Base rate proceeding
2000						
2001						
2002						
2003						
2004						
2005						
2006						
2007						
2008						
2009						
2010						
2011						
2012						

A.

See Attachment No. 1 for the requested plant additions, total plant costs, and each year that a general rate proceeding was concluded. Note, the total plant costs are stated as of when the plant began commercial operation and include any related land, distribution, transmission, and other costs directly associated with the generation plant addition. In addition, the listing excludes nuclear uprates and solar facilities as these are recovered through a mechanism other than a general base rate proceeding.

As reflected in Attachment No. 1, FPL's general base rate proceedings over the course of the requested period concluded with stipulation and settlement agreements. These settlement provisions included depreciation credits, the cessation of certain accruals, which, together with all other provisions of the respective agreements, were sufficient to mitigate the cost increases associated with the new plant additions. Further, please note that high sales growth can partially offset the increased revenue requirements associated with bringing new power plants into service. FPL's sales growth was very high from 1985 through 2005, but has slowed substantially thereafter.

Plant Additions from 2000 through 2012

Year	Plant Addition (Name)	Plant Cost ($) [1]	Base Rate Proceeding
2000	None	$ -	None - Operating Under Stipulation and Settlement Agreement - Order No. PSC-99-0519-AS-EI
2001	Martin Unit 8 Simple Cycle Operation of 2 CT's	$ 97,214,790	None - Operating Under Stipulation and Settlement Agreement - Order No. PSC-99-0519-AS-EI
2002	Ft Myers Unit 2 Repowering Combined Cycle Operation	$ 497,319,789	Stipulation and Settlement Agreement - Order No. PSC-02-0501-AS-EI [5]
	Sanford Repowering Unit 5 Combined Cycle Operation [2]	$ 351,147,202	
2003	Sanford Repowering Unit 4 Combined Cycle Operation [2]	$ 348,447,094	None - Operating Under Stipulation and Settlement Agreement - Order No. PSC-02-0501-AS-EI
	Combustion Turbine Peaking Units Ft Myers	$ 119,680,384	
2004	None	$ -	None - Operating Under Stipulation and Settlement Agreement - Order No. PSC-02-0501-AS-EI
2005	Manatee Unit 3 Combined Cycle Operation	$ 476,806,319	Stipulation and Settlement Agreement - Order No. PSC-05-0902-S-EI [6]
	Martin Unit 8 Combined Cycle Operation	$ 390,270,642	
2006	None	$ -	None - Operating Under Stipulation and Settlement Agreement - Order No. PSC-05-0902-S-EI
2007	Turkey Point Unit 5 Combined Cycle Operation [3]	$ 546,599,306	None - Operating Under Stipulation and Settlement Agreement - Order No. PSC-05-0902-S-EI (GBRA)
2008	None	$ -	None - Operating Under Stipulation and Settlement Agreement - Order No. PSC-05-0902-S-EI
2009	West County Unit 1 Combined Cycle Operation [2],[3]	$ 727,784,082	None - Operating Under Stipulation and Settlement Agreement - Order No. PSC-05-0902-S-EI (GBRA)
	West County Unit 2 Combined Cycle Operation [2],[3]	$ 592,431,224	
2010	None	$ -	Order No. PSC-10-0153-FOF-EI, Docket No. 080677-EI [7]
2011	West County Unit 3 Combined Cycle Operation [4]	$ 842,152,567	Stipulation and Settlement Agreement - Order No. PSC-11-0089-S-EI [8]
2012	None	$ -	None - Operating Under Stipulation and Settlement Agreement - Order No. PSC-11-0089-S-EI

Notes:

(1) Amounts reflected are as of the commercial operation date and include the cost of land, construction overheads and AFUDC. Costs associated with FPL's solar plants and nuclear unit uprates are excluded as these costs are recovered through a mechanism other than a general base rate proceeding. These are capital costs, not revenue requirements.

(2) Costs related to distribution plant, general plant, site common, intangible plant, and transmission plant were assigned the same budget activity code for both units at each site. For purposes of this request, the presentation of these costs have been allocated based on the ratio of generation costs to the total costs for the respective units.

(3) Base rates were increased commensurate with commercial operation of this unit via the GBRA mechanism approved by the Commission in Order No. PSC-05-0902-S-EI, Docket No. 050045-EI.

(4) Pursuant to Order No. PSC-11-0089-EI, Docket No. 080677-EI, FPL was authorized to recover the lower of revenue requirements or fuel savings through its capacity clause factor commensurate with the commercial operation of this unit.

(5) Settlement term was April 15, 2002 through December 31, 2005.

(6) Settlement term was January 1, 2006 through December 31, 2009.

(7) Order was superseded by stipulation and settlement agreement in note 8.

(8) Settlement term is February 1, 2011 through December 31, 2012.

QUESTION

For Interrogatory Nos. 545-548, please refer to paragraph 12(a)(ii) of the proposed stipulation and settlement.

Please describe in detail each form of asset optimization mentioned in this paragraph.

RESPONSE

Gas Storage Optimization - FPL may be able to either sub-lease a portion of its gas storage capacity or sell gas directly out of storage. FPL would seek to execute these types of transactions predominately during non-critical demand periods when full gas storage volumes are not required. The revenue that would be generated from either type of transaction, a lease payment or a gain on the sale of gas, would directly benefit customers by reducing overall natural gas expenses.

Delivered City-Gate Gas Sales - FPL may be able to make natural gas sales in the Market Area utilizing its natural gas transportation capacity when it is not needed for its own requirements. While the opportunity for these types of sales is limited due to FPL's high utilization of its firm gas transportation and the necessity to retain a portion of its gas transportation to cover forecast errors, if FPL was able to execute this type of sale, the gain would benefit customers by reducing overall natural gas expenses.

Production (Upstream) Area Gas Sales - FPL would engage in these types of gas sales when generation or consumption requirements change, forcing FPL to balance its natural gas supply with its demand. These types of sales are made in the Production Area and do not require FPL to use its natural gas transportation capacity. Opportunities could potentially exist outside of balancing requirements. Gains for these transactions would benefit customers by reducing overall natural gas expenses.

Capacity Release of Gas Transportation - FPL could directly sell a piece of its gas transportation capacity for short durations when it is not needed for its own requirements. While the opportunity for these types of sales is limited due to FPL's high utilization of its firm gas transportation and the necessity to retain a portion of its gas transportation to cover forecast errors, if FPL was able to execute this type of sale, the revenues would benefit customers by reducing overall natural gas expenses.

Electric Transmission Sales – FPL could engage in the resale of idle electric transmission service that it owns on a third party transmission system. FPL currently engages in the sale of idle electric transmission because it owns long-term firm electric transmission service on the Southern Company system to support its UPS purchased power agreements. Under the terms of the UPS agreements, if FPL does not schedule UPS power by the day-ahead deadline defined in each agreement, FPL loses its scheduling rights for the next day. If FPL determines that it does not require UPS power for a given day, it can re-post its electric transmission service on Southern Company's OASIS system for other entities to purchase.

Because the electric transmission service would otherwise go unutilized, the revenue received from this type of transaction directly reduces the cost of unutilized electric transmission service for FPL's customers.

AMA – FPL could outsource a portion of the optimization of its natural gas storage or natural gas transportation capacity to a third party in exchange for a premium and potentially a share of optimization revenues generated by the third party. The third party would be independent of FPL or NextEra Energy, Inc. and would typically have an existing portfolio of assets that, when combined with FPL's asset(s), could be optimized to provide value to both entities. The third party would be better suited to extract the value of FPL's asset(s) from both a resource perspective (i.e., personnel, expertise, market presence...etc.) and from a portfolio of assets perspective.

Q.
For Interrogatory Nos. 545-548, please refer to paragraph 12(a)(ii) of the proposed stipulation and settlement.

Please provide a hypothetical Asset Management Agreement, as described in paragraph 12 of the Settlement, that FPL believes would be eligible for inclusion in the incentive mechanism.

A.
FPL has received several informal AMA proposals from certain potential counterparties, which will be provided in FPL's response to Staff's Fifteenth Request for Production of Documents No. 92. At this point, however, FPL does not have what it considers to be a standardized form of AMA that would be appropriate for execution. FPL will describe below the types of provisions that it would expect to see included in a form AMA:

AMA's are typically structured as follows: a shipper (FPL) holding firm transportation and/or storage capacity, temporarily releases a portion of its capacity to an asset manager (Third party marketing company) which uses the released capacity to serve the gas supply requirements of the releasing shipper (FPL). By permitting capacity holders to use third party experts to manage their gas supply arrangements and their pipeline capacity, AMA's can lower gas supply costs for releasing shippers. AMA's provide, in general, for lower gas supply costs, resulting in ultimate savings for end-use customers.

AMA's generally include provisions for the asset manager to share with the releasing shipper the value it is able to obtain from the releasing shipper's capacity and other assigned assets. The asset manager may share that value by: (1) paying a fixed "optimization" fee to the releasing shipper; (2) sharing with the releasing shipper the asset manager's profits from the use of the released capacity and other assigned assets pursuant to an agreed-upon formula (3) making gas sales to the releasing shipper at a below-market commodity price; or (4) in some other way mutually agreed to by the contracting parties.

Hypothetical example of an Asset Management Agreement (AMA):

FPL releases 100,000 MMBtu/day of its total 580,000 MMBtu/day of firm gas transportation on the Southeast Supply Header (SESH) pipeline to Company XYZ. Company XYZ agrees to pay FPL an annual premium of $120,000. FPL receives 100,000 MMBtu/day of natural gas at Delivery Point A for a cost that is no greater than what FPL would have paid for gas at Delivery Point A utilizing the transportation on its own. Company XYZ also agrees to pay FPL 25% of any revenues it receives from its optimization activities related to the 100,000 MMBtu/day of firm gas transportation.

Under this example, the reliability of fuel supply and the cost of natural gas are not impacted by entering into the AMA. At a minimum, FPL's total gas expenses are reduced by $120,000 and could potentially be reduced additionally through the 25% of profit sharing.

Q.
Just considering economy sales and economy purchases, will FPL have savings on economy purchases (short-term wholesale purchases) that, along with gains on economy sales (short-term wholesale sales), will exceed $46 million for any of the years 2013 through 2016? In your response, please explain in detail the savings.

A.
At this time, FPL is not projecting that the combination of gains on wholesale sales and savings on wholesale purchases (including purchases that are reported on Schedule A7) will exceed $46 million for any of the years from 2013 through 2016. While specific events could occur that drive gains on wholesale sales and savings on wholesale purchases above currently projected levels, it would be impossible to project those types of random events and the impact that they would have on sales and purchases. FPL will continue to, as it does today, capitalize on all wholesale power transactions that help reduce overall fuel costs for FPL's customers.

Q.

For Interrogatory Nos. 550-555, please refer to paragraph 12(a)(i) of the proposed stipulation and settlement.

Please explain in detail if FPL expects a decrease in economy purchases for 2013 to 2016 compared to 2009 to 2012.

A.

Future projections of economy purchases (and sales) are highly uncertain. Many factors collectively drive FPL's ability to make economy power purchases, including the relationship between fuel prices, load, generation availability, overhaul schedules, transmission availability and the condition of other utility systems. From 2009 through 2012 (actual data through September and estimates from October through December), FPL purchased approximately 5.45 million MWh of economy power. From 2013 through 2016, FPL is projecting to purchase approximately 4.2 million MWh of economy power. FPL expects this overall decrease from previous levels due to the addition of highly efficient, combined cycle units at Cape Canaveral (2013), Riviera (2014) and Port Everglades (2016). FPL is projecting that the addition of these units will help lower, on average, FPL's marginal cost against which economy purchases are made, somewhat reducing FPL's ability to find lower cost power in the market. Additionally, and more significantly, the expected lowering of FPL's marginal cost would also reduce the savings margins from prior years. Therefore, FPL expects that the more significant decrease will occur in the savings realized through economy purchases rather than in the volume of economy purchases.

Q.
For Interrogatory Nos. 550-555, please refer to paragraph 12(a)(i) of the proposed stipulation and settlement.

Do the additions of TP5 and WCEC 1, 2, and 3 decrease the need for economy purchases during 2013 to 2016? Please explain.

A.
The addition of more efficient units does not necessarily decrease the need for economy purchases. The benefits of economy purchases always exist, and to the extent lower cost power is available, it will be purchased. As stated in FPL's response to Staff's Twentieth Set of Interrogatories No. 550, FPL believes that the additions of Cape Canaveral, Riviera and Port Everglades modernizations will make it slightly harder for FPL to find economy power purchases that can be made on favorable terms and will lower the savings margins associated with economy purchases. These expectations seem intuitive and also would have applied when TP5 and WCEC 1, 2 and 3 were brought on-line. Actual data from 2006 through 2012 demonstrates the difficulty in projecting wholesale power transactions, particularly when bringing new units on-line, and the importance of the factors (referenced in FPL's response to Staff's Twentieth Set of Interrogatories No. 550) that drive a utility's ability to participate in the wholesale power market. As expected, the addition of Turkey Point Unit 5 in 2007 appears to have impacted economy purchases in both 2007 and 2008 as both volumes and savings were down in both years as compared to 2006. In contrast, however, FPL's volumes of economy purchases, as well as savings margins, increased substantially in 2009 and 2010 even as WCEC Unit 1 and WCEC Unit 2 were brought on-line. While the volume of economy purchases decreased in 2011 from 2010 levels, total savings continued to be significant even with the addition of WCEC Unit 3. A major factor contributing to this trend beginning in 2009 was the increasing gap between heavy fuel oil and natural gas prices. As natural gas prices continued to decline, heavy oil prices remained relatively high and even increased at times. Therefore, FPL's ability to make economy purchases when heavy oil was on the margin increased significantly. In summary, unanticipated market forces mitigated in part, the impact that the addition of new units had on FPL's participation in the wholesale power market.

Q.

For Interrogatory Nos. 550-555, please refer to paragraph 12(a)(i) of the proposed stipulation and settlement.

Does the shift away from fuel oil generation to gas-fired generation reduce the need for economy purchases or lessen the volume of economy purchases for the period 2013 through 2016? Please explain in detail how it lessens the volume of economy purchases or reduces the need for economy purchases for the period 2013 through 2016.

A.

The volume of economy purchases can be impacted by a shift to a lower cost fuel, because that shift can impact one's ability to find available power in the market that is at a lower cost than one's own generation. As described in FPL's response to Staff's Twentieth Set of Interrogatories No. 551, the addition of highly efficient, gas-fired generation does not always have the expected impact on economy purchases due to the numerous factors that collectively drive the opportunity for economy power purchases. In theory, however, the fact that oil-fired generation is now approximately five times the cost of combined cycle generation, additional gas-fired generation should impact to some extent the volume of economy purchases and savings margins if the additional gas-fired generation reduces the need for oil-fired generation. FPL's projections for the 2013 through 2016 time period take this into account with slightly lower purchase volumes and significantly reduced overall savings.

Q.

For Interrogatory Nos. 550-555, please refer to paragraph 12(a)(i) of the proposed stipulation and settlement.

Please explain in detail if the changes in Interrogatory No. 552 affect FPL's ability to increase economy sales.

A.

FPL's ability to make economy sales is driven by the same factors that impact its ability to make economy purchases and therefore, future projections are highly uncertain. If FPL's reliance on heavy fuel oil decreases, lowering its average marginal cost, the opportunities to participate in the economy sales market should increase. FPL's projections for the 2013 through 2016 time period take this into account with slightly higher economy sales volumes and slightly higher gains.

Q.
For Interrogatory Nos. 550-555, please refer to paragraph 12(a)(i) of the proposed stipulation and settlement. Refer to paragraph 12(a)(iii) of the settlement.

Please explain in detail if the $36 million is based on projected economy sales for 2013 and projected fuel savings for economy purchases for 2013.

A.
Yes. FPL's first threshold of $36 million ("Customer Savings Threshold") is based on its 2013 projections for power sales gains and purchased power savings that were filed on August 31, 2012 in Docket No. 120001-EI. For 2013, FPL projects power sales gains of $4,238,116 and purchased power savings of $30,907,083, or $35,145,199 in total.

Q.
For Interrogatory Nos. 550-555, please refer to paragraph 12(a)(i) of the proposed stipulation and settlement.

Please identify the Commission orders that specifically support and authorize the calculation of fuel savings on Schedules E9 and A9 filed in the fuel docket (current Docket No. 120001-EI).

A.
The Minimum Filing Requirements set forth in the Commission Directive dated April 24, 1980, and revised by the Commission Memorandum issued by the Division of Electric and Gas dated December 13, 1994, support and authorize the Fuel Savings calculations on Schedules E9 and A9. The Schedule E9 and Schedule A9 forms included with the Commission Memorandum show the fuel savings calculations in column 8 and column 7, respectively.

QUESTION

Please complete the table below summarizing FPL's actual and projected gains from asset optimization as described in paragraph 12 of the settlement.

	Short-Term Wholesale Sales	Short-Term Wholesale Purchases	Gas Storage Utilization	Delivered city-gage gas sales using existing transport	Production (upstream) area sales	Capacity Release of gas transport	Capacity Release of electric transmission	Asset Management Agreement	Other
2007									
2008									
2009									
2010									
2011									
2012									
2013									
2014									
2015									
2016									

RESPONSE

Year	Short-Term Wholesale Sales	Short-Term Wholesale Purchases	Gas Storage Utilization	Delivered City-Gate Gas Sales	[1]Production Area Sales	Capacity Release of Gas Transport	Capacity Release of Electric Transmission	Asset Management Agreement	Other	Total
2007	18,545,406	16,274,883	0	0	0	0	0	0	0	34,820,289
2008	17,001,482	14,887,826	0	0	0	0	0	0	0	31,889,308
2009	10,700,431	39,751,658	0	0	0	0	0	0	0	50,452,089
2010	4,421,987	78,316,363	0	0	0	0	0	0	0	82,738,350
2011	4,918,688	64,644,735	0	0	0	0	43,500	0	0	69,606,923
[2]2012	3,627,951	38,460,208	0	0	0	0	589,066	0	0	42,677,225
2013	4,238,116	30,907,083							0	35,145,199
2014	4,620,331	20,241,887							0	24,862,218
2015	4,620,331	20,537,303							0	25,157,634
2016	4,620,331	26,824,181							0	31,444,512

[1]FPL has made Production Area Sales in the past due to unexpected load changes, however FPL has not calculated gains or losses associated with these sales.
[2]2012 wholesale power data reflects actuals through September and estimates from October through December (2012 Actual/Estimated True-Up filed on August 1, 2012). Capacity Release of Electric Transmission reflects actuals through October 23, 2012.

FPL has not projected gains from asset optimization measures other than wholesale power sales and purchases for future years. FPL has not engaged in these additional asset optimization measures (except for the resale of idle electric transmission) and has no reference for the potential benefits that can be achieved. FPL has engaged in wholesale power transactions for numerous years and has accumulated a significant amount of historical data. While historical data is not necessarily a great predictor of future results, the data can be used to identify trends over time and it can then be adjusted to incorporate system changes, such as unit additions, to yield estimates that have some merit. Except for minimal electric transmission resale data, FPL does not have any historical data for other asset optimization measures as it has not executed these types of transactions. Furthermore, these types of transactions are extremely dependent on real-time system and market conditions which are not known at this time. From a reliability perspective, it would be difficult for FPL to commit ahead of time to any type of transaction regarding natural gas supply, transportation or electric transmission. Typically, these types of transactions would be done on a short-term basis (i.e., daily) when there is a high degree of certainty regarding system requirements. Due to this fact, projections for gains on these types of asset optimization measures at this time would have very little credibility. As described in the FPL's response to Staff's Nineteenth Set of Interrogatories No. 532, given the relatively low volatility that currently exists in the natural gas market, FPL believes that it could be difficult to execute these types of transactions in 2013.

Q.
Please provide a sample of the Total Gains Schedule that FPL is proposing to file in the Fuel clause pursuant to paragraph 12 of the Settlement. For the purposes of this sample please assume the projected gains, for the year 2013, provided in response to Interrogatory No. 556 above.

A.
Please see Attachment No. 1, a sample of the Total Gains Schedule FPL is proposing to file in the Fuel Clause pursuant to paragraph 12 of the Proposed Settlement Agreement. The wholesale power data shown on the schedule represents the data that FPL filed as part of its 2013 Projection Filing in Docket No. 120001-EI on August 31, 2012. The data shown in Column (6) of Table 1 for Asset Optimization Savings is hypothetical as FPL has not projected these savings. Additionally, FPL has included an "Incremental Optimization Costs" Schedule (Table 3) for reference. The values shown in Column (2) and (3) of Table 3 are hypothetical. The values shown in Column (5) of Table 3 represent FPL's 2013 projections for wholesale sales as filed on August 31, 2012 (2013 Projection Filing, Docket No. 120001-EI).

Sample - "Total Gains Schedule"

Florida Power & Light Company
Docket No. 120015-EI
Staff's Twentieth Set of Interrogatories
Interrogatory No. 558
Attachment No.1; Page 1 of 2

TOTAL GAINS SCHEDULE
Actual for the Period of: January 2013 through December 2013

TABLE 1

(1) Month	(2) Wholesale Sales (MWh)	(3) Wholesale Sales Total Gains ($)	(4) Wholesale Purchases (MWh)	(5) Wholesale Purchases Total Savings ($)	(6) Asset Optimization Savings ($)	(7) Monthly Gains (MG) ($)	(8) Cumulative Gains (CG) ($)	(9) Threshold 1 CG ≤ $36M 100% Customer Benefit ($)	(10) Threshold 2 $36M > CG ≤ $46M 100% Customer Benefit ($)	(11) Threshold 1 and 2 Total Customer Benefit ($)
						(3) + (5) + (6)				(9) + (10)
January	85,200	888,156	600	8,166	490,000	1,386,322	1,386,322	1,386,322	0	1,386,322
February	66,100	641,976	14,500	133,400	420,000	1,195,376	2,581,698	1,195,376	0	1,195,376
March	26,400	232,510	52,000	761,778	430,000	1,424,288	4,005,986	1,424,288	0	1,424,288
April	17,400	192,428	143,300	2,662,940	330,000	3,185,368	7,191,354	3,185,368	0	3,185,368
May	13,100	132,846	167,600	4,133,035	410,000	4,675,881	11,867,235	4,675,881	0	4,675,881
June	20,900	207,652	71,800	581,580	150,000	939,232	12,806,467	939,232	0	939,232
July	16,900	179,359	87,600	2,207,520	100,000	2,486,879	15,293,346	2,486,879	0	2,486,879
August	24,000	276,415	259,900	9,852,401	100,000	10,228,816	25,522,162	10,228,816	0	10,228,816
September	12,000	117,119	195,800	9,056,850	230,000	9,403,969	34,926,131	9,403,969	0	9,403,969
October	23,700	215,230	43,500	1,177,540	230,000	1,622,770	36,548,901	1,073,869	548,901	1,622,770
November	50,500	510,215	16,700	268,663	350,000	1,128,878	37,677,779	0	1,128,878	1,128,878
December	57,200	644,210	6,700	63,210	500,000	1,207,420	38,885,199	0	1,207,420	1,207,420
Total	**413,400**	**4,238,116**	**1,060,000**	**30,907,083**	**3,740,000**	**38,885,199**		**36,000,000**	**2,885,199**	**38,885,199**

TABLE 2

(1) Month	(2) Cumulative Gains (CG) ($)	(3) Incremental Gains (IG) $46M > IG ≤ $75M ($)	(4) Incremental Gains (IG) $75M > IG ≤ $100M ($)	(5) Incremental Gains (IG) IG > $100M ($)	(6) Threshold 3 $46M > IG ≤ $75M 30% Customer Benefit ($)	(7) Threshold 3 $46M > IG ≤ $75M 70% FPL Benefit ($)	(8) Threshold 4 $75M > IG ≤ $100M 40% Customer Benefit ($)	(9) Threshold 4 $75M > IG ≤ $100M 60% FPL Benefit ($)	(10) Threshold 5 IG > $100M 50% Customer Benefit ($)	(11) Threshold 5 IG > $100M 50% FPL Benefit ($)
	Column (8) Table 1									
January	1,386,322	0	0	0	0	0	0	0	0	0
February	2,581,698	0	0	0	0	0	0	0	0	0
March	4,005,986	0	0	0	0	0	0	0	0	0
April	7,191,354	0	0	0	0	0	0	0	0	0
May	11,867,235	0	0	0	0	0	0	0	0	0
June	12,806,467	0	0	0	0	0	0	0	0	0
July	15,293,346	0	0	0	0	0	0	0	0	0
August	25,522,162	0	0	0	0	0	0	0	0	0
September	34,926,131	0	0	0	0	0	0	0	0	0
October	36,548,901	0	0	0	0	0	0	0	0	0
November	37,677,779	0	0	0	0	0	0	0	0	0
December	38,885,199	0	0	0	0	0	0	0	0	0
Total		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Sample - "Total Gains Schedule"

INCREMENTAL OPTIMIZATION COSTS
Actual for the Period of: January 2013 through December 2013

TABLE 3

(1) Month	(2) Personnel Expenses * ($)	(3) Other Expenses ** ($)	(4) Wholesale Sales (MWh)	(5) Cumulative Sales Generation (MWh)	(6) Sales Generation Threshold*** (MWh)	(7) Sales Generation Above Threshold (MWh)	(8) Weighted Average Variable O&M**** ($/MWh)	(9) Incremental Generator Variable O&M ($)	(10) Total Incremental O&M Expenses ($)
			(From (2) Table 1)			*****		(6) * (7)	(2) + (3) + (8)
January	37,500	0	85,200	85,200	514,000	0	1.51	0	37,500
February	37,500	0	66,100	151,300	514,000	0	1.51	0	37,500
March	37,500	0	26,400	177,700	514,000	0	1.51	0	37,500
April	37,500	0	17,400	195,100	514,000	0	1.51	0	37,500
May	37,500	6,250	13,100	208,200	514,000	0	1.51	0	43,750
June	37,500	6,250	20,900	229,100	514,000	0	1.51	0	43,750
July	37,500	6,250	16,900	246,000	514,000	0	1.51	0	43,750
August	37,500	6,250	24,000	270,000	514,000	0	1.51	0	43,750
September	37,500	6,250	12,000	282,000	514,000	0	1.51	0	43,750
October	37,500	6,250	23,700	305,700	514,000	0	1.51	0	43,750
November	37,500	6,250	50,500	356,200	514,000	0	1.51	0	43,750
December	37,500	6,250	57,200	413,400	514,000	0	1.51	0	43,750
Total	**450,000**	**50,000**	**413,400**			**0**		**0**	**500,000**

Footnotes:
* Personnel expenses are for payroll and loadings for three additional trading personnel in 2013
** Other expenses are for a software license lease that began in May 2013
*** "Sales Generation Threshold" is the level of wholesale sales assumed in projecting power plant O&M costs for the 2013 test year MFR's.
**** "Weighted Average Variable O&M" reflects the monthly variable power plant O&M costs projected in the 2013 test year MFR's.
***** Column (7) Formula: If Column (5) - Column (6) > 0, then Column (7) equals the lower of Column (5) - Column (6) or Column (4)

Q.

Please refer to paragraph 12(a)(ii) of the proposed stipulation and settlement and to FPL's response to staff's second data request #1(b) and (c), which are now Interrogatory Nos. 529 and 530. Order No. PSC-06-1053-S-EI allows FPL to recover the cost of gas storage in fuel cost recovery. Given this, please explain how FPL currently bears the risk of a gas storage transaction with no prospect of sharing in a gain.

A.

Order No. PSC-06-1053-S-EI states that the appropriate avenue for cost recover of natural gas monthly storage reservation charges, fuel retention and commodity charges for injection and withdrawal and monthly insurance charges associated with FPL's participation in Bay Gas and MoBay natural gas storage facilities is through the fuel clause. The order does not pre-approve the execution of optimization measures that could potentially result in gains or losses and the associated regulatory treatment. Therefore, FPL bears the risk of being deemed imprudent if it executes an optimization measure that results in a loss.

Q.
Please provide and describe in detail three plausible, likely scenarios of what has to occur for the incentive mechanism gains to exceed $46 million.

A.
FPL believes that the threshold level of $46 million is a "stretch" goal. The actual levels of benefits that can be achieved are driven by numerous factors, including random events that significantly impact market conditions. FPL must be ready to capitalize on all opportunities that exist, regardless of what was projected for each optimization measure. For example, as described in FPL's response to Staff's Twentieth Set of Interrogatories No. 551, when FPL brought WCEC Units 1, 2 and 3 on-line, real-time system and market conditions presented opportunities to reduce fuel expenses by purchasing power. While this was not the expectation, FPL was able to capitalize on those opportunities and significantly reduce overall fuel expenses. As shown in the table provided in FPL's response to Staff's Twentieth Set of Interrogatories No. 556, FPL's projections for gains and savings on wholesale power sales and purchases is lower, in total, for 2014, 2015 and 2016 when compared with 2013. Specific events such as extreme cold weather in the southeast coupled with mild temperatures in Florida could have a large impact on FPL's opportunities to make power sales in the winter; however those types of events are impossible to predict. The severity and duration of that type of event would also be important factors in driving a significant increase in gains. Conversely, extremely hot weather in Southern Florida for an extended period of time could increase the opportunities for FPL to purchase power if heavy oil becomes the predominant marginal fuel, in turn increasing savings margins. Finally, while FPL projects that its opportunity to engage in an AMA is very limited due to current gas market stability, a continued decrease in Gulf of Mexico off-shore production coupled with continuing strong, on-shore production could widen the basis differential between FGT Zone 3 pricing and the Perryville Hub making the market conducive to entering into an AMA. This type of change could also increase the value of other types of asset optimization measures.

Q.
Please complete the table below summarizing FPL's projected Incremental Optimizations Costs, as defined in paragraph 12 of the settlement, from asset optimization.

	Incremental O&M
2013	
2014	
2015	
2016	
2017	

A.

Year	Incremental Optimization Costs	
	Personnel, Software, Hardware	Variable Power Plant O&M
2013	$500,000	$0
2014	$515,000	$0
2015	$530,450	$0
2016	$546,364	$0
*2017	$0	$0

As described in FPL's response to Staff's Nineteenth Set of Interrogatories No. 533, filed on October 19, 2012 in Docket No. 120015-EI, FPL has not definitively determined what level of personnel, software, and/or hardware costs would be required to support an expanded optimization program. The values shown in the table represent an initial estimate for three additional personnel as well as supporting computer hardware and software, escalated at 3% per year. These estimates are subject to change based on the opportunities that are identified over time.

*The term of the Proposed Settlement Agreement is from 2013 through 2016. Therefore, Incremental Optimization Costs are projected to be $0 for 2017 excluding any true-up amount from 2016.

Q.
Please provide an example of a variable power plant O&M cost, as described in footnote 3 of the settlement, that FPL believes may be incurred as a result of short-term wholesale sales.

A.
Chemicals (ammonia and phosphates) are used continuously to maintain the water chemistry quality in a unit's boiler and closed cooling water system to protect tubing from corrosion. Acids are used in the on-line analyzers to test water quality pH, silica, and phosphates. The amount of chemicals used is a function of unit output. When a wholesale power sale is made and a units' output increases, the use of chemicals increases.

Q.

Will any FIPUG, SFHHA, or FEA members or entities represented by these groups engage in (or be likely to engage in) transactions with FPL or a third party administrator involving the incentive mechanism in paragraph 12 of the proposed stipulation and settlement? Please identify the entity/entities.

A.

FPL is not aware of any FIPUG, SFHHA, or FEA members or entities represented by these groups that will engage in transactions with FPL or a third party administrator involving the proposed Incentive Mechanism.

Q.

For Interrogatory Nos. 568-575, please refer to paragraph 12(a)(ii) of the proposed stipulation and settlement.

Why does FPL propose a third party for the optimization function instead of creating the value in-house?

A.

FPL is not proposing to outsource the entire optimization function to a third party. Rather, FPL is proposing that it could outsource the optimization function of a portion of its storage capacity or transportation capacity for specific positions that it holds. For example, FPL holds 580,000 MMBtu of firm transportation capacity on the Southeast Supply Header (SESH) pipeline, which is one specific transportation position. Through an AMA, FPL could allocate a portion of this position to a third party in exchange for a premium and/or profit sharing. The third party would typically have an existing portfolio of assets that, when combined with FPL's asset(s) could be optimized to provide value to both entities. The AMA would facilitate the extraction of additional value that FPL could not achieve on its own. The third party would be better suited to extract the value of FPL's asset(s) from both a resource perspective (i.e., personnel, expertise, market presence...etc.) and from a portfolio of assets perspective.

Q.
For Interrogatory Nos. 568-575, please refer to paragraph 12(a)(ii) of the proposed stipulation and settlement.

Please identify and describe currently active companies that FPL has considered or evaluated to be top candidates to provide the asset optimization services.

A.
FPL has had preliminary discussions with several entities regarding the potential for an AMA. At that time, FPL's discussions with NJR Energy Services Company, Louis Dreyfus Energy Services L.P., and Chevron Natural Gas resulted in the most in-depth exchange of information.

Q.

For Interrogatory Nos. 568-575, please refer to paragraph 12(a)(ii) of the proposed stipulation and settlement.

Please name the top 8 holders of firm transportation capacity on the FGT pipeline and on the Gulfstream pipeline.

A.

The top eight (8) holders of firm transportation capacity on the FGT pipeline are: 1) Florida Power & Light Company; 2) Angola LNG Supply Services; 3) Peoples Gas System; 4) Florida Gas Utility; 5) Progress Energy Florida; 6) Tampa Electric Company; 7) Orlando Utilities Commission; and 8) RRI Energy Services. The top eight (8) holders of firm transportation capacity in the Market Area on the FGT pipeline are: 1) Florida Power & Light Company; 2) Peoples Gas System; 3) Florida Gas Utility; 4) Progress Energy Florida; 5) Tampa Electric Company; 6) Orlando Utilities Commission; 7) RRI Energy Services; and 8) Seminole Electric Cooperative.

The top eight (8) holders of firm transportation capacity on the Gulfstream pipeline are: 1) Florida Power & Light Company; 2) Progress Energy Florida; 3) Calpine Energy Services; 4) Tampa Electric Company; 5) Peoples Gas System; 6) Seminole Electric Cooperative; 7) City of Lakeland; and 8) Central Florida Gas Company, Florida Municipal Power Agency (tie). There are currently only nine (9) firm capacity holders listed on the Gulfstream natural gas pipeline Index of Customers.

Q.
Could the incentive mechanism create rates, credits, rebates, or incentives that will benefit specific customers and not the general body of ratepayers (or at the expense of the general body of ratepayers)? Please explain.

A.
No. All benefits of the Incentive Mechanism will be flowed back to customers through the fuel and/or capacity clause so the entire body of customers will share in the benefit.

Q.

Please refer to the last sentence of paragraph 12(a)(i) of the proposed stipulation and settlement. Does FPL intend for the Commission to make a prudent cost determination for each asset optimization measure as part of the final true-up review in the fuel docket? In your response, please explain the criteria for determining eligibility for inclusion in the incentive mechanism.

A.

Yes. FPL will provide the Commission will all necessary supporting documentation for all transactions executed for the Incentive Mechanism. To the extent that FPL executes a transaction(s) that is not listed in paragraph 12(a)(ii) of the Proposed Settlement Agreement, FPL will provide the Commission with additional documentation supporting the reasons for inclusion.

Q.
Please refer to paragraph 12(b) of the proposed settlement. FPL explains that the final true-up "Incremental Optimization Costs" would be provided for the prior year and subject to review and Commission approval. Would the Commission be required to approve annually the incremental optimization costs involving Asset Optimization? By what vehicle or docket would the Commission conduct this review?

A.
Yes. FPL will include estimates of the Incremental Optimization Costs associated with incremental personnel, software and hardware with its annual projection filing in the fuel clause each year. This will be identical to the manner in which FPL recovered incremental operating and maintenance expenses incurred for the purpose of initiating and/or maintaining a new or expanded hedging program. To the extent that FPL projects its power sales will exceed 514,000 MWh (the level of sales assumed for the purpose of forecasting 2013 test year power plant O&M costs in the MFRs filed with the 2012 Rate Petition), estimated variable power plant O&M costs will also be included in the annual projection filing as a charge to the "Fuel Cost of Power Sold" in the month they are projected to be incurred. All Incremental Optimization Cost estimates will be subject to the standard true-up mechanism. The review of these costs would be conducted in the fuel docket through the normal provisions the Commission utilizes to conduct reviews of any fuel clause data.

Q.
Currently, are personnel, software, and variable O&M costs associated with short-term wholesale power sales and purchases charged to base rates? In your response, please explain.

A.
Yes. Currently, personnel, software, and hardware costs associated with short-term wholesale power sales and purchases are charged to base rates. Expenses associated with short-term wholesale power sales and purchases are included in the Trade Floor, Accounting, Risk, and Systems Cost Centers. The costs accumulated in these Cost Centers then roll-up to Business Area AO1. Expenses summarized in AO1 are included as base costs. Likewise, variable power plant O&M costs associated with short-term wholesale power sales below the 514,000 MWh threshold level included in FPL's 2013 Test Year would be charged to base rates.

The "Incremental Optimization Costs" included in the Proposed Settlement Agreement are broken down into two categories: (1) incremental personnel, software and hardware costs associated with managing the various asset optimization activities; and (2) variable power plant O&M costs incurred to generate additional wholesale sales. Incremental personnel, software, and hardware costs are for the implementation of an expanded optimization program. Incremental variable O&M costs would be applied to power sales in excess of the 514,000 MWh level included in base rates.

Q.

Should the Commission consider the incentive mechanism/asset optimization part of the proposed settlement (paragraph 12) in a generic policy proceeding involving all Florida IOUs and intervenors? Please explain.

A.

The specific terms of the proposed Incentive Mechanism were negotiated as part of the settlement agreement and, accordingly, should be considered as part of the proceedings in Docket No. 120015-EI. Such a mechanism, in the way that other elements of a settlement agreement may be unique to a party, can be applied to one Florida IOU without the need to consider a broader application; moreover, this Incentive Mechanism was not negotiated on behalf of other Florida IOUs and FPL would not purport to speak on their behalf.

Q.

Please describe in detail the worst case for FPL customers regarding the incentive mechanism.

A.

The worst case for FPL's customers would be a situation where the additional value of the expanded optimization program does not off-set the Incremental Optimization Costs FPL incurs in implementing the expanded optimization program. FPL believes these costs (Please see FPL's response to Staff's Twentieth Set of Interrogatories No. 564) will be very modest, however, in comparison to the $46 million of savings that customers will receive before FPL begins to share in the savings that it produces.

AFFIDAVIT

RBDeaton
Renae B. Deaton

State of Florida

County of Palm Beach

I hereby certify that on this 24th day of Oct., 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 co-sponsored the answers to Interrogatory Nos. **535, 536,** and sponsored the answers to Interrogatory Nos. **534** from **Staff's Twentieth** Set of Interrogatories 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 24th day of Oct., 2012.

Morgan A Sabato
Notary Public, State of Florida

Notary Stamp:

NOTARY PUBLIC STATE OF FLORIDA
MORGAN A. SABATO
Notary Public - State of Florida
My Comm. Expires Oct 23, 2015
Commission # EE 140489

AFFIDAVIT

Robert E Barrett Jr

(Robert E. Barrett, Jr.)

State of Florida)

County of Palm Beach)

I hereby certify that on this 24th the day of October, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Robert E. Barrett, Jr, who is personally known to me, and he acknowledged before me that he co-sponsored the answers to Request Nos. 535-536 and sponsored the answers to Request Nos. 537-541 and 544 from Staff's Twentieth Set of Interrogatories 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 24th day of October, 2012.

Notary Public, State of Florida

Notary Stamp:

NOTARY PUBLIC STATE OF FLORIDA
Notary Public State of Florida
Jennifer A Reklinski
My Commission DD944536
Expires 02/27/2014

AFFIDAVIT

Sam A. Forrest

State of Florida)

County of Palm Beach)

I hereby certify that on this 24th day of October 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared **Sam A. Forrest**, who is personally known to me, and he acknowledged before me that he sponsored the answers to **Interrogatory Nos. 545-596**, from Staff's 20th Set of Interrogatories 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 24th day of October, 2012.

Maritza Miranda-Wise

Notary Public/State of Florida

Notary Stamp:

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

652

FPL's Responses to Staff's 21st Set of Interrogatories, Nos. 597-606

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120015-EI EXHIBIT 652

PARTY Staff's Hearing Exhibit 652

DESCRIPTION FPL's Response to Staff's 21st set of

DATE Interrogatories (Bates Nos. 03070-03081)

Q.

According to Order No. PSC-11-0381-PAA-EI, issued September 12, 2011, in Docket No. 100458-EI, In re: Petition for approval of 2010 nuclear decommissioning study, by Florida Power & Light, the Commission ordered FPL to file its next nuclear decommissioning study no later than December 13, 2015. Does FPL intend to file its next nuclear decommissioning study in accord with the order, i.e., no later than December 13, 2015? If not, please explain.

A.

Yes. The proposed settlement agreement does not address the filing of FPL's next nuclear decommissioning study. As such, per Order No. PSC-11-0381-PAA-EI and Rule No. 25-6.04365(3), Nuclear Decommissioning, FPL is required to file its next nuclear decommissioning study no later than December 13, 2015.

Q.
Please refer to paragraph 11 of the proposed settlement agreement. Please cite the specific subparts of Rules 25-6.0436 and 25-6.04364, Florida Administrative Code, that would not apply to FPL during the term of the proposed settlement agreement.

A.
The subparts of Rule 25-6.0436 (Depreciation Rule) that would not apply to FPL during the term of the settlement are those specifically related to filing a depreciation study and are subparts (4), (5), (6), (7), and (8). During the term of the settlement, FPL will continue compliance with the five remaining subparts of the rule that are not directly associated with filing requirements. Those remaining subparts are outlined as follows:

Subpart (1) – definitions
Subpart (2) - maintenance of depreciation rates
Subpart (3) – maintenance of records
Subpart (9) - annual reporting
Subpart (10) - capital recovery schedules

Q.
Please refer to FPL witness Barrett's direct testimony (proposed settlement agreement), page 19, for the following questions.

a. Referring to lines 5-7, please describe and explain the term "historical conditions" as it relates to the depreciation reserve surplus.
b. Referring to lines 5-7, please explain how the historical conditions "are already fully reflected" in current depreciation rates.
c. Referring to lines 5-8, please explain why "FPL does not expect those conditions to be repeated."

A.
a. The term "historical conditions" is meant to summarize the results of cumulative events over a number of years that gave rise to the depreciation reserve surplus in the 2009 rate case. Those events include the depreciation rates and depreciation parameters approved (e.g. average service lives and net salvage rates) in previous filed studies, and differing calculation methodologies on certain items in the 2009 rate case order. One of the primary drivers of depreciation surplus was the extension of service lives of the nuclear units as a result of license extension.

b. The 2009 rate case order and resulting ordered depreciation rates took into consideration "historical conditions" and adjusted FPL's reserve to account for underlying events discussed in response to part a, so that the resulting reserve as of December 31, 2009 would equal the calculated theoretical reserve prescribed in the order. Therefore, all else equal and ignoring the passage of time, using the 2009 rate case order authorized parameters and depreciation rates, FPL would not expect a net theoretical reserve surplus or a requirement to adjust its book reserve again to a calculated theoretical reserve in 2013.

c. Please refer to the discussion in response to subpart (b). In addition to that response, with the addition of $9 billion in plant investment in the period 2010 through 2013, and the utilization of current ordered parameters and depreciation rates, FPL would not expect a surplus in its theoretical reserve analysis as of December 31, 2013. Instead, FPL would expect a deficit trend in its theoretical reserve analysis at that date due to the significant increased spending on assets where remaining lives may have not lengthened significantly during that timeframe (e.g. nuclear license dates have not changed and therefore additional spending must be recovered over shorter remaining lives with the passage of each year if FPL is to recover all its investment by the end of the license dates).

Q.
For the purposes of the following Interrogatory, please refer to the Direct Testimony and Exhibits of Robert E Barrett, Jr. (Proposed Settlement Agreement), pages 16-17, lines 22 thru 1 on page 17. According to the testimony, an amortization of $209 million would increase the annual dismantlement accrual by approximately $7.0 million. Please explain in detail why table 2 Exhibit REB-11 used $135.8 million compared to the $209 million contained in written testimony.

A.
In this illustrative example, $135.8 million was used because it reflected the net amount impacting dismantlement accruals over the 4-year settlement period 2013 through 2016. FPL would continue to accrue the 2009 rate case ordered $18.3 million in dismantlement accruals annually between 2013 and 2016 because the settlement does not change authorized accrual amounts during the term of the settlement. FPL would also flowback back $209 million over the four years under the terms of the settlement in this illustrative example. The 4-year net amount of these two items is $135.8 million and is considered the net amount to be recovered in future periods in this illustrative example.

Q.
What is the estimated annual accrual beginning in 2017 if $135.8 million is flowed back to the customers?

A.
As reflected in Table 3 of the illustrative example on Exhibit REB-11, the annual accrual beginning 2017 would be $25.2 million, if both $209 million is flowed back and $73.2 million in current authorized dismantlement accruals continue to be accrued (see Table 1 on Exhibit REB-11) between 2013 and 2016.

Q.
What is the estimated annual accrual beginning in 2017 if $209 million is flowed back to the customers?

A.
See FPL's response to Staff's Twenty-first Set of Interrogatories No. 601.

Q.
For the purposes of the following Interrogatory, please refer to the Direct Testimony and Exhibits of Robert E Barrett, Jr. (Proposed Settlement Agreement), page 17, lines 17-18. Of the total cost to dismantle a typical plant site, what percentage (rough estimate or range) of the total cost can be attributed to the "full cost of green field dismantlement." Please detail some of the activities and/or costs that can be solely attributed to full green field dismantlement of a plant site. As in, which functions of dismantling a plant site would only occur if the site is being returned to full green field status?

A.
As reflected in FPL's filed 2009 dismantlement study (the latest study for which an estimate exists), the estimated percentage of total dismantlement costs (in future dollars) attributable to known "green fielding" activities is 15% to 20%. At a minimum, the activities related directly to "green fielding" would include:

- Grading and seeding
- Removal of circulation and service water systems

Every site is unique, however, and there are a variety of other, site-specific activities that may be required in order to ensure the site is free of contamination or other risks to the public. Therefore, this estimated percentage may be lower than the ultimate cost required to return certain sites to green field conditions.

Q.
Given the Company's assertion that its "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", is it conceivable that the currently authorized annual dismantlement accrual of $18.5 million (system) could be reduced following a 2013 dismantlement study and accrual calculation if no reductions to the reserve are made?

A.
Yes.

Q.

If FPL's proposed stipulation is approved, will the amortization of $191,000,000 in theoretical depreciation conclude the flow-back of the $894 million as outlined in FPL's 2010 Rate Order and 2010 Rate Settlement?

A.

The amortization of the higher of $191 million or the actual portion of the $894 million net theoretical depreciation reserve surplus flowback ordered by the Commission in FPL's 2010 Rate Order and 2010 Rate Settlement that remains at the end of 2012 will conclude the flowback of the $894 million.

Q.
Please state, by month, to the extent they have been determined, the actual monthly amounts of depreciation reserve surplus that FPL has amortized during 2012.

A.
See chart below for actual monthly amounts of net theoretical depreciation reserve surplus amortization recorded in 2012:

Date	Amount
Jan-12	$ (89,436,266)
Feb-12	(25,848,063)
Mar-12	(49,332,642)
Apr-12	(19,168,797)
May-12	(78,062,178)
Jun-12	(67,553,547)
Jul-12	(23,415,154)
Aug-12	(44,809,934)
Sep-12	34,761,762
Total	**$ (362,864,819)**

AFFIDAVIT

Robert E Barrett Jr
(Robert E. Barrett, Jr.)

State of Florida)

County of Palm Beach)

I hereby certify that on this 24th the day of October, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Robert E. Barrett, Jr, who is personally known to me, and he acknowledged before me that he sponsored the answer to Request Nos. 597-606 from Staff's Twenty First Set of Interrogatories 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 24th day of October, 2012.

Notary Public, State of Florida

Notary Stamp: NOTARY PUBLIC STATE OF FLORIDA Notary Public State of Florida Jennifer A Reklinski My Commission DD944536 Expires 02/27/2014

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FPL's Responses to Staff's 22nd Set of Interrogatories, Nos. 608-612 and 617-618

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 653
PARTY Staff's Hearing Exhibit 653
DESCRIPTION FPL's Response to Staff's 22nd set of
DATE Interrogotories (Bates 03082-03091)

Q.
Please refer to page 6 of the testimony of Sam Forrest, lines 7 through 15, for interrogatories 608 through 611.

What are the risks to FPL retail customers of these transactions?

A.
First and foremost, as stated in previous Interrogatory responses, FPL does not intend to jeopardize the reliability of fuel supply or FPL's system with the execution of these asset optimization measures. FPL has participated in the power market for numerous years without impacting the reliability of FPL's system and will apply the same principles when evaluating potential asset optimization transactions to arrive at decisions that maintain reliability while helping to reduce overall fuel costs for customers. With that said, the asset optimization measures described in paragraph 12 of the Proposed Settlement Agreement have associated risks, including market risk, credit risk and operational risk. These types of risks introduce the possibility of monetary losses. While FPL will have safeguards in place to help mitigate some of the risks associated with these types of transactions, it is impossible to eliminate all risk. The safeguards that FPL will have in place are addressed in FPL's response to Staff's Twenty Second Set of Interrogatories No. 610.

Q.
Please refer to page 6 of the testimony of Sam Forrest, lines 7 through 15, for interrogatories 608 through 611.

What are the risks to FPL of these transactions?

A.
The risks to FPL are the same as described in FPL's response to Staff's Twenty Second Set of Interrogatories No. 608. To the extent that monetary losses were incurred, FPL's customers would experience less total benefits from the asset optimization measures than they otherwise would have, and FPL's ability to reach the threshold(s) and potentially share in the overall benefits would be impaired.

QUESTION

Please refer to page 6 of the testimony of Sam Forrest, lines 7 through 15, for interrogatories 608 through 611.

What safeguards are necessary to address the risks of these transactions?

RESPONSE

The execution of asset optimization transactions will be strictly governed by additional Risk Management policies and procedures that are reviewed by FPL's Risk Management department, with ultimate oversight by the Exposure Management Committee (EMC). Market risk limits (i.e., tenor, stop-loss, open positions...etc.) will be set to help mitigate market risk. FPL will manage credit risk, as it does today, through appropriate creditworthiness reviews, monitoring and the inclusion of contractual risk mitigation terms and conditions whenever possible. Operational risk due to weather uncertainty and changes in forecasts will be addressed through the retention of a portion of gas transportation or storage capacity to cover forecast errors. FPL will utilize forecasted and historical data to further determine if system conditions allow for the execution of optimization measures. Generally, given the uncertainty of weather and unit availability, FPL will execute transactions that are short-term in nature. Finally, contractual provisions, such as the ability to "call-back" delivered gas sales under certain conditions, will be used to help mitigate certain risks as much as possible while maintaining the value of the transaction(s).

The following table summarizes the safeguards that FPL has, or will have, in place to help mitigate the risks associated with asset optimization. As stated previously, these safeguards will help to mitigate some of the risks described in this response; however, it is impossible to eliminate all risk:

Asset Optimization Measure	Safeguard(s)
Gas Storage Optimization	
Sublease Capacity	Risk Management policies and procedures, retention of a portion of capacity to compensate for forecast errors, consumption of alternate fuels, short-term transactions, contractual provisions
Gas Sales	
From Gas Storage	Risk Management policies and procedures, retention of a portion of capacity/supply to compensate for forecast errors, consumption of alternate fuels, short-term transactions
Within Production Area	Risk Management policies and procedures
City-Gate Delivered	Risk Management policies and procedures, retention of a portion of capacity to compensate for forecast errors, consumption of alternate fuels, short-term transactions, contractual provisions
Capacity Release	
Natural Gas Transportation	Risk Management policies and procedures, retention of a portion of capacity to compensate for forecast errors, consumption of alternate fuels, short-term transactions
Electric Transmission	Risk Management policies and procedures
Asset Management Agreements	
Natural Gas Transportation	Risk Management policies and procedures, contractual provisions
Natural Gas Storage Capacity	Risk Management policies and procedures, contractual provisions

Q.

Please refer to page 6 of the testimony of Sam Forrest, lines 7 through 15, for interrogatories 608 through 611.

Could these transactions result in negative gains (losses), and what could cause such a result? Please explain by each form of asset optimization stated in paragraph 12 of the proposed settlement agreement.

A.

It is possible that these transactions could result in negative gains (losses). Monetary losses could be caused by any of the risks listed in FPL's response to Staff's Twenty Second Set of Interrogatories No. 608 and described in FPL's response to Twenty Second Set of Interrogatories No. 610. Causes could range from supplier delivery failure to changes in weather or unit availability that results in the consumption of higher-priced, alternate fuels.

Q.
On page 7, starting on line 8, FPL states that it would submit documentation to the Commission, on an annual basis, details regarding the asset optimization measures the Company proposes to utilize in the Incentive Mechanism. Would this documentation address all asset optimization measures FPL to seeks to include in the Incentive Mechanism, or only new or modified asset optimization measure? Please state the timeline and proceedings implied by this statement.

A.
The documentation that FPL submits will include all asset optimization measures undertaken during the year that FPL seeks to include in the Incentive Mechanism. The "Total Gains Schedule" will provide a summary of the activity and FPL will also include specific documentation supporting each optimization measure executed. FPL will file the results of the Incentive Mechanism activities with its annual Final True-Up filing. The Commission will then have several months to review the data prior to FPL including any gains for collection from the Incentive Mechanism in its annual Projection Filing made for the subsequent year.

Q.

Starting on page 21, line 16, FPL discusses the estimated incremental optimization costs that it expects to incur in 2013, and states that it would include estimates of the incremental optimization costs with its annual projection filing in the fuel clause. Would these incremental optimization costs be subject to Commission review to determine eligibility for inclusion in the Incentive Mechanism, similar to asset optimization measures discussed earlier in witness Forrest's direct testimony?

A.

Yes. FPL will include estimates of the Incremental Optimization Costs associated with incremental personnel, software and hardware with its annual projection filing in the fuel clause each year. This will be identical to the manner in which FPL recovered incremental operating and maintenance expenses incurred for the purpose of initiating and/or maintaining a new or expanded hedging program. To the extent that FPL projects its power sales will exceed 514,000 MWh (the level of sales assumed for the purpose of forecasting 2013 test year power plant O&M costs in the MFRs filed with the 2012 Rate Petition), estimated variable power plant O&M costs will also be included in the annual projection filing as a charge to the "Fuel Cost of Power Sold" in the month they are projected to be incurred. All Incremental Optimization Cost estimates will be subject to the standard true-up mechanism. The review of these costs would be conducted in the fuel docket through the normal provisions the Commission utilizes to conduct reviews of any fuel clause data.

Q.
Please refer to page 19 of the testimony of Sam Forrest, lines 19 through 22 and to lines 1 and 2 of page 20. Does FPL contemplate calculating an Incentive Mechanism factor separately along with the level fuel factor and the GPIF calculations? Please explain.

A.
Yes. FPL will separately calculate an Incentive Mechanism factor as it does a GPIF factor. Identical to the manner in which rewards/penalties are reflected for GPIF in the calculation of fuel factors, shared Incentive Mechanism gains will be divided by projected retail sales for the period to arrive at the Incentive Mechanism factor, which will be included in the calculation of fuel factors for the period. The Incentive Mechanism factor will be shown on Schedules E1, E1-C and E2. Additionally, identical to the manner in which GPIF rewards/penalties are collected/refunded, shared Incentive Mechanism gains will be collected in equal monthly increments and shown on Schedule A2 under "Fuel Adjustment Revenues Not Applicable to Period."

AFFIDAVIT

Sam A. Forrest

State of Florida)

County of Palm Beach)

I hereby certify that on this 30th day of October 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Sam A. Forrest, who is personally known to me, and he acknowledged before me that he sponsored the answers to **Interrogatory Nos. 607 to 618**, from Staff's 22nd Set of Interrogatories 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 October, 2012.

Maritza Miranda-Wise
Notary Public, State of Florida

Notary Stamp:

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

654

FPL's Responses to Staff's 23rd Set of Interrogatories, Nos. 619-621

FLORIDA PUBLIC SERVICE COMMISSION			
DOCKET NO.	120015-EI	EXHIBIT	654
PARTY	Staff's Hearing Exhibit 654		
DESCRIPTION	FPL's response to Staff's 23rd set of		
DATE	Interrogatories (Bates Nos. 03092-03098)		

Q.
Please provide by unit, by site, FPL's latest dismantlement reserve plant balances.

A.

See Attachment No. 1 for the requested dismantlement reserve plant balances as of October 31, 2012.

Dismantlement Reserve
October 2012

Site	Unit	Sum of End Reserve
Cape Canaveral	CapeCanaveral Comm	(5,795,515)
	CapeCanaveral U1	4,519,184
	CapeCanaveral U2	4,050,541
Cape Canaveral Total		2,774,210
Cutler	Cutler U5	5,166,761
	Cutler U6	7,352,863
Cutler Total		12,519,624
Desoto	Desoto Solar	206,006
Desoto Total		206,006
Ft Lauderdale	FtLauderdale GTs	501,744
	FtLauderdale U4	12,287,928
	FtLauderdale U5	9,588,108
Ft Lauderdale Total		22,377,779
Ft Myers	FtMyers Comm	11,041,790
	FtMyers GTs	3,273,655
	FtMyers U2	6,871,320
	FtMyers U3	2,072,072
Ft Myers Total		23,258,837
Manatee	Manatee Comm	21,158,952
	Manatee U1	16,520,109
	Manatee U2	16,458,425
	Manatee U3	8,913,838
Manatee Total		63,051,324
Martin	Martin Comm	34,113,283
	Martin U1	12,854,323
	Martin U2	12,738,709
	Martin U3	4,961,498
	Martin U4	3,331,155
	Martin U8	4,506,263
Martin Total		72,505,230
Martin Solar	Martin Solar	663,481
Martin Solar Total		663,481
Pt Everglades	PtEverglades Comm	16,717,669
	PtEverglades GTs	363,522
	PtEverglades U1	14,498,897
	PtEverglades U2	13,089,800
	PtEverglades U3	9,517,627
	PtEverglades U4	9,889,027
Pt Everglades Total		64,076,542
Putnam	Putnam Comm	10,507,502
	Putnam U1	1,099,651
	Putnam U2	1,106,778
Putnam Total		12,713,932
Riviera	Riviera Comm	(3,581,720)
	Riviera U3	3,518,538
	Riviera U4	3,518,795
Riviera Total		3,455,613
Sanford	Sanford Comm	9,560,849
	Sanford U3	5,686,719
	Sanford U4	5,414,721
	Sanford U5	6,057,486
Sanford Total		26,719,775
Scherer	Scherer Comm	18,329,677
	Scherer Comm U3&4	2,344,011
	Scherer U4	15,894,284
Scherer Total		36,567,971

Space Coast	Space Coast Solar	90,272
Space Coast Total		90,272
St Johns River Power Plant	SJRPP - Coal & Limestone	2,322,340
	SJRPP - Comm	9,587,145
	SJRPP - Gypsum	606,516
	SJRPP U1	4,813,489
	SJRPP U2	4,703,834
St Johns River Power Plant Total		22,033,326
Turkey Pt	Turkey Pt Comm	9,340,068
	Turkey Pt U1	5,201,596
	Turkey Pt U2	5,226,054
	Turkey Pt U5	2,072,991
Turkey Pt Total		21,840,709
WestCountyEC	WestCountyEC U1	1,436,976
	WestCountyEC U2	1,436,976
	WestCountyEC U3	477,018
WestCountyEC Total		3,350,970
Grand Total		**388,205,601**

Q.
For the purposes of estimating base dismantlement costs, does the company perform their own cost studies or does it retain the services of an independent cost estimator?

A.
The company prepares its own dismantlement studies.

Q.

Please refer to the Direct Testimony and Exhibits of Robert E Barrett, Jr. (Proposed Settlement Agreement), page 16, lines 16-17, how did the Company determine that the $135 million amount would be the highest possible reserve flow-back?

A.

In this illustrative example, FPL determined $135.8 million as the net highest possible reserve flow-back amount by flowing back $209 million under the terms of the Proposed Settlement offset by $73.2 million in total dismantlement accruals (the product of currently authorized annual accruals of $18.3 multiplied by 4-years). The $209 million is derived from Section 10 of the Proposed Settlement and is calculated by reducing the Total Reserve Amount of $400 million by the $191 million of Depreciation Reserve Surplus. Please refer to FPL's response to Staff's Twenty-First Set of Interrogatories No. 600 for further discussion on this net amount of $135.8 million. Of course, $135 million is the highest possible net reserve flowback during the settlement term; to the extent more than $191 million of Depreciation Reserve Surplus remains at the end of 2012, the level of the possible net reserve flowback would be less.

AFFIDAVIT

Robert E Barrett Jr

(Robert E. Barrett, Jr.)

State of Florida)

County of Palm Beach)

I hereby certify that on this the 7th day of November, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Robert E. Barrett, Jr, who is personally known to me, and he acknowledged before me that he sponsored the answer to Request Nos. 619-621 from Staff's Twenty Third Set of Interrogatories 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 7th day of November, 2012.

Notary Public, State of Florida

Notary Stamp: Notary Public State of Florida Jennifer A Reklinski My Commission DD944536 Expires 02/27/2014

655

FPL's Responses to Staff's 24th Set of Interrogatories, Nos. 622-623

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120015-EI EXHIBIT 655

PARTY Staff's Hearing Exhibit 655

DESCRIPTION FPL's response to Staff's 24th set of

DATE Interrogatories (Bates Nos. 03099-03103)

Q.

In its previous base rate proceeding, Docket No. 080677-EI, FPL filed testimony concerning the dismantlement of Ft. Lauderdale fossil Units 4 and 5, which occurred in 1992. The Company stated that the estimated cost to dismantle these plants was $8.9 million, while the actual costs of dismantlement in order to re-power the units was $9.8 million, thus underestimating the cost of dismantling the units by approximately $900,000. FPL further claimed that the Company's estimated costs of partial dismantlement, in order to re-power a generating unit, are in line with actual costs. As an example, Witness Ousdahl referred to FPL's Ft. Myers steam units:

> FPL's estimate of the cost to dismantle the Ft. Myers steam units and common facilities was $20.7 million, of which $5.4 million was for Unit 1 and $9.3 million for Unit 2, totaling $14.7 million. The actual cost for partial dismantlement (of Units 4 and 5 steam supply systems) in order to re-power the two units was $12.9 million. This evidence demonstrates that in a partial dismantlement scenario, the company expended 88 percent of the full dismantlement estimate.

These two examples reflect an underestimate of dismantlement costs. Why does FPL expect its current cost estimation methodology will produce a reserve surplus given these two examples provided in support of its currently authorized annual accrual?

A.

The two examples cited from Witness Ousdahl's Rebuttal Testimony in the 2009 Rate Case with regard to dismantlement are not inconsistent with FPL's testimony in this proceeding that a significant portion of the total dismantlement costs will be deferred for many years with respect to the Modernization Projects because greenfielding will not be required while those projects are in service. The first example is simply an illustration that, in some instances, the <u>total</u> cost for dismantlement can exceed the dismantlement estimate. This says nothing about the portion of total dismantlement expense that greenfielding would represent. In the second example, the 88% ratio between partial dismantlement costs incurred to the full dismantlement estimate is supportive of FPL's estimate that approximately 15% to 20% of the total dismantlement estimate relates to greenfielding costs.

QUESTION

For the purposes of the following request, please refer to FPL's responses to Staff's Twenty-First Set of Interrogatories, No. 606.

a. Why did the Company record a positive depreciation flow-back amount for the month of September 2012?

b. Does FPL still anticipate flowing back $526M of depreciation reserve surplus for calendar year 2012?

c. If the Company does not anticipate flowing back $526M of depreciation reserve surplus for calendar year 2012, what is the company's most current projection for the 2012 flow-back amount?

d. How will the amount contained in the response to (c.) effect the flow-back of the full 894M as outlined in FPL's 2010 Rate Order and 2010 Rate Settlement?

RESPONSE

a. The Earning Surveillance Report ROE is based on a rolling 12 month calculation for which surplus depreciation is used (increase or decrease) to allow FPL to maintain an 11% ROE. When September 2012 results were computed, it was determined that a positive $34 million depreciation flow-back amount was needed for the month of September 2012, in order not to exceed the cap of 11.00% on regulatory ROE, as required by the settlement agreement.

b. No.

c. & d. As reflected in FPL's response to OPC's Fourteenth Request for Production of Documents No. 108, the Company projects it will record $488M of depreciation reserve surplus in the calendar year 2012 instead of the $526M originally forecasted and included in FPL's March 2012 base rate petition. This revision in surplus amortization for 2012 is reflected below along with the revised surplus flowback breakdown, totaling the $894M ordered by the Commission in FPL's 2010 Rate Order and 2010 Rate Settlement. Note that this projection for 2012 is still subject to the normal fluctuations in revenues and expenses for the balance of the year.

($ millions)					
	As-Filed			Revised	
2010 (actual)	$	4.0	2010 (actual)	$	4.0
2011 (est)		173.0	2011 (actual)		187.0
2012 (est)		526.0	2012 (est)		488.0
2013 (est)		191.0	2013 (est)		215.0
Total	$	894.0	Total	$	894.0

If the currently projected higher level of depreciation reserve surplus remaining to be amortized in 2013 is realized, then the amount of dismantlement reserve available for amortization during the settlement term will be lower. Specifically, the amortization of dismantlement reserve would be capped at $185M ($400M total reserve amortization less $215M of depreciation reserve surplus amortization), rather than the $209M originally anticipated.

AFFIDAVIT

Robert E Barrett Jr

(Robert E. Barrett, Jr.)

State of Florida)

County of Palm Beach)

I hereby certify that on this the 13th day of November, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Robert E. Barrett, Jr, who is personally known to me, and he acknowledged before me that he sponsored the answer to Request Nos. 622-623 from Staff's Twenty-Fourth Set of Interrogatories 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 13th day of November, 2012.

Lily A. Rodriguez

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

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FPL's Responses to Staff's 13th Request for Production of Documents, No. 90

<u>See Staff's Hearing Exhibit CD for this Excel file</u>

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 656
PARTY Staff's Hearing Exhibit 656
DESCRIPTION FPL's responses to staff's 13th PODs, No. 90
DATE See CD.

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FPL's Responses to OPC's 16th Set of Interrogatories, Nos. 271, 275, and 278

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 657
PARTY Staff's Hearing Exhibit 657
DESCRIPTION FPL's response to OPC's 16th set of
DATE Interrogatories (Bates 03105-03112)

Q.

For each of the modernization projects (Cape Canaveral, Riviera, and Port Everglades), please provide: (1) the date of the determination of need; (2) the date on which construction began; and (3) the currently estimated in-service-date.

A.

	Need Determination Date	Construction Start Date	Estimated In-Service Date
Cape Canaveral Energy Center	9/12/2008	3/1/2011	6/1/2013
Riviera Beach Energy Center	9/12/2008	11/4/2011	6/1/2014
Pt. Everglades Energy Center	4/9/2012	TBD	6/1/2016

Q.
Please refer to the Direct Testimony of Robert Barrett, Jr. (Proposed Settlement Agreement), page 8, lines 15 through 20, which indicates that historically FPL's "actual capital costs for plants placed into rates using GBRA have been no more than, and in most cases less than, the need determination revenue requirement which form the basis for the cumulative present value revenue requirements ("CPVRR") analysis upon which the need determination was based." For each of FPL's plants that have been placed into rates using GBRA referenced in this testimony, please provide the following:

a. The projected plant in service amounts included in the need determinations by FPL and the actual plant in service amounts, by plant type.

b. The projected rate base included in the need determinations by FPL and the actual rate base amount, by each component of rate base.

c. The projected net operating income (loss) reflected in the need determinations by FPL and the actual net operating income (loss), by eachcomponent of net operating income (i.e., O&M expenses, depreciation expenses, property taxes, etc.).

A.
In response to this request, FPL has assumed that the period in question relates to the first year of operations for the units subject to the GBRA mechanism approved in the 2005 Rate Order (Order No. PSC-05-0902-S-EI), which are Turkey Point Unit 5 (TP5), West County Energy Center Unit 1 (WCEC1), and West County Energy Center Unit 2 (WCEC2).

As discussed in FPL's response to OPC's Sixteenth Set of Interrogatories No. 273, at the time a project is complete and transferred from FERC account 107 (CWIP) to account 106 (completed construction not classified) and then unitized to account 101 (plant-in-service), it is identifiable in the accounting records from a capital cost standpoint. This point in time is referred to as COD. However, after COD and once a project is in service, many of the cost components are not tracked separately such as deferred taxes, operating expenses and property taxes because base rates are set on a total system embedded cost basis and many support costs serve more than one asset. The assets associated with the units subject to the GBRA mechanism are included as part of FPL's jurisdictional adjusted rate base, and their operating expenses are included as part of FPL's jurisdictional adjusted net operating income. This treatment is consistent with how the units are reflected for monthly earnings surveillance reporting purposes. FPL has provided what is readily identifiable for the requested GBRA plants along with all need determination amounts in Attachment No. 1.

Turkey Point Unit 5 (TP5) and West County Energy Center (WCEC) Units 1 & 2
($ millions)

	Need Determination				Actuals				
Rate Base	**TP5 as of 4/30/08**	**WCEC1 as of 7/31/10**	**WCEC2 as of 10/31/10**	**Total for WCEC1 and WCEC2**	**TP5 as of 4/30/08**	**WCEC1 as of 7/31/10**	**WCEC2 as of 10/31/10**	**Total for WCEC1 and WCEC2**	**Notes**
Production Plant	$ 580.3	$ 688.6	$ 632.4	$ 1,321.0	$ 546.7	$ 712.0	$ 537.3	$ 1,249.3	Amounts represent total project construction costs. The need amounts included transmission plant and such amounts were not specifically identified. The actual costs incurred for TP5, WCEC1 and WCEC2 are based on the underlying fixed asset records of the company. Actuals for TP5 are consistent with the actual costs incurred through June 30, 2008 as reported in the true-up calculation filed in on September 2, 2008 in Docket No. 080001-EI. The actual amounts depicted for WCEC 1 and 2 are consistent with the actual costs incurred through July 31, 2012 as reported in FPL's cost update letter provided to the Commission on September 19, 2012. Note, the cost of land for the entire WCEC site of $44.7M and WCEC site common costs of $41.4M are included in actuals for WCEC1. The site common costs include, but are not limited to, the admin building, storm ponds, water tanks, injection well, and waste water system.
Transmission Plant	-	-	-	-	12.3	29.6	41.3	70.9	For actuals, see notes included in production plant above.
Production Reserve	(23.2)	(27.5)	(25.3)	(52.8)	(26.5)	(24.7)	(19.0)	(43.8)	Need amounts include transmission plant; Actual amounts are based on plant-in-service balances for these periods, which include retirements, not the total project construction costs as reported for plant above.
Transmission Reserve	-	-	-	-	N/A	N/A	N/A	N/A	FPL's depreciation expense and reserve are calculated at a depreciation group level and not at the individual asset level. For transmission assets, FPL's depreciation groups are not specific to site and unit, therefore, the transmission depreciation expense and reserve cannot be separated and reported at the level requested.
Deferred Taxes	12.3	7.2	0.5	7.7	N/A	N/A	N/A	N/A	FPL's actual deferred taxes are not calculated nor tracked at a unit/project level.
Rate Base	$ 569.4	$ 668.3	$ 607.6	$ 1,275.8					
Average Rate Base	$ 583.8	$ 686.1	$ 627.6	$ 1,313.7					Amounts represent the simple average of the estimated beginning rate base balance when the unit went into service and the ending rate base balance at the end of first year of operations
Interest Expense	16.8	21.3	19.5	40.8					
Income Tax - Interest Expense	(6.5)	(8.2)	(7.5)	(15.7)					

120015 Hearing Exhibits 03108

Turkey Point Unit 5 (TP5) and West County Energy Center (WCEC) Units 1 & 2
($ millions)

	Need Determination				Actuals				
Operating Expenses	TP5 5/1/07 - 4/30/08	WCEC1 8/1/09 - 7/31/10	WCEC2 11/1/09 - 10/31/10	Total for WCEC1 and WCEC2	TP5 5/1/07 - 4/30/08	WCEC1 8/1/09 - 7/31/10	WCEC2 11/1/09 - 10/31/10	Total for WCEC1 and WCEC2	
Operations and Maintenance	$ 5.2	$ 7.0	$ 5.3	$ 12.3	$ 4.3	$ 10.4	$ 8.8	$ 19.3	In regards to actuals for WCEC1 and WCEC2, FPL's accounting and budgeting systems have the capability to budget and track certain costs associated with operating and maintaining WCEC Units 1, 2 and 3. The company utilized this capability for tracking overhaul expenditures. Overhaul expenditures are unit specific whereas other components of the site's cost structure are shared across units. Daily work and variable operating and maintenance costs (i.e. chemicals, water) are utilized similarly for each unit at the site. The company does not believe the benefits of segregating similar non-overhaul expenditures by unit outweigh the effort required to budget and track actual costs at this level of detail. For purposes of this request, FPL has split the cost of operations equally between the two units for daily work and variable O&M costs starting at the point in time when both units were in operation.
Property Insurance	2.1	3.3	3.1	6.4	N/A	N/A	N/A	N/A	In regards to the actual amounts, the company purchases property insurance at the FPL level and does not allocate premium by FPL site. The only time there may be premium that is specific to a site is when it is initially added to an existing policy during the policy term. For TP5, the project was added during the policy period and received a nominal premium charge for one month of coverage of $0.1 million until renewal. For WCEC1 and 2, the projects were included in the respective year's renewal and subject to changes in FPL's entire portfolio as well as market conditions at that time. As such, these projects were included in the respective year's renewal and no project specific premium was identified or allocated when these projects were added.
Capital Replacement Costs	7.5	8.6	8.7	17.3	-	-	-	-	All capital replacement costs are included as part of plant-in-service
Depreciation	23.2	27.5	25.3	52.8	26.5	24.8	19.0	43.8	Need amounts include depreciation for both production and transmission plant. For actuals, amounts represent depreciation expense for production assets based on the amount included in plant-in-service, which include retirements (not total project construction costs). For transmission assets, the depreciation groups are not specific to site and unit, therefore, the transmission depreciation expense cannot be separated and reported at the level requested.
Property Taxes	12.0	-	-	-	9.1	-	-	20.6	Actuals for TP5 represents what was paid in 2008 for the calendar year 2008. For WCEC1 and WCEC2 actuals, the amount paid was for both units, therefore, we can not split out the amount. The total paid in 2010 for the calendar year 2010 for both units was $20,576,314
Total Operating Expenses	$ 50.1	$ 46.5	$ 42.3	$ 88.8					
Net Operating Income (System)									
Operating Expenses	$ (50.1)	$ (46.5)	$ (42.3)	$ (88.8)					
Income Tax - Operating Expenses	19.3	17.9	16.3	34.2					
Income Tax - Interest Expense	6.5	8.2	7.5	15.7					
Other Income Taxes	(0.8)	(1.2)	(1.3)	(2.5)					
Total Net Operating Income (Loss)	$ (25.1)	$ (21.6)	$ (19.8)	$ (41.3)					

120015 Hearing Exhibits 03109

Q.

Please refer to the Direct Testimony of Robert Barrett, Jr. (Proposed Settlement Agreement), at page 7 lines 14-18. Please provide all assumptions and calculations underlying the "reduction in ROE of 103 bps, 148 bps, 136 bps..."

A.
See Attachment No. 1 for the details on all assumptions and calculations underlying the reduction in ROE of 103bps, 148bps and 136bps for the Canaveral, Riviera and Port Everglades Modernization Projects, respectively, if the GBRA mechanism was not approved.

Revenue Requirement Impact on FPL's 2013 Test Year ROE absent GBRA Mechanism (000)'s

Line #	Description	Reference	Canaveral	Riviera	Port Everglades
1	First Year Revenue Requirements per Robert Barett Jr.'s Exhibit REB- 10 [1]		$165,289	$236,043	$217,862
2					
3	2013 Test Year Revenue Requirement change per 100 basis points ROE [2]		$160,000	$160,000	$160,000
4					
5	ROE Basis Points (bps) Impact of Revenue Requirements	(Ln 1 / Ln 3) * 100	**103 bps**	**148 bps**	**136 bps**
6					
7	**Notes:**				
8	1. Per Exhibit "REB-10 – MFR A-1 Canaveral, Riviera, and Port Everglades" of FPL Witness Bob Barrett's direct testimony (Proposed Settlement Agreement).				
9	2. $160MM Revenue Requirement change represents approximately 100 Basis Points of ROE per calculation below:				
10					
11	2013 Test Year Juris. Adj Utility Common Equity Balance per revised MFR D-1a included in Appendix II of FPL's post hearing brief:		$9,768,463		
12	100 Basis Points		1%		
13		(Ln 11 * Ln 12)	$97,684.63		
14	2013 Test Year Net Operating Income Multiplier per MFR C-44:		1.63188		
15		(Ln 13 * Ln 14)	**$159,410**		
16					

AFFIDAVIT

Robert E Barrett Jr

(Robert E. Barrett, Jr.)

State of Florida)

County of Palm Beach)

I hereby certify that on this 31st day of October, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Robert E. Barrett, Jr, who is personally known to me, and he acknowledged before me that he sponsored the answers to Request Nos. 269-275 and 278 from OPC's Sixteenth Set of Interrogatories 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 31st day of October, 2012.

Traci D. Goldwire

Notary Public, State of Florida

Notary Stamp:

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

658

FIPUG's Response to Staff's Second Set of Interrogatories, No. 5

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI **EXHIBIT** 658
PARTY Staff's Hearing Exhibit 658
DESCRIPTION FIPUG's Response to Staff's 2nd set of
DATE Interrogatories, No 5. (Bates 03113- 03116)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Increase in Rates by Florida Power & Light Company.	DOCKET NO. 120015-EI SERVED: October 12, 2012

FLORIDA INDUSTRIAL POWER USERS GROUP'S RESPONSE <u>TO STAFF'S SECOND SET OF INTERROGATORIES (NO. 5)</u>

The Florida Industrial Power Users Group (FIPUG), pursuant to rule 1.340, Florida Rules of Civil Procedure, submits the following response to Staff's Second Set of Interrogatories (No. 5).

<u>INTERROGATORY RESPONSE</u>

1. In Docket No. 080677-EI, FPIUG took the following position to Issue #8 (Should FPL be allowed to implement a GBRA mechanism, see page 31 of Order No. PSC-09-0573-PHO-EI)

> "No. Capital additions, such as new generating plants, should not be automatically recovered through yet another recovery clause. If FPL believes that the addition of generating plant necessitates a rate change, it may petition the Commission for such a change in a full rate case where the Commission and the parties may examine all of FPL's revenues and expenses, rather than giving FPL guaranteed recovery of new plant in isolation from other factors that affect rates. This issue should not be considered in this rate case, but should be the subject of a generic docket or rulemaking."

Does FIPUG still support this position? If so, please explain how the incorporation of a GBRA mechanism that is part of the proposed settlement is in the best interest of FPL's ratepayers at this time. If not, what is the rationale for the change in FIPUG's position?

<u>Response</u>: The above quoted position was FIPUG's view in the context of a fully-litigated rate case, such as the one from which this quote was taken. In the context of the settlement in this case, there are many compromises and "gives and takes." As such, the settlement, taken as a whole, is fair to FPL ratepayers for a number of reasons. Those reasons include, but are not limited to, the fact that the settlement provides rate stability for four years and provides appropriate incentives and signals to encourage the maintenance and development of jobs and economic growth as Florida attempts to emerge from a deep recession. The GBRA mechanism contemplated in the Settlement Agreement is limited to the term of the Agreement, and not applicable to future power plant additions. It was a negotiated term that was part of the "give and take" process. While FIPUG supports the negotiated GBRA mechanism contained within the Settlement Agreement because the Agreement, taken as a whole, is in the public interest, FIPUG's view expressed in Docket No. 080677-EI was set forth accurately, but in a materially different context.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF Hillsborough

I hereby certify that on this 11th day of OCTOBER, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Steven F. Davis, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory number(s) 1 from Staff's Second Set of Interrogatories to Florida Industrial Power Users Group (No. 5) in Docket No(s). 120015-EI, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 11th day of October, 2012.

Steve Davis, President
Florida Industrial Power Users Group

Diane W. Smith
Notary Public Diane W. Smith
State of Florida, at Large

DIANE W. SMITH
Commission # EE 072445
Expires March 10, 2015
Bonded Thru Troy Fain Insurance 800-385-7019

My Commission Expires:
03/10/15

659

FIPUG's Responses to Staff's Third Set of Interrogatories, Nos. 6 and 7

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI **EXHIBIT** 659
PARTY Staff's Hearing Exhibit 659
DESCRIPTION FIPUG's response to Staff's 3rd set of
DATE Interrogatories (Bates Nos. 03117-03119)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Increase in Rates by Florida Power & Light Company.	DOCKET NO. 120015-EI SERVED: October 12, 2012

FLORIDA INDUSTRIAL POWER USERS GROUP'S RESPONSE TO STAFF'S THIRD SET OF INTERROGATORIES (NO. 6-7)

The Florida Industrial Power Users Group (FIPUG), pursuant to rule 1.340, Florida Rules of Civil Procedure, submits the following response to Staff's Third Set of Interrogatories (No. 6-7).

INTERROGATORY RESPONSES

6. Will any FIPUG members or entities engage in (or be likely to engage in) transactions with FPL or a third party administrator involving the incentive mechanism in paragraph 12? Please identify the entity or entities.

Response: To the best of FIPUG's knowledge, there are no present plans, agreements or understandings between FPL or a third party administrator and FIPUG or any of its members operating within FPL's service territory involving the incentive mechanism in paragraph 12 of the Settlement Agreement.

7. Does FIPUG believe the Commission should consider the incentive mechanism/asset optimization part of the proposed settlement (paragraph 12) in a generic policy proceeding involving all Florida IOUs and intervenors? Please explain.

Response: FIPUG believes that the Commission should consider the incentive mechanism/asset optimization matter as part of the proposed Settlement Agreement contained in paragraph 12 of the Agreement. Specifically, FIPUG supports consideration of this issue during the evidentiary hearing currently scheduled for November 19-21, 2012. However, FIPUG does not and would not oppose consideration of this issue in a generic proceeding should that be will of the Commission.

AFFIDAVIT

STATE OF ~~FLORIDA~~) N C

COUNTY OF Clay)

I hereby certify that on this 25 day of Oct, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Steve Davis, who has produced sufficient identification, and he acknowledged before me that he provided the answers to interrogatory number(s) 6 and 7 from Staff's Third Set of Interrogatories to Florida Industrial Power Users Group (No. 6-7) in Docket No(s). 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 25 day of Oct., 2012.

KATHY G. HOGSED
NOTARY
PUBLIC
EXPIRES AUG. 13, 2016
CLAY COUNTY, N.C.

Steve Davis
Steve Davis, President
Florida Industrial Power Users Group

Kathy D Hogsed
Notary Public
State of North Carolina, at Large

My Commission Expires:
8-13-2016

120015 Hearing Exhibits 03119

660

SFHHA's Response to Staff's First Set of Interrogatories, No. 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 660
PARTY Staff's Hearing Exhibit 660
DESCRIPTION SFHHA's response to Staff's 1st set of
DATE Interrogatories, No. 1 (Bates Nos. 03120-03123)

South Florida Hospital and Healthcare Association
Docket No. 120015-EI
Staff's First Set of Interrogatories
Interrogatory No. 1

Q. During Docket 080677-EI, SFHHA sponsored witness Kollen who criticized the GBRA mechanism because "it provides the Company an almost unfettered ability to automatically impose base rate increases to recover selective increases in certain costs without consideration of increases in revenues and reduction in all other costs." (See page 15-16 of Order PSC-10-0153-FOF-EI). Does the SFHHA still support witness Kollen's statement? If so, please explain why the SFHHA now believes that a GBRA mechanism is in the best interest of FPL's ratepayers. If not, please explain the rationale for the change in SFHHA's position.

A. A Generation Base Rate Adjustment ("GBRA") mechanism was first adopted, to SFHHA's knowledge, by the Settlement Agreement, dated August 22, 2005, that resolved Docket Nos. 050045-EI and 050188-EI. That Settlement Agreement, and the adoption of a GBRA mechanism, was supported by, among others, the Attorney General of the State of Florida and the Office of Public Counsel. The Commission approved that settlement, including adoption of the GBRA mechanism as part of the settlement, in an order issued September 14, 2005. *See* PSC Order No. PSC-05-0902-S-EI.

In Docket No. 080677-EI, Mr. Kollen and SFHHA opposed FPL's request for a GBRA mechanism as a stand-alone issue in the context of the litigated case for the reasons stated in Mr. Kollen's Direct Testimony in that proceeding. Mr. Kollen and SFHHA support the settlement in this proceeding that includes a GBRA in the context of a comprehensive settlement that provides benefits to all FPL ratepayers and to the South Florida economy. These benefits include a significant reduction from FPL's requested rate increase, which will be locked in for the next four years due to the four year stay out provision, and rate stability over the four-year period with increases only through the GBRA, which are limited to the costs already approved by the Commission. The settlement also specifies how the GBRA will be quantified.

The GBRA mechanism is an integral part of the proposed settlement and contributes to the benefits of the proposed settlement by allowing the parties to avoid the costs of litigating potential future requests by FPL to increase base rates as completes the Canaveral, Riviera and Port Everglades projects and they commence commercial operation and invests additional amounts in transmission and distribution. The Commission has approved the Canaveral, Riviera and Port Everglades projects in need determinations. In addition, unlike the proposed GBRA in the prior proceeding, the GBRA included in the settlement does not continue beyond the three specified modernization projects. As a result, acceptance of the GBRA mechanism with respect to the Canaveral, Riviera and Port Everglades projects in the context of the proposed settlement does not provide FPL unfettered ability to automatically impose base rate increases as was the case in Docket 080677-EI. Agreement to a GBRA mechanism reflects part of the inherent give and take inherent in the settlement process.

Although Mr. Kollen and SFHHA opposed FPL's proposed GBRA in the prior proceeding and still would oppose a similar GBRA on a standalone basis if it had been proposed in this proceeding, Mr. Kollen and SFHHA support the GBRA mechanism in this settlement proceeding as an integral part of the proposed settlement.

AFFIDAVIT

Lane Kollen

Roswell, GA

BEFORE ME, the undersigned authority, personally appeared Lane Kollen, who deposed and stated that he provided the answer to Interrogatory No. 1 served on South Florida Hospital and Healthcare Association by Florida Public Service Commission Staff ("Staff") on October 12, 2012 in Docket No. 120015-EI, and that the response is true and correct to the best of his information and belief.

DATED at Roswell, GA this 12th day of October, 2012.

Sworn to and subscribed before me this 12th day of October, 2012.

Notary Public

Notary Stamp:

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY PUBLIC
JULY 31, 2015
CHEROKEE COUNTY, GEORGIA

661

SFHHA's Responses to Staff's Second Set of Interrogatories, Nos. 2 and 3

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI **EXHIBIT** 661
PARTY Staff's Hearing Exhibit 661
DESCRIPTION SFHHA Response to Staff's 2nd set of
DATE Interrogatories Nos. 2 and 3. (Bates 03124-03127)

Q. Will any SFHHA members or entities represented by SFHHA engage in (or be likely to engage in) transactions with FPL or a third party administrator involving the incentive mechanism in paragraph 12 of the stipulation and settlement agreement? Please identify the entity or entities.

A. SFHHA is not privy to the commercial transactions that are undertaken individually by its current or future members and therefore has no information concerning whether such members or entities represented by SFHHA will engage in (or be likely to engage in) transactions with FPL or a third party administrator involving the incentive mechanism in paragraph 12 of the stipulation and settlement agreement. As a result, at this time, SFHHA has no knowledge of such a potential arrangement.

Q. Does SFHHA believe the Commission should consider the incentive mechanism/asset optimization part of the proposed settlement (paragraph 12) in a generic policy proceeding involving all Florida IOUs and intervenors? Please explain.

A. SFHHA believes the Commission should consider the incentive mechanism/asset optimization part of the proposed settlement (paragraph 12) in the context of its consideration of the proposed settlement in this docket and not in a generic policy proceeding involving all Florida IOUs and intervenors. The incentive mechanism/asset optimization provides substantial benefits to all FPL ratepayers and was agreed to as part of the various compromises that resulted in the proposed settlement. The incentive mechanism/asset optimization provision therefore is an integral part of the proposed settlement, and the parties agreement to the proposed settlement is based upon the Commission's approval of the proposed settlement in its entirety, without modification.

Further, the particular levels of specific thresholds embodied in the incentive mechanism/asset optimization part of the proposed settlement may not align with other utilities' circumstances. Similarly, other Florida utilities' ability to dedicate resources to an incentive mechanism will vary depending upon, *inter alia*, individual utilities' fuel mix and contract circumstances. That being said, SFHHA has no objection to the Commission initiating a generic policy proceeding to consider the propriety of establishing incentive mechanism/asset optimization mechanisms for all Florida IOUs so long as such a proceeding (1) would not affect, alter, or negate in any way the operation of the specific incentive mechanism/asset optimization mechanism that is part of the proposed settlement during the term of the proposed settlement, or (2) result in any delay to the Commission's timely approval of the proposed settlement.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF COBB)

I hereby certify that on this 25th day of October, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Lane Kollen, who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory number(s) 2-3 from Staff's Second Set of Interrogatories to South Florida Hospital and Healthcare Association in Docket No(s). 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 25TH day of October, 2012.

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY PUBLIC
JULY 31, 2015
CHEROKEE COUNTY, GEORGIA

Jessica K. I

Notary Public
State of Georgia

My Commission Expires:
July 31, 2015

WAS:188286.1

662

FEA's Responses to Staff's First Set of Interrogatories, Nos. 1 and 2

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 662
PARTY Staff's Hearing Exhibit 662
DESCRIPTION FEA's Response to Staff's 1st set of
DATE Interrogatories (Bates 03128-03131)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for Increase in Rates	)	
by Florida Power & Light Company	)	Docket No. 120015-EI
	)	Served: October 25, 2012

FEDERAL EXECUTIVE AGENCIES' RESPONSE TO STAFF'S FIRST SET OF INTERROGATORIES (NO. 1-2)

The Federal Executive Agencies ("FEA") pursuant to rule 1.3.40(a) of the Florida Rules of Civil Procedure and in accordance with the Florida Public Service Commission's Order No PSC-12-0529-PCO-EI, hereby files its responses to the Commission Staff's ("Staff") First Set of Interrogatories (No. 1-2).

RESOPONSES TO INTERROGATORIES

1. Will any FEA members or entities engage in (or be likely to engage in) transactions with FPL or a third party administrator involving the incentive mechanism in paragraph 12? Please identify the entity or entities.

FEA RESPONSE

At this time FEA does not expect to engage in (or be likely to engage in) transactions with FPL or third party administrators involving the incentive mechanism in paragraph 12 (of the stipulation and settlement agreement).

2. Does FEA believe the Commission should consider the incentive mechanism/asset optimization part of the proposed settlement (paragraph 12) in a generic policy proceeding involving all Florida IOUs and intervenors? Please explain.

FEA RESPONSE

FEA believes the Commission should consider the incentive mechanism/asset optimization part of the proposed settlement (paragraph 12) as part of the proposed settlement in this docket (120015-EI). However, FEA has no objection to the Commission initiating a

separate generic policy proceeding involving all Florida IOUs and intervenors regarding the incentive mechanism/asset optimization so long as such a proceeding would not adversely impact the Commissions' ability to issue a timely decision with respect to the proposed settlement in the current docket (120015-EI).

Prepared by counsel.

Respectfully submitted this 25th day of October 2012.

Gregory J. Fike, Lt Col, USAF
Gregory.fike@tyndall.af.mil
Karen White
Samuel Miller, Capt, USAF
Federal Executive Agencies
AFLOA/JACL-ULFSC
139 Barnes Drive, Suite 1
Tyndall Air Force Base, FL 32403

663

OPC's Response to Staff's First Set of Interrogatories, No. 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 663
PARTY Staff's Hearing Exhibit 663
DESCRIPTION OPC's response to Staff's 1st set of
DATE Interrogatories (Bates Nos. 03131-03134)

663

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company
_______________________________/

Docket No: 120015-EI

Filed: October 26, 2012

CITIZENS' RESPONSE TO FLORIDA PUBLIC SERVICE COMMISSION FIRST SET OF INTERROGATORIES (No. 1)

Office of Public Counsel, ("Citizens"), by the requirements set forth in Commission Order No. PSC-12-0529-PCO-EI, Rule 1.340(a), Florida Rule of Civil Procedure, submit the following responses to the First Set of Interrogatories (No. 1) propounded by the Staff of the Florida Public Service Commission on October 16, 2012.

INTERROGATORIES

1. Does OPC believe the Commission should consider the incentive mechanism/asset optimization part of the proposed settlement (paragraph 12) in a generic policy proceeding involving all Florida IOU's and intervenors? Please explain.

   Response: As phrased, the question may imply (whether or not intentionally) that the proposed mechanism should be considered either in a single utility's rate proceeding or in a generic proceeding. Citizens' position is that there is a threshold question as to whether the subjects of the proposal include activities that a utility exercising prudent stewardship of assets paid for by its customers should pursue diligently in the absence of a monetary incentive. This overarching policy consideration is not unique to FPL. Therefore, Citizens believe that, if the type of incentive mechanism/asset optimization which is part of the proposed settlement (Paragraph 12) is to be considered *at all*, such consideration should be part of a generic proceeding involving all Florida IOUs. Further, a generic proceeding would incorporate realistic and adequate time frames designed to allow the full

development of a record to determine if this type of mechanism can be created which benefits customers as well as utilities.

(response provided by Counsel)

Patricia A. Christensen
Associate Public Counsel

Office of Public Counsel
c/o The Florida Legislature
111 W. Madison Street
Room 812
Tallahassee, FL 32399-1400

(850) 488-9330
Attorney for Florida's Citizens

AFFADAVIT

STATE OF Florida

COUNTY OF Leon

BEFORE ME, the undersigned authority, personally appeared

Patricia A. Christensen, who deposed and stated that she

provided the answers to interrogatory No. 1

served on Office of Public Counsel by Commission Staff on

October 16, 2012 and that the responses are true and

correct to the best of his/her information and belief.

Patricia A. Christensen

DATED at October 26, 2012.

Sworn to and subscribed before me this 26th day of

October, 2012.

Lynda L Kelly

NOTARY PUBLIC

State of Florida at Large

My Commission Expires:

LYNDA L. KELLY
Commission # DD 902764
Expires October 26, 2013
Bonded Thru Troy Fain Insurance 800-385-7019

664

FRF's Response to Staff's First Set of Interrogatories, No. 1

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120015-EI EXHIBIT 664

PARTY Staff's Hearing Exhibit 664

DESCRIPTION FRF's response to Staff's 1st set of

DATE Interrogatories (Bates Nos. 03135-03137)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for Increase In Rates)
By Florida Power & Light Company) DOCKET NO. 120015-EI
) FILED: OCTOBER 25, 2012

THE FLORIDA RETAIL FEDERATION'S RESPONSES TO STAFF'S FIRST SET OF INTERROGATORIES (NO. 1)

The Florida Retail Federation ("FRF") hereby files its responses to the Commission Staff's First Set of Interrogatories (No. 1), which was propounded on October 16, 2012.

RESPONSES TO INTERROGATORIES

1. Does FRF believe the Commission should consider the incentive mechanism/asset optimization part of the proposed settlement (paragraph 12) in a generic policy proceeding involving all Florida IOUs and intervenors? Please explain.

FRF RESPONSE:

If the Commission intends to consider this proposal at all, it should do so generically in a rulemaking docket.

Prepared by counsel.

Respectfully submitted this 25th day of October 2012.

Robert Scheffel Wright

Robert Scheffel Wright
schef@gbwlegal.com
John T. LaVia, III
jlavia@gbwlegal.com
Gardner, Bist, Wiener, Wadsworth, Bowden, Bush, Dee, LaVia & Wright, P.A.
1300 Thomaswood Drive
Tallahassee, Florida 32308
Telephone (850) 385-0070
Facsimile (850) 385-5416

Attorneys for the Florida Retail Federation

665

Pinecrest's Response to Staff's First Set of Interrogatories, No. 1

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120015-EI EXHIBIT 665

PARTY Staff's Hearing Exhibit 665

DESCRIPTION Pinecrest's response to Staff's 1st set of

DATE Interrogatories (Bates Nos. 03138-03140)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Petition for Increase in Rates by Florida Power & Light Company	)))	DOCKET NO.: 120015-EI FILED: October 26, 2012

THE VILLAGE OF PINECREST'S RESPONSE TO FLORIDA PUBLIC SERVICE COMMISSION STAFF'S FIRST SET OF INTERROGATORIES (No. 1)

The Village of Pinecrest ("Pinecrest") hereby files its response to Commission Staff's First Set of Interrogatories (No. 1), which was propounded on October 16, 2012.

RESPONSE TO INTERROGATORY

1. Does the Village of Pinecrest believe the Commission should consider the incentive mechanism/asset optimization part of the proposed settlement (paragraph 12) in a generic policy proceeding involving all Florida IOUs and intervenors? Please explain.

PINECREST'S RESPONSE:

If the Commission considers the proposal, it should be done in a generic proceeding. As a matter of fundamental fairness to the entire community of regulated utilities, the Commission's policies concerning incentives should be uniformly applied to all similarly situated utilities. Development and application of incentive mechanisms on an ad hoc basis fails to provide certainty that desired behaviors will be rewarded. The creation of rules, where possible, provides more certainty that behavior consistent with the generally applicable rule will be recognized and rewarded by the Commission, because the presence of a generally applicable rule reduces the potential for selective application of policy.

Prepared by counsel.

Respectfully submitted this 26th Day of October 2012.

William C. Garner
Florida Bar No. 577189
Brian P. Armstrong
Florida Bar No. 888575
Nabors, Giblin & Nickerson, P.A.
1500 Mahan Drive, Suite 200
Tallahassee, Florida 32308
(850) 224-4070 Telephone
(850) 224-4073 Facsimile

Attorneys for the Village of Pinecrest

666

Hendrick's Response to Staff's First Set of Interrogatories, No. 1

FLORIDA PUBLIC SERVICE COMMISSION			
DOCKET NO.	120015-EI	EXHIBIT	666
PARTY	Staff's Hearing Exhibit 666		
DESCRIPTION	Hendrick's Response to Staff's 1st set of		
DATE	Interrogatories No. 1 (Bates 03141-03145)		

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for increase in rates by Florida Power & Light Company.	DOCKET NO. 120015-EI DATED: OCTOBER 23, 2012

HENDRICKS' RESPONSE TO STAFF'S FIRST SET OF INTERROGATORIES

TO JOHN W. HENDRICKS (NO. 1)

John W. Hendricks submits the following response to Staff's First Set of Interrogatories (No. 1) dated October 16, 2012.

INTERROGATORY

1. Do you believe the Commission should consider the incentive mechanism/asset optimization part of the proposed settlement (paragraph 12) in a generic policy proceeding involving all Florida IOUs and intervenors? Please explain.

RESPONSE

No. The proposed incentive mechanism should not be considered in a generic policy proceeding.

The incentive mechanism and asset optimization part of the proposed settlement should be considered now in this case, in the context of the proposed settlement agreement, including the elements of the original FPL request that remain unchanged by the settlement proposal, and FPL's specific territory and assets to be managed. If consideration of this proposed settlement is terminated or this incentive mechanism is rejected, I would still recommend that incentives in this area be considered in the future, but only in the context of a specific utility.

FPL's size, sophistication and increasing deployment of combined cycle gas generation make it a good candidate for incentives to optimize management of assets related to power and fuel transactions. An incentive mechanism can be a powerful tool to improve performance in areas where rate of return regulation is less effective in delivering optimized results, but it is not a trivial matter to design a new incentive mechanism or assess a specific proposal, as in this case.

It will be a challenge to assess the likely effectiveness and efficiency of the specific incentives proposed if they are to operate in the specific decision context that FPL faces. It would be a serious mistake to add additional complications by trying to develop a generic incentive policy for optimization of a complex set of power and fuel decisions, across the broad range of companies and territories the Commission regulates, before observing the performance of a broad scope mechanism in this area at a single Florida utility. A "one size fits all" incentive mechanism for these functions is likely to "fit badly," and could do more harm than good.

That being said, the specific terms in the incentive mechanism as proposed in the settlement agreement are problematical. Determining if the proposed mechanism appropriately balances the interests of the utility and its ratepayers will require consideration of alternative values for key parameters, such as the benchmark, sharing thresholds and sharing percentages, as well as the scope and term of the mechanism. The commission should be should be prepared to adjust the incentive mechanism as necessary to improve the balance or overall savings, or mitigate potential unwanted consequences. We cannot determine if the proposed mechanism is in the public interest by treating it as a take-it or leave-it "black box."

In summary, the incentive mechanism described in the proposed settlement should be evaluated in this case to determine if, in whole or in part, as specified or with appropriate adjustments, it would be in the public interest. It should be subject to the same level of scrutiny as any other part of the rate case, and the commission should proactively consider adjustments as needed to make sure it is in the public interest. This would be much more likely to deliver an efficient and effective incentive mechanism than would either a take-it or leave-it choice in this case, or trying to create a one size fits all generic mechanism without sufficient experience with broad incentive mechanisms and the potential outsourcing of asset management.

s/ John W. Hendricks
John W. Hendricks
367 S Shore Drive
Sarasota, Florida 34234
Telephone: (941) 685-0223
Email: jwhendricks@sti2.com

PAGE 4

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF Sarasota)

I hereby certify that on this 23rd day of Oct, 2012, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared John W Hendricks who is personally known to me, and he/she acknowledged before me that he/she provided the answers to interrogatory number(s) I from Staff's First Set of Interrogatories to John W. Hendricks (No. 1) in Docket No(s). 120015-EI, and that the responses are true and correct based on his/her personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 23rd day of Oct, 2012.

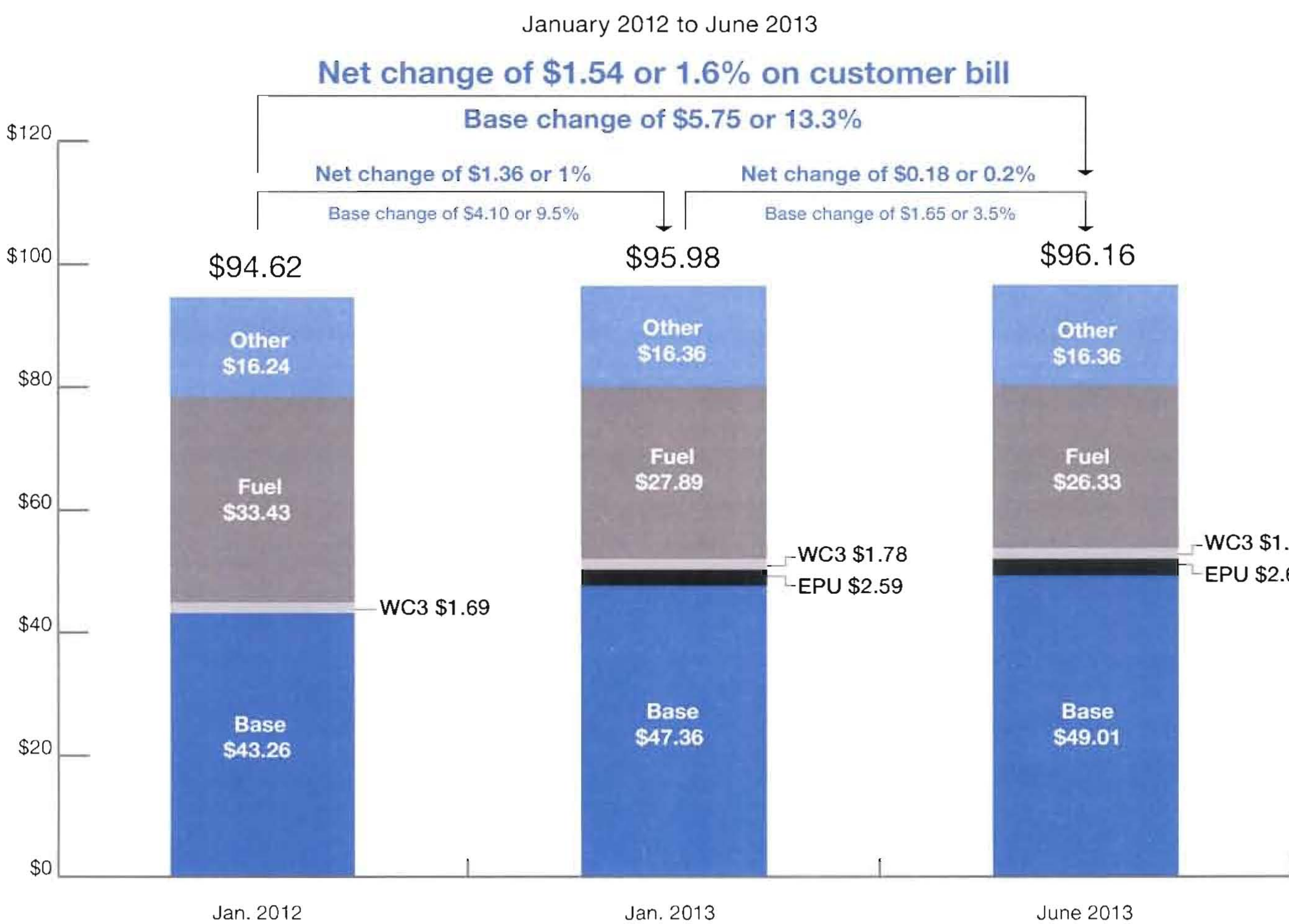
JACQUELINE ESRITA
Notary Public - State of Florida
My Comm. Expires Sep 10, 2016
Commission # EE 200005
Bonded Through National Notary Assn.

Jacqueline Esrita
Notary Public
State of Florida, at Large

My Commission Expires:
9-10-16

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI **EXHIBIT** 667
PARTY FPL; Ranae B. Deaton (RBD-12)
DESCRIPTION FPL Bill Comparison Under Settlemet Rates - January 2012 - January 2013, June 2013

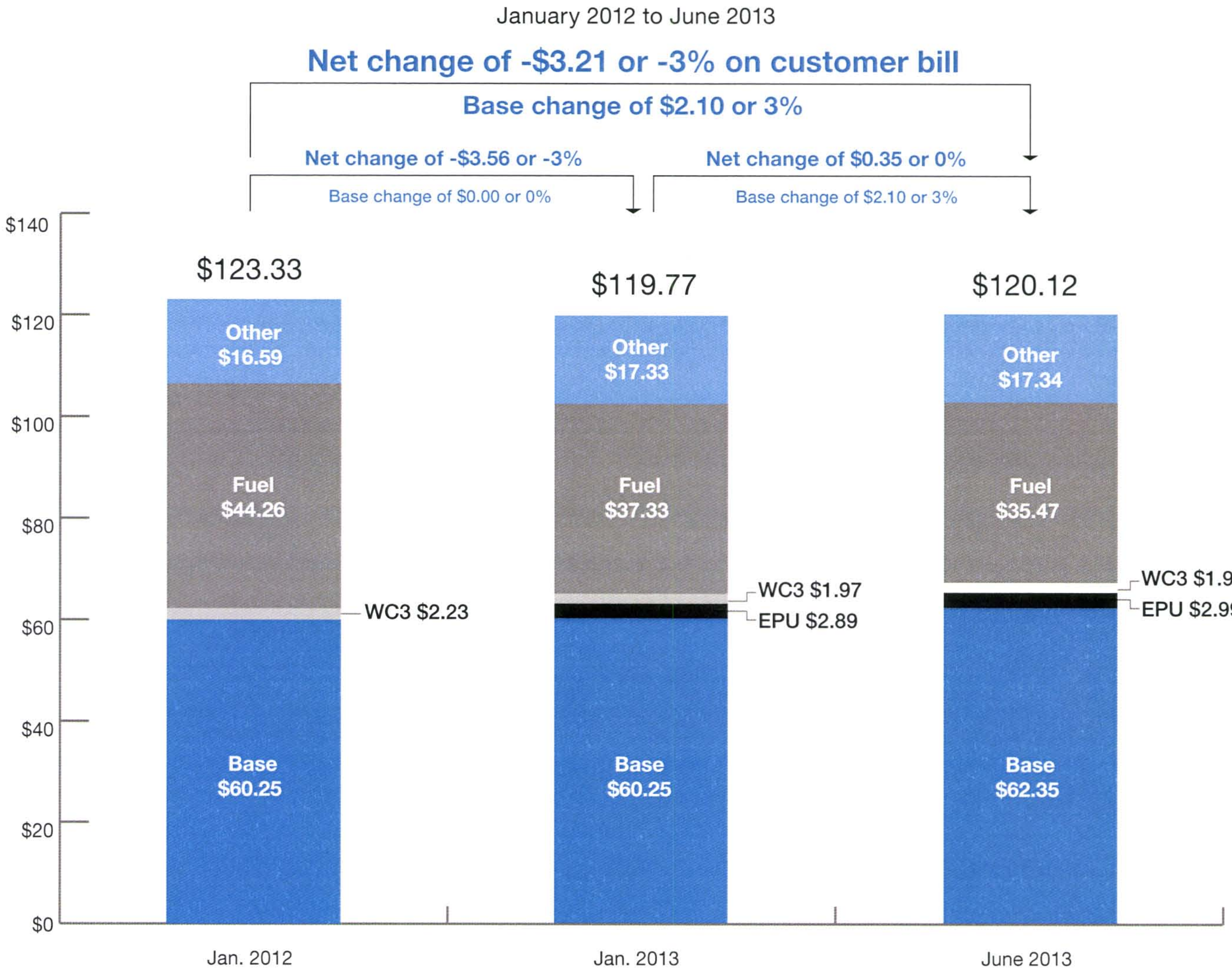
Typical 1,000-kWh Residential Customer Bill Comparison



For 2013, Fuel and Other clause projections as filed in their respective dockets. "EPU" is the base increase for the Extended Power Uprate (filed in a separate docket on October 1, 2012). "WC3" are West County 3 costs, which shall continue to be recovered through the capacity clause. Other includes 21 cents for CILC and CDR increases that will not be recovered in 2013 but will be deferred to 2014 if the Proposed Settlement Agreement is approved.

1,200-kWh Commercial Customer Bill Comparison (non-demand)

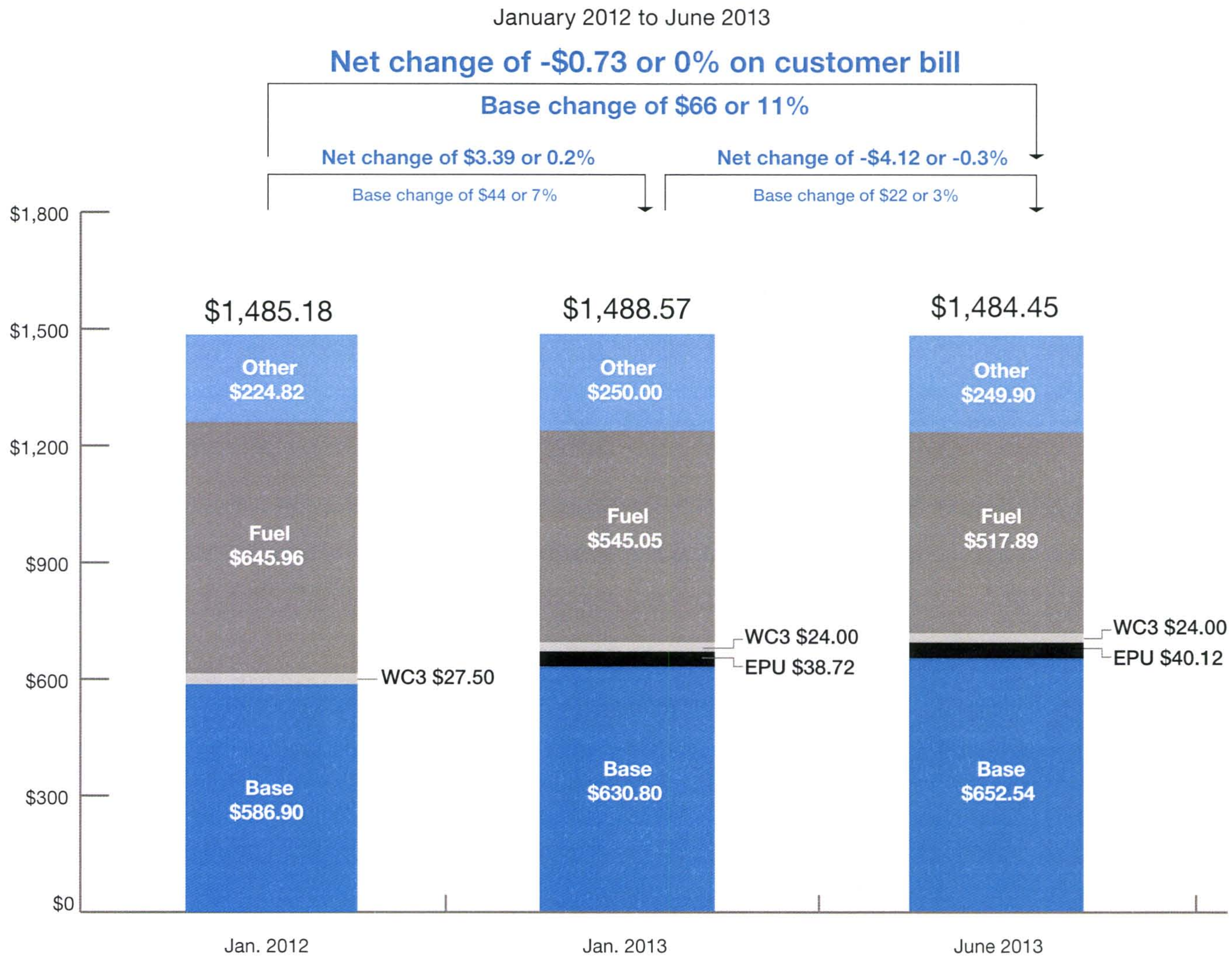
The General Service Non-Demand ("GS-1") rate class comprises more than 391,000 customer accounts, or approximately 77% of FPL's business customer accounts. These customers are typically small businesses.



For 2013, Fuel and Other clause projections as filed in their respective dockets. "EPU" is the base increase for the Extended Power Uprate (filed in a separate docket on October 1, 2012). "WC3" are West County 3 costs, which shall continue to be recovered through the capacity clause. Other includes 22 cents for CILC and CDR increases that will not be recovered in 2013 but will be deferred to 2014 if the Proposed Settlement Agreement is approved.

17,520-kWh Commercial Customer Bill Comparison

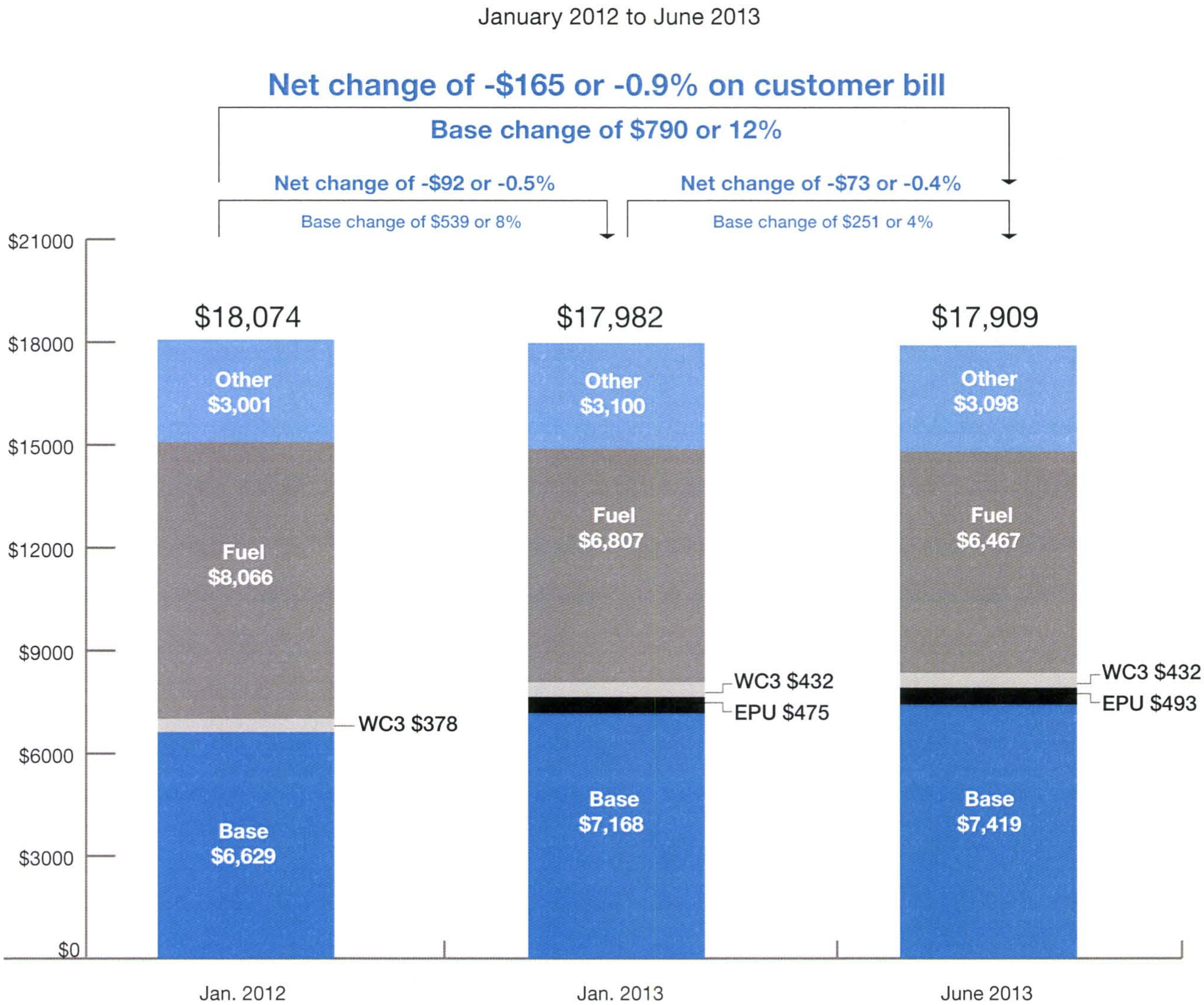
GSD-1 Rate 50 kW, 48% load factor



For 2013, Fuel and Other clause projections as filed in their respective dockets. "EPU" is the base increase for the Extended Power Uprate (filed in a separate docket on October 1, 2012). "WC3" are West County 3 costs, which shall continue to be recovered through the capacity clause. Other includes $3.50 for CILC and CDR increases that will not be recovered in 2013 but will be deferred to 2014 if the Proposed Settlement Agreement is approved.

219,000-kWh Commercial Customer Bill Comparison

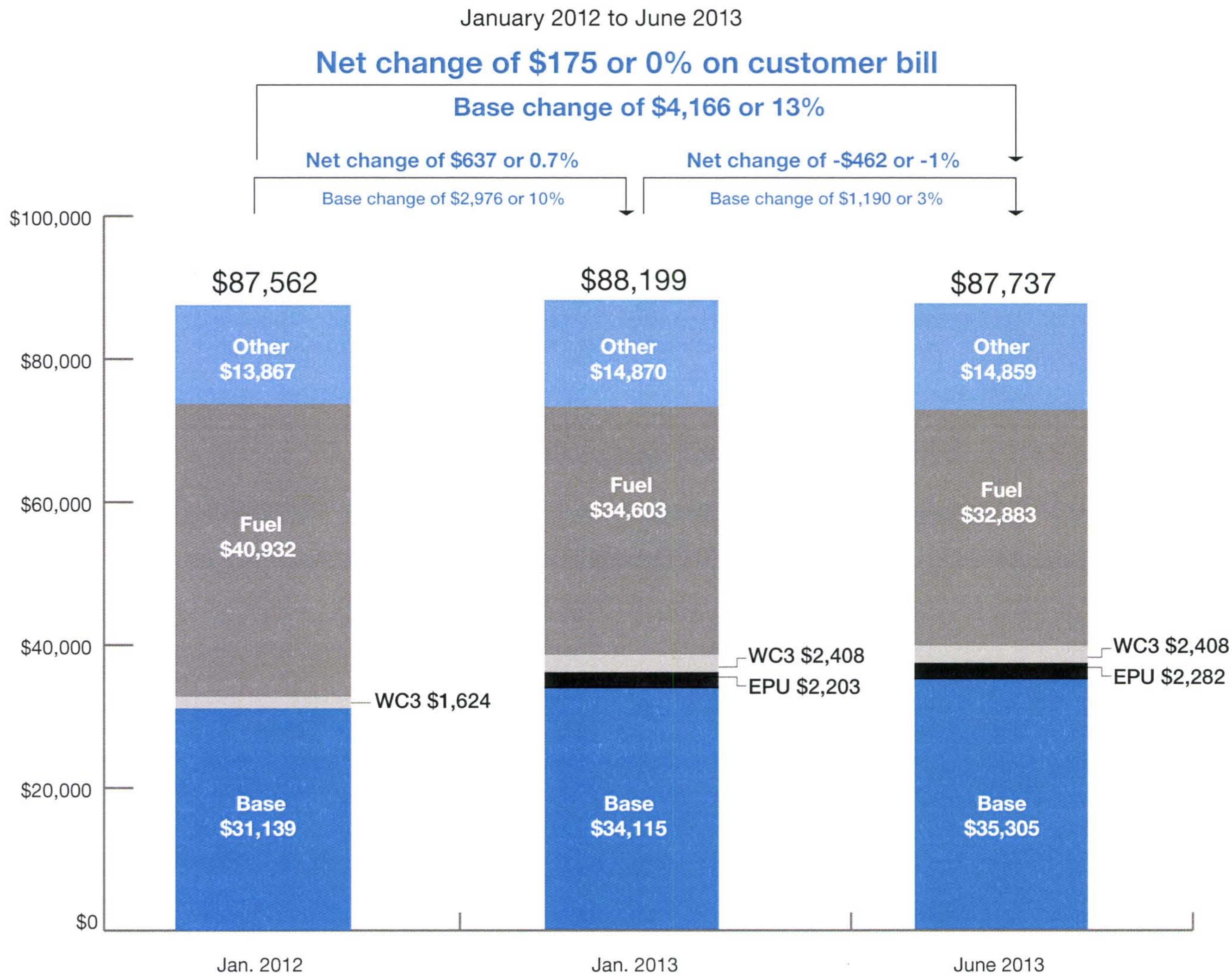
GSLD-1 Rate 600 kW, 50% load factor



For 2013, Fuel and Other clause projections as filed in their respective dockets. "EPU" is the base increase for the Extended Power Uprate (filed in a separate docket on October 1, 2012). "WC3" are West County 3 costs, which shall continue to be recovered through the capacity clause. Other includes $40 for CILC and CDR increases that will not be recovered in 2013 but will be deferred to 2014 if the Proposed Settlement Agreement is approved.

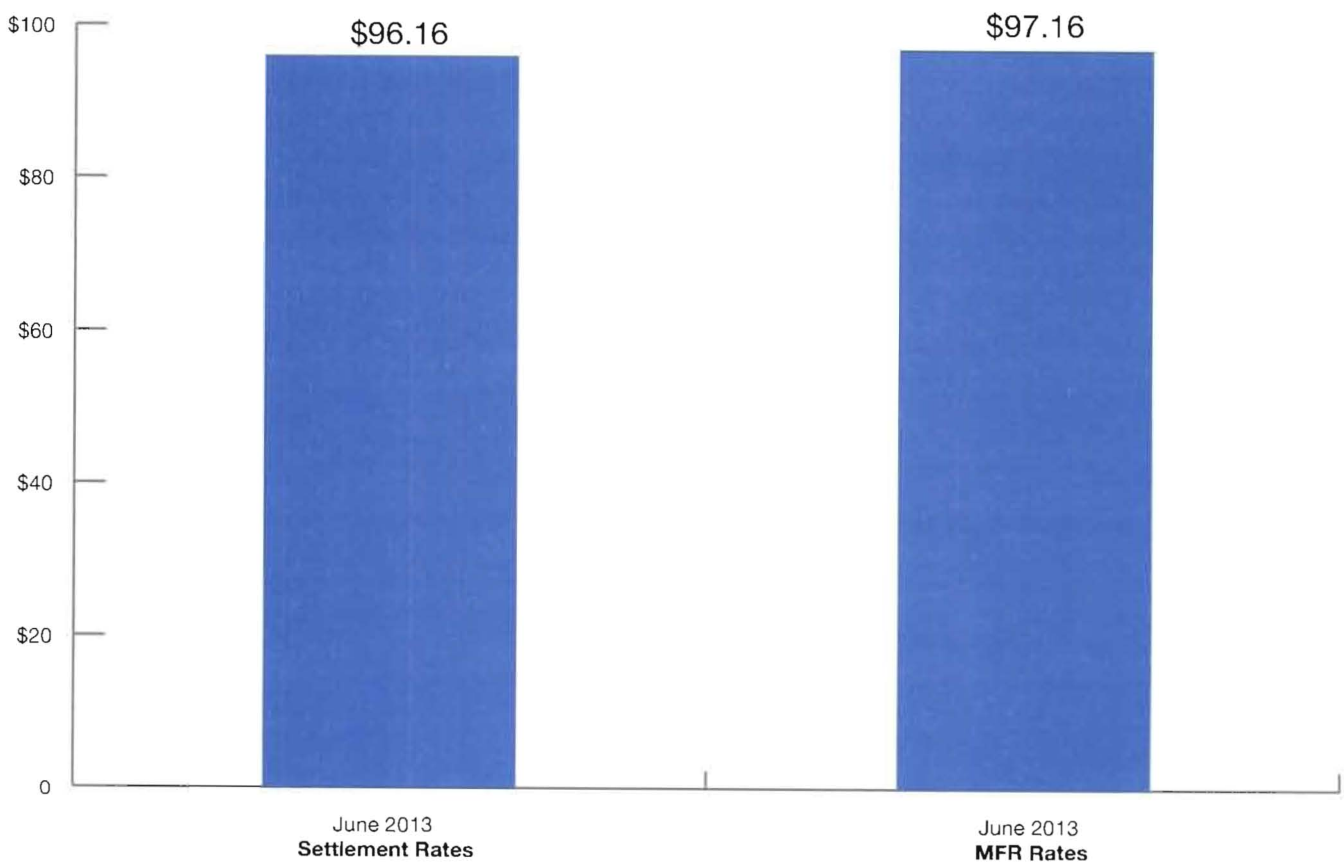
1,124,200-kWh Commercial Customer Bill Comparison

GSLD-2 Rate 2,800 kW, 55% load factor



For 2013, Fuel and Other clause projections as filed in their respective dockets. "EPU" is the base increase for the Extended Power Uprate (filed in a separate docket on October 1, 2012). "WC3" are West County 3 costs, which shall continue to be recovered through the capacity clause. Other includes $196 for CILC and CDR increases that will not be recovered in 2013 but will be deferred to 2014 if the Proposed Settlement Agreement is approved.

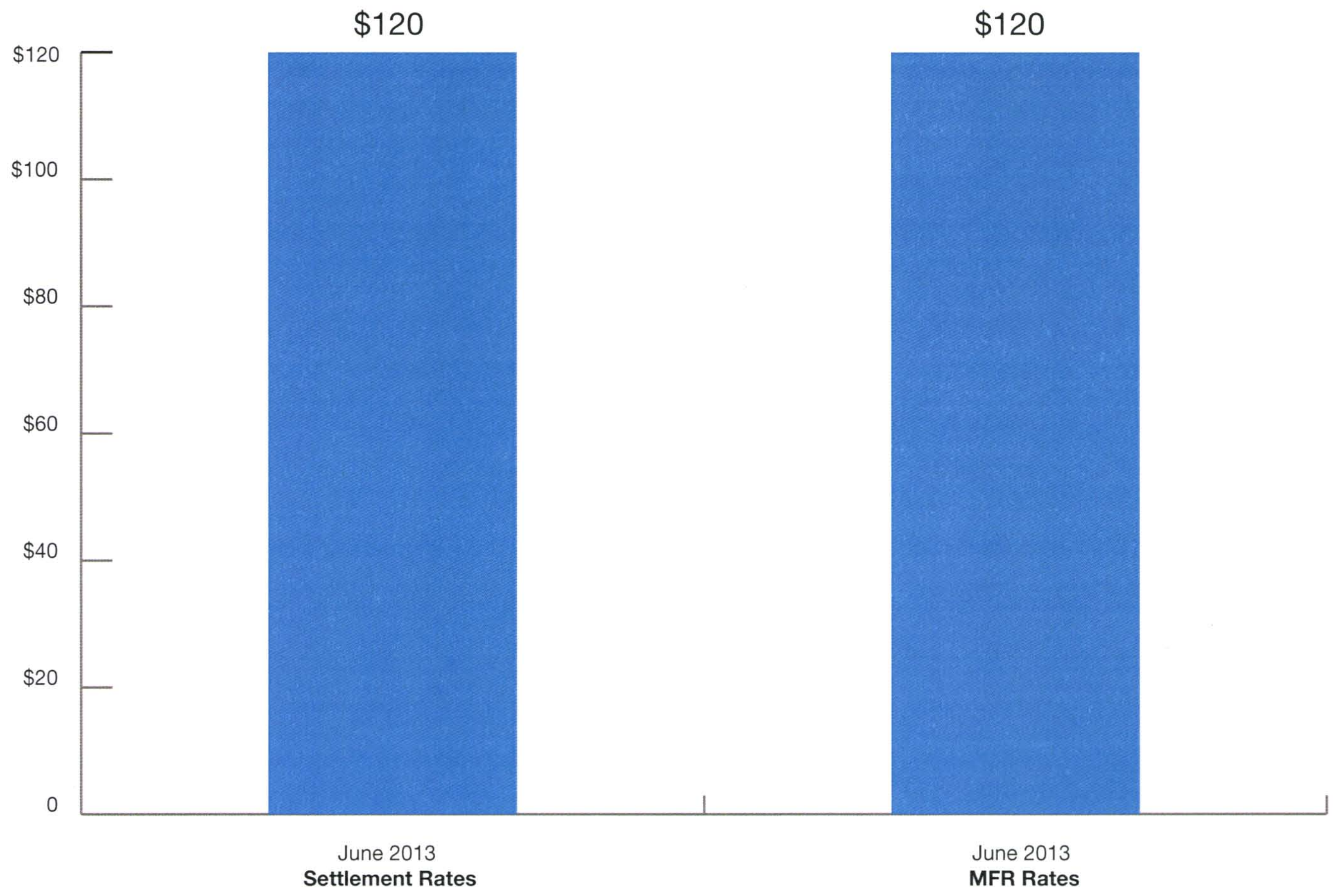
Typical 1,000-kWh Residential Customer Bill Comparison



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 668
PARTY FPL; Ranae B. Deaton (RBD-13) Bill
DESCRIPTION Comparison Under Setltement Rates
Proposed in March 2012, MFRs June 2013

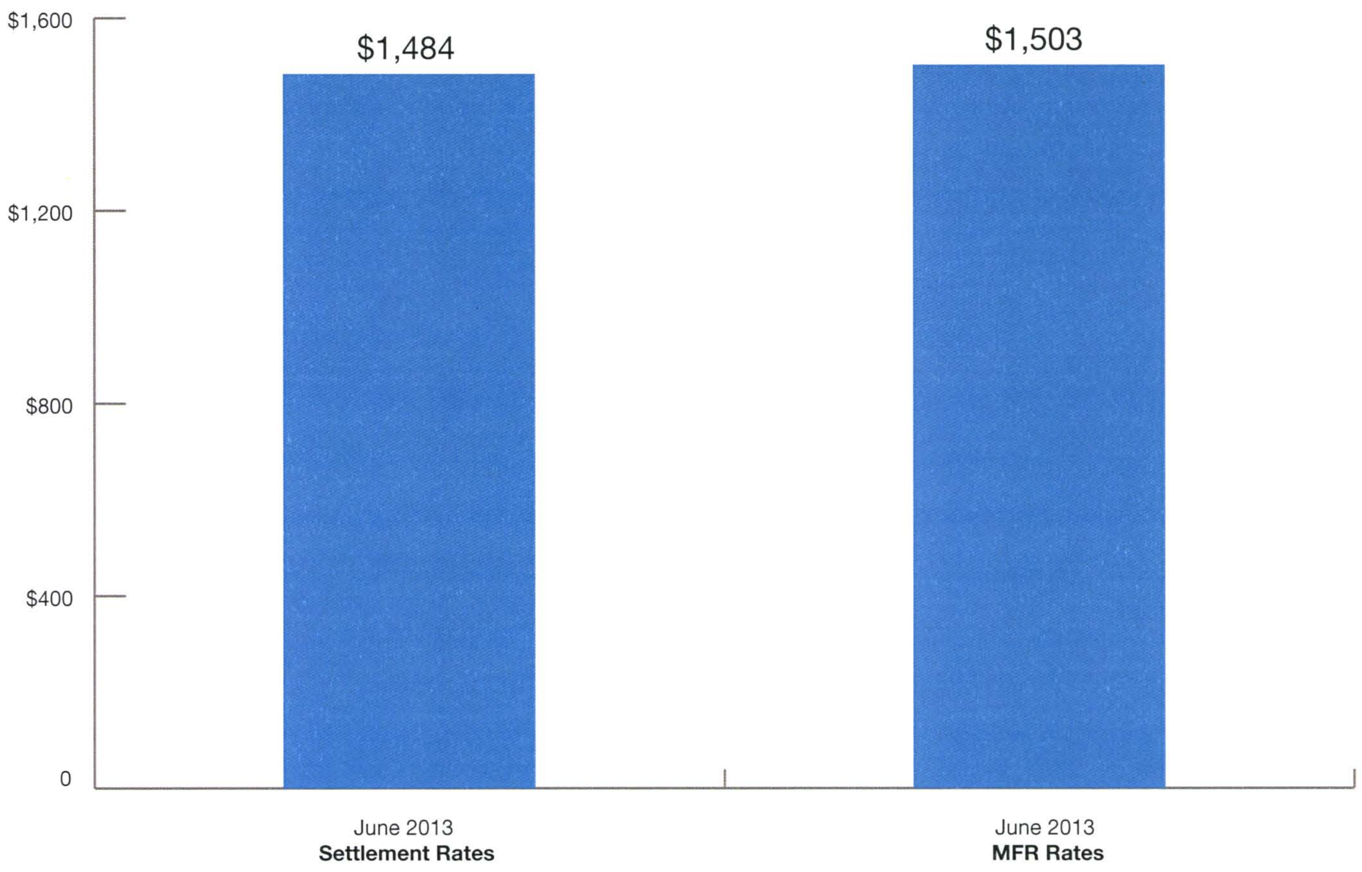
1,200-kWh Commercial Customer Bill Comparison (non-demand)

The General Service Non-Demand ("GS-1") rate class comprises more than 391,000 customer accounts, or approximately 77% of FPL's business customer accounts. These customers are typically small businesses.



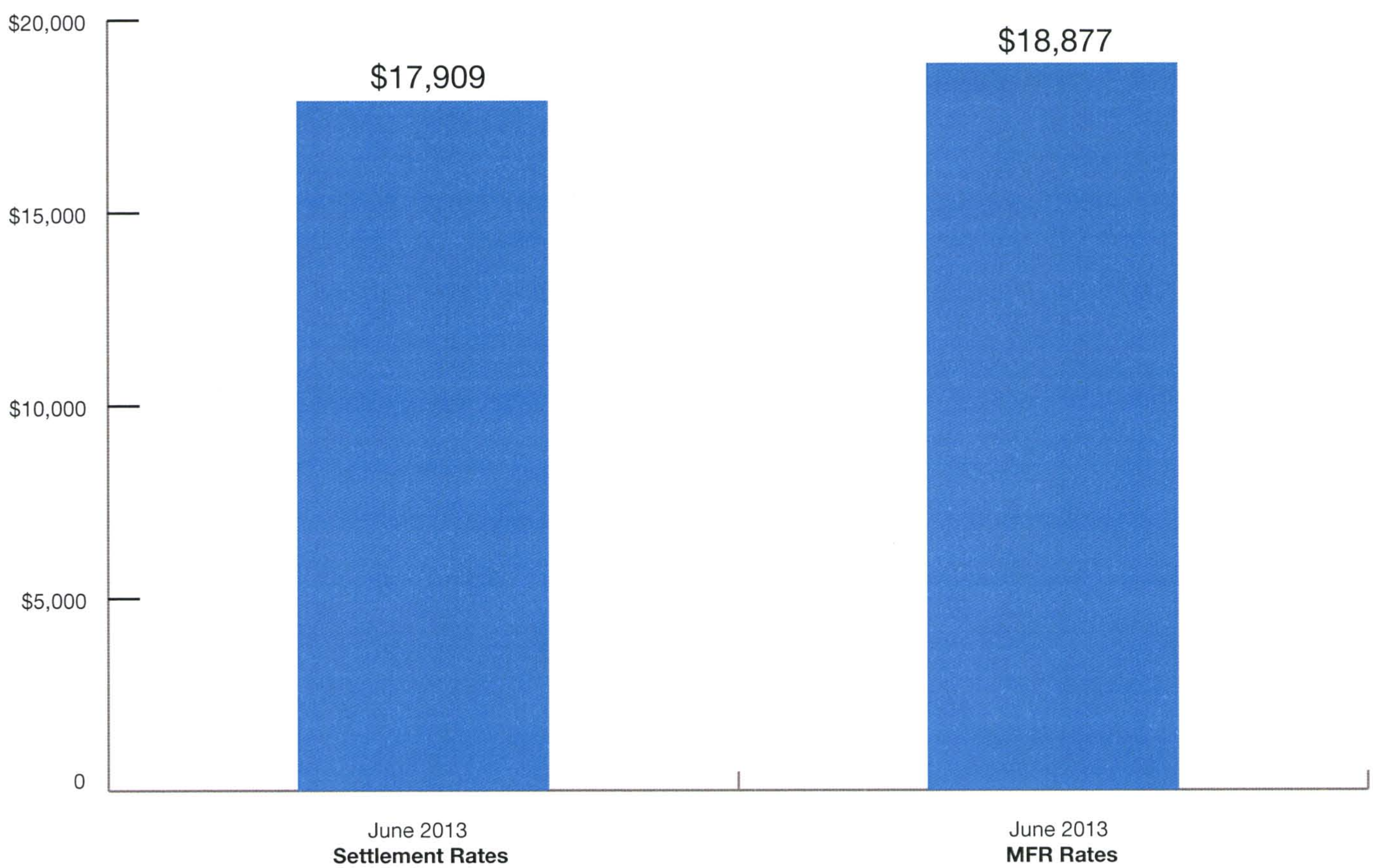
17,520-kWh Commercial Customer Bill Comparison

GSD-1 Rate 50 kW, 48% load factor



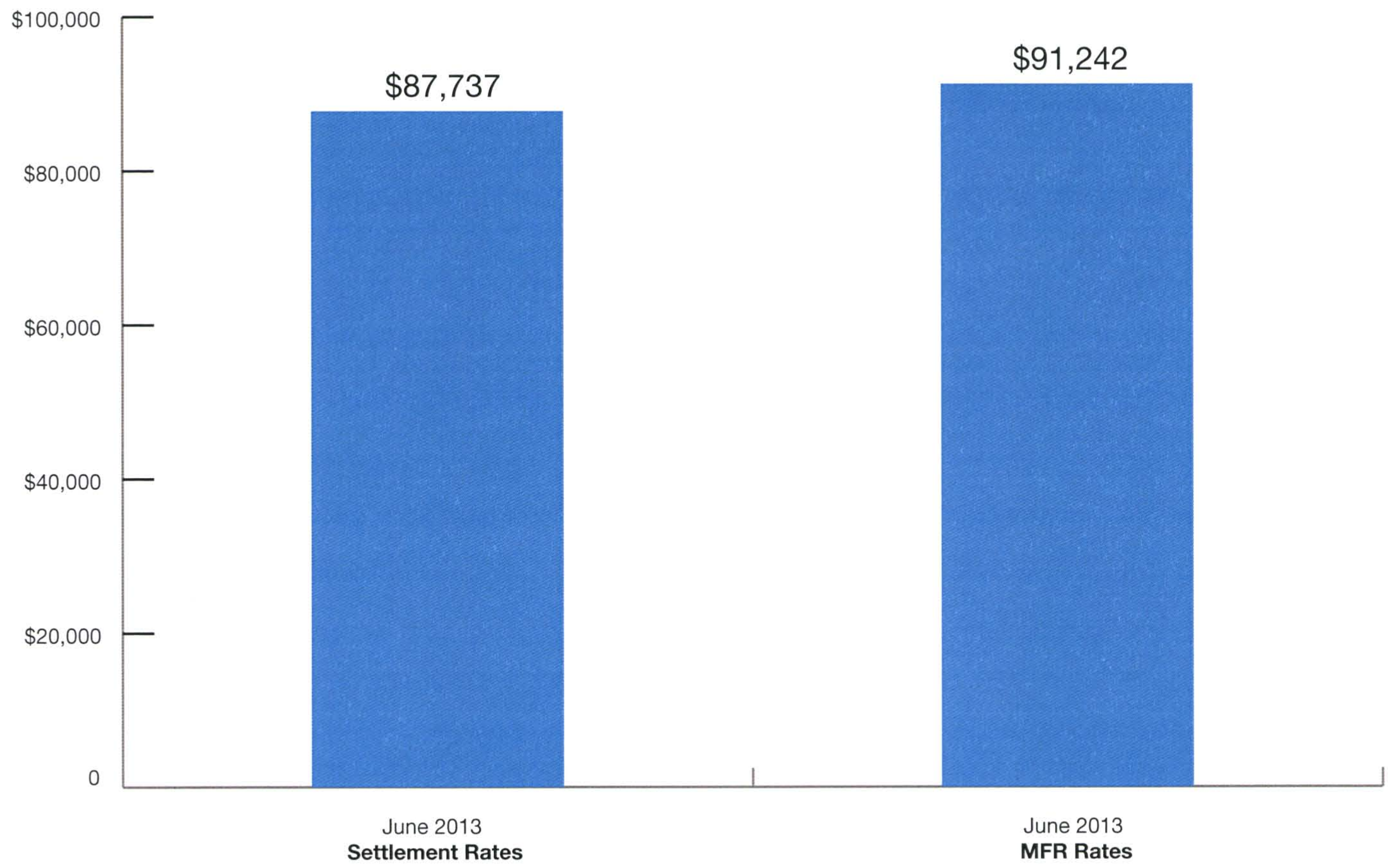
219,000-kWh Commercial Customer Bill Comparison

GSLD-1 Rate 600 kW, 50% load factor



1,124,200-kWh Commercial Customer Bill Comparison

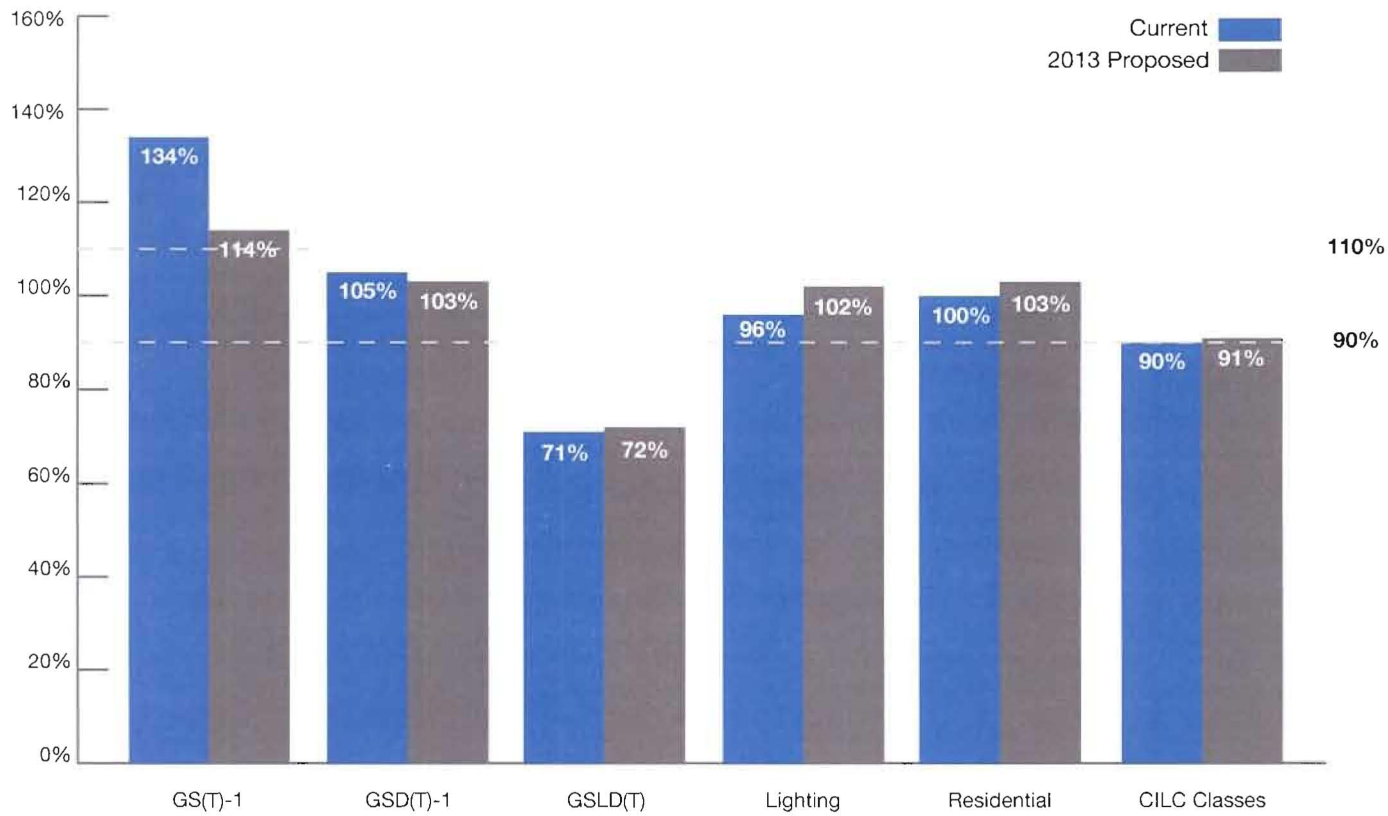
GSLD-2 Rate 2,800 kW, 55% load factor



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 669
PARTY FPL; Ranae B. Deaton (RBD-14) Parity of
DESCRIPTION Major Rate Classes: Current and Proposed
Settlement Agreement

Parity of Major Rate Classes

Current and Proposed Settlement Agreement



GSLD(T) includes GSLD(T)-1, GSLD(T)-2 and GSLD(T)-3

The parity of all classes that are outside the range of 90% to 110% is improved under the Proposed Settlement Agreement.

EEI Industrial Bill Comparison -January 2012
Southeastern Utilities

Company	State	50 MW 15000 MWh	Rank	50 MW 25000 MWh	Rank	50 MW 32500 MWh	Rank
Alabama Power Company	Alabama	1,132,674	9	1,607,676	10	1,963,928	13
Florida Power & Light Company	Florida	938,468	6	1,373,778	7	1,700,260	8
Progress Energy Florida	Florida	1,521,305	21	2,232,366	21	2,833,209	22
Gulf Power Company	Florida	1,621,075	22	2,375,858	22	2,748,632	21
Old Dominion Power Company	Virginia	1,161,775	11	1,610,575	11	1,947,175	10
Southwestern Electric Power Company	Arkansas	686,410	1	982,713	1	1,204,941	1
Tampa Electric Company	Florida	1,487,905	19	2,126,981	20	2,606,289	20
AEP (Appalachian Power Rate Area)	Virginia	960,520	7	1,251,920	5	1,470,470	3
Entergy Arkansas, Inc.	Arkansas	1,024,575	8	1,403,052	8	1,637,257	7
Progress Energy Carolinas, Inc.	North Carolina	1,331,496	17	1,853,796	17	2,094,246	15
Duke Energy Carolinas	North Carolina	911,051	4	1,246,611	4	1,514,401	5
Entergy Mississippi, Inc.	Mississippi	928,877	5	1,317,989	6	1,609,823	6
Dominion Virginia Power	Virginia	1,314,225	16	1,678,845	13	1,952,310	11
Empire District Electric Company	Arkansas	1,158,333	10	1,529,673	9	1,799,666	9
Mississippi Power Company	Mississippi	1,235,612	13	1,804,448	16	2,184,503	17
South Carolina Electric & Gas Company	South Carolina	1,411,450	18	1,888,550	18	2,246,375	18
Georgia Power Company	Georgia	1,520,265	20	2,048,826	19	2,425,047	19
Dominion North Carolina Power	North Carolina	1,309,072	15	1,773,072	14	2,121,072	16
OG&E Electric Services	Arkansas	881,470	3	1,227,300	3	1,486,673	4
Progress Energy Carolinas, Inc.	South Carolina	1,301,825	14	1,803,425	15	2,066,875	14
Duke Energy Carolinas	South Carolina	881,069	2	1,168,201	2	1,412,564	2
SE Average		1,177,117		1,633,603		1,953,606	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 670
PARTY FPL; Ranae B. Deaton (RBD-15)
DESCRIPTION EEI Industrial Bill Comparison January 2012

Late Payment Charge Survey

Business / Entity	Type	Late Payment Fee Structure	Minimum Late Payment Charge
FPL (Current)	Electric service	1.5%	N/A
FPL (2013 Proposed Rate Settlement)	Electric service	Greater of $6 or 1.5%	$6.00
Progress Energy Florida	Electric service	Greater of $5 or 1.5%	$5.00
Tampa Electric Company	Electric service	Greater of $5 or 1.5%	$5.00
Florida Public Utilities Company	Electric service	Greater of $5 or 1.5%	$5.00
OUC (Orlando)	Electric service	Greater of $3 or 1.5%	$3.00
JEA (Jacksonville)	Electric service	1.5%	N/A
Lake Worth Utilities	Electric service	Residential: $11; Commercial: $25	$11.00
Lee County Electric Coop	Electric service	Residential: $10; Commercial: 8%	$10.00
Peace River Electric Coop	Electric service	Greater of $10 or 3%	$10.00
City of Ocala Utility Service	Electric service	5%	N/A
Clay Electric Coop	Electric service	Greater of $5 or 5%	$5.00
Lakeland Electric	Electric service	$3.50 or 1.5%	$3.50
City of Alachula	Electric Service	10% on the balance of current charges	N/A
City of Blountstown	Electric Service	10% on the balance of current charges	N/A
City of Bushnell	Electric Service	5% on the balance of current charges	N/A
City of Chattahoochee	Electric Service	10% on the balance of current charges	N/A
City of Fort Meade	Electric Service	$10 every billing cycle until paid in full	$10.00
City of Fort Pierce	Electric Service	1.5% if not paid by due date an additional $15.00 if not paid within 10 days	$15 after 10 days
City of Gainesville	Electric Service	Greater of $1 or 1.5%	$1.00
City of Green Cove Spring	Electric Service	5% on the balance of current charges (minimum of $5 and maximum of $500)	$5.00
Town of Havana	Electric Service	$10 dollars first 10 days, $10 dollars next 10 days and $30 after 20 days	$10.00
City of Homestead	Electric Service	1.50%	N/A
Kissimee Utility Authority	Electric Service	5% on the balance of current charges	N/A
City of Leesburg	Electric Service	5% on the balance of current charges	N/A
Moore Haven Municipal Light	Electric Service	10% on the balance of current charges	N/A
City of New Smyrna Beach	Electric Service	Greater of $5 or 1.5%	$5.00
City of Quincy	Electric Service	5% on the balance of current charges	N/A
City of St. Cloud	Electric Service	Greater of $3 or 1.5%	$3.00
City of Vero Beach	Electric Service	$5	$5.00
City of Wauchula	Electric Service	$15	$15.00
Talquin Electric Cooperative	Electric Service	1.5% maximum of $10	N/A
West Florida Electric Cooperative	Electric Service	1.5% maximum of $10	N/A
Central Florida Cooperative	Electric Service	Greater of 5% or $10	$10.00
Choctawhatchee Cooperative	Electric Service	10% of first $25 and 2% thereafter	N/A
Clay Cooperative	Electric Service	Greater of $5.00 or 5%	$5.00
Escambia River Cooperative	Electric Service	$10	$10.00
Peace River Cooperative	Electric Service	Greater of $10 or 3%	$10.00
Sumter Cooperative	Electric Service	1 5% of balance but not less than $5.00	$5.00
Suwannee Valley Cooperative	Electric Service	Greater of $5.00 or 5%	$5.00
Tri-County Cooperative	Electric Service	2% of unpaid balance	NA
Withlacoochee River Cooperative	Electric Service	1.5% of balance but not less than $5.00	$5.00
City of Deland	Water service	$10	$10.00
Polk County Utilities	Water service	Greater of $6 or 5%	$6.00
City of Winter Haven	Water service	Greater of $5.38 or 5%	$5.38
City of Longwood	Water service	Greater of $5 or 10%	$5.00
Pinellas County Utilities	Water service	10% ($1 min)	$1.00
City of Miramar Utilities	Water service	$15	$15.00
City of Palm Bay	Water service	Greater of $5 or 5%	$5.00
City of Tarpon Springs	Water service	10%	N/A
Bay County Utility	Water service	10%	N/A

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI **EXHIBIT** 671
PARTY FPL; Ranae B. Deaton (RBD-16)
DESCRIPTION Late Payment Charge Survey

Historical Performance of Existing Incentive Mechanism

Year	Filed Gains	3-Year Average Threshold	Customer Benefit	Shareholder Benefit
1998	62,276,204			
1999	59,183,161			
2000	37,400,076			
2001	17,846,596	52,953,147	17,846,596	0
2002	9,726,487	38,143,278	9,726,487	0
2003	17,827,648	21,657,720	17,827,648	0
2004	18,558,415	15,133,577	17,873,447	684,968
2005	21,022,022	15,370,850	19,891,788	1,130,234
2006	19,438,254	19,136,028	19,377,809	60,445
2007	18,545,406	19,672,897	18,545,406	0
2008	17,001,482	19,668,561	17,001,482	0
2009	10,700,431	18,328,381	10,700,431	0
2010	4,421,987	15,415,773	4,421,987	0
2011	4,918,688	10,707,967	4,918,688	0
*2012	3,627,952	6,680,369	3,627,952	0
Total (2001-2011)	**160,007,416**		**158,131,769**	**1,875,647**

*2012 - Estimated total gains based on January through September actuals and October through December projections as filed with FPL's Actual/Estimated True-Up on August 1, 2012 in Docket No. 120001-EI.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 672
PARTY FPL; Sam A. Forrest (SF-1)
DESCRIPTION Historical Performance of Existing Incentive Mechanism

Historical Performance of Power Sales Gains and Purchased Power Savings

Year	Total Power Sales Gains	Total Purchased Power Savings	Total Customer Benefit
2001	17,846,596	14,596,830	32,443,426
2002	9,726,487	20,999,240	30,725,727
2003	17,827,648	30,111,501	47,939,149
2004	18,558,415	17,572,194	36,130,609
2005	21,022,022	28,589,989	49,612,011
2006	19,438,254	17,026,127	36,464,381
2007	18,545,406	16,274,883	34,820,289
2008	17,001,482	14,887,826	31,889,308
2009	10,700,431	39,751,658	50,452,089
2010	4,421,987	78,316,363	82,738,350
2011	4,918,688	64,644,735	69,563,423
*2012	3,627,952	38,460,208	42,088,160
**2013	4,238,116	30,907,083	35,145,199
Total (2001-2011)	**160,007,416**	**342,771,346**	**502,778,762**

*2012 - Estimated total gains and purchased power savings based on January through September actuals and October through December projections as filed with FPL's Actual/Estimated True-Up on August 1, 2012 in Docket No. 120001-EI.
**2013 - Estimated total gains and purchased power savings based on projections as filed with FPL's 2013 Projection Filing on August 31, 2012 in Docket No. 120001-EI.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 673
PARTY FPL; Sam A. Forrest (SF-2) Historical
DESCRIPTION Performance of Power Sales Gains and Purchased Power Savings

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120015-EI **EXHIBIT** 674

PARTY FPL; Sam A. Forrest (SF-3)

DESCRIPTION Example - "Total Gains Schedule"

TOTAL GAINS SCHEDULE

Actual for the Period of: January 20XX through December 20XX

TABLE 1

(1) Month	(2) Wholesale Sales (MWh)	(3) Wholesale Sales Total Gains ($)	(4) Wholesale Purchases (MWh)	(5) Wholesale Purchases Total Savings ($)	(6) Asset Optimization Savings ($)	(7) Monthly Gains (MG) ($)	(8) Cumulative Gains (CG) ($)	(9) Threshold 1 CG ≤ $36M 100% Customer Benefit ($)	(10) Threshold 2 $36M > CG ≤ $46M 100% Customer Benefit ($)	(11) Threshold 1 and 2 Total Customer Benefit ($)
						(3) + (5) + (6)				(9) + (10)
January	100,000	1,000,000	25,000	250,000	1,000,000	2,250,000	2,250,000	2,250,000	0	2,250,000
February	100,000	1,000,000	25,000	250,000	1,000,000	2,250,000	4,500,000	2,250,000	0	2,250,000
March	50,000	500,000	50,000	1,000,000	1,000,000	2,500,000	7,000,000	2,500,000	0	2,500,000
April	50,000	500,000	125,000	2,500,000	1,000,000	4,000,000	11,000,000	4,000,000	0	4,000,000
May	50,000	500,000	150,000	3,000,000	1,000,000	4,500,000	15,500,000	4,500,000	0	4,500,000
June	50,000	500,000	150,000	3,000,000	1,000,000	4,500,000	20,000,000	4,500,000	0	4,500,000
July	50,000	500,000	200,000	6,000,000	1,000,000	7,500,000	27,500,000	7,500,000	0	7,500,000
August	50,000	500,000	200,000	6,000,000	1,000,000	7,500,000	35,000,000	7,500,000	0	7,500,000
September	50,000	500,000	200,000	6,000,000	1,000,000	7,500,000	42,500,000	1,000,000	6,500,000	7,500,000
October	50,000	500,000	75,000	1,500,000	1,000,000	3,000,000	45,500,000	0	3,000,000	3,000,000
November	100,000	1,000,000	25,000	250,000	1,000,000	2,250,000	47,750,000	0	500,000	500,000
December	100,000	1,000,000	25,000	250,000	1,000,000	2,250,000	50,000,000	0	0	0
Total	**800,000**	**8,000,000**	**1,250,000**	**30,000,000**	**12,000,000**	**50,000,000**		**36,000,000**	**10,000,000**	**46,000,000**

TABLE 2

(1) Month	(2) Cumulative Gains (CG) ($)	(3) Incremental Gains (IG) $46M > IG ≤ $75M ($)	(4) Incremental Gains (IG) $75M > IG ≤ $100M ($)	(5) Incremental Gains (IG) IG > $100M ($)	(6) Threshold 3 $46M > IG ≤ $75M 30% Customer Benefit ($)	(7) Threshold 3 $46M > IG ≤ $75M 70% FPL Benefit ($)	(8) Threshold 4 $75M > IG ≤ $100M 40% Customer Benefit ($)	(9) Threshold 4 $75M > IG ≤ $100M 60% FPL Benefit ($)	(10) Threshold 5 IG > $100M 50% Customer Benefit ($)	(11) Threshold 5 IG > $100M 50% FPL Benefit ($)
	Column (8) Table 1									
January	2,250,000	0	0	0	0	0	0	0	0	0
February	4,500,000	0	0	0	0	0	0	0	0	0
March	7,000,000	0	0	0	0	0	0	0	0	0
April	11,000,000	0	0	0	0	0	0	0	0	0
May	15,500,000	0	0	0	0	0	0	0	0	0
June	20,000,000	0	0	0	0	0	0	0	0	0
July	27,500,000	0	0	0	0	0	0	0	0	0
August	35,000,000	0	0	0	0	0	0	0	0	0
September	42,500,000	0	0	0	0	0	0	0	0	0
October	45,500,000	0	0	0	0	0	0	0	0	0
November	47,750,000	1,750,000	0	0	525,000	1,225,000	0	0	0	0
December	50,000,000	2,250,000	0	0	675,000	1,575,000	0	0	0	0
Total		**4,000,000**	**0**	**0**	**1,200,000**	**2,800,000**	**0**	**0**	**0**	**0**

INCREMENTAL OPTIMIZATION COSTS
Actual for the Period of: January 20XX through December 20XX

(1) Month	(2) Personnel Expenses * ($)	(3) Other Expenses ** ($)	(4) Wholesale Sales (MWh)	(5) Cumulative Sales Generation (MWh)	(6) Sales Generation Threshold*** (MWh)	(7) Sales Generation Above Threshold (MWh)	(8) Weighted Average Variable O&M**** ($/MWh)	(9) Incremental Generation Variable O&M ($)	(10) Total Incremental O&M Expenses ($)
			(From (2) Above)			*****		(6) * (7)	(2) + (3) + (8)
January	25,000	0	100,000	100,000	514,000	0	1.51	0	25,000
February	25,000	0	100,000	200,000	514,000	0	1.51	0	25,000
March	25,000	0	50,000	250,000	514,000	0	1.51	0	25,000
April	25,000	0	50,000	300,000	514,000	0	1.51	0	25,000
May	25,000	6,250	50,000	350,000	514,000	0	1.51	0	31,250
June	25,000	6,250	50,000	400,000	514,000	0	1.51	0	31,250
July	25,000	6,250	50,000	450,000	514,000	0	1.51	0	31,250
August	25,000	6,250	50,000	500,000	514,000	0	1.51	0	31,250
September	25,000	6,250	50,000	550,000	514,000	36,000	1.51	54,360	85,610
October	25,000	6,250	50,000	600,000	514,000	50,000	1.51	75,500	106,750
November	25,000	6,250	100,000	700,000	514,000	100,000	1.51	151,000	182,250
December	25,000	6,250	100,000	800,000	514,000	100,000	1.51	151,000	182,250
Total	**300,000**	**50,000**	**800,000**			**286,000**		**431,860**	**781,860**

Footnotes:
* Personnel expenses are for payroll and loadings for two additional trading personnel in 20XX
** Other expenses are for a software license lease that began in May 20XX
*** "Sales Generation Threshold" is the level of wholesale sales assumed in projecting power plant O&M costs for the 2013 test year MFR's.
**** "Weighted Average Variable O&M" reflects the monthly variable power plant O&M costs projected in the 2013 test year MFR's.
***** Column (7) Formula: If Column (5) - Column (6) > 0, then Column (7) equals the lower of Column (5) - Column (6) or Column (4)

GBRA ROE Midpoint Illustrative Example

	Before Incremental GBRA Plant			Incremental GBRA Plant			After Incremental GBRA Plant		
Rate base	$20,000			$1,000			$21,000		
Capital structure	**Amount**	**Cost Rate**	**Weighted Average**	**Amount**	**Cost Rate**	**Weighted Average**	**Amount**	**Cost Rate**	**Weighted Average**
Debt	$6,800	5.30%	1.80%	$404	4.10%	1.66%	$7,204	5.23%	1.80%
Equity	9,200	10.70%	4.92%	596	10.70%	6.38%	9,796	10.70%	4.99%
Deferred taxes	4,000	0.00%	0.00%	0	0.00%	0.00%	4,000	0.00%	0.00%
Total	**$20,000**		**6.72%**	**$1,000**		**8.03%**	**$21,000**		**6.79%**

FPL Earning at 10.7%, GBRA is at 10.7%	Before Incremental GBRA Plant	Incremental GBRA Plant	After Incremental GBRA Plant
Net operating income	$1,345	$80	$1,425
Rate of return	6.72%	8.03%	6.79%
Non equity costs	1.80%	1.66%	1.80%
Available to equity	4.92%	6.38%	4.99%
Equity ratio	46.00%	59.60%	46.65%
Earned return on equity	**10.70%**	**10.70%**	**10.70%**

FPL Earning at 10.5%, GBRA is at 10.7%	Before Incremental GBRA Plant	Incremental GBRA Plant	After Incremental GBRA Plant
Net operating income	$1,326	$80	$1,407
Rate of return	6.63%	8.03%	6.70%
Non equity costs	1.80%	1.66%	1.80%
Available to equity	4.83%	6.38%	4.90%
Equity ratio	46.00%	59.60%	46.65%
Earned return on equity	**10.50%**	**10.70%**	**10.51%**

FPL Earning at 10.9%, GBRA is at 10.7%	Before Incremental GBRA Plant	Incremental GBRA Plant	After Incremental GBRA Plant
Net operating income	$1,363	$80	$1,444
Rate of return	6.82%	8.03%	6.87%
Non equity costs	1.80%	1.66%	1.80%
Available to equity	5.01%	6.38%	5.08%
Equity ratio	46.00%	59.60%	46.65%
Earned return on equity	**10.90%**	**10.70%**	**10.89%**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 675
PARTY FPL; Robert Barrett (REB-9); GBRA ROE
DESCRIPTION Midpoint Illustrative Example
DATE

CANAVERAL MODERNIZATION PROJECT
ESTIMATED FIRST YEAR REVENUE REQUIREMENTS

Revenue Requirement Calculation	FIRST YEAR OPERATIONS ($000)
Jurisdictional Adjusted Rate Base	$811,809
Rate of Return on Rate Base	8.550%
Required Jurisdictional Net Operating Income	69,411
Required Net Operating Income	69,411
Jurisdictional Adjusted Net Operating Income (Loss)	(31,876)
Net Operating Income Deficiency (Excess)	101,287
Net Operating Income Multiplier	1.63188
Revenue Requirement (1)	$165,289
ROE Impact of Revenue Requirements (2)	103 bps

Notes:
(1) Based on the following assumptions: the revised Cape Canaveral Modernization Project costs and expenses included in the Appendix to FPL's post hearing brief filed on September 21, 2012, the as-filed, incremental capital structure, the revised long term debt cost rate as described by FPL in its post hearing brief, and the settlement ROE of 10.7%.

(2) Based on $160M in Revenue Requirement change per 100 basis points (bps).

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 676
PARTY FPL; Robert Barrett (REB-10) MFR A-1
DESCRIPTION Canaveral, Riviera, and Port Everglades
DATE

RIVIERA MODERNIZATION PROJECT
ESTIMATED FIRST YEAR REVENUE REQUIREMENTS

Revenue Requirement Calculation	FIRST YEAR OPERATIONS ($000)
Jurisdictional Adjusted Rate Base	$1,220,926
Rate of Return on Rate Base	8.550%
Required Jurisdictional Net Operating Income	104,392
Required Net Operating Income	104,392
Jurisdictional Adjusted Net Operating Income (Loss)	(40,253)
Net Operating Income Deficiency (Excess)	144,645
Net Operating Income Multiplier	1.63188
Revenue Requirement (1)	$236,043
ROE Impact of Revenue Requirements (2)	148 bps

Note:

(1) Based on the following assumptions: the projected capital costs and expenses included in the Riviera Modernization project need determination filing, the as filed and revised incremental capital structure and cost rates for the Canaveral Modernization Project, and the settlement ROE of 10.7%, consistent with Paragraph 8(c) of the Proposed Settlement Agreement.

(2) Based on $160M in Revenue Requirement change per 100 basis points (bps).

PORT EVERGLADES MODERNIZATION PROJECT
ESTIMATED FIRST YEAR REVENUE REQUIREMENTS

Revenue Requirement Calculation	FIRST YEAR OPERATIONS ($000)
Jurisdictional Adjusted Rate Base	$1,144,824
Rate of Return on Rate Base	8.550%
Required Jurisdictional Net Operating Income	97,885
Required Net Operating Income	97,885
Jurisdictional Adjusted Net Operating Income (Loss)	(35,618)
Net Operating Income Deficiency (Excess)	133,503
Net Operating Income Multiplier	1.63188
Revenue Requirement (1)	$217,862
ROE Impact of Revenue Requirements (2)	136 bps

Note:

(1) Based on the following assumptions: the projected capital costs and expenses included in the Port Everglades Modernization project need determination filing, the as filed and revised incremental capital structure and cost rates for the Canaveral Modernization Project, and the settlement ROE of 10.7%, consistent with Paragraph 8(c) of the Proposed Settlement Agreement.

(2) Based on $160M in Revenue Requirement change per 100 basis points (bps).

Dismantlement Reserve

Illustrative Example of Impact of Amortization on Future Accruals

($ millions)

Table 1: Computation of Net Accrual Activity (2013 - 2016)

Description: This table summarizes the 4-year activity for current authorized accrual adjusted for an illustrative dismantlement flowback.

	2013	2014	2015	2016	Total	Comments
Authorized Accruals	$ 18.3	$ 18.3	$ 18.3	$ 18.3	$ 73.2	Current authorized accrual
Annual Flowback	(52.3)	(52.3)	(52.3)	(52.3)	(209.0)	Maximum flowback to dismantlement expense spread ratably over 2013 - 2016
Net Accrual Impact	**$ (34.0)**	**$ (34.0)**	**$ (34.0)**	**$ (34.0)**	**$ (135.8)**	Net impact on accrual activity during 2013 - 2016

Table 2: Computation of Recollection Due to Illustrative Flowback

Description: This table summarizes the recollection of flowback over remaining life and the potential impact on the 2017 proposed accrual.

		Comments
Assumed Recollected Accrual		
Total	$ 135.8	Due to 2013 - 2016 flowback
Present Value	75.4	Using compounding rate
Compounding Rate	4%	Current compounding inflation based on cost escalations (most plants between 3 and 5%)
Average Remaining Life	15.0	Estimated after 4 years passage (current is 19)
Annualized Recollection	**$ 7.2**	Annual recollection amount (most recent 4-year average from Table 4)

Table 3: Comparison of Authorized (2010) and Potential Accruals (2017)

Description: This table summarizes the comparison of the 2010 authorized accrual and the estimate on the 2017 potential accrual.

Current Authorized Accrual	$ 18.3	
Potential 2017 Accrual	25.5	
Accrual Net Change	**$ 7.2**	Assume no other changes in assumptions during 2013 - 2016

Table 4: Flowback PV of $75.4M

Year	Amount
2017	$ 6.8
2018	7.1
2019	7.3
2020	7.6
2021	7.9
2022	8.3
2023	8.6
2024	8.9
2025	9.3
2026	9.7
2027	10.0
2028	10.4
2029	10.9
2030	11.3
2031	11.7
	$ 135.8

4 year average = $7.2M

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI **EXHIBIT** 677
PARTY FPL; Robert Barrett (REB-11) Dismantlement
DESCRIPTION Reserve - Illustrative Ex. of Impact of
DATE Amortization on Future Accruals

Depreciation Accrual

Illustrative Example of Effect of Nuclear Plant Additions on Accrual(I)

(Dollars in Millions)

Line No.			2009 Approved Depreciation Rate and Parameters with 2009 Forecast Plant and Commission Ordered Reserve	2010 - 2013 Incremental Spending and Reserve	2009 Approved Depreciation Rate and Forecast Spending through 2013	2009 Parameters (Updated Remaining Life) and Forecast Spending through 2013	Annual Deficit in Depreciation Accrual (2013 and beyond) from Additional Spending in 2010-2013 and Passage of Time	2017 Amounts Assuming Continued Use of 2009 Parameters and No Additional Spending Beyond 2013	2017 Amounts Assuming use of Updated Remaining Life (E)	Diff in Annual Accrual (F)
1	Plant Balance (G)		$ 3,970	$ 2,806	$ 6,776	$ 6,776		$ 6,776	$ 6,776	
2	Net Salvage	Line 1 x 1.2%	48	34		82		82	82	
3	Total Cost	Lines 1 + 2	$ 4,018	$ 2,840		$ 6,858		$ 6,858	$ 6,858	
4	Reserve (H)		(1,994)	(304)		(2,298)		(2,834)	(3,127)	
5	Future Accruals (NBV)	Lines 3 - 4	2,024	2,536		4,560		4,024	3,731	
6	Average Remaining Life		26		26	22		18	18	
7	Annual Accrual		$ 78	$ 56	$ 134 A	$ 207 B	$ 73 C	$ 224 D	$ 207	$ 17
8	Accrual Rate	Lines 7 ÷ 1	2.0%		2.0%	3.1%		3.3%	3.1%	

Notes:

A: Continued use of 2% (2009 approved accrual rate) would result in an annual accrual in 2013 of $134 million ($6,776*2%)

B: The accrual should be $207 million (rate of 3.1%) beginning in 2013 if it is recalculated by taking the NBV of $4,560 over the remaining life of 22 years

C: The annual deficit, or shortfall, in the accrual is $73 million if the Company kept using an accrual rate of 2% rather than 3.1% based on remaining life

D: Deferring the study until 2017 means the accrual would now need to be $224 million (rate of 3.3%) - $17 million higher than if it had been adjusted in 2013.

E: Represents the resulting amounts had the accrual for 2013 through 2016 been $207 million (see note B)

F: Represents the difference in the annual accrual between the $207 million (see Note E) and the $224 million (see Note D).

G: Total system 13-month average nuclear plant balance of $6,776 million at December 31, 2013 agrees to MFR B-6, page 1.

H: Total system 13-month average nuclear reserve balance of $2,298 million at December 31, 2013 agrees to MFR B-6, page 5.

I: In this illustrative example, of the total required increase in the annual accrual of $90 million in 2017 (D - A), delaying the study for four years accounts for less than 20% of the increase, or $17 million (D - B)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 678
PARTY FPL; Robert Barrett (REB-12)
DESCRIPTION Depreciation Accrual - Illustrative Ex. of effect
DATE of Nuclear Plant Additions on Accrual

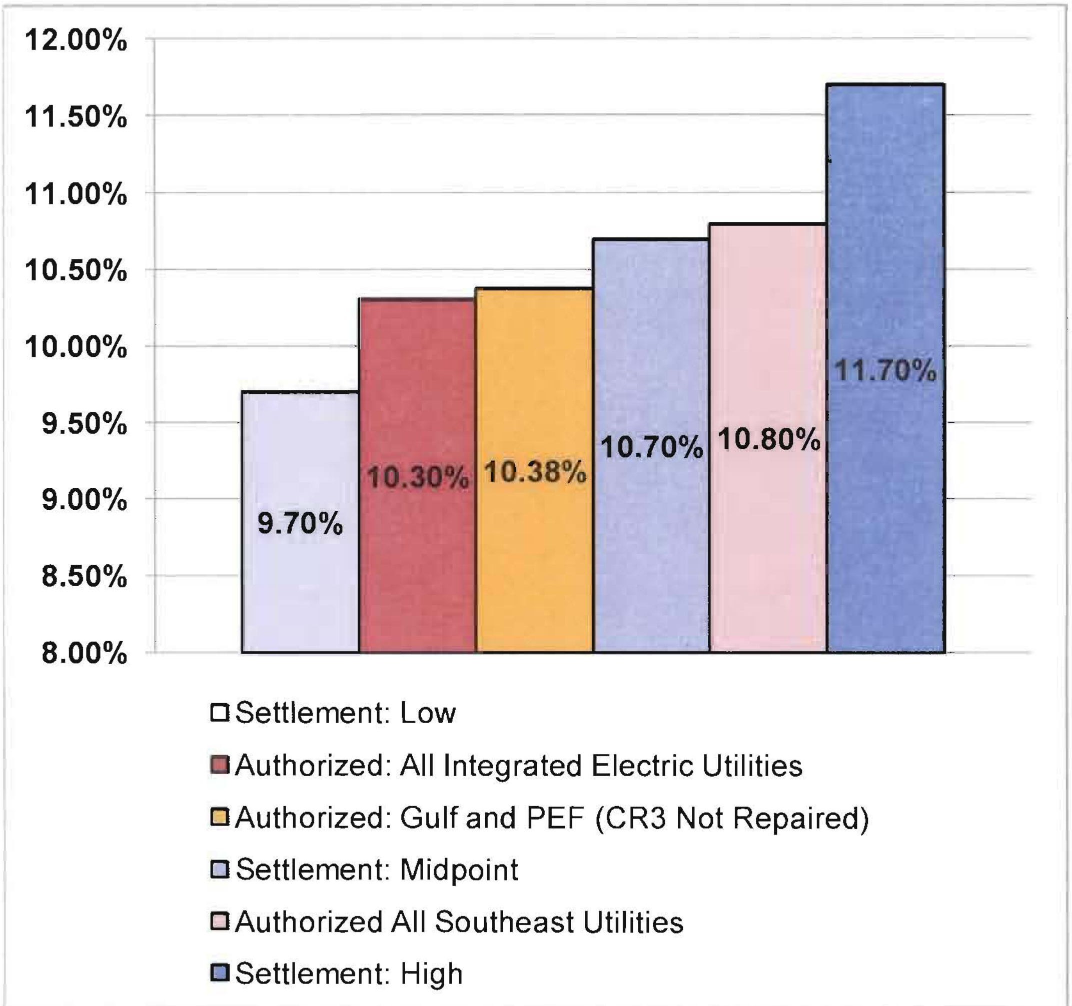
Docket No. 120015-EI
Depreciation Accrual - Illustrative
Example of Effect of Nuclear Plant
Additions on Accrual
Exhibit REB-12, Page 1 of 1

FLORIDA POWER & LIGHT COMPANY

Revenue Requirement Associated With Additional Infrastructure-Related Costs Since FPL's Last Rate Case Test Year Ending December 31, 2013 (Dollar Amounts in $000)

Line	Description	Incremental Infrastructure Costs
		(1)
1	Jurisdictional Adjusted Rate Base	$4,282,845
2	Pre-Tax Return at 10.70% ROE	9.78%
3	Return and Associated Taxes	$418,740
4	Property Insurance	$6,515
5	Depreciation (excluding Decommissioning)	$48,911
6	Property Tax	$26,622
7	Revenue Deficiency	$500,788
	Amortize Remaining Surplus Depreciation	
8	Over 18 Months	-$114,800
9	Adjusted Revenue Deficiency	$385,988
10	Settlement Base Revenue Increase	$378,000

FLORIDA POWER & LIGHT COMPANY
Authorized Versus Settlement
Return on Equity

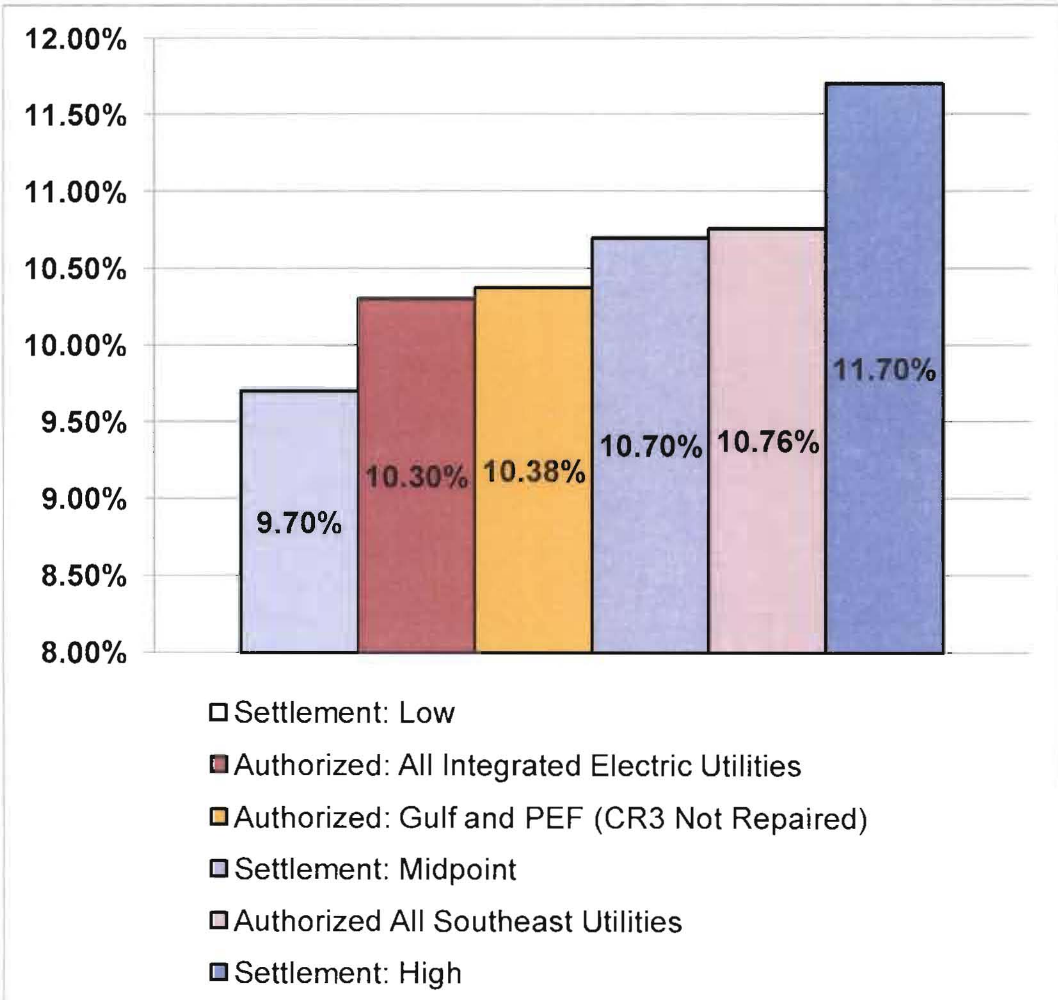


FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 680
PARTY FIPUG; Jeffry Pollock (JP-16)
DESCRIPTION Return on Equity

Source: SNL Financial.

Docket No. 120015-EI
Return on Equity
Exhibit JP-22
(Errata to Exhibit JP-16)

FLORIDA POWER & LIGHT COMPANY
Authorized Versus Settlement
Return on Equity



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 680
PARTY FIPUG; Jeffry Pollock (JP-22)
DESCRIPTION Return on Equity (Errata to JP-16)
DATE

Source: SNL Financial.

FLORIDA POWER & LIGHT COMPANY
Proposed Versus Settlement Increase
Test Year Ending December 31, 2013
(Dollar Amounts in $000)

Line	Rate Class	Proposed Increase Amount	Proposed Increase Percent	Settlement Increase Amount	Settlement Increase Percent	Difference Amount	Difference Percent
		(1)	(2)	(3)	(4)	(5)	(6)
1	Residential	$279,823	11.0%	$219,981	8.7%	-$59,842	-21.4%
2	GS(T)-1	1,065	0.3%	0	0.0%	-1,065	-100.0%
3	GSCU-1	38	2.3%	34	2.0%	-4	-10.4%
4	GSD(T)	92,661	10.8%	64,172	7.5%	-28,489	-30.7%
5	GSLD(T)-1	65,246	21.3%	24,936	8.1%	-40,310	-61.8%
6	GSLD(T)-2	12,932	22.9%	4,916	8.7%	-8,016	-62.0%
7	GSLD(T)-3	591	14.6%	0	0.0%	-591	-100.0%
8	CILC-1D	12,927	22.8%	5,693	10.1%	-7,234	-56.0%
9	CILC-1G	331	7.4%	471	10.6%	140	42.1%
10	CILC-1T	5,670	35.1%	2,779	17.2%	-2,891	-51.0%
11	MET	553	19.1%	559	19.3%	6	1.0%
12	SL-1	7,832	11.1%	8,019	11.3%	187	2.4%
13	SL-2	-296	-23.6%	0	0.0%	296	-100.0%
14	OL-1	1,230	10.7%	1,257	10.9%	27	2.2%
15	OS-2	123	14.4%	126	14.8%	3	2.3%
16	SST-DST	58	15.8%	59	16.0%	1	1.4%
17	SST-TST	736	17.2%	0	0.0%	-736	-100.0%
18	Total Electricity Sales	$481,522	11.4%	$333,002	7.9%	-$148,520	-30.8%
19	Other Revenues	34,999	20.9%	44,998	26.8%	9,999	28.6%
20	Total FPSC Jurisdiction	$516,521	11.7%	$378,000	8.6%	-$138,521	-26.8%

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 681
PARTY FIPUG; Jeffry Pollock (JP-17)
DESCRIPTION 2013 Class Revenue Allocation

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?

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 682
PARTY FIPUG; Jeffry Pollock (JP-18)
DESCRIPTION Cost Effectiveness

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.

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120015-EI **EXHIBIT** 683

PARTY FEA, Ryan M. Allen (RMA-1), 2011 Economic

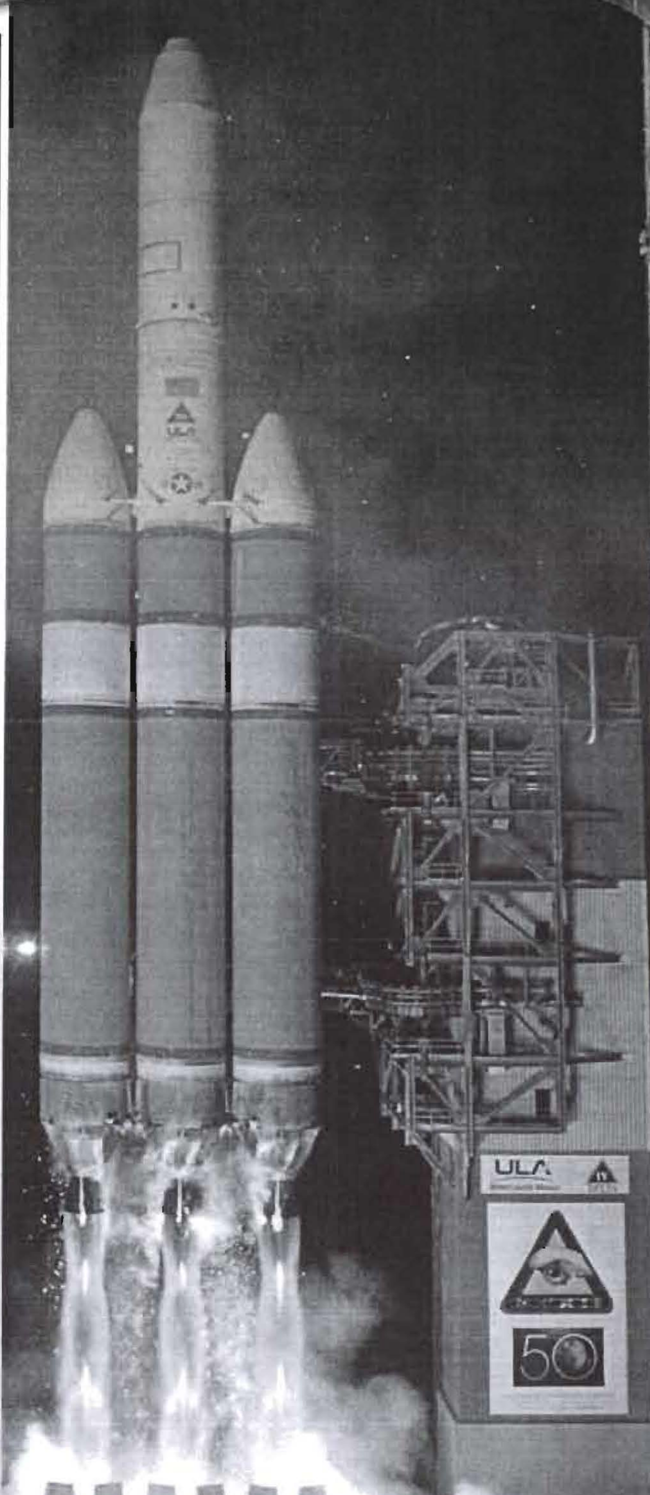
DESCRIPTION Impact Analysis Patrick AFB, and Cape Canaveral Air Force Station

2011 ECONOMIC IMPACT ANALYSIS

PATRICK AIR FORCE BASE &
CAPE CANAVERAL AIR FORCE STATION

45TH SPACE WING
1201 EDWARD H. WHITE II STREET
PATRICK AFB, 32925

45TH SPACE WING



45th Space Wing Public Affairs Office may be contacted
at (321) 494-5933 to answer any questions concerning this document

ECONOMIC IMPACT ANALYSIS
PATRICK AFB - FY11

TABLE 1
PERSONNEL BY CLASSIFICATION AND HOUSING LOCATION

As of: 4-Jan-11

CLASSIFICATION	LIVING ON BASE*	LIVING OFF BASE	TOTAL
1. APPROPRIATED FUND MILITARY			
Active Duty (AD)	123	2,065	2,188
Air Force Reserve/Air National Guard		154	154
Non-Extended Active Duty Reserve/ANG		1,063	1,063
Individual Mobilization Augmentees		243	243
Trainees/Cadets			0
TOTAL:	123	3,525	3,648

*Dorm residents only; all considered AD for purposes of reporting

CLASSIFICATION	LIVING ON BASE*	LIVING OFF BASE	TOTAL
2. ACTIVE DUTY MILITARY DEPENDENTS	0	5,051	5,051
3. APPROPRIATED FUND CIVILIANS			
General Schedule, Wage Grade, DICPS, NSPS			2,181
Other			
		TOTAL:	2,181
4. NON-APPROPRIATED FUND CONTRACT CIVILIANS AND PRIVATE BUSINESS			
Civilian NAF			263
Civilian BX			150
Contract Civilians (not elsewhere included)			3,665
Private Businesses On Base, By Type:			9
Branch Banks/Credit Union			8
Other Civilians (not elsewhere included)			1
		TOTAL:	4,087
		TOTAL PERSONNEL:	14,967

ECONOMIC IMPACT ANALYSIS

PATRICK AFB - FY11

TABLE 2
ANNUAL PAYROLL BY CLASSIFICATION AND HOUSING LOCATION

As of: 4-Jan-11

CLASSIFICATION		LIVING ON BASE ($)	LIVING OFF BASE ($)	TOTAL ($)
1. APPROPRIATED FUND MILITARY				
Active Duty (AD)		$2,614,874	$158,117,652	$160,732,526
Air Force Reserve/Air National Guard			$13,656,728	$13,656,728
Non-Extended Active Duty Reserve/ANG			$27,952,429	$27,952,429
Individual Mobilization Augmentees			$5,555,203	$5,555,203
Trainees/Cadets				$0
	TOTAL:	$2,614,874	$205,282,012	$207,896,886
2. APPROPRIATED FUND CIVILIANS				
General Schedule, Wage Grade, DICPS, NSPS				$116,756,377
Other				
			TOTAL:	$116,756,377
3 NON-APPROPRIATED FUND CONTRACT CIVILIANS AND PRIVATE BUSINESS				
Civilian NAF				$7,107,196
Civilian BX				$4,366,162
Contract Civilians (not elsewhere included)				$0
Private Businesses On Base, By Type:				$259,269
Branch Banks/Credit Union				$206,167
Other Civilians (not elsewhere included)				$53,102
			TOTAL:	$11,732,627
			TOTAL ANNUAL PAYROLL:	$336,385,891

ECONOMIC IMPACT ANALYSIS

PATRICK AFB - FY11

TABLE 3
EXPENDITURES FOR CONSTRUCTION, SERVICES, AND PROCUREMENT OF MATERIALS, EQUIPMENT, AND SUPPLIES
(Not including contracts for services supplied to other Air Force installations)

As of: 4-Jan-11

		ACTUAL ANNUAL EXPENDITURES
1. CONSTRUCTION		
Military Construction Program		$151,506,906
Non-Appropriated Fund		$309,213
Military Family Housing		$0
O&M		$65,775,759
Other		$7,352,009
	TOTAL:	$224,943,887
2. SERVICES		
Services Contracts *		$439,143,083
Other Services (not elsewhere included)		$0
	TOTAL:	$439,143,083
3. MATERIALS, EQUIPMENT, AND SUPPLIES PROCUREMENT		
Commissary		$2,912,178
Base Exchange (BX)		$0
Health (CHAMPUS, Government cost only)		$8,911,773
Education (Impact aid and tuition assistance)		$2,109,630
TDY		$3,164,321
Other Materials, Equipment & Supplies (not elsewhere included)		$20,207,334
	TOTAL:	$37,305,236
	TOTAL ANNUAL EXPENDITURES:	**$701,392,206**

* Includes only contracts in the local economic area or contracts requiring the use of locally supplied goods and services

ECONOMIC IMPACT ANALYSIS

PATRICK AFB - FY11

TABLE 4
ESTIMATE OF NUMBER AND DOLLAR VALUE OF INDIRECT JOBS CREATED

As of: 4-Jan-11

Type of Personnel	# of Base Jobs	Multiplier	# of Indirect Jobs
ACTIVE DUTY MILITARY	2,188	0.41	897
RESERVE/ANG/TRAINEES	1,217	0.41	499
APF CIVILIANS	2,181	0.55	1,200
OTHER CIVILIANS	4,087	0.55	2,248
TOTAL:	9,673		4,844

ESTIMATED NUMBER OF INDIRECT JOBS CREATED: 4,844

AVERAGE ANNUAL PAY FOR THE LOCAL COMMUNITY: $42,990

ESTIMATED ANNUAL DOLLAR VALUE OF JOBS CREATED: $208,243,560

Data Sources:
Multipliers: LMI Economic Impact Database, Installations and Indirect/Induced Job Multipliers, Feb 95
Avg Annual Pay: http://www.bls.gov/oes/current/oes_37340.htm#00-0000

ECONOMIC IMPACT ANALYSIS

PATRICK AFB - FY11

TABLE 5
TOTAL ANNUAL ECONOMIC IMPACT ESTIMATE

As of: 4-Jan-11

ANNUAL PAYROLL:			$336,385,891
	Military	$207,896,886	
	Federal Civilian	$116,756,377	
	Other Civilian	$11,732,627	
ANNUAL EXPENDITURES:			$701,392,206
ESTIMATED ANNUAL DOLLAR VALUE OF JOBS CREATED:			$208,243,560
	Estimated Indirect Jobs Created	4,844	
	Average Annual Pay	$42,990	
	GRAND TOTAL:		**$1,246,021,657**

The total economic impact of Patrick Air Force Base and its tenants on the local economy was $1.246 billion for Fiscal Year 2011. An additional $352 million in retired military pay is received locally.

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120015-EI EXHIBIT 684

PARTY OPC ; James W. Daniel (JWD-1); List of

DESCRIPTION Regulatory Proceedings

DATE

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
1/1/1976	Federal Power Commission	ER76-530	Arizona Public Service Company
2/76	South Dakota Public Utility Commission	F-3055	Northwestern Public Service Company
5/79	Federal Energy Regulatory Commission	ER78-379,ER78-380 ER78-381,ER78-382 ER78-383	Indiana & Michigan Electric Company
11/80	New Mexico Public Service Commission	1627	Kit Carson Electric Cooperative (Direct Testimony)
6/81	Arizona Corporation Commission	9962-E-1032	Citizens Utilities Company
9/81	Federal Energy Regulatory Commission	ER81-179	Arizona Public Service Commission (Direct Testimony)
3/84	Texas Public Utility Commission	5640	Texas Utilities Electric Company
4/2/1984	Public Utility Commission of Texas	5560	Gulf States Utility Company (Direct Testimony)
7/3/84	Texas Public Utility Commission	5640	Texas Utilities Electric Company (Direct Testimony)
11/15/1984	Texas Public Utility Commission	5709	Texas Utilities Electric Company (Direct Testimony)
1/85	Federal Energy Regulatory Commission	ER84-568-000	Gulf States Utilities Company (Direct Testimony)
11/20/1985	Federal Energy Regulatory Commission	ER85-538-001	Gulf States Utilities Company (Direct Testimony)
1/7/86	Louisiana Public Service Commission	U-16510	Central Louisiana Electric Company (Direct Testimony)
3/10/86	Texas Public Utility Commission	6677	Texas Utilities Electric Company
3/14/86	Federal Energy Regulatory Commission	ER85-538-001	Gulf States Utilities Company (Rebuttal and Surrebuttal Testimony)
6/20/88	Texas Public Utility Commission	8032	Lower Colorado River Authority (Direct Testimony)
7/15/88	Texas Public Utility Commission	8032	Lower Colorado River Authority (Supplemental Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
3/7/90	Texas Public Utility Commission	9165	El Paso Electric Company (Direct Testimony)
4/12/90	Texas Public Utility Commission	9300	Texas Utilities Electric Company (Direct Testimony - Revenue Requirements Phase)
5/1/1990	Texas Public Utility Commission	9300	Texas Utilities Electric Company (Direct Testimony - Phase II - Rate Design)
7/6/90	Texas Public Utility Commission	9300	Texas Utilities Electric Company (Supplemental Testimony - Revenue Requirements)
7/10/90	Texas Public Utility Commission	9427	Lower Colorado River Authority (Direct Testimony - Rate Design)
7/30/90	Texas Public Utility Commission	9427	Lower Colorado River Authority (Rebuttal Testimony - Rate Design)
8/23/90	Texas Public Utility Commission	9561	Central Power & Light Company (Direct Testimony - Rate Design)
1/11/91	Texas Public Utility Commission	9427	Lower Colorado River Authority (Rebuttal Testimony)
9/24/91	Texas Public Utility Commission	10404	Guadalupe Valley Electric Cooperative (Direct Testimony)
12/91	Rate Area 2&3 Nebraska Municipalities	N/A	Peoples Natural Gas Company
7/31/92	Texas Public Utility Commission	11266	Guadalupe-Blanco River Authority (Direct Testimony)
8/7/92	State Corporation Commission of Kansas	180,416-U	Peoples Natural Gas Company (Direct Testimony)
9/8/92	Texas Public Utility Commission	11266	Guadalupe-Blanco River Authority (Direct Testimony)
9/92	Texas Public Utility Commission	10894	Gulf States Utilities Company (Direct Testimony)
5/93	Texas Public Utility Commission	11735	Texas Utilities Electric Company (Rebuttal Testimony)
6/93	Texas Public Utility Commission	11892	Generic Proceeding Regarding Purchased Power (Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
09/08/93	State Corporation Commission of Kansas	186,363-U	KN Energy (Direct Testimony)
09/94	State Corporation Commission of Kansas	190,362-U	Kansas Natural Pipeline and Kansas Natural Partnership (Direct Testimony)
10/17/94	Texas Public Utility Commission	12820	Central Power and Light Company (Direct Testimony)
11/15/1994	City of Houston	NA	Houston Lighting and Power Company (Direct Testimony)
11/15/1994	Texas Public Utility Commission	12065	Houston Lighting and Power Company (Direct Testimony - Revenue Requirements Phase)
12/12/1994	Texas Public Utility Commission	12820	Central Power & Light Company (Supplemental Testimony)
1/10/1995	Texas Public Utility Commission	12065	Houston Lighting & Power Company (Direct Testimony - Rate Design Phase)
5/23/95	Federal Energy Regulatory Commission	TX94-4-000	Texas Utilities Electric Company and Southwestern Electric Service (Affidavit)
8/7/95	Texas Public Utility Commission	13369	West Texas Utilities Company (Rebuttal Testimony - Rate Design Phase)
10/31/95	Texas Public Utility Commission	14435	Southwestern Electric Power Company (Direct Testimony)
11/95	Rate Area 3 Nebraska Municipalities	N/A	Peoples Natural Gas Company (Municipal Report)
02/07/96	Federal Energy Regulatory Commission	TX96-2-000	City of College Station, Texas (Affidavit)
5/15/96	Texas Public Utility Commission	14965	Central Power & Light Company (Direct Testimony)
5/29/1996	Texas Public Utility Commission	14965	Central Power & Light Company (Rebuttal Testimony)
07/19/96	Texas Public Utility Commission	15766	City of Bryan, Texas (Direct Testimony)
8/29/1996	Texas Public Utility Commission	15296	City of Bryan, Texas (Direct Testimony)
08/07/96	State of Illinois Commerce Commission	96-0245 & 96-0248	Commonwealth Edison Company (Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
09/06/96	Texas Public Utility Commission	15643	Central Power & Light Company and West Texas Utilities Company (Direct Testimony)
9/17/1996	Texas Public Utility Commission	15296	City of Bryan, Texas (Rebuttal Testimony)
09/18/96	Texas Public Utility Commission	15638	Texas Utilities Electric Company (Direct Testimony)
10/22/96	Texas Natural Resource Conservation Commission	96-0652-UCR	Longbranch Associates, L.P. (Direct Testimony)
08/05/97	Arkansas Public Service Commission	97-019-U	Arkansas Western Gas Company (Direct Testimony)
08/06/97	Texas Public Utility Commission	16705	Entergy Texas (Direct Testimony)
08/25/97	Texas Public Utility Commission	16705	Entergy Texas (Rebuttal Testimony - Rate Design Phase)
09/23/97	Arkansas Public Service Commission	97-019-U	Arkansas Western Gas Company (Surrebuttal Testimony)
09/30/97	Texas Public Utility Commission	16705	Entergy Texas (Direct Testimony - Competitive Issues Phase)
12/97	United States Tax Court	7685-96 and 4979-97	Lykes Energy, Inc. (Report)
12/97	Condemnation Court Appointed by the Supreme Court of Nebraska	13880	Peoples Natural Gas
12/1/1997	Condemnation Court Appointed by the Supreme Court of Nebraska	NA	Peoples Natural Gas Company (Report to City of Wahoo, Nebraska)
8/1/1998	Condemnation Court Appointed by the Supreme Court of Nebraska	101	Peoples Natural Gas (Report to City of Scribner, Nebraska)
10/98	Federal Energy Regulatory Commission	EL-99-6-000	Entergy Gulf States, Inc. (Affidavit)
10/19/1998	Federal Energy Regulatory Commission	TX98-	Gulf States Utilities Company (Affidavit)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
12/31/1998	Texas Public Utility Commission	20292	Sharyland Utilities, L.P. (Direct Testimony)
3/11/1999	Texas Public Utility Commission	20292	Sharyland Utilities, L.P. (Supplemental Testimony)
4/30/1999	Texas Public Utility Commission	20292	Sharyland Utilities, L.P. (Rebuttal Testimony)
7/16/1999	Texas Public Utility Commission	19265	Central and South West Corporation and American Electric Power Company, Inc. (Direct Testimony)
11/1/1999	Texas Public Utility Commission	21591	Sharyland Utilities, L.P. (Direct Testimony)
11/24/1999	Texas Public Utility Commission	21528	Central Power and Light Company (Direct Testimony)
1/27/2000	Texas Railroad Commission	8976	Texas Utilities Company Lone Star Pipeline (Direct Testimony)
3/31/2000	Texas Public Utility Commission	22348	Sharyland Utilities, L.P. (Direct Testimony)
08/2000	Texas Public Utility Commission	20624	Reliant Energy HL&P (Direct Testimony)
10/16/2000	Texas Public Utility Commission	22344	Generic Issues Associated with Unbundled Cost of Service Rate (Direct Testimony)
10/23/2000	Texas Public Utility Commission	21956	Reliant Energy, Inc. (Direct Testimony)
11/14/2000	Texas Public Utility Commission	22350	TXU Electric Company (Direct Testimony)
11/17/2000	Texas Public Utility Commission	22352	Central Power and Light Company (Direct Testimony)
12/12/2000	Texas Public Utility Commission	22355	Reliant Energy HL&P (Direct - Final Phase) (Direct Testimony)
12/21/2000	Texas Public Utility Commission	22355	Reliant Energy HL&P (Direct Testimony - Rate Case Expense Phase)
12/29/2000	Texas Public Utility Commission	22355	Reliant Energy HL&P (Supplemental & Rebuttal Testimonies)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
7/5/2001	Texas Public Utility Commission	23950	Reliant Energy (Direct Testimony)
9/6/2001	Texas Public Utility Commission	24239	Mutual Energy CPL, LP (Direct Testimony)
4/22/2002	State Corporation Commission of Kansas	02-WSRE-301-RTS	Western Resources, Inc. and Kansas Gas and Electric Company (Direct Testimony)
6/19/2002	Federal Energy Regulatory Commission	TX96-2-000	City of College Station, Texas (Direct Testimony)
8/5/2002	Corporation Commission of the State of Oklahoma	200100455	Oklahoma Corporation Commission (Direct Testimony)
12/31/2002	Texas Public Utility Commission	26195	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
4/24/2003	Texas Public Utility Commission	25089	Market Protocols for the Portions of Texas Within the Southeastern Reliability Council (Rebuttal Testimony)
6/9/2003	Texas Public Utility Commission	25089	Market Protocols for the Portions of Texas Within the Southeastern Reliability Council (Supplemental Direct Testimony)
7/11/2003	State Corporation Commission of Kansas	03-KGSG-602-RTS	Kansas Gas Service, a Division of ONEOK, Inc. (Direct Testimony)
8/11/2003	Texas Public Utility Commission	25089	Market Protocols for the Portions of Texas Within the Southeastern Reliability Council (Second Supplemental Direct Testimony)
8/18/2003	State Corporation Commission of Kansas	03-KGSG-602-RTS	Kansas Gas Service, a Division of ONEOK, Inc. (Supplemental Testimony)
10/29/2003	Federal Energy Regulatory Commission	ER04-35-000	Entergy Services, Inc. (Affidavit)
11/5/2003	Texas Public Utility Commission	26195	CenterPoint Energy Houston Electric, LLC (Supplemental Direct Testimony)
2/9/2004	Texas Public Utility Commission	28840	AEP Texas Central Company (Direct Testimony)
6/1/2004	Texas Public Utility Commission	29526	CenterPoint Energy Houston Electric, LLC, Reliant Energy Retail Services, LLC, and Texas Genco, LP (Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
8/30/2004	Texas Public Utility Commission	28813	Cap Rock Energy Corporation (Direct Testimony)
1/7/2005	Texas Public Utility Commission	30485	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
3/16/2005	Texas Public Utility Commission	30706	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
6/9/2005	Texas Public Utility Commission	29801	Southwestern Public Service Company (Direct Testimony)
9/2/2005	Texas Public Utility Commission	31056	AEP Texas Central Company and CPL Retail Energy, LP (Direct Testimony)
9/9/2005	State Corporation Commission of Kansas	05-WSEE-981-RTS	Westar Energy, Inc. and Kansas Gas and Electric Company (Direct Testimony)
9/29/2005	Georgia Public Service Commission	20298-U	Atmos Energy Corporation (Direct Testimony)
4/24/2006	Texas Public Utility Commission	32475	AEP Texas Central Company (Cross Answering Testimony)
8/11/2006	Texas Public Utility Commission	32093	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
8/23/2006	Texas Public Utility Commission	32795	Reallocation of Stranded Costs Pursuant to PURA §139.253(f) (Direct Testimony)
8/24/2006	Texas Public Utility Commission	32758	AEP Texas Central Company (Direct Testimony)
12/22/2006	Texas Public Utility Commission	32766	Southwestern Public Service Company (Direct Testimony)
3/13/2007	Texas Public Utility Commission	33309	AEP Texas Central Company (Direct Testimony)
3/19/2007	State Corporation Commission of Kansas	07-AQLG-431-RTS	Aquila Networks-KGO (Direct Testimony)
4/27/2007	Texas Public Utility Commission	33687	Entergy Gulf States, Inc. (Direct Testimony)
7/11/2007	Texas Public Utility Commission	33823	CenterPoint Energy Houston Electric, LLC (Direct Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
7/13/2007	Texas Public Utility Commission	33687	East Texas Cooperatives (Supplemental Testimony)
1/11/2008	Texas Public Utility Commission	35219	Guadalupe Valley Electric Cooperative, Inc (Direct Testimony)
1/29/2008	Texas Public Utility Commission	35287	Sharyland Utilities, L.P. (Direct Testimony)
7/1/2008	Georgia Public Service Commission	27163	Atmos Energy Corporation (Direct Testimony)
9/16/2008	Texas Public Utility Commission	34442	JD Wind (Direct Testimony)
9/29/2008	State Corporation Commission of the State of Kansas	08-WSEE-1041-RTS	Westar Energy, Inc. and Kansas Gas and Electric Company (Direct Testimony)
10/13/2008	Texas Public Utility Commission	35763	Southwestern Public Services Company (Direct Testimony)
11/26/2008	Texas Public Utility Commission	35717	Oncor Electric Delivery Company (Direct Testimony)
6/26/2009	State Corporation Commission of the State of Kansas	09-WSEE-641-GIE	Westar Energy, Inc. and Kansas Gas and Electric Company (Direct Testimony)
6/29/2009	Texas Public Utility Commission	36918	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
9/30/2009	State Corporation Commission of the State of Kansas	09-WSEE-925-RTS	Westar Energy, Inc. and Kansas Gas and Electric Company (Direct Testimony)
7/10/2010	Pennsylvania Public Utility Commission	R-2010-2161575, et. al.	PECO Energy Company (Direct Testimony)
9/3/2010	Texas Public Utility Commission	38324	Oncor Electric Delivery Company, LLC (Direct Testimony)
9/10/2010	Texas Public Utility Commission	38339	CenterPoint Energy Houston Electric, LLC (Direct Testimony)
9/24/2010	Texas Public Utility Commission	38339	CenterPoint Energy Houston Electric, LLC (Cross-Rebuttal Testimony)
9/27/2010	Texas Public Utility Commission	38324	Oncor Electric Delivery Company, LLC (Cross-Rebuttal Testimony)

LIST OF TESTIMONY, AFFIDAVITS, AND EXPERT REPORTS PRESENTED IN REGULATORY AND COURT PROCEEDINGS BY JAMES W. DANIEL

DATE	REGULATORY AGENCY/COURT	DOCKET	UTILITY INVOLVED
11/5/2010	Texas Public Utility Commission	38577	Modification of CREZ Transmission Plan (Direct Testimony)
2/4/2011	Texas Railroad Commission	GUD 10038	CenterPoint Energy Texas Gas (Direct Testimony)
3/1/2011	Texas Public Utility Commission	39070	Sharyland Utilities, L.P. (Direct Testimony)
10/19/2011	Texas Public Utility Commission	39856	Guadelupe Valley Electric Cooperative (Direct Testimony)
5/1/2012	Texas Public Utility Commission	40364	Sharyland Utitilies, L.P. (Direct Testimony)
5/15/2012	Delaware Public Service Commisison	11-528	Delmarva Power & Light Company (Direct Testimony)

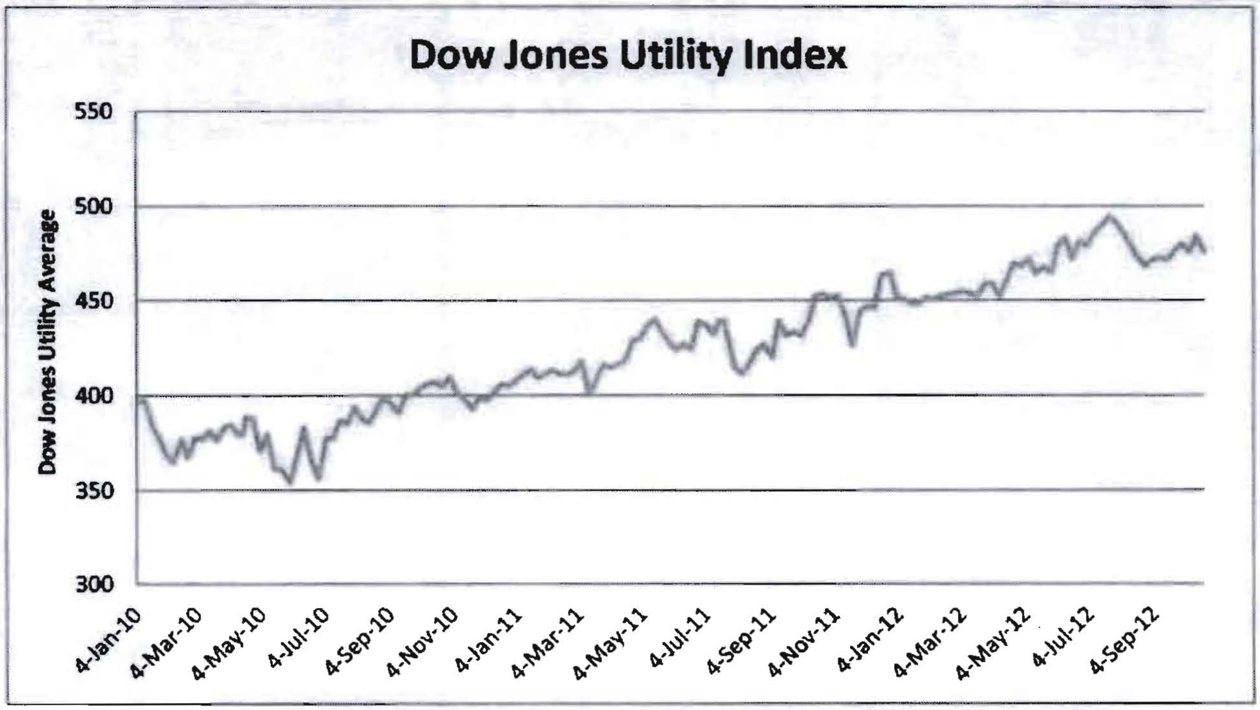
Florida Public Service Commission
Docket No. 120015-E1

Increase in FPL Profits
If Proposed Incentive Mechanism
Had Been In Effect Since 2001

				Customer's Share of Claimed Benefits				FPL's Share of Claimed Benefits			
				Current Incentive Mechanism		Proposed Incentive Mechanism		Current Incentive Mechanism		Proposed Incentive Mechanism	
Line No.	Year	Proposed Incentive Mechanism: Total Claimed Benefits*	Proposed Claimed Benefits less Threshold of $46,000,000	Amount	% of Total	Amount	% of Total	Amount	% of Total	Amount	% of Total
(a)	(b)	(c)	(d)	(c)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	2003	$47,939,149	$1,939,149	$47,939,149	100.00%	$46,581,745	97.17%	$0	0.00%	$1,357,404	2.83%
2	2005	$49,612,011	$2,481,777	$48,481,777	97.72%	$46,744,533	94.22%	$1,130,234	2.28%	$1,737,244	3.50%
3	2009	$50,452,089	$4,452,089	$50,452,089	100.00%	$47,335,627	93.82%	$0	0.00%	$3,116,462	6.18%
4	2010	$82,738,350	$36,738,350	$82,738,350	100.00%	$57,795,340	69.85%	$0	0.00%	$24,943,010	30.15%
5	2011	$69,563,423	$23,563,423	$69,563,423	100.00%	$53,069,027	76.29%	$0	0.00%	$16,494,396	23.71%
6	Total	$300,305,022	$69,174,788	$299,174,788	99.62%	$251,526,271	83.76%	$1,130,234	0.38%	$47,648,517	15.87%

* From FPL's Exhibit SF-2, page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 685
PARTY OPC ; James W. Daniel (JWD-2)
DESCRIPTION Incentive Mechanism Comparison
DATE



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 686
PARTY OPC ; Kevin O'Donnell (KWO-11)
DESCRIPTION Dow Jones Utility Index
DATE

Docket No. 120015-EI
Federal Reserve Article
Exhibit No.__(KWO-12)
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abc NEWS

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Federal Reserve Expects to Keep Interest Rates Low Through Mid-2015

Fed OKs New Stimulus: Dow Up 200 Points

AUTO START: ON OFF

By SUSANNA KIM (@skimm)
Sept. 13, 2012

The Federal Reserve announced its highly-anticipated quantitative easing, or its so-called QE3, purchasing additional agency mortgage-backed securities at a pace of $40 billion per month in another effort to stimulate the struggling economy.

The Fed wants to lower near-zero interest rates, citing an "elevated" unemployment rate and "strains in global financial markets."

The Fed said it was "concerned that, without further policy accommodation, economic growth might not be strong enough to generate sustained improvement in labor market conditions."

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 687
PARTY OPC ; Kevin O'Donnell (KWO-12)
DESCRIPTION Federal Reserve Article
DATE

Docket No. 120015-EI
Federal Reserve Article
Exhibit No.__(KWO-12)
Page 2 of 4

Scott Brown, chief economist with Raymond James, said the Fed's open-ended securities purchases will depend critically on the jobs market. On Friday, the Labor Department announced the U.S. added a meager 96,000 jobs in August though the unemployment rate fell to 8.1 percent on account of the unemployed leaving the labor force.

The Federal Reserve said it expects the unemployment rate to remain around 8 to 8.2 percent through 2012, 7.6 to 7.9 percent in 2013, 6.7 to 7.3 percent in 2014 and 6 to 6.8 percent in 2015.

"The idea is that you want to encourage more economic activity," Brown said. "Having low interest rates, consumers are more likely to be able to borrow, take risks and to make car and home purchases."

The Fed's policies will help keep mortgage rates down, though monetary policy affects the economy with a lag.

"People shouldn't expect this to light a fire under the economy right away," he said.

The Federal Reserve released its post-meeting policy statement at 12:30 P.M. eastern time after the Federal Open Market Committee (FOMC) completed its two-day meeting.

The committee also said it will extend the average maturity of its holdings of securities it announced in June through the end of the year.

In its statement, the Federal Reserve said it would keep the federal funds rate at zero to 1/4 percent at least through mid-2015.

The U.S. financial markets spiked after the statement was released. The Dow Jones Industrial average rose 0.81 percent to 13,441 while the S&P 500 was up 0.78 percent to 1,447 minutes after the announcement.

Federal Reserve Chairman Ben Bernanke speaks.. View Full Size

Federal Reserve Extends Low Interest Rates, Will it Help Jobs? Watch Video

This is the fourth of five economic projections the committee makes a year. The next two-day meeting and projections will take place Dec. 11 and 12.

In previous announcements, the Federal Reserve had said it expected to keep short-term interest rates near zero until 2014.

Brown said Thursday's announcement could be perceived as countering further economic and political headwinds next year.

The so-called fiscal cliff is expected in 2013, which includes the expiration of Bush-era tax cuts and the two percentage point reduction in the payroll tax, plus the start of automatic spending cuts.

"We may see most of that kicked down the road if they extend a portion of Bush tax cuts," Brown said. "But we don't know that. There's a lot of uncertainty which is also a negative."

Real Money: Turn Your Old Gadgets Into Cash Watch Video

Jobless Claims Drop, Apple Earnings, Windows 8 Plan Watch Video

Ahead of the Federal Reserve's announcement, government-sponsored Freddie Mac announced fixed mortgage rates held steady as the financial markets speculated there would be further stimulus.

The 30-year fixed-rate mortgage averaged 3.55 percent for the week ending Sept. 13, the same as the previous week. Last year at the same time, the 30-year rate averaged 4.09 percent.

The 15-year rate averaged 2.85 percent this week, down from 2.86 percent last week and 3.3 percent a year ago.

"If the outlook for the labor market does not improve substantially, the Committee will continue its purchases of agency mortgage-backed securities, undertake additional asset purchases, and employ its other policy tools as appropriate until such improvement is achieved in a context of price stability," the central bank said in its statement.

Francisco Torralba, economist in Morningstar's Investment Management division, said he was "skeptical" that the Fed's actions will have a strong effect on the economy.

He said three issues will have a stronger impact on hiring and business spending: the fiscal cliff, the banking crisis in Europe, and the global economy at large, including how China will address its slowdown.

He called the Fed's communication strategy regarding near-zero interest rates a "double-edged sword."

He said a policy of "unconditional, semi-permanent zero interest rates can be self-defeating" if it negatively shapes the economic expectations of the public.

"Is the Fed announcing zero short-term rates 'forever' because they want to stimulate the economy, or because they expect a weak economy until 2014?" he asked. "If the Fed was expecting policy to improve things within the next couple of years, why would they commit to low rates? Does that mean that they don't expect low interest rates to work?"

The economic "hawks" within the FOMC have feared that large purchases of Treasuries and a commitment to low rates, would lead to higher inflation in the future, or to an unmooring of inflation expectations, he said.

"I do not agree with this position, but their opinion has not changed," he said.

As Torralba expected, the Federal reserve did not announce a new program of Treasury purchases, and instead expanded its mortgage-

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Federal Reserve Article
Exhibit No. __(KWO-12)
Page 4 of 4

backed securities purchase program.

"Employment and growth have deteriorated, but not to alarming levels, and inflation is not dangerously low—at least not yet," Torralba said. "Besides, in spite of Bernanke's defense of Treasury purchases at Jackson Hole, the level of confidence on this particular policy action within the FOMC has decreased."

1 2 NEXT PAGE

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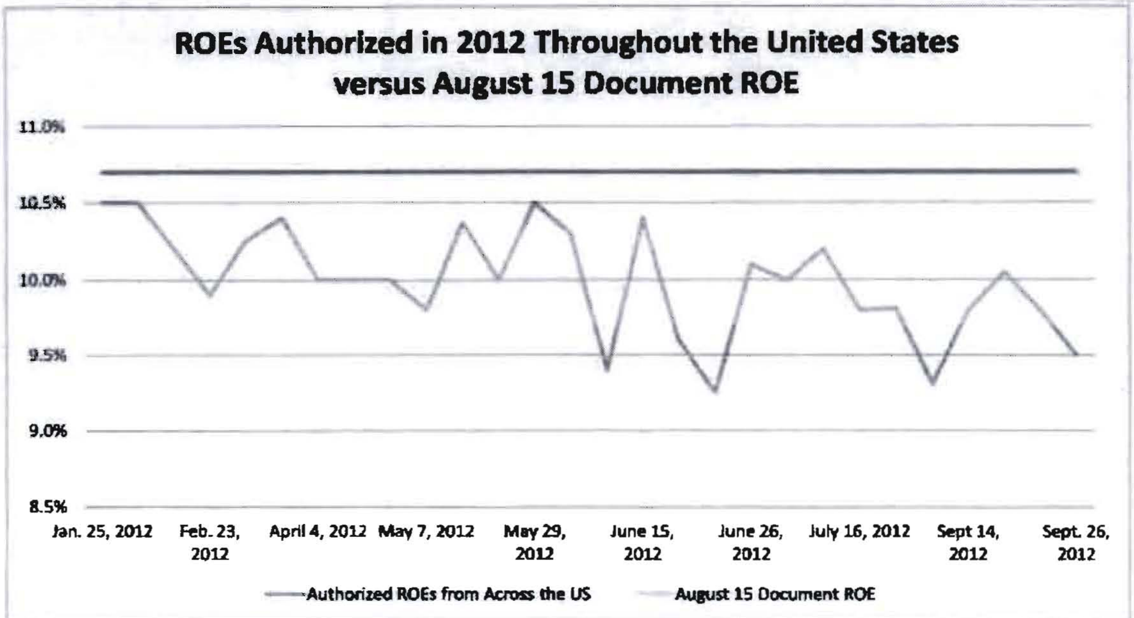
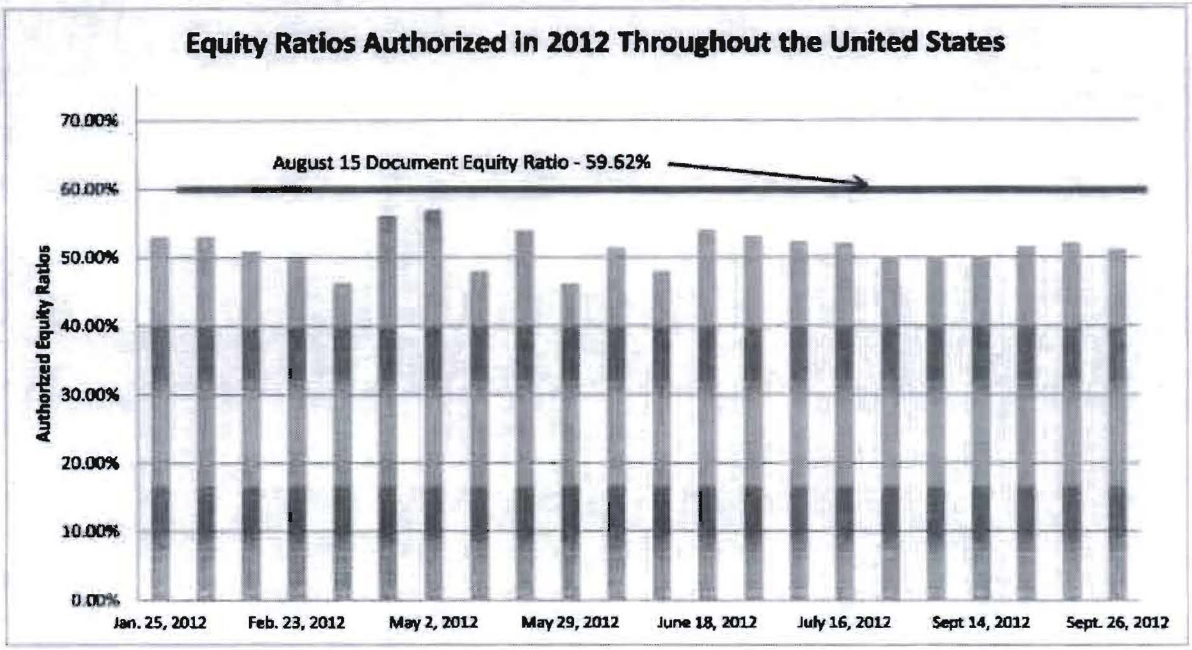


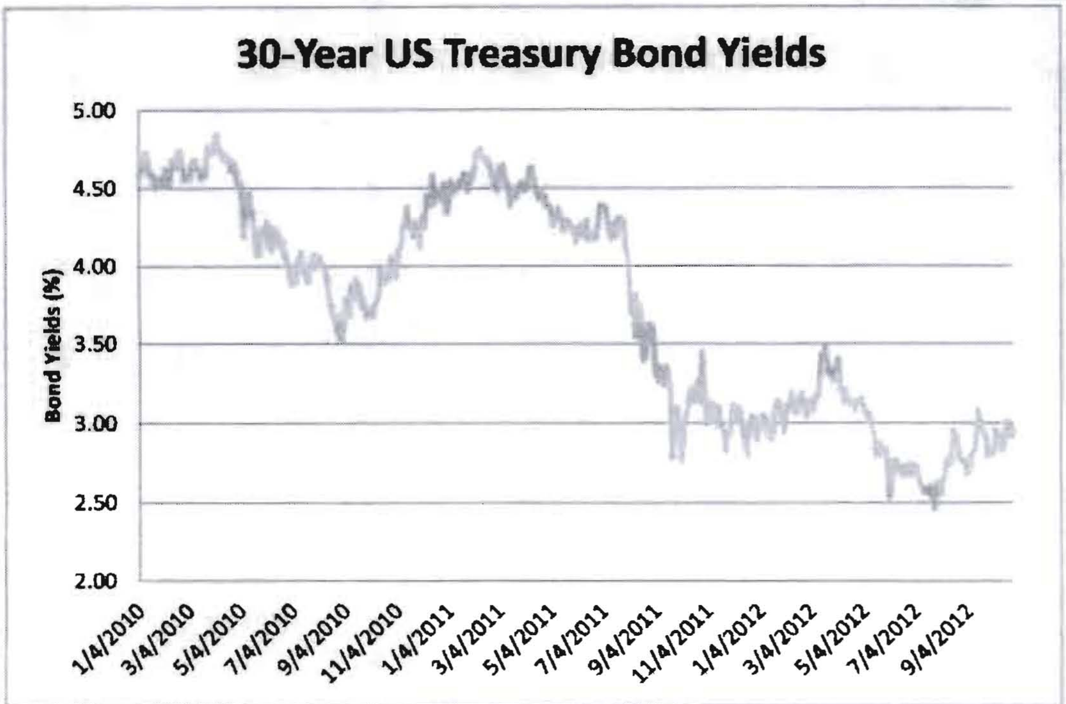
Date of Final Order	Utility	Jurisdiction	Docket No.	Authorized ROE	Specific Cite
Jan. 25, 2012	Duke Energy Carolinas	SC	2011-271-E	10.50%	p. 8 of settlement
Jan. 27, 2012	Duke Energy Carolinas	NC	E-7, Sub 989	10.50%	p. 9 of final order
Feb. 15, 2012	Indiana-Michigan Power	MI	16801	10.20%	p. 7 of final order
Feb. 23, 2012	Idaho Power	OR	UE233	9.90%	p. 4 and 5 of stipulation
Feb. 27, 2012	Gulf Power	FL	110138	10.25%	p. 52 of final order
Feb. 29, 2012	Northern States Power	ND	PU-10-657	10.40%	p. 4 of final order
April 4, 2012	Hawaii Electric Light Co.	HI	2009-0164	10.00%	p. 85 of final order
April 26, 2012	Public Service of Colorado	CO	11AL-947E	10.00%	p. 16 of final order
May 2, 2012	Maui Electric Company	HI	2009-0163	10.00%	p. 86 of final order
May 7, 2012	Puget Sound Energy	WA	UE-0111048	9.80%	p. 33 of final order
May 14, 2012	Northern States Power	MN	10-971	10.37%	p. 18 of brief
May 15, 2012	Arizona Public Service	AZ	E-01345A-11-0224	10.00%	p. 33 of final order
May 29, 2012	Commonwealth Edison	IL	11-0721	10.50%	p. 138 of final order
June 7, 2012	Consumers Energy	MI	16794	10.30%	p. 65 of final order
June 14, 2012	Orange & Rockland Utilities	NY	11-E-0408	9.40%	p. 11 of final order
June 15, 2012	Wisconsin Power and Light	WI	6680-UR-118	10.40%	p. 2 of final order
June 18, 2012	Cheyenne Light Fuel Power	WY	20003-114-ER-11	9.60%	press release
June 19, 2012	Northern States Power	SD	EL11-019	9.25%	p. 2 of final order
June 26, 2012	Wisconsin Power and Light	MI	16830	10.10%	p. 18 of final order
June 29, 2012	Hawaii Electric	HI	2010-0080	10.00%	p. 127 of final order
July 9, 2012	Oklahoma Gas & Electric	OK	PUD201100087	10.20%	p. 2 of final order
July 16, 2012	Rocky Mountain Power	WY	20000-405-ER-11	9.80%	p. 6 of stipulation
July 20, 2012	Delmarva Power & Light	MD	9285	9.81%	p. 79 of final order
July 20, 2012	Potomac Edison	MD	9286	9.31%	p. 109 of final order
Sept 14, 2012	Entergy Texas	TX	39896	9.80%	p. 6 of final order
Sept. 19, 2012	Ameren Illinois	IL	12-0001	10.05%	p. 106 of final order
Sept. 19, 2012	Rocky Mountain Power	UT	11-035-200	9.80%	p. 2 of final order
Sept. 26, 2012	Potomac Edison	DC	1087	9.50%	p. 61 of final order
			Average	9.99%	
			High	10.50%	
			Low	9.25%	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 688
PARTY OPC ; Kevin O'Donnell (KWO-13)
DESCRIPTION ROE Comparison
DATE



Date of Final Order	Utility	Jurisdiction	Docket No.	Authorized Equity Ratio	Specific Cite
Jan. 25, 2012	Duke Energy Carolinas	SC	2011-271-E	53.00%	p. 15 of settlement
Jan. 27, 2012	Duke Energy Carolinas	NC	E-7, Sub 989	53.00%	p. 9 of final order
Feb. 15, 2012	Indiana-Michigan Power	MI	16801	50.92%	p. 7 of final order
Feb. 23, 2012	Idaho Power	OR	UE233	49.90%	p. 2 of stipulation
Feb. 27, 2012	Gulf Power	FL	110138	46.26%	p. 139 of final order
April 26, 2012	Public Service of Colorado	CO	11AL-947E	56.00%	p. 16 of final order
May 2, 2012	Maui Electric Company	HI	2009-0163	56.86%	p. 86 of final order
May 7, 2012	Puget Sound Energy	WA	UE-0111048	48.00%	p. 21 of final order
May 15, 2012	Arizona Public Service	AZ	E-01345A-11-0224	53.94%	p. 11 of final order
May 29, 2012	Commonwealth Edison	IL	11-0721	46.17%	p. 117 of final order
June 7, 2012	Consumers Energy	MI	16794	51.38%	p. 42 of final order
June 14, 2012	Orange & Rockland Utilities	NY	11-E-0408	48.00%	p. 12 and 13 of final order
June 18, 2012	Cheyenne Light Fuel Power	WY	20003-114-ER-11	54.00%	p. 1 of press release
June 19, 2012	Northern States Power	SD	EL11-019	53.04%	p. 2 of final order
June 26, 2012	Wisconsin Power and Light	MI	16830	52.28%	p. 18 of final order
July 16, 2012	Rocky Mountain Power	WY	20000-405-ER-11	52.10%	p. 6 of stipulation
July 20, 2012	Delmarva Power & Light	MD	9285	50.06%	p. 86 of final order
July 20, 2012	Potomac Edison	MD	9286	50.13%	p. 109 of final order
Sept 14, 2012	Entergy Texas	TX	39896	49.92%	p. 18 of final order
Sept. 19, 2012	Ameren Illinois	IL	12-0001	51.49%	p. 128 of final order
Sept. 19, 2012	Rocky Mountain Power	UT	11-035-200	52.10%	p. 10 of final order
Sept. 26, 2012	Potomac Edison	DC	1087	51.21%	p. 63 of final order
			Average	51.35%	
			High	56.86%	
			Low	46.17%	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 689
PARTY OPC ; Kevin O'Donnell (KWO-14)
DESCRIPTION Equity Ratio Comparison
DATE



FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120015-EI EXHIBIT 690

PARTY OPC ; Kevin O'Donnell (KWO-15)

DESCRIPTION 30-Year US Treasury Yields

DATE

Amounts in Thousands

Line No.	Description	Per FPL Original Filing (A)	Per FPL With Revised ROR (B)	Source/Reference
1	Jurisdictional Adjusted Rate Base	$ 21,036,823	$ 21,036,823	MFR Sch. A-1
2	Required Rate of Return	7.00%	6.55%	See Page 2 of 2
3	Jurisdictional Income Required	1,472,878	1,378,470	Line 1 x Line 2
4	Jurisdictional Adj. Net Operating Income	1,156,359	1,156,359	MFR Sch. A-1
5	Income Deficiency (Sufficiency)	316,519	222,111	Line 3 - Line 4
6	Earned Rate of Return	5.50%	5.50%	Line 5 / Line 1
7	Net Operating Income Multiplier	1.63188	1.63188	
8	Revenue Deficiency (Sufficiency)	$ 516,520	$ 362,456	Line 5 x line 7

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI **EXHIBIT** 691
PARTY OPC; Donna Ramas (DR-7); Per FPL Original
DESCRIPTION Revenue Requirement, Modified for Revised
DATE ROR

	FPL Original Filing Request	Jurisdictional Capital Structure Per Company	Capital Ratio Per FPL	Per FPL Cost Rate	Per FPL Weighted Cost Rate
		(A)	(B)	(C)	(D)
1	Long Term Debt	6,199,550	29.47%	5.26%	1.55%
2	Short Term Debt	360,542	1.71%	2.11%	0.04%
3	Preferred Stock	-	0.00%	0.00%	0.00%
4	Common Equity	9,684,101	46.03%	11.50%	5.29%
5	Customer Deposits	426,531	2.03%	5.99%	0.12%
6	Deferred Taxes	4,365,176	20.75%	0.00%	0.00%
7	Investment Tax Credits	923	0.00%	9.06%	0.00%
8	Total	21,036,823	100.00%		7.00%

	Modified Amounts	Jurisdictional Capital Structure Per Company	Capital Ratio Per FPL	Per FPL Cost Rate	Per FPL Weighted Cost Rate
		(A)	(B)	(C)	(D)
9	Long Term Debt	6,199,550	29.47%	5.26%	1.55%
10	Short Term Debt	360,542	1.71%	2.11%	0.04%
11	Preferred Stock	-	0.00%	0.00%	0.00%
12	Common Equity (1)	9,684,101	46.03%	10.70%	4.93%
13	Customer Deposits (2)	426,531	2.03%	1.99%	0.04%
14	Deferred Taxes	4,365,176	20.75%	0.00%	0.00%
15	Investment Tax Credits	923	0.00%	8.58%	0.00%
16	Total	21,036,823	100.00%		6.55%

Source:
FPL MFR. Sch. D-1a, other than as noted below.

(1) Common Equity Rate modified to Settlement Agreement Rate of 10.70%
(2) Interest applied to customer deposits was reduced in Order No. PSC-12-0358-FOF-PU

Amounts in Thousands

Line No.	Description	Per FPL Post-Hrg Brief Amts (A)	Per FPL With Revised ROR (B)	Source/Reference
1	Jurisdictional Adjusted Rate Base	$ 21,220,083	$ 21,220,083	(1)
2	Required Rate of Return	6.9009%	6.5326%	See Page 2 of 2
3	Jurisdictional Income Required	1,464,382	1,386,223	Line 1 x Line 2
4	Jurisdictional Adj. Net Operating Income	1,142,605	1,142,605	(1)
5	Income Deficiency (Sufficiency)	321,777	243,618	Line 3 - Line 4
6	Earned Rate of Return	5.38%	5.38%	Line 5 / Line 1
7	Net Operating Income Multiplier	1.63188	1.63188	
8	Revenue Deficiency (Sufficiency)	$ 525,100	$ 397,554	Line 5 x line 7

(1) Amounts from FPL's Post-Hearing Brief, Appendix I

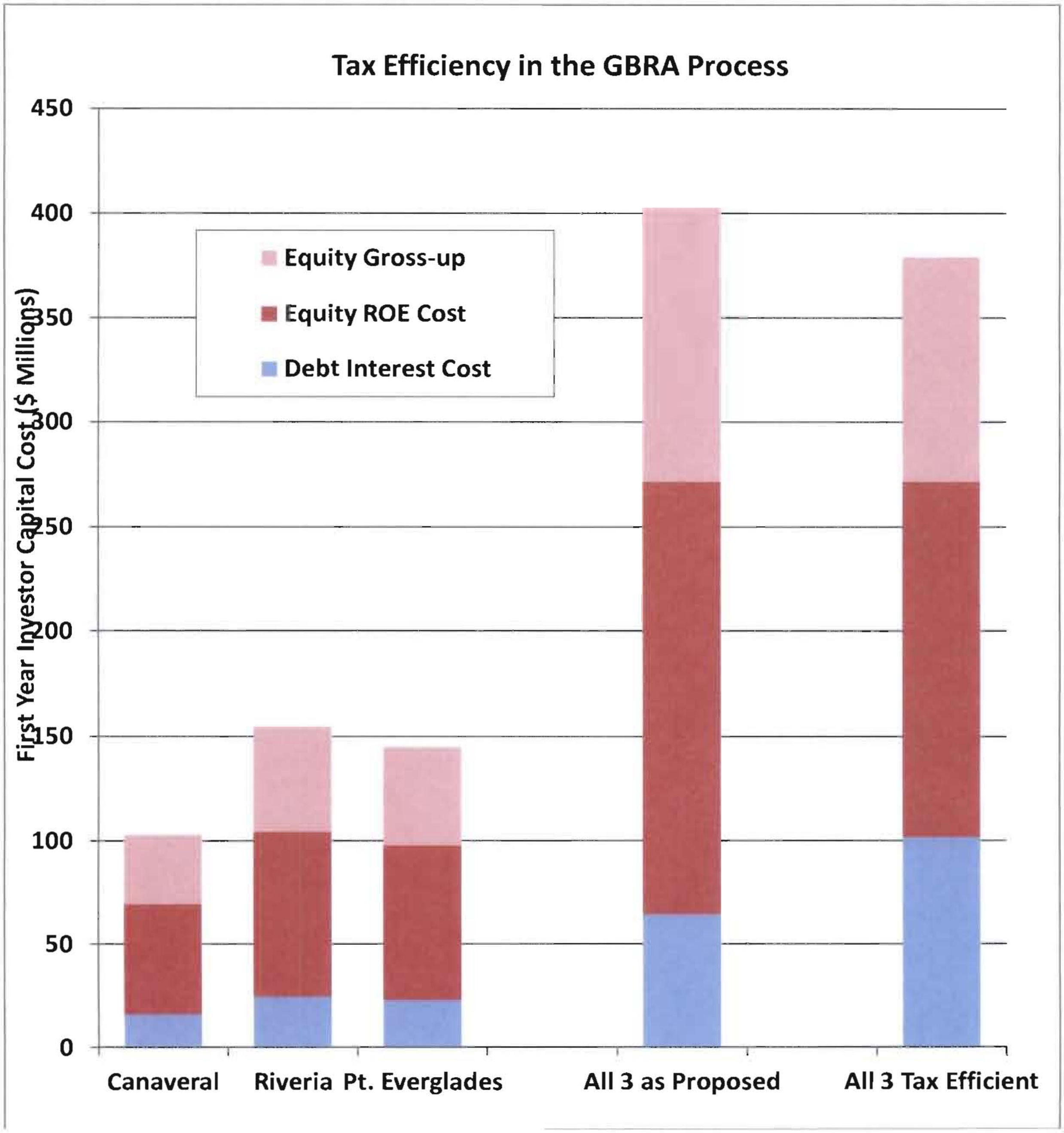
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 692
PARTY OPC; Donna Ramas (DR-8)
DESCRIPTION Per FPL Post-Hrg Revenue Requirement
DATE Modified for revised ROR

	FPL Amounts per Post-Hrg. Brief	Jurisdictional Capital Structure Per Company	Capital Ratio Per FPL	Per FPL Cost Rate	Per FPL Weighted Cost Rate
		(A)	(B)	(C)	(D)
1	Long Term Debt	6,253,557	29.47%	5.192%	1.53%
2	Short Term Debt	363,683	1.71%	2.107%	0.04%
3	Preferred Stock	-	0.00%	0.000%	0.00%
4	Common Equity	9,768,463	46.03%	11.500%	5.29%
5	Customer Deposits	430,247	2.03%	1.992%	0.04%
6	Deferred Taxes	4,403,203	20.75%	0.000%	0.00%
7	Investment Tax Credits	931	0.00%	9.038%	0.00%
8	Total	21,220,084	100.00%		6.9009%

	Modified Amounts	Jurisdictional Capital Structure Per Company	Capital Ratio Per FPL	Per FPL Cost Rate	Per FPL Weighted Cost Rate
		(A)	(B)	(C)	(D)
9	Long Term Debt	6,253,557	29.47%	5.192%	1.53%
10	Short Term Debt	363,683	1.71%	2.107%	0.04%
11	Preferred Stock	-	0.00%	0.000%	0.00%
12	Common Equity (1)	9,768,463	46.03%	10.700%	4.93%
13	Customer Deposits	430,247	2.03%	1.992%	0.04%
14	Deferred Taxes	4,403,203	20.75%	0.000%	0.00%
15	Investment Tax Credits	931	0.00%	8.550%	0.00%
16	Total	21,220,084	100.00%		6.5326%

Source:
FPL's Post-Hearing Brief, Appendix I

(1) Common Equity Rate modified to Settlement Agreement Rate of 10.70%



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 693
PARTY John W. Hendricks (JWH-7) Tax Efficiency
DESCRIPTION in GBRA Process
DATE

Docket No. 120015-EI
Incentive Mechanism Comparison
Exhibit SF-4, Page 1 of 1

Incentive Mechanism Comparison

Line No. (a)	Year (b)	Proposed Incentive Mechanism: Total Claimed Benefits (c)	Proposed Claimed Benefits less Threshold of $46,000,000 (d)	Customer's Share of Claimed Benefits — Current Incentive Mechanism: Amount (e)	Customer's Share — Current: % of Total (f)	Customer's Share — Proposed Incentive Mechanism: Amount (g)	Customer's Share — Proposed: % of Total (h)	FPL's Share of Claimed Benefits — Current Incentive Mechanism: Amount (i)	FPL's Share — Current: % of Total (j)	FPL's Share — Proposed Incentive Mechanism: Amount (k)	FPL's Share — Proposed: % of Total (l)
1	2001	$32,443,426	$0	$32,443,426	100.00%	$32,443,426	100.00%	$0	0.00%	$0	0.00%
2	2002	$30,725,727	$0	$30,725,727	100.00%	$30,725,727	100.00%	$0	0.00%	$0	0.00%
3	2003	$47,939,149	$1,939,149	$47,939,149	100.00%	$46,581,745	97.17%	$0	0.00%	$1,357,404	2.83%
4	2004	$36,130,609	$0	$35,445,641	98.10%	$36,130,609	100.00%	$684,968	1.90%	$0	0.00%
5	2005	$49,612,011	$3,612,011	$48,481,777	97.72%	$47,083,603	94.90%	$1,130,234	2.28%	$2,528,408	5.10%
6	2006	$36,464,381	$0	$36,403,936	99.83%	$36,464,381	100.00%	$60,445	0.17%	$0	0.00%
7	2007	$34,820,289	$0	$34,820,289	100.00%	$34,820,289	100.00%	$0	0.00%	$0	0.00%
8	2008	$31,889,308	$0	$31,889,308	100.00%	$31,889,308	100.00%	$0	0.00%	$0	0.00%
9	2009	$50,452,089	$4,452,089	$50,452,089	100.00%	$47,335,627	93.82%	$0	0.00%	$3,116,462	6.18%
10	2010	$82,738,350	$36,738,350	$82,738,350	100.00%	$57,795,340	69.85%	$0	0.00%	$24,943,010	30.15%
11	2011	$69,563,423	$23,563,423	$69,563,423	100.00%	$53,069,027	76.29%	$0	0.00%	$16,494,396	23.71%
	Total	**$502,778,762**	**$70,305,022**	**$500,903,115**	**99.63%**	**$454,339,082**	**90.37%**	**$1,875,647**	**0.37%**	**$48,439,680**	**9.63%**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 694
PARTY FPL; Sam A. Forrest (SF-4)
DESCRIPTION Incentive Mechanism Comparison
DATE

Florida Power & Light Company
Docket No. 120015-EI
Staff's Twenty-Second Set of Interrogatories
Interrogatory No. 608
Page 1 of 1

Q.
Please refer to page 6 of the testimony of Sam Forrest, lines 7 through 15, for interrogatories 608 through 611.

What are the risks to FPL retail customers of these transactions?

A.
First and foremost, as stated in previous Interrogatory responses, FPL does not intend to jeopardize the reliability of fuel supply or FPL's system with the execution of these asset optimization measures. FPL has participated in the power market for numerous years without impacting the reliability of FPL's system and will apply the same principles when evaluating potential asset optimization transactions to arrive at decisions that maintain reliability while helping to reduce overall fuel costs for customers. With that said, the asset optimization measures described in paragraph 12 of the Proposed Settlement Agreement have associated risks, including market risk, credit risk and operational risk. These types of risks introduce the possibility of monetary losses. While FPL will have safeguards in place to help mitigate some of the risks associated with these types of transactions, it is impossible to eliminate all risk. The safeguards that FPL will have in place are addressed in FPL's response to Staff's Twenty Second Set of Interrogatories No. 610.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 695
PARTY FPL; Sam A. Forrest (SF-5)
DESCRIPTION FPL Responses to Staff's 22nd set of Irrogs
DATE Nos. 608 through 611

Florida Power & Light Company
Docket No. 120015-EI
Staff's Twenty-Second Set of Interrogatories
Interrogatory No. 609
Page 1 of 1

Q.
Please refer to page 6 of the testimony of Sam Forrest, lines 7 through 15, for interrogatories 608 through 611.

What are the risks to FPL of these transactions?

A.
The risks to FPL are the same as described in FPL's response to Staff's Twenty Second Set of Interrogatories No. 608. To the extent that monetary losses were incurred, FPL's customers would experience less total benefits from the asset optimization measures than they otherwise would have, and FPL's ability to reach the threshold(s) and potentially share in the overall benefits would be impaired.

Q.

Please refer to page 6 of the testimony of Sam Forrest, lines 7 through 15, for interrogatories 608 through 611.

What safeguards are necessary to address the risks of these transactions?

A.

The execution of asset optimization transactions will be strictly governed by additional Risk Management policies and procedures that are reviewed by FPL's Risk Management department, with ultimate oversight by the Exposure Management Committee (EMC). Market risk limits (i.e., tenor, stop-loss, open positions...etc.) will be set to help mitigate market risk. FPL will manage credit risk, as it does today, through appropriate creditworthiness reviews, monitoring and the inclusion of contractual risk mitigation terms and conditions whenever possible. Operational risk due to weather uncertainty and changes in forecasts will be addressed through the retention of a portion of gas transportation or storage capacity to cover forecast errors. FPL will utilize forecasted and historical data to further determine if system conditions allow for the execution of optimization measures. Generally, given the uncertainty of weather and unit availability, FPL will execute transactions that are short-term in nature. Finally, contractual provisions, such as the ability to "call-back" delivered gas sales under certain conditions, will be used to help mitigate certain risks as much as possible while maintaining the value of the transaction(s).

The following table summarizes the safeguards that FPL has, or will have, in place to help mitigate the risks associated with asset optimization. As stated previously, these safeguards will help to mitigate some of the risks described in this response; however, it is impossible to eliminate all risk:

Asset Optimization Measure	Safeguard(s)
Gas Storage Optimization	
Sublease Capacity	Risk Management policies and procedures, retention of a portion of capacity to compensate for forecast errors, consumption of alternate fuels, short-term transactions, contractual provisions
Gas Sales	
From Gas Storage	Risk Management policies and procedures, retention of a portion of capacity/supply to compensate for forecast errors, consumption of alternate fuels, short-term transactions
Within Production Area	Risk Management policies and procedures
City-Gate Delivered	Risk Management policies and procedures, retention of a portion of capacity to compensate for forecast errors, consumption of alternate fuels, short-term transactions, contractual provisions
Capacity Release	
Natural Gas Transportation	Risk Management policies and procedures, retention of a portion of capacity to compensate for forecast errors, consumption of alternate fuels, short-term transactions
Electric Transmission	Risk Management policies and procedures
Asset Management Agreements	
Natural Gas Transportation	Risk Management policies and procedures, contractual provisions
Natural Gas Storage Capacity	Risk Management policies and procedures, contractual provisions

Florida Power & Light Company
Docket No. 120015-EI
Staff's Twenty-Second Set of Interrogatories
Interrogatory No. 611
Page 1 of 1

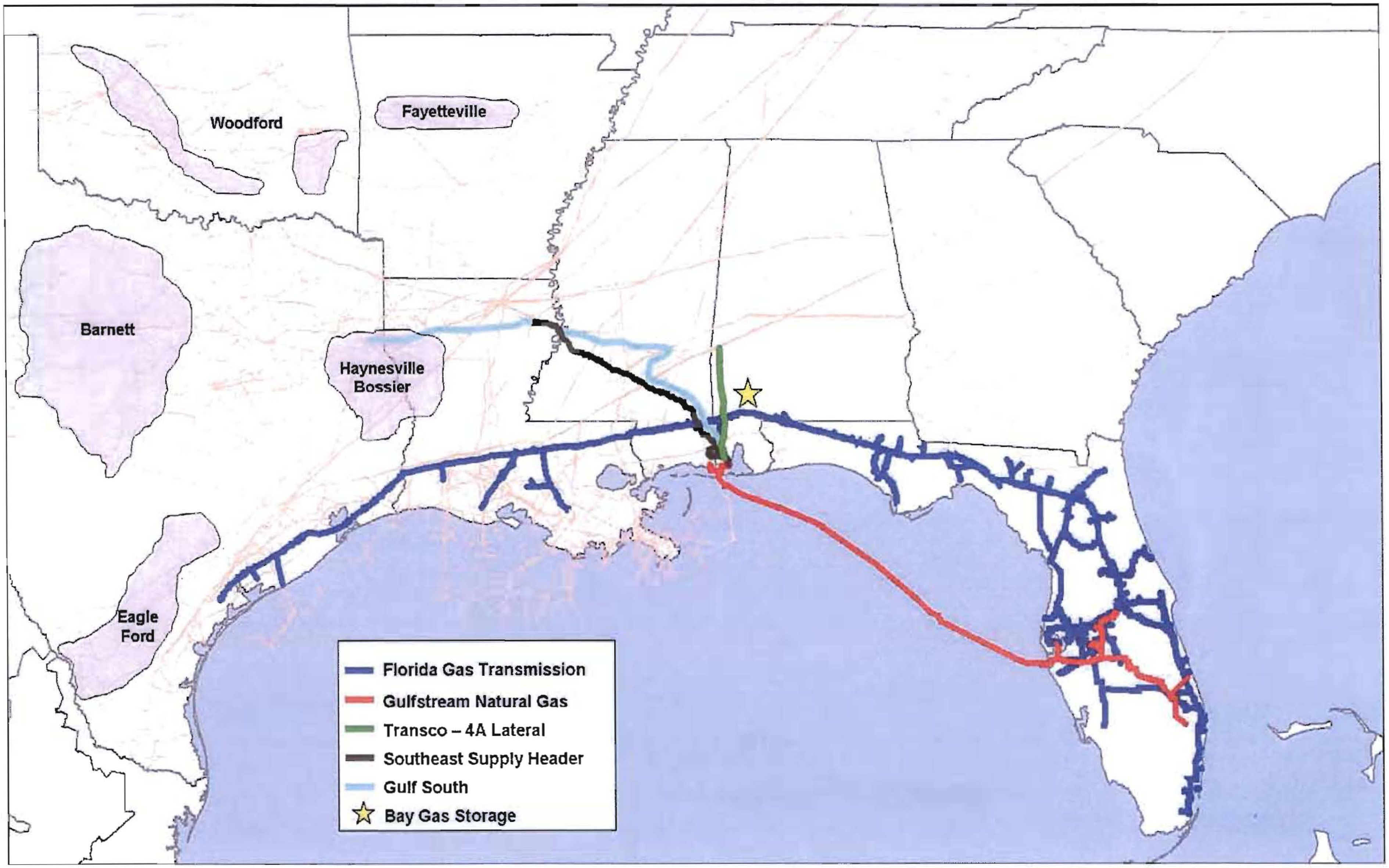
Q.

Please refer to page 6 of the testimony of Sam Forrest, lines 7 through 15, for interrogatories 608 through 611.

Could these transactions result in negative gains (losses), and what could cause such a result? Please explain by each form of asset optimization stated in paragraph 12 of the proposed settlement agreement.

A.

It is possible that these transactions could result in negative gains (losses). Monetary losses could be caused by any of the risks listed in FPL's response to Staff's Twenty Second Set of Interrogatories No. 608 and described in FPL's response to Twenty Second Set of Interrogatories No. 610. Causes could range from supplier delivery failure to changes in weather or unit availability that results in the consumption of higher-priced, alternate fuels.



FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120015-EI EXHIBIT 696

PARTY FPL; Sam A. Forrest (SF-6);

DESCRIPTION FPL's Natural Gas Assets

DATE

Docket No. 120015-EI
FPL's Natural Gas Assets
Exhibit SF-6, Page 1 of 1

Expanded OPC Witness Ramas Exhibit DR-8 – Adjusted Earned ROE
($ thousands)

Line No.	Description	Per FPL Post-Hrg Brief Amts (A)	Per FPL With Revised ROR (B)	Source/Reference	Per Proposed Settlement Agreement
1	JURISDICTIONAL ADJUSTED RATE BASE	$ 21,220,083	$ 21,220,083	(1)	
2	REQUIRED RATE OF RETURN	6.9009%	6.5326%	See Page 2 of 2 of DR-8	
3	JURISDICTIONAL INCOME REQUIRED	1,464,382	1,386,223	Line 1 x Line 2	
4	JURISDICTIONAL ADJ. NET OPERATING INCOME	1,142,605	1,142,605	(1)	
5	INCOME DEFICIENCY (SUFFICIENCY)	321,778	243,618	Line 3 - Line 4	
6	EARNED RATE OF RETURN	5.38%	5.38%	Line 5 / Line 1	
7	NET OPERATING INCOME MULTIPLIER	1.63188	1.63188		
8	REVENUE DEFICIENCY (SUFFICIENCY)	$ 525,100	$ 397,554	Line 5 x Line 7	$ 378,000
9	INCOME DEFICIENCY (SUFFICIENCY)		243,618	Line 8 / Line 7, Col (B)	231,635
10	JURISDICTIONAL ADJUSTED NET OPERATING INCOME		1,386,223	Line 4, Col (B) + Line 9	1,374,240
11	EARNED RATE OF RETURN		6.53%	Line 10 / Line 1, Col (B)	6.48%
12	NON EQUITY COST OF CAPITAL		1.61%	(1)	1.61%
13	EARNINGS AVAILABLE FOR COMMON		4.93%	Line 11 - Line 12	4.87%
14	COMMON EQUITY RATIO		46.03%	(1)	46.03%
15	JURISDICTIONAL ADJUSTED EARNED RETURN ON COMMON EQUITY (ROE)		10.70%	Line 13 / Line 14	10.58%

Note:
(1) Amounts from FPL's Post Hearing Brief, Appendix I

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 697
PARTY FPL; Robert E. Barrett (REB-13)
DESCRIPTION Expanded OPC Witness Ramas Exhibit DR-8
DATE Adjusted Earned ROE

Projected Capital Expenditures (2014 - 2016)
Excerpt from FPL's Third Quarter Form 10-Q
($ in millions)

	2014	2015	2016	Total
Generation:				
Existing Generation	$ 655.0	$ 550.0	$ 440.0	$ 1,645.0
Transmission & Distribution(1)	690.0	660.0	705.0	2,055.0
Nuclear Fuel	205.0	245.0	245.0	695.0
General & Other	120.0	80.0	85.0	285.0
Total Excluding New Generation	$ 1,670.0	$ 1,535.0	$ 1,475.0	$ 4,680.0

(1) Includes Storm Secure and Advanced Metering Infrastructure.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 698
PARTY FPL; Robert E. Barrett (REB-14)
DESCRIPTION Projected Capital Expenditures (2014-2016)
DATE Excluding New Generation

Florida Power & Light Company
Docket No. 120015-EI
OPC's Sixteenth Set of Interrogatories
Interrogatory No. 275
Page 1 of 1

Q.
Please refer to the Direct Testimony of Robert Barrett, Jr. (Proposed Settlement Agreement), page 8, lines 15 through 20, which indicates that historically FPL's "actual capital costs for plants placed into rates using GBRA have been no more than, and in most cases less than, the need determination revenue requirement which form the basis for the cumulative present value revenue requirements ("CPVRR") analysis upon which the need determination was based." For each of FPL's plants that have been placed into rates using GBRA referenced in this testimony, please provide the following:

a. The projected plant in service amounts included in the need determinations by FPL and the actual plant in service amounts, by plant type.

b. The projected rate base included in the need determinations by FPL and the actual rate base amount, by each component of rate base.

c. The projected net operating income (loss) reflected in the need determinations by FPL and the actual net operating income (loss), by eachcomponent of net operating income (i.e., O&M expenses, depreciation expenses, property taxes, etc.).

A.
In response to this request, FPL has assumed that the period in question relates to the first year of operations for the units subject to the GBRA mechanism approved in the 2005 Rate Order (Order No. PSC-05-0902-S-EI), which are Turkey Point Unit 5 (TP5), West County Energy Center Unit 1 (WCEC1), and West County Energy Center Unit 2 (WCEC2).

As discussed in FPL's response to OPC's Sixteenth Set of Interrogatories No. 273, at the time a project is complete and transferred from FERC account 107 (CWIP) to account 106 (completed construction not classified) and then unitized to account 101 (plant-in-service), it is identifiable in the accounting records from a capital cost standpoint. This point in time is referred to as COD. However, after COD and once a project is in service, many of the cost components are not tracked separately such as deferred taxes, operating expenses and property taxes because base rates are set on a total system embedded cost basis and many support costs serve more than one asset. The assets associated with the units subject to the GBRA mechanism are included as part of FPL's jurisdictional adjusted rate base, and their operating expenses are included as part of FPL's jurisdictional adjusted net operating income. This treatment is consistent with how the units are reflected for monthly earnings surveillance reporting purposes. FPL has provided what is readily identifiable for the requested GBRA plants along with all need determination amounts in Attachment No. 1.

FLORIDA PUBLIC SERVICE COMMISSION	
DOCKET NO. 120015-EI	**EXHIBIT** 699
PARTY FPL; Robert E. Barrett (REB-15)	
DESCRIPTION FPL's response to OPC's 16th set of	
DATE Irrogs, Question No. 275	

Turkey Point Unit 5 (TP5) and West County Energy Center (WCEC) Units 1 & 2
($ millions)

	Need Determination				Actuals				
Rate Base	TP5 as of 4/30/08	WCEC1 as of 7/31/10	WCEC2 as of 10/31/10	Total for WCEC1 and WCEC2	TP5 as of 4/30/08	WCEC1 as of 7/31/10	WCEC2 as of 10/31/10	Total for WCEC1 and WCEC2	Notes
Production Plant	$ 580.3	$ 688.6	$ 632.4	$ 1,321.0	$ 546.7	$ 712.0	$ 537.3	$ 1,249.3	Amounts represent total project construction costs. The need amounts included transmission plant and such amounts were not specifically identified. The actual costs incurred for TP5, WCEC1 and WCEC2 are based on the underlying fixed asset records of the company. Actuals for TP5 are consistent with the actual costs incurred through June 30, 2008 as reported in the true-up calculation filed in on September 2, 2008 in Docket No. 080001-EI. The actual amounts depicted for WCEC 1 and 2 are consistent with the actual costs incurred through July 31, 2012 as reported in FPL's cost update letter provided to the Commission on September 19, 2012. Note, the cost of land for the entire WCEC site of $44.7M and WCEC site common costs of $41.4M are included in actuals for WCEC1. The site common costs include, but are not limited to, the admin building, storm ponds, water tanks, injection well, and waste water system.
Transmission Plant	-	-	-	-	12.3	29.6	41.3	70.9	For actuals, see notes included in production plant above.
Production Reserve	(23.2)	(27.5)	(25.3)	(52.8)	(26.5)	(24.7)	(19.0)	(43.8)	Need amounts include transmission plant; Actual amounts are based on plant-in-service balances for these periods, which include retirements, not the total project construction costs as reported for plant above.
Transmission Reserve	-	-	-	-	N/A	N/A	N/A	N/A	FPL's depreciation expense and reserve are calculated at a depreciation group level and not at the individual asset level. For transmission assets, FPL's depreciation groups are not specific to site and unit, therefore, the transmission depreciation expense and reserve cannot be separated and reported at the level requested.
Deferred Taxes	12.3	7.2	0.5	7.7	N/A	N/A	N/A	N/A	FPL's actual deferred taxes are not calculated nor tracked at a unit/project level.
Rate Base	$ 569.4	$ 668.3	$ 607.6	$ 1,275.8					
Average Rate Base	$ 583.8	$ 686.1	$ 627.6	$ 1,313.7					Amounts represent the simple average of the estimated beginning rate base balance when the unit went into service and the ending rate base balance at the end of first year of operations
Interest Expense	18.8	21.3	19.5	40.8					
Income Tax - Interest Expense	(6.5)	(8.2)	(7.5)	(15.7)					

Turkey Point Unit 5 (TP5) and West County Energy Center (WCEC) Units 1 & 2
($ millions)

	Need Determination				Actuals				
Operating Expenses	TP5 5/1/07 - 4/30/08	WCEC1 8/1/09 - 7/31/10	WCEC2 11/1/09 - 10/31/10	Total for WCEC1 and WCEC2	TP5 5/1/07 - 4/30/08	WCEC1 8/1/09 - 7/31/10	WCEC2 11/1/09 - 10/31/10	Total for WCEC1 and WCEC2	
Operations and Maintenance	$ 5.2	$ 7.0	$ 5.3	$ 12.3	$ 4.3	$ 10.4	$ 8.8	$ 19.3	In regards to actuals for WCEC1 and WCEC2, FPL's accounting and budgeting systems have the capability to budget and track certain costs associated with operating and maintaining WCEC Units 1, 2 and 3. The company utilized this capability for tracking overhaul expenditures. Overhaul expenditures are unit specific whereas other components of the site's cost structure are shared across units. Daily work and variable operating and maintenance costs (i.e. chemicals, water) are utilized similarly for each unit at the site. The company does not believe the benefits of segregating similar non-overhaul expenditures by unit outweigh the effort required to budget and track actual costs at this level of detail. For purposes of this request, FPL has split the cost of operations equally between the two units for daily work and variable O&M costs starting at the point in time when both units were in operation.
Property Insurance	2.1	3.3	3.1	6.4	N/A	N/A	N/A	N/A	In regards to the actual amounts, the company purchases property insurance at the FPL level and does not allocate premium by FPL site. The only time there may be premium that is specific to a site is when it is initially added to an existing policy during the policy term. For TP5, the project was added during the policy period and received a nominal premium charge for one month of coverage of $0.1 million until renewal. For WCEC1 and 2, the projects were included in the respective year's renewal and subject to changes in FPL's entire portfolio as well as market conditions at that time. As such, these projects were included in the respective year's renewal and no project specific premium was identified or allocated when those projects were added.
Capital Replacement Costs	7.5	8.6	8.7	17.3	-	-	-	-	All capital replacement costs are included as part of plant-in-service
Depreciation	23.2	27.5	25.3	52.8	26.5	24.8	19.0	43.8	Need amounts include depreciation for both production and transmission plant. For actuals, amounts represent depreciation expense for production assets based on the amount included in plant-in-service, which include retirements (not total project construction costs). For transmission assets, the depreciation groups are not specific to site and unit, therefore, the transmission depreciation expense cannot be separated and reported at the level requested.
Property Taxes	12.0	-	-	-	9.1	-	-	20.6	Actuals for TP5 represents what was paid in 2008 for the calendar year 2008. For WCEC1 and WCEC2 actuals, the amount paid was for both units, therefore, we can not split out the amount. The total paid in 2010 for the calendar year 2010 for both units was $20,578,314
Total Operating Expenses	$ 50.1	$ 46.5	$ 42.3	$ 88.8					
Net Operating Income (System)									
Operating Expenses	$ (50.1)	$ (46.5)	$ (42.3)	$ (88.8)					
Income Tax - Operating Expenses	19.3	17.9	16.3	34.2					
Income Tax - Interest Expense	6.5	8.2	7.5	15.7					
Other Income Taxes	(0.8)	(1.2)	(1.3)	(2.5)					
Total Net Operating Income (Loss)	$ (25.1)	$ (21.6)	$ (19.8)	$ (41.3)					

Total Project Construction Costs
Turkey Point Unit 5 (TP5) and
West County Energy Center (WCEC) Units 1 & 2

($ millions)

	Need Determination Estimates	Actual Costs (1)	Difference	% Difference
TP5	$ 580.3	$ 559.0	$ 21.3	-3.68%
WCEC1	688.6	741.6	(53.0)	7.69%
WCEC2	632.4	578.6	53.8	-8.50%
Total for WCEC 1&2	$ 1,321.0	$ 1,320.2	$ 0.8	-0.06%
Total	**$ 1,901.3**	**$ 1,879.2**	**$ 22.1**	**-1.16%**

Notes

(1) Actuals for TP5 are consistent with the actual costs incurred through June 30, 2008 as reported in the true-up calculation filed in on September 2, 2008 in Docket No. 080001-EI.

The actual amounts depicted for WCEC 1 and 2 are consistent with the actual costs incurred through July 31, 2012 as reported in FPL's cost update letter provided to the Commission on September 19, 2012. Note, the cost of land for the entire WCEC site of $44.7M and WCEC site common costs of $41.4M are included in actuals for WCEC1. The site common costs include, but are not limited to, the admin building, storm ponds, water tanks, injection well, and waste water system.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 700
PARTY FPL; Robert E. Barrett (REB-16)
DESCRIPTION Total Projects Construction Costs for TP5 and WCEC 1 and 2; Need vs. Actual
DATE

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for increase in rates by Florida Power & Light Company.	)))	Docket No. 120015-EI

STIPULATION AND SETTLEMENT

WHEREAS, Florida Power & Light Company ("FPL" or the "Company"), the Florida Industrial Power Users Group ("FIPUG"), the South Florida Hospital and Healthcare Association ("SFHHA") and the Federal Executive Agencies ("FEA") have signed this Stipulation and Settlement (the "Agreement"; unless the context clearly requires otherwise, the term "Party" or "Parties" means a signatory to this Agreement); and

WHEREAS, on February 1, 2011, the Florida Public Service Commission ("FPSC" or "Commission") entered Order No. PSC-11-0089-S-EI approving a stipulation and settlement of FPL's rate case in Docket Nos. 080677-EI and 090130-EI, which continues in effect through the last billing cycle in December 2012 (the "2010 Rate Case Stipulation"); and

WHEREAS, on March 19, 2012, FPL petitioned the Commission for an increase in base rates of approximately $516.5 million to be effective on January 1, 2013 following the expiration of the 2010 Rate Case Stipulation, for a step increase of $173.9 million to be effective upon the commercial in-service date of the Canaveral Modernization Project (scheduled to be June 1, 2013), and for other related relief (the "2012 Rate Petition"); and

WHEREAS, the Parties have filed voluminous prepared testimony with accompanying exhibits and conducted extensive discovery; and

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI **EXHIBIT** 701
PARTY FPL; Moray P. Dwhurst (MD-11); Proposed
DESCRIPTION Settlement Agreement
DATE ______

WHEREAS, the Parties recognize that this is a period of substantial economic uncertainty, in which economic development and job creation are vitally important to the state of Florida; and

WHEREAS, the Parties to this Agreement have undertaken to resolve the issues raised in these proceedings so as to maintain a degree of stability and predictability with respect to FPL's base rates and charges, as well as to promote economic development, job creation and stability;

NOW THEREFORE, in consideration of the foregoing and the covenants contained herein, the Parties hereby stipulate and agree:

1. This Agreement will become effective on the first billing cycle of January 2013 (the "Implementation Date") and continue through the last billing cycle in December 2016 (the period from the Implementation Date through the last billing cycle in December 2016 may be referred to herein as the "Term").

2. FPL's authorized rate of return on common equity ("ROE") shall be a range of 9.70% to 11.70%, with a mid-point of 10.70%. FPL's authorized ROE range and mid-point shall be used for all purposes during the Term.

3. (a) Upon the Implementation Date and effective with the first billing cycle in January 2013, FPL shall increase its base rates and service charges by an amount that is intended to generate an additional $378 million of annual revenues, based on the projected 2013 test year billing determinants reflected in the Minimum Filing Requirements ("MFRs")

filed with the 2012 Rate Petition, and in the respective amounts and manner shown on Exhibit A, attached hereto.

(b) Attached hereto as Exhibit B are tariff sheets for new base rates and service charges that implement the $378 million rate increase described in Paragraph (3)(a) above, which tariff sheets shall become effective on the first billing cycle of January 2013. The new base rates reflected in the attached tariff sheets are based on the billing determinants, cost of service allocations and rate design in the MFRs accompanying the 2012 Rate Petition and include additional adjustments, all of which are reflected in Exhibit A; provided, however, that: (i) the minimum late payment charge of $5.00 proposed in FPL's filing is increased to $6.00; and (ii) consistent with FPL's recently approved revised Economic Development Rider and to promote further economic development and job creation, (A) the energy and demand charges for business and commercial rates are adjusted as shown in Exhibit B, and (B) the utility-controlled demand credits for large commercial and industrial customers in the new CILC and CDR rates are greater than the credits reflected in such MFRs, and the relationship between the non-fuel energy and demand charges in the CILC rates are revised. FPL shall be entitled to recover the increased CILC and CDR credits through the energy conservation cost recovery ("ECCR") clause.

(c) Base rates set in accordance with this Paragraph 3 shall not be changed during the Term except as otherwise permitted in this Agreement.

4. Nothing in this Agreement shall preclude FPL from requesting the Commission to approve the recovery of costs that are recoverable through base rates under the nuclear

cost recovery statute, Section 366.93, Florida Statutes, and Commission Rule 25-6.0423, F.A.C. Parties may participate in nuclear cost recovery proceedings and proceedings related thereto and may oppose FPL's requests.

5. (a) Nothing in this Agreement shall preclude FPL from petitioning the Commission to seek recovery of costs associated with any storms without the application of any form of earnings test or measure and irrespective of previous or current base rate earnings or level of theoretical depreciation reserve. Consistent with the rate design method set forth in Order No. PSC-06-0464-FOF-EI, the Parties agree that recovery of storm costs from customers will begin, on an interim basis, sixty days following the filing of a cost recovery petition and tariff with the Commission and will be based on a 12-month recovery period if the storm costs do not exceed $4.00/1,000 kWh on monthly residential customer bills. In the event the storm costs exceed that level, any additional costs in excess of $4.00/1,000 kWh shall be recovered in a subsequent year or years as determined by the Commission. All storm related costs subject to interim recovery under this Paragraph 5 shall be calculated and disposed of pursuant to Commission Rule 25-6.0143, F.A.C., and will be limited to costs resulting from a tropical system named by the National Hurricane Center or its successor, to the estimate of incremental costs above the level of storm reserve prior to the storm and to the replenishment of the storm reserve to the level as of the Implementation Date. The Parties to this Agreement are not precluded from participating in any such proceedings and opposing the amount of FPL's claimed costs but not the mechanism agreed to herein.

(b) The Parties agree that the $4.00/1,000 kWh cap in this Paragraph 5 will apply in aggregate for a calendar year; provided, however, that FPL may petition the Commission to allow FPL to increase the initial 12 month recovery beyond $4.00/1,000 kWh in the event FPL incurs in excess of $800 million of storm recovery costs that qualify for recovery in a given calendar year, inclusive of the amount needed to replenish the storm reserve to the level that existed as of the Implementation Date. All Parties reserve their right to oppose such a petition.

(c) The Parties expressly agree that any proceeding to recover costs associated with any storm shall not be a vehicle for a "rate case" type inquiry concerning the expenses, investment, or financial results of operations of the Company and shall not apply any form of earnings test or measure or consider previous or current base rate earnings or level of theoretical depreciation reserve.

6. Nothing shall preclude the Company from requesting the Commission to approve the recovery of costs (a) that are of a type which traditionally and historically would be, have been, or are presently recovered through cost recovery clauses or surcharges, or (b) that are incremental costs not currently recovered in base rates which the Legislature or Commission determines are clause recoverable subsequent to the approval of this Agreement. It is the intent of the Parties in this Paragraph 6 that FPL not be allowed to recover through cost recovery clauses increases in the magnitude of costs of types or categories (including but not limited to, for example, investment in and maintenance of transmission assets) that have been and traditionally, historically, and ordinarily would be recovered through base rates. It is further the intent of the Parties to recognize that an authorized governmental entity may impose requirements on FPL involving new or

atypical kinds of costs (including but not limited to, for example, requirements related to cybersecurity or the requirements for seismic and flood protection at nuclear plants arising out of the Fukushima Daiichi event), and concurrently or in connection with the imposition of such requirements, the Legislature and/or Commission may authorize FPL to recover those related costs through a cost recovery clause. Nothing in this Agreement shall affect the shifts from clause to base rate recovery and from base rate to clause recovery that were set forth in the 2012 Rate Petition and accompanying MFRs.

7. (a) FPL will continue throughout the Term to recover the annual non-fuel revenue requirements for West County Unit 3 via its capacity cost recovery clause (the "Capacity Clause") in the manner provided in the 2010 Rate Case Stipulation; provided, however, that commencing upon the Implementation Date, such recovery shall not be limited to the projected fuel cost savings for West County Unit 3.

(b) The revenue requirements associated with West County Unit 3 quantified pursuant to this paragraph shall be allocated to customer classes utilizing the same cost of service and rate design methodology reflected in the MFRs accompanying the 2012 Rate Petition.

(c) FPL's right to recover the non-fuel revenue requirements for West County Unit 3 pursuant to this Paragraph 7 shall survive termination of this Agreement and shall continue until such time as new base rates are authorized for FPL that are based on a test year that reflects the then applicable non-fuel revenue requirements for West County Unit 3.

8. (a) FPL projects that the following three power plant modernization projects will enter commercial service while this Agreement is in effect: the Canaveral Modernization Project (projected to go into service June 2013), the Riviera Modernization Project (projected to go into service June 2014), and the Port Everglades Modernization Project (projected to go in service June 2016). For each of these three modernization projects, FPL's base rates will be increased by the annualized base revenue requirement for the first 12 months of operation (the "Annualized Base Revenue Requirement"). For the Canaveral Modernization Project, the Annualized Base Revenue Requirement shall be as reflected in the 2012 Rate Petition and accompanying MFRs; for the Riviera and Port Everglades Modernization Projects, the Annualized Base Revenue Requirement shall reflect the costs upon which the cumulative present value of revenue requirements was predicated, and pursuant to which a need determination was granted by the Commission. Each such base rate adjustment will be referred to as a Generation Base Rate Adjustment ("GBRA").

(b) Each GBRA is to be reflected on FPL's customer bills by increasing base charges and base credits by an equal percentage contemporaneously. The calculation of the percentage change in rates is based on the ratio of the jurisdictional Annualized Base Revenue Requirement and the forecasted retail base revenues from the sales of electricity (excluding West County Unit 3 revenues) during the first twelve months of operation. FPL will begin applying the incremental base rate charges and base credits for each of the three modernization projects to meter readings made on and after the commercial in-service date of that modernization project.

(c) Each GBRA will be calculated using a 10.70% ROE and the capital structure reflected in the Canaveral Step Increase MFRs accompanying the 2012 Rate Petition. FPL will calculate and submit for Commission confirmation that amount of the GBRA for each modernization project using the Capacity Clause projection filing for the year that modernization project is to go into service.

(d) In the event that the actual capital expenditures are less than the projected costs used to develop the initial GBRA factor, the lower figure shall be the basis for the full revenue requirements and a one-time credit will be made through the Capacity Clause. In order to determine the amount of this credit, a revised GBRA Factor will be computed using the same data and methodology incorporated in the initial GBRA factor, with the exception that the actual capital expenditures will be used in lieu of the capital expenditures on which the Annualized Base Revenue Requirement was based. On a going forward basis, base rates will be adjusted to reflect the revised GBRA factor. The difference between the cumulative base revenues since the implementation of the initial GBRA factor and the cumulative base revenues that would have resulted if the revised GBRA factor had been in-place during the same time period will be credited to customers through the Capacity Clause with interest at the 30-day commercial paper rate as specified in Rule 25-6.109, F.A.C.

(e) In the event that actual capital costs for a modernization project are higher than the projection on which the Annualized Base Revenue Requirement was based, FPL at its option may initiate a limited proceeding per Section 366.076, Florida Statutes, limited to the issue of whether FPL has met the requirements of Rule 25-22.082(15), F.A.C. If the Commission finds that FPL has met the requirements of Rule 25-22.082(15), then FPL shall increase the GBRA by the corresponding incremental revenue requirement due to such additional capital costs. However, FPL's election not to seek such an increase in the GBRA shall not preclude FPL from booking any incremental costs for surveillance reporting and all regulatory purposes subject only to a finding of imprudence or disallowance by the Commission. Any Party may participate in any such limited proceeding for the purpose of challenging whether FPL has met the requirements of Rule 25-22.082(15).

(f) Upon expiration or termination of this Agreement, FPL's base rate levels, including the effects of the GBRAs as implemented in this Agreement (i.e., uniform percent increase for all rate classes applied to base revenues) for each of the modernization projects that achieved commercial in-service operation during the term of this Agreement, shall continue in effect until next reset by the Commission.

9. (a) Notwithstanding Paragraph 3 above, if FPL's earned return on common equity falls below 9.70% during the Term on an FPL monthly earnings surveillance report stated on an FPSC actual, adjusted basis, FPL may petition the FPSC to amend its base rates, either as a general rate proceeding under Sections 366.06 and 366.07, Florida Statutes, and/or as a limited proceeding under Section 366.076, Florida Statutes. (Throughout this Agreement, "FPSC actual, adjusted basis" and "actual adjusted earned return" shall mean results reflecting all adjustments to FPL's books required by the Commission by rule or

order, but excluding pro forma, weather-related adjustments.) If FPL files a petition to initiate a general rate proceeding pursuant to this provision, FPL may request an interim rate increase pursuant to the provisions of Section 366.071, Florida Statutes. The other Parties to this Agreement shall be entitled to participate in any proceeding initiated by FPL to increase base rates pursuant to this paragraph, and may oppose FPL's request.

(b) Notwithstanding Paragraph 3 above, if FPL's earned return on common equity exceeds 11.70% during the Term on an FPL monthly earnings surveillance report stated on an FPSC actual, adjusted basis, any other Party shall be entitled to petition the Commission for a review of FPL's base rates. In any case initiated by FPL or any other Party pursuant to this paragraph, all parties will have full rights conferred by law.

(c) Notwithstanding Paragraph 3 above, this Agreement shall terminate upon the effective date of any final order issued in any such proceeding pursuant to this Paragraph 9 that changes FPL's base rates prior to the last billing cycle of December 2016.

(d) This Paragraph 9 shall not (i) be construed to bar or limit FPL to any recovery of costs otherwise contemplated by this Agreement; (ii) apply to any request to change FPL's base rates that would become effective after this Agreement terminates; or (iii) limit any Party's rights in proceedings concerning changes to base rates that would become effective subsequent to the termination of this Agreement to argue that FPL's authorized ROE range should be different than 9.70% to 11.70%.

10. (a) In Order No. PSC-10-0153-FOF-EI, the Commission determined a net theoretical depreciation reserve surplus in the total amount of $894 million (the "Total Depreciation Reserve Surplus"). The Commission directed FPL to amortize the Total Depreciation

Reserve Surplus over four years, ending in 2013. Pursuant to the 2010 Rate Case Stipulation, the Parties therein agreed that in each year during the term of that agreement, FPL would have discretion to vary the amount of amortization of Total Depreciation Reserve Surplus taken in that year, subject to certain limitations. As a result of FPL's actual and projected discretionary amortization during 2010-2012, the 2012 Rate Petition and accompanying MFRs projected that FPL would have $191 million of Total Depreciation Reserve Surplus remaining at the end of 2012 and would amortize that amount in 2013. The actual remaining amount may differ from the projected amount of $191 million.

(b) Notwithstanding Order No. PSC-10-0153-FOF-EI or the 2010 Rate Case Stipulation, the Parties agree that over the Term of this Agreement, FPL may amortize the Total Depreciation Reserve Surplus remaining at the end of 2012, plus a portion of FPL's Fossil Dismantlement Reserve (together the "Reserve Amount") with the amounts to be amortized in each year of the Term left to FPL's discretion subject to the following conditions: (i) the amount of Total Depreciation Reserve Surplus that FPL may amortize during the term shall not be less than $191 million (or the actual amount of Total Depreciation Reserve Surplus remaining at the end of 2012) and the total Reserve Amount amortized during the Term shall not exceed $400 million[1] subject to (iii) below; (ii) for any surveillance reports submitted by FPL during the Term on which its return on equity (measured on an FPSC actual, adjusted basis) would otherwise fall below 9.70%, FPL must amortize at least the amount of the available Reserve Amount necessary to

[1] The Company would record the $191 million of net surplus amortization or the actual amount of Total Depreciation Reserve Surplus remaining at the end of 2012, to the cost of removal component of the depreciation reserve to ensure that the amount of net surplus amortization on the financial statements equals the amount of net surplus amortization reflected in rates.

maintain in each such 12-month period a return on equity of 9.70% (measured on an FPSC actual, adjusted basis); and (iii) FPL may not amortize Reserve Amount in an amount that results in FPL achieving a return on equity of greater than 11.70% (measured on an FPSC actual, adjusted basis) in any such 12-month period as measured by surveillance reports submitted by FPL during the Term. FPL shall not satisfy the requirement of Paragraph 9 that its actual adjusted earned return on equity must fall below 9.70% on a monthly surveillance report before it may initiate a petition to increase base rates during the Term unless FPL first uses any of the Reserve Amount that remains available for the purpose of increasing its earned return on equity to at least 9.70% for the period in question.

11. Notwithstanding any requirements of Rules 25-6.0436 and 25-6.04364, F.A.C., FPL shall not be required during the Term to file any depreciation study or dismantlement study. The depreciation rates and dismantlement accrual rates in effect as of the Implementation Date shall remain in effect throughout the Term. The Parties agree that the provisions of Rules 25-6.0436 and 25-6.04364 pursuant to which depreciation and dismantlement studies are generally filed at least every four years will not apply to FPL during the Term.

12. (a) In order to create additional value for customers by FPL engaging in both wholesale power purchases and sales, as well as all forms of asset optimization, the Parties agree that FPL will be subject to the following mechanism, effective on the Implementation Date (the "Incentive Mechanism"):

(i) FPL will file each year as part of its fuel cost recovery clause ("Fuel Clause") final true-up filing a schedule showing its gains in the prior calendar year on short-term wholesale sales, short-term wholesale purchases (including purchases that are reported on Schedule A-7), and all forms of asset optimization that it undertook in that year (the "Total Gains Schedule").[2] FPL's final true-up filing will include a description of each asset optimization measure for which gain is included on the Total Gains Schedule for the prior year, and such measures shall be subject to review by the Commission to determine that they are eligible for inclusion in the Incentive Mechanism.

(ii) For the purposes of the Incentive Mechanism, "asset optimization" includes but is not limited to:

- Gas storage utilization (FPL could release contracted storage space or sell stored gas during non-critical demand seasons);
- Delivered city-gate gas sales using existing transport (FPL could sell gas to Florida customers, using FPL's existing gas transportation capacity during periods when it is not needed to serve FPL's native load);
- Production (upstream) area sales (FPL could sell gas in the gas-production areas, using FPL's existing gas transportation capacity during periods when it is not needed to serve FPL's native load);

[2] For the purpose of this Agreement, "short-term" is intended to refer to non-separated wholesale sales and purchases. Order No. PSC-97-0262-FOF-EI defined "non-separated" sales as "sales that are non-firm or less than one year in duration."

- Capacity Release of gas transport and electric transmission (FPL could sell idle gas transportation and/or electric transmission capacity for short periods when it is not needed to serve FPL's native load;
- Asset Management Agreement ("AMA") (FPL could outsource optimization function such as those described above to a third party through assignment of transportation and/or storage rights in exchange for a premium to be paid to FPL).

(iii) On an annual basis, FPL customers will receive 100% of the gain described in Paragraph 12(b)(i), up to a threshold of $36 million ("Customer Savings Threshold"). In addition, FPL customers will receive 100% of the gain described in Paragraph 12(b)(i) for the first $10 million above the Customer Savings Threshold ("Additional Customer Savings"). Incremental gains above the total of the Customer Savings Threshold and the Additional Customer Savings (i.e., above a gain of $46 million) will be shared between FPL and customers as follows: FPL will retain 70% and customers will receive 30% of incremental gains between $46 million and $75 million; FPL will retain 60% and customers will receive 40% of incremental gains between $75 million and $100 million; and FPL will retain 50% and customers will receive 50% of all incremental gains in excess of $100 million. The customers' portion of all gains will be reflected as a reduction to fuel costs recovered through the Fuel Clause. FPL agrees that it will not require any native load customer to be interrupted in order to initiate or maintain an economy sale, whether that sale is firm or non-firm.

(b) FPL will be entitled to recover through the Fuel Clause the following types of reasonable and prudent incremental O&M costs incurred in implementing its expanded short-term wholesale purchases and sales programs as well as the asset optimization measures (the "Incremental Optimization Costs"):

(i) incremental personnel, software and associated hardware costs incurred by FPL to manage the expanded short-term wholesale purchases and sales programs and the asset optimization measures; and

(ii) variable power plant O&M costs[3] incurred by FPL to generate additional output in order to make wholesale sales, to the extent that the level of such sales exceed 514,000 MWh (*i.e.*, the level of sales assumed for the purpose of forecasting 2013 test year power plant O&M costs in the MFRs filed with the 2012 Rate Petition), with such costs determined by multiplying the sales above that threshold times the monthly weighted average variable power plant O&M cost per MWh reflected in the 2013 test year MFRs.

FPL's final true-up filing will separately state and describe the Incremental Optimization Costs that it incurred in the prior year, and such costs shall be subject to review and approval by the Commission.

13. No Party to this Agreement will request, support, or seek to impose a change in the application of any provision hereof. Except as provided in Paragraph 9, a Party to this Agreement will neither seek nor support any reduction in FPL's base rates, including limited, interim or any other rate decreases, that would take effect prior to the first billing cycle for January 2017, except for any such reduction requested by FPL or as otherwise

[3] For the purpose of this Agreement, "variable power plant O&M costs" includes non-fuel O&M expenses and costs for capital replacement parts that vary as a function of a power plant's output.

provided for in this Agreement. FPL shall not seek interim, limited, or general base rate relief during the Term except as provided for in Paragraph 9 of this Agreement. FPL is not precluded from seeking interim, limited or general base rate relief that would be effective during or after the first billing cycle in January 2017, nor are the Parties precluded from opposing such relief. Such interim relief may be based on time periods before January 1, 2017, consistent with Section 366.071, Florida Statutes, and calculated without regard to the provisions of this Agreement.

14. Nothing in this Agreement will preclude FPL from filing and the Commission from approving any new or revised tariff provisions or rate schedules requested by FPL, provided that such tariff request does not increase any existing base rate component of a tariff or rate schedule during the Term unless the application of such new or revised tariff or rate schedule is optional to FPL's customers.

15. The provisions of this Agreement are contingent on approval of this Agreement in its entirety by the Commission without modification. The Parties further agree that they will support this Agreement and will not request or support any order, relief, outcome, or result in conflict with the terms of this Agreement in any administrative or judicial proceeding relating to, reviewing, or challenging the establishment, approval, adoption, or implementation of this Agreement or the subject matter hereof; provided, however, that nothing in this Agreement shall affect FIPUG's right to continue its appeal of Order No. PSC-12-0187-FOF-EI granting an affirmative determination of need for the Port Everglades Modernization Project or FPL's right to oppose that appeal. No party will

assert in any proceeding before the Commission that this Agreement or any of the terms in the Agreement shall have any precedential value. Approval of this Agreement in its entirety will resolve all matters in Docket No. 120015-EI pursuant to and in accordance with Section 120.57(4), Florida Statutes. This docket will be closed effective on the date the Commission Order approving this Agreement is final, and no Party shall seek appellate review of any order issued in these Dockets.

16. This Agreement is dated as of August 15, 2012. It may be executed in counterpart originals, and a facsimile of an original signature shall be deemed an original. Any person or entity that executes a signature page to this Agreement shall become and be deemed a Party with the full range of rights and responsibilities provided hereunder, notwithstanding that such person or entity is not listed in the first recital above and executes the signature page subsequent to the date of this Agreement, it being expressly understood that the addition of any such additional Party(ies) shall not disturb or diminish the benefits of this Agreement to any current Party.

In Witness Whereof, the Parties evidence their acceptance and agreement with the provisions of this Agreement by their signature.

Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408

By: ______________________
Eric E. Silagy

The Florida Industrial Power Users Group
Jon C. Moyle, Jr., Esquire
Vicki Gordon Kaufman, Esquire
Moyle Law Firm
The Perkins House
118 North Gadsden Street
Tallahassee, FL 32301

By: ______________________ 8-15-12
Jon C. Moyle, Jr.

South Florida Hospital and Healthcare
Association
Kenneth L. Wiseman, Esquire
Andrews Kurth, LLP
1350 I Street, N.W., Suite 1100
Washington, DC 20005

By: ______________________
Kenneth L. Wiseman

Federal Executive Agencies
Karen White/Lt. Col. Gregory Fike
AFLOA/JACL-ULFSC
139 Barnes Drive, Suite 1
Tyndall AFB, FL 32403

By: Gregory J. Fike
Lt. Col. Gregory Fike

EXHIBIT "A"

REVENUE INCREASE BY RATE CLASS - JANUARY 1, 2013 **EXHIBIT A**

($000)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
Line No.	Description of Source	Total	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3	MET	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
1	REVENUE INCREASE																		
2	*January 1, 2013:*																		
3	ELECTRICITY SALES:																		
4	RETAIL BILLED SALES BASE REVENUES	302,460	(3,896)	(119)	(1,439)	-	33	60,287	20,801	4,158	0	541	1,216	122	212,937	7,762	-	57	(0)
5	RETAIL UNBILLED SALES REVENUES	10,662	182	15	89	-	1	2,055	798	157	0	18	40	4	7,043	257	-	2	(0)
6	INCREASE IN CILC/CDR CREDIT OFFSETS	19,879	9,407	575	4,129	-		1,831	3,337	601	-				-				-
7	*ELECTRICITY SALES INCREASE*	333,001	5,693	471	2,779	-	34	64,172	24,936	4,916	0	559	1,257	126	219,981	8,019		59	(0)
8																			
9	OTHER OPERATING REVENUE:																		
10	FIELD COLLECTION & LATE PAYMENT CHARGES	42,975	138	7	12	3,009	1	5,784	1,060	160	3		91	0	32,395	206	91	0	17
11	MISC SERVICE REVS - INITIAL CONNECT NEW PREMISE	-	-	-	-	-		-	-	-	-				-				-
12	MISC SERVICE REVS - RECONNECT AFTER NON PAYMENT	-	-	-	-	-		-	-	-	-				-				-
13	MISC SERVICE REVS - CONNECT / DISCONNECT EXIST. PREMISE		-	-	-	-		-	-	-	-				-				-
14	MISC SERVICE REVS - RETURNED CUSTOMER CHECKS	1,907	-	-	-	86		76	5	-	-		4		1,736	0			-
15	MISC SERVICE REVS - OTHER BILLINGS	117	0	0	0	10	0	3	0	0	0	0	0	0	103	0	0	0	0
16	OTH ELECTRIC REVENUES - MISC	-	-	-	-	-		-	-	-	-				-				-
17	*OTHER OPERATING REVENUE INCREASE*	44,999	138	7	12	3,106	1	5,863	1,065	160	3	0	95	0	34,234	206	91	0	17
18																			
19	*TOTAL INCREASE 1/1/2013*	378,000	5,831	477	2,791	3,106	35	70,036	26,001	5,076	4	559	1,352	126	254,214	8,225	91	59	17

Totals may not add due to rounding.

EXHIBIT "B"

Exhibit B

Tariff Sheets in Legislative and Clean Format

SERVICE CHARGES

A $14.88 service charge will be made for an initial connection.

A $17.66 Reconnection Charge will be made for the reconnection of service after disconnection for nonpayment or violation of a rule or regulation.

A $14.88 service charge will be made for the connection of an existing account.

A Returned Payment Charge ~~of $23.24 or 5% of the amount of the payment, whichever is greater, shall be added to the customer's bill for electric service for each payment dishonored by the bank upon which it is drawn~~ as allowed by Florida Statute 68.065 shall apply for each check or draft dishonored by the bank upon which it is drawn. Termination of service shall not be made for failure to pay the Returned Payment Charge.

Charges for services due and rendered which are unpaid as of the past due date are subject to a Late Payment Charge of the greater of $6.00 or 1.5% applied to any past due unpaid balance of all accounts, except the accounts of federal, state, and local governmental entities, agencies, and instrumentalities. A Late Payment Charge shall be applied to the accounts of federal, state, and local governmental entities, agencies, and instrumentalities at a rate no greater than allowed, and in a manner permitted, by applicable law.

A $5.11 Field Collection Charge will be added to a customer's bill for electric service when a field visit is made and payment is collected on a delinquent account. If service is disconnected, or a current receipt of payment is shown at the time of the field visit, this charge will not be applied.

FPL may waive the Reconnection Charge, Returned Payment Charge, Late Payment Charge and Field Collection Charge for Customers affected by natural disasters or during periods of declared emergencies or once in any twelve (12) month period for any Customer who would otherwise have had a satisfactory payment record (as defined in 25-6.097(2) F.A.C.), upon acceptance by FPL of a reasonable explanation justifying a waiver. In addition, FPL may waive the charge for connection of an existing account and the charge for an initial connection for new or existing Customers affected by natural disasters or during periods of declared emergencies.

CONSERVATION INSPECTIONS AND SERVICES

Residential Dwelling Units:
A charge of $15.00 will be made for a computerized energy analysis in which a comprehensive on-site evaluation of the residence is performed.

Commercial/Industrial:
There is no charge for conservation inspections and services (Business Energy Services).

TEMPORARY/CONSTRUCTION SERVICE

APPLICATION:

For short term electric service to installations such as fairs, exhibitions, construction projects, displays and similar installations.

SERVICE:

Single phase or three phase, 60 hertz at the available standard secondary distribution voltage. This service is available only when the Company has existing capacity in lines, transformers and other equipment at the requested point of delivery. The Customer's service entrance electrical cable shall not exceed 200 Amp capacity.

CHARGE:

The non-refundable charge must be paid in advance of installation of such facilities which shall include service and metering equipment.

Installing and removing overhead service and meter	$~~255.00~~297.00
Connecting and disconnecting Customer's service cable to Company's direct-buried underground facilities including installation and removal of meter	$~~142.00~~175.00

MONTHLY RATE:

This temporary service shall be billed under the appropriate rate schedule applicable to commercial and industrial type installations.

SPECIAL CONDITIONS:

If specific electrical service other than that stated above is required, the Company, at the Customer's request, will provide such service based on the estimated cost of installing and removing such additional electrical equipment. This estimated cost will be a contribution in aid of construction payable in advance to the Company and subject to adjustment after removal of the required facilities. All Temporary/Construction services shall be subject to all of the applicable Rules, Regulations and Tariff charges of the Company, including Service Charges.

INDEX OF RATE SCHEDULES

Issued by: S. E. Romig, Director, Rates and Tariffs
Effective: ~~January 3, 2012~~January 1, 2013

GENERAL SERVICE DEMAND

RATE SCHEDULE: GSD-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose with a measured Demand in excess of 20 kW and less than 500 kW. Customers with a Demand of 20 kW or less may enter an agreement for service under this schedule based on a Demand Charge for a minimum of 21 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	~~$16.44~~$18.00
Demand Charges:	
Base Demand Charge	~~$6.50~~$7.00 per kW
Capacity Payment Charge	See Sheet No. 8.030, per kW
Conservation Charge	See Sheet No. 8.030, per kW
Non-Fuel Energy Charges:	
Base Energy Charge	~~1.401~~1.500¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of 20 kW or less who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 21 kW times the Base Demand Charge; therefore the minimum charge is ~~$152.94,~~$165.00

DEMAND:

The Demand is the kW to the nearest whole kW, as determined from the Company's thermal type meter or, at the Company's option, integrating type meter for the 30-minute period of Customer's greatest use during the month as adjusted for power factor.

TERM OF SERVICE:

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

GENERAL SERVICE DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: GSDT-1

AVAILABLE:
In all territory served.

APPLICATION:
For electric service required for commercial or industrial lighting, power and any other purpose with a measured Demand in excess of 20 kW and less than 500 kW. Customers with Demands of less than 21 kW may enter an agreement for service under this schedule based on a Demand Charge for a minimum of 21 kW. This is an optional rate available to General Service Demand customers upon request subject to availability of meters.

SERVICE:
Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	~~$22.77~~$24.00	
Demand Charges:		
Base Demand Charge	~~$6.50~~$7.00 per kW of Demand occurring during the On-Peak period.	
Capacity Payment Charge	See Sheet No. 8.030, per kW of Demand occurring during the On-Peak period.	
Conservation Charge	See Sheet No. 8.030, per kW of Demand occurring during the On-Peak period.	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	~~3.121~~3.440¢ per kWh	~~0.654~~0.710¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 21 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 21 kW times the Base Demand Charge.

If the Customer elects to make a lump sum payment to the Company for time of use metering costs of ~~$379.80~~$360.00 the then Customer Charge and the Minimum Charge shall be ~~$16.44~~18.00 and ~~$152.94~~165.00, respectively.

RATING PERIODS:
On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.108)

GENERAL SERVICE CONSTANT USAGE

RATE SCHEDULE: GSCU-1

AVAILABLE:

In all territory served.

APPLICATION:

Available to General Service - Non Demand customers that maintain a relatively constant kWh usage, and a demand of 20 kW or less. Eligibility is restricted to General Service customers whose Maximum kWh Per Service Day, over the current and prior 23 months, is within 5% of their average monthly kWh per service days calculated over the same 24-month period. Customers under this Rate Schedule shall enter into a General Service Constant Use Agreement. This is an optional Rate Schedule available to General Service customers upon request.

SERVICE:

Single phase, 60 hertz and at any available standard voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	~~$6.00~~$12.00
Non-Fuel Energy Charges:	
Base Energy Charge*	~~3.446~~2.808¢ per Constant Usage kWh
Conservation Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.030
Capacity Payment Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.030
Environmental Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.030
Additional Charges:	
Fuel Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.030
Storm Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

* The fuel, storm and non-fuel energy charges will be assessed on the Constant Usage kWh

TERM OF SERVICE:

Initial term of service under this rate schedule shall be not less than one (1) billing period, unless there is a termination of service due to a Customer's violation of the General Service Constant Usage Agreement. Upon the Customer's violation of any of the terms of the General Service Constant Usage Agreement, service under this Rate Schedule will be terminated immediately. To terminate service, either party must provide thirty (30) days written notice to the other party prior to the desired termination date. Absent such notice, the term of service shall automatically be extended another billing period. In addition, if service under this Rate Schedule is terminated by either the Customer or the Company, the account may not resume service under this Rate Schedule for a period of at least one (1) year.

DEFINITIONS:

kWh Per Service Day – the total kWh in billing month divided by the number of days in the billing month

Maximum kWh Per Service Day - the highest kWh Per Service Day experienced over the current and prior 23 month billing periods

Constant Usage kWh – the Maximum kWh Per Service Day multiplied by the number of service days in the current billing period

(Continued on Sheet 8.123)

RESIDENTIAL SERVICE

RATE SCHEDULE: RS-1

AVAILABLE:

In all territory served.

APPLICATION:

For service for all domestic purposes in individually metered dwelling units and in duplexes and triplexes, including the separately-metered non-commercial facilities of a residential Customer (i.e., garages, water pumps, etc.). Also for service to commonly-owned facilities of condominium, cooperative and homeowners' associations as set forth on Sheet No. 8.211, Rider CU.

SERVICE:

Single phase, 60 hertz at available standard voltage. Three phase service may be furnished but only under special arrangements. All residential service required on the premises by Customer shall be supplied through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	~~$5.90~~$7.00
Non-Fuel Charges:	
Base Energy Charge:	
First 1,000 kWh	~~3.736~~4.036¢ per kWh
All additional kWh	~~4.736~~5.036¢ per kWh
Conservation Charge	See Sheet No. 8.030
Capacity Payment Charge	See Sheet No. 8.030
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Residential Load Management Program (if applicable)	See Sheet No. 8.207
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031
Minimum:	~~$5.90~~$7.00

TERM OF SERVICE:

Not less than one (1) billing period.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

RESIDENTIAL TIME OF USE RIDER – RTR-1
(OPTIONAL)

RIDER: RTR-1

AVAILABLE:
In all territory served.

APPLICATION:

For service for all domestic purposes in individually metered dwelling units and in duplexes and triplexes, including the separately-metered non-commercial facilities of a residential Customer (i.e., garages, water pumps, etc.). Also for service to commonly-owned facilities of condominium, cooperative and homeowners' associations as set forth on Sheet No. 8.211, Rider CU. This is an optional rider available to residential customers served under the RS-1 Rate Schedule subject to availability of meters. Customers taking service under RTR-1 are not eligible for service under Rate Schedule RLP.

SERVICE:
Single phase, 60 hertz at available standard voltage. Three phase may be supplied but only under special arrangements. All residential service required on the premises by Customer shall be supplied through one meter. Resale of service is not permitted hereunder.

Initial service under this rate schedule shall begin on the first scheduled meter reading date following the installation of the time of use meter. The Customer's first bill will reflect the lesser of the charges under Rate Schedule RS-1 or RTR-1.

MONTHLY RATE:

Except for the Customer Charge, all rates and charges under Rate Schedule RS-1 shall apply. In addition, the RTR-1 Customer Charge, the RTR-1 Base Energy and Fuel Charges and Credits applicable to on and off peak usage shall apply.

Customer Charge: $11.00

Base Energy Charges/Credits:	On-Peak Period	Off-Peak Period
Base Energy Charge	8.391¢ per kWh	(3.656)¢ per kWh

Additional Charges/Credits:
RTR Fuel Charge/Credit See Sheet No. 8.030

Minimum: $11.00
If the Customer elects to make a lump sum payment to the Company for time of use metering costs of $240.00, then the Customer Charge and Minimum Charge shall be $7.00.

RATING PERIODS:
On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

Issued by: S. E. Romig, Director, Rates and Tariffs
Effective:

RESIDENTIAL SERVICE - TIME OF USE
(OPTIONAL) (Closed Schedule)

RATE SCHEDULE: RST-1

AVAILABLE:
In all territory served.

APPLICATION:

For service for all domestic purposes in individually metered dwelling units and in duplexes and triplexes, including the separately-metered non-commercial facilities of a residential Customer (i.e., garages, water pumps, etc.). Also for service to commonly-owned facilities of condominium, cooperative and homeowners' associations as set forth on Sheet No. 8.211, Rider CU. This is an optional rate available to residential customers, ~~upon request subject to availability of meters~~provided the customer was taking service pursuant to this schedule as of December 31, 2012.

SERVICE:
Single phase, 60 hertz at available standard voltage. Three phase may be supplied but only under special arrangements. All residential service required on the premises by Customer shall be supplied through one meter. Resale of service is not permitted hereunder.

Initial service under this rate schedule shall begin on the first scheduled meter reading date following the installation of the time of use meter. The Customer's first bill will reflect the lesser of the charges under Rate Schedule RS-1 or RST-1.

MONTHLY RATE:

Customer Charge:	~~\$16.04~~\$11.00	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	~~7.759~~12.759¢ per kWh	~~2.479~~0.712¢ per kWh
Conservation Charge	See Sheet No. 8.030	
Capacity Payment Charge	See Sheet No. 8.030	
Environmental Charge	See Sheet No. 8.030	

Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: ~~\$16.04~~\$11.00
If the Customer elects to make a lump sum payment to the Company for time of use metering costs of ~~\$608.40,~~\$240.00, then the Customer Charge and Minimum Charge shall be ~~\$5.90.~~\$7.00.

RATING PERIODS:
On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.206)

GENERAL SERVICE LARGE DEMAND

RATE SCHEDULE: GSLD-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose to any Customer with a measured demand of 500 kW and less than 2,000 kW. Customers with demands of less than 500 kW may enter an agreement for service under this Rate Schedule based on a Demand Charge for a minimum of 500 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	~~$50.13~~$55.00
Demand Charges:	
Base Demand Charge	~~$7.60~~$8.00 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030
Conservation Charge	See Sheet No. 8.030
Non-Fuel Energy Charges:	
Base Energy Charge	~~0.922~~1.056¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charges	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 500 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 500 kW times the Base Demand Charge; therefore the minimum charge is ~~$3850.13.~~$4,055.00.

DEMAND:

The Demand is the kW to the nearest whole kW, as determined from the Company's thermal type meter or, at the Company's option, integrating type meter for the 30-minute period of Customer's greatest use during the month as adjusted for power factor.

TERM OF SERVICE:

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

GENERAL SERVICE LARGE DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE GSLDT-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose to any Customer with a measured demand of 500 kW and less than 2,000 kW. Customers with demands of less than 500 kW may enter an agreement for service under this schedule based on a Demand Charge for a minimum of 500 kW. This is an optional rate available to General Service Large Demand customers upon request subject to availability of meters.

SERVICE:

Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	~~$50.13~~$55.00	
Demand Charges:		
Base Demand Charge	~~$7.60~~$8.00 per kW of Demand occurring during the On-Peak period.	
Capacity Payment Charge	See Sheet No. 8.030	
Conservation Charge	See Sheet No. 8.030	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	~~2.047~~1.901¢ per kWh	~~0.426~~0.704¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for currently effective Base Demand. For those Customers with a Demand of less than 500 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 500 kW times the Base Demand Charge; therefore the minimum charge is ~~$3,850.13.~~$4,055.00.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.321)

CURTAILABLE SERVICE
(OPTIONAL)

RATE SCHEDULE: CS-1

AVAILABLE:
In all territory served.

APPLICATION:
For any commercial or industrial Customer who qualifies for Rate Schedule GSLD-1 (500 kW - 1,999 kW) and will curtail this Demand by 200 kW or more upon request of the Company from time to time. Customers with demands of at least 200 kW but less than 500 kW may enter an agreement for service under this Rate Schedule based on a Demand Charge for a minimum of 500 kW.

SERVICE:
Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	~~$50.13~~$80.00
Demand Charges:	
Base Demand Charge	~~$7.60~~$8.00 per kW of Demand.
Capacity Payment Charge	See Sheet No. 8.030
Conservation Charge	See Sheet No. 8.030
Non-Fuel Energy Charges:	
Base Energy Charge	~~0.922~~1.056¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 500 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 500 kW times the Base Demand Charge; therefore the minimum charge is ~~$3,850.13.~~$4,080.00.

CURTAILMENT CREDITS:
A monthly credit of $1.72 per kW is allowed based on the current Non-Firm Demand. The Customer has the option to revise the Firm Demand once during the initial twelve (12) month period. Thereafter, subject to the Term of Service and/or the Provisions for Early Termination, a change to the Firm Demand may be made provided that the revision does not decrease the total amount of Non-Firm Demand during the lesser of: (i) the average of the previous 12 months; or (ii) the average of the number of billing months under this Rate Schedule.

CHARGES FOR NON-COMPLIANCE OF CURTAILMENT DEMAND:
If the Customer records a higher Demand during the current Curtailment Period than the Firm Demand, the Customer will be:

1. Rebilled at $1.72/kW for the prior 36 months or the number of months since the prior Curtailment Period, whichever is less, and
2. Billed a penalty charge of $3.70/kW for the current month.

The kW used for both the rebilling and penalty charge calculations is determined by taking the difference between the maximum Demand during the current Curtailment Period and the Firm Demand for a Curtailment Period.

(Continued on Sheet No. 8.331)

CURTAILABLE SERVICE - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: CST-1

AVAILABLE:
In all territory served.

APPLICATION:
For any commercial or industrial Customer who qualifies for Rate Schedule GSLD-1 (500 kW - 1,999 kW) and will curtail this Demand by 200 kW or more upon request of the Company from time to time. This is an optional Rate Schedule available to Curtailable General Service Customers upon request. Customers with demands of at least 200 kW but less than 500 kW may enter an agreement for service under this Rate Schedule based on a Demand Charge for a minimum of 500 kW

SERVICE:

Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	~~$50.13~~$80.00	
Demand Charges:		
Base Demand Charge	~~$7.60~~$8.00 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030	
Conservation Charge	See Sheet No. 8.030	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	~~2.047~~1.901¢ per kWh	~~0.426~~0.704¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 500 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 500 kW times the Base Demand Charge; therefore the minimum charge is ~~$3,850.13~~$4,080.00

RATING PERIODS:

On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.341)

GENERAL SERVICE LARGE DEMAND

RATE SCHEDULE: GSLD-2

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose to any Customer with a measured demand of 2,000 kW or more. Customers with demands of less than 2,000 kW may enter an agreement for service under this schedule based on a demand charge for a minimum of 2,000 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	~~$179.19~~$195.00
Demand Charges:	
Base Demand Charge	~~$7.60~~$8.30 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030
Conservation Charge	See Sheet No. 8.030
Non-Fuel Energy Charges:	
Base Energy Charge	~~0.861~~0.950¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a demand of less than 2,000 kW who enter an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 2,000 kW times the Base Demand Charge; therefore the minimum charge is ~~$15,379.19.~~$16,795.00.

DEMAND:

The Demand is the kW to the nearest whole kW, as determined from the Company's metering equipment, for the 30-minute period of the Customer's greatest use during the month as adjusted for power factor.

TERM OF SERVICE:

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

GENERAL SERVICE LARGE DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: GSLDT-2

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose to any Customer who has established a measured demand of 2,000 kW or more. Customers with demands of less than 2,000 kW may enter an agreement for service under this schedule based on a demand charge for a minimum of 2,000 kW.

SERVICE:

Three phase, 60 hertz and at any available standard secondary or distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	~~$179.19~~$195.00	
Demand Charges:		
Base Demand Charge	~~$7.60~~$8.30 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030	
Conservation Charge	See Sheet No. 8.030	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	~~1.512~~1.620¢ per kWh	~~0.620~~0.697¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a demand of less than 2,000 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 2,000 kW times the Base Demand Charge; therefore the minimum charge is ~~$15,379.19~~$16,795.00

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.421)

HIGH LOAD FACTOR – TIME OF USE
(OPTIONAL)

RATE SCHEDULE: HLFT

AVAILABLE:
In all territory served.

APPLICATION:
For electric service required for commercial or industrial lighting, power and any other purpose with a measured Demand in excess of 20 kW. This is an optional rate schedule available to customers otherwise served under the GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, or GSLDT-2 Rate Schedules.

SERVICE:
Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:	HLFT-1	HLFT-2	HLFT-3
Annual Maximum Demand	21-499 kW	500-1,999 kW	2,000 kW or greater
Customer Charge:	~~$22.77~~$24.00	~~$50.13~~$55.00	~~$179.19~~$195.00
Demand Charges:			
On-peak Demand Charge	~~$7.83~~$8.40	~~$7.83~~$8.50	~~$7.83~~$8.50
Maximum Demand Charge	~~$1.81~~$1.90	~~$1.81~~$2.00	~~$1.81~~$2.00
Capacity Payment Charge	See Sheet No. 8.030, per kW of On-Peak Demand		
Conservation Charge	See Sheet No. 8.030, per kW of On-Peak Demand		
Non-Fuel Energy Charges:			
On-Peak Period per kWh	~~1.198~~1.218¢	~~0.546~~0.572¢	~~0.513~~0.526¢
Off-Peak Period per kWh	~~0.654~~0.710¢	~~0.546~~0.572¢	~~0.513~~0.526¢
Environmental Charge	See Sheet No. 8.030		
Additional Charges			
Fuel Charge	See Sheet No. 8.030		
Storm Charge	See Sheet No. 8.040		
Franchise Fee	See Sheet No. 8.031		
Tax Clause	See Sheet No. 8.031		

Minimum Charge: The Customer Charge plus the currently effective Demand Charges.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.426)

Issued by: S. E. Romig, Director, Rates and Tariffs
Effective: January ~~3, 2012~~1, 2013

CURTAILABLE SERVICE
(OPTIONAL)

RATE SCHEDULE: CS-2

AVAILABLE:

In all territory served.

APPLICATION:

For any commercial or industrial Customer who qualifies for Rate Schedule GSLD-2 (2,000 kW and above) and will curtail this Demand by 200 kW or more upon request of the Company from time to time. Customers with demands of less than 2,000 kW may enter an Agreement for service under this schedule based on a Demand Charge for a minimum of 2,000 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	~~$179.19~~$220.00
Demand Charges:	
Base Demand Charge	~~$7.60~~$8.30 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030
Conservation Charge	See Sheet No. 8.030
Non-Fuel Energy Charges:	
Base Energy Charge	~~0.861~~0.950¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 2,000 kW who enter an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 2,000 kW times the Base Demand Charge; therefore the minimum charge is ~~$15,379.19.~~$16,820.00.

CURTAILMENT CREDITS:

A monthly credit of $1.72 per kW is allowed based on the current Non-Firm Demand. The Customer has the option to revise the Firm Demand once during the initial twelve (12) month period. Thereafter, subject to the Term of Service and/or the Provisions for Early Termination, a change to the Firm Demand may be made provided that the revision does not decrease the total amount of Non-Firm Demand during the lesser of: (i) the average of the previous 12 months; or (ii) the average of the number of billing months under this Rate Schedule.

CHARGES FOR NON-COMPLIANCE OF CURTAILMENT DEMAND:

If the Customer records a higher Demand during the current period than the Firm Demand, then the Customer will be:

1. Rebilled at $1.72/kW for the prior 36 months or the number of months since the prior Curtailment Period, whichever is less, and
2. Billed a penalty charge of $3.70/kW for the current month.

The kW used for both the rebilling and penalty charge calculations is determined by taking the difference between the maximum Demand during the current Curtailment Period and the contracted Firm Demand for a Curtailment Period.

(Continued on Sheet No. 8.433)

CURTAILABLE SERVICE - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: CST-2

AVAILABLE:
In all territory served.

APPLICATION:
For any commercial or industrial Customer who qualifies for Rate Schedule GSLDT-2 (2,000 kW and above) and will curtail this Demand by 200 kW or more upon request of the Company from time to time. Customers with demands of less than 2,000 kW may enter an agreement for service under this schedule based on a Demand Charge for a minimum of 2,000 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	~~$179.19~~$220.00	
Demand Charges:		
Base Demand Charge	~~$7.60~~$8.30 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030	
Conservation Charge	See Sheet No. 8.030	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	~~1.512~~1.620¢ per kWh	~~0.620~~0.697¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 2,000 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 2,000 kW times the Base Demand Charge; therefore the minimum charge is ~~$15,379.19.~~$16,820.00.

RATING PERIODS:

On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.441)

CURTAILABLE SERVICE - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: CST-3

AVAILABLE:

In all territory served.

APPLICATION:

For any commercial or industrial Customer who qualifies for Rate Schedule GSLDT-3 and will curtail this Demand by 200 kW or more upon request of the Company from time to time.

SERVICE:

Three phase, 60 hertz at the available transmission voltage of 69 kV or higher. The Customer will provide and maintain all transformers and related facilities necessary for handling and utilizing the power and energy delivered hereunder. All service required by the Customer at each separate point of delivery served hereunder shall be furnished through one meter at, or compensated to, the available transmission voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	~~$1,441.88~~$1,466.88	
Demand Charges:		
Base Demand Charge	$6.32 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030.1	
Conservation Charge	See Sheet No. 8.030.1	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	0.739¢ per kWh	0.604¢ per kWh
Environmental Charge	See Sheet No. 8.030.1	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030.1	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.543)

CURTAILABLE SERVICE
(OPTIONAL)

RATE SCHEDULE: CS-3

AVAILABLE:
In all territory served.

APPLICATION:
For any commercial or industrial Customer who qualifies for Rate Schedule GSLD-3 and will curtail this Demand by 200 kW or more upon request of the Company from time to time.

SERVICE:
Three phase, 60 hertz at the available transmission voltage of 69 kV or higher. The Customer will provide and maintain all transformers and related facilities necessary for handling and utilizing the power and energy delivered hereunder. All service required by the Customer at each separate point of delivery served hereunder shall be furnished through one meter at, or compensated to, the available transmission voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	~~$1,441.88~~$1,466.88
Demand Charges:	
Base Demand Charge	$6.32 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030.1
Conservation Charge	See Sheet No. 8.030.1
Non-Fuel Energy Charges:	
Base Energy Charge	0.640¢ per kWh
Environmental Charge	See Sheet No. 8.030.1
Additional Charges:	
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum Charge: The Customer Charge plus the charge for the currently effective Base Demand.

CURTAILMENT CREDITS:
A monthly credit of $1.72 per kW is allowed based on the current Non-Firm Demand. The Customer has the option to revise the Firm Demand once during the initial twelve (12) month period. Thereafter, subject to the Term of Service and/or the Provisions for Early Termination, a change to the Firm Demand may be made provided that the revision does not decrease the total amount of Non-Firm Demand during the lesser of: (i) the average of the previous 12 months; or (ii) the average of the number of billing months under this Rate Schedule.

CHARGES FOR NON-COMPLIANCE OF CURTAILMENT DEMAND:

If the Customer records a higher Demand during the current Curtailment Period than the Firm Demand, then the Customer will be:
1. Rebilled at $1.72/kW for the prior 36 months or the number of months since the prior Curtailment Period, whichever is less, and
2. Billed a penalty charge of $3.70/kW for the current month.

The kW used for both the rebilling and penalty charge calculations is determined by taking the difference between the maximum Demand during the current Curtailment Period and the Firm Demand for a Curtailment Period.

(Continued on Sheet No. 8.546)

SPORTS FIELD SERVICE
(Closed Schedule)

RATE SCHEDULE: OS-2

AVAILABLE:

In all territory served.

APPLICATION:

This is a transitional rate available to municipal, county and school board accounts for the operation of a football, baseball or other playground, or civic or community auditorium, when all such service is taken at the available primary distribution voltage at a single point of delivery and measured through one meter, and who were active as of October 4, 1981. Customer may also elect to receive service from other appropriate rate schedules.

LIMITATION OF SERVICE:

Offices, concessions, businesses or space occupied by tenants, other than areas directly related to the operations above specified, are excluded hereunder and shall be separately served by the Company at utilization voltage. Not applicable when Rider TR is used.

MONTHLY RATE:

Customer Charge:	~~$97.28~~$103.00
Non-Fuel Energy Charges:	
Base Energy Charge	~~4.885~~5.928¢ per kWh
Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Additional Charges:	
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031
Minimum Charge:	~~$97.28~~$103.00

TERM OF SERVICE:

Pending termination by Florida Public Service Commission Order.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

METROPOLITAN TRANSIT SERVICE

RATE SCHEDULE: MET

AVAILABLE:

For electric service to Metropolitan Dade County Electric Transit System (METRORAIL) at each point of delivery required for the operation of an electric transit system on continuous and contiguous rights-of-way.

APPLICATION:

Service to be supplied will be three phase, 60 hertz and at the standard primary voltage of 13,200 volts. All service required by Customer at each separate point of delivery served hereunder shall be furnished through one meter reflecting delivery at primary voltage. Resale of service is not permitted hereunder. Rider TR or a voltage discount is not applicable.

MONTHLY RATE:

Customer Charge:	~~$373.94~~$400.00
Demand Charges:	
Base Demand Charge	~~$9.28~~$10.60 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030.1
Conservation Charge	See Sheet No. 8.030.1
Non-Fuel Energy Charges:	
Base Energy Charge	~~0.846~~1.248¢ per kWh
Environmental Charge	See Sheet No. 8.030.1
Additional Charges:	
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand.

DEMAND:

The billing Demand is the kW, at each point of delivery, to the nearest whole kW, as determined from the Company's recording type metering equipment, for the period coincident with the 30-minute period of the electric rail transit system's greatest use supplied by the Company during the month adjusted for power factor.

BILLING:

Each point of delivery shall be separately billed according to the monthly charges as stated herein. All billing units related to charges under this rate schedule shall be determined from metering data on a monthly basis and determined for each point of delivery on the same monthly billing cycle day.

TERMS OF SERVICE

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

(Continued from Sheet No. 8.650)

MONTHLY RATE:

Delivery Voltage Level	Distribution below 69 kV		69 kV & above
	CILC-1(G)	CILC-1(D)	CILC-1(T)
Maximum Demand Level	200-499 kW	500 kW & above	
Customer Charge:	~~$122.00~~$100.00	~~$175.00~~$150.00	~~$1,866.00~~$1,975.00
Demand Charges:			
Base Demand Charges:			
per kW of Maximum Demand	~~$3.20~~$3.40	~~$3.17~~$3.10	None
per kW of Load Control On-Peak Demand	~~$1.32~~$1.30	~~$1.35~~$1.30	~~$1.29~~$1.30
per kW of Firm On-Peak Demand	~~$6.92~~$7.31	~~$7.12~~$7.11	~~$6.79~~$7.25

Capacity Payment and Conservation Charge:

CILC-1(G)	See Sheet No. 8.030.1
CILC-1(D)	See Sheet No. 8.030.1
CILC-1(T)	See Sheet No. 8.030.1

Non-Fuel Energy Charges:			
Base Energy Charges:			
On-Peak Period charge per kWh	~~1.175~~1.074¢	~~0.646~~0.542¢	~~0.599~~0.471¢
Off-Peak Period charge per kWh	~~1.175~~1.074¢	~~0.646~~0.542¢	~~0.599~~0.471¢

Environmental Charge See Sheet No. 8.030.1

Additional Charges:

Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the Base Demand Charges.

(Continued on Sheet No. 8.652)

COMMERCIAL/INDUSTRIAL DEMAND REDUCTION RIDER (CDR)
(OPTIONAL)

AVAILABLE:

In all territory served. Available to any commercial or industrial customer receiving service under Rate Schedules GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, GSLDT-2, GSLD-3, GSLDT-3, or HLFT through the execution of a Commercial/Industrial Demand Reduction Rider Agreement in which the load control provisions of this rider can feasibly be applied.

LIMITATION OF AVAILABILITY:

This Rider may be modified or withdrawn subject to determinations made under Commission Rules 25-17.0021(4), F.A.C., Goals for Electric Utilities and 25-6.0438, F.A.C., Non-Firm Electric Service - Terms and Conditions or any other Commission determination.

APPLICATION:

For electric service provided to any commercial or industrial customer receiving service under Rate Schedule GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, GSLDT-2, GSLD-3, GSLDT-3, or HLFT who as a part of the Commercial/Industrial Demand Reduction Rider Agreement between the Customer and the Company, agrees to allow the Company to control at least 200 kW of the Customer's load, or agrees to operate Backup Generation Equipment (see Definitions) and designate (if applicable) additional controllable demand to serve at least 200 kW of the Customer's own load during periods when the Company is controlling load. A Customer shall enter into a Commercial/Industrial Reduction Demand Rider Agreement with the Company to be eligible for this Rider. To establish the initial qualification for this Rider, the Customer must have had a Utility Controlled Demand during the summer Controllable Rating Period (April 1 through October 31) for at least three out of seven months of at least 200 kW greater than the Firm Demand level specified in Section 4 of the Commercial/Industrial Demand Reduction Rider Agreement. The Utility Controlled Demand shall not be served on a firm service basis until service has been terminated under this Rider.

LIMITATION OF SERVICE:

Customers participating in the General Service Load Management Program (FPL "Business On Call" Program) are not eligible for this Rider.

MONTHLY RATE:

All rates and charges under Rate Schedules GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, GSLDT-2, GSLD-3, GSLDT-3, HLFT shall apply. In addition, the applicable Monthly Administrative Adder and Utility Controlled Demand Credit shall apply.

MONTHLY ADMINISTRATIVE ADDER:

Rate Schedule	Adder
GSD-1	~~$570.14~~$75.00
GSDT-1, HLFT (21-499 kW)	~~$563.58~~$75.00
GSLD-1, GSLDT-1, HLFT (500-1,999 kW)	~~$564.07~~$125.00
GSLD-2, GSLDT-2, HLFT (2,000 kW or greater)	~~$433.91~~$50.00
GSLD-3, GSLDT-3	~~$2,825.46~~$475.00

UTILITY CONTROLLED DEMAND CREDIT:

A monthly credit **of ~~$4.68~~7.30** per kW is allowed based on the Customer's Utility Controlled Demand.

UTILITY CONTROLLED DEMAND:

The Utility Controlled Demand for a month in which there are no load control events during the Controllable Rating Period shall be the sum of the Customer's kWh usage during the hours of the applicable Controllable Rating Period, divided by the total number of hours in the applicable Controllable Rating Period, less the Customer's Firm Demand.

In the event of Load Control occurring during the Controllable Rating Period, the Utility Controlled Demand shall be the sum of the Customer's kWh usage during the hours of the applicable Controllable Rating Period less the sum of the Customer's kWh usage during the Load Control Period, divided by the number of non-load control hours occurring during the applicable Controllable Rating Period, less the Customer's Firm Demand.

(Continued on Sheet No. 8.681)

(Continued from Sheet No. 8.681)

PROVISIONS FOR ENERGY USE DURING CONTROL PERIODS:

Customers notified of a load control event should not exceed their Firm Demand during periods when the Company is controlling load. However, electricity will be made available during control periods if the Customer's failure to meet its Firm Demand is a result of one of the following conditions:

1. Force Majeure events (see Definitions) which can be demonstrated to the satisfaction of the Company, or
2. maintenance of generation equipment necessary for the implementation of load control which is performed at a pre-arranged time and date mutually agreeable to the Company and the Customer (See Special Provisions), or
3. adding firm load that was not previously non-firm load to the Customer's facility, or
4. an event affecting local, state or national security, or
5. an event whose nature requires that space launch activities be placed in the critical mode (requiring a closed-loop configuration of FPL's transmission system) as designated and documented by the NASA Test Director at Kennedy Space Center and/or the USAF Range Safety Officer at Cape Canaveral Air Force Station.

The Customer's energy use (in excess of the Firm Demand) for the conditions listed above will be billed pursuant to the Continuity of Service Provision. For periods during which power under the Continuity of Service Provision is no longer available, the Customer will be billed, in addition to the normal charges provided hereunder, the greater of the Company's As-Available Energy cost, or the most expensive energy (calculated on a cents per kilowatt-hour basis) that FPL is purchasing or selling during that period, less the applicable class fuel charge. As-Available Energy cost is the cost calculated for Schedule COG-1 in accordance with FPSC Rule 25-17.0825, F.A.C.

If the Company determines that the Customer has utilized one or more of the exceptions above in an excessive manner, the Company will terminate service under this rider as described in TERM OF SERVICE.

If the Customer exceeds the Firm Demand during a period when the Company is controlling load for any reason other than those specified above, then the Customer will be:

1. billed a ~~$4.68~~ $7.30 charge per kW of excess kW for the prior sixty (60) months or the number of months the Customer has been billed under this rider, whichever is less, and
2. billed a penalty charge of $0.99 per kW of excess kW for each month of rebilling.

Excess kW for rebilling and penalty charges is determined by taking the difference between the Customer's kWh usage during the load control period divided by the number of hours in the load control period and the Customer's "Firm Demand". The Customer will not be rebilled or penalized twice for the same excess kW in the calculation described above.

(Continued on Sheet No. 8.683)

(Continued from Sheet No. 8.683)

In the event the Customer pays the Charges for Early Termination because no replacement Customer(s) is (are) available as specified in paragraph d. above, but the replacement Customer(s) does(do) become available within twelve (12) months from the date of termination of service under this Rider or FPL later determines that there is no need for the MW reduction in accordance with the FPL Numeric Commercial/Industrial Conservation Goals, then the Customer will be refunded all or part of the rebilling and penalty in proportion to the amount of MW obtained to replace the lost capacity less the additional cost incurred by the Company to serve those MW during any load control periods which may occur before the replacement Customer(s) became available.

Charges for Early Termination:

In the event that:

a) service is terminated by the Company for any reason(s) specified in this section, or

b) there is a termination of the Customer's existing service and, within twelve (12) months of such termination of service, the Company receives a request to re-establish service of similar character under a firm service or a curtailable service rate schedule, or under this rider with a shift from non-firm load to firm service,

   i) at a different location in the Company's service area, or

   ii) under a different name or different ownership, or

   iii) under other circumstances whose effect would be to increase firm demand on the Company's system without the requisite five (5) years' advance written notice, or

c) the Customer transfers the controllable portion of the Customer's load to "Firm Demand" or to a firm or a curtailable service rate schedule without providing at least five (5) years' advance written notice,

then the Customer will be:

1. rebilled ~~$4.68~~ $7.30 per kW of Utility Controlled Demand for the shorter of (a) the most recent prior sixty (60) months during which the Customer was billed for service under this Rider, or (b) the number of months the Customer has been billed under this Rider, and

2. billed a penalty charge of $0.99 per kW of Utility Controlled Demand times the number of months rebilled in No. 1 above.

SPECIAL PROVISIONS:

1. Control of the Customer's load shall be accomplished through the Company's load management systems by use of control circuits connected directly to the Customer's switching equipment or the Customer's load may be controlled by use of an energy management system where the firm demand level can be established or modified only by means of joint access by the Customer and the Company.

2. The Customer shall grant the Company reasonable access for installing, maintaining, inspecting, testing and/or removing Company-owned load control equipment.

3. It shall be the responsibility of the Customer to determine that all electrical equipment to be controlled is in good repair and working condition. The Company will not be responsible for the repair, maintenance or replacement of the Customer's electrical equipment.

4. The Company is not required to install load control equipment if the installation cannot be economically justified.

5. Credits under this Rider will commence after the installation, inspection and successful testing of the load control equipment.

6. Maintenance of equipment (including generators) necessary for the implementation of load control will not be scheduled during periods where the Company projects that it would not be able to withstand the loss of its largest unit and continue to serve firm service customers.

(Continued on Sheet No. 8.685)

(Continued from Sheet No. 8.715)

REMOVAL OF FACILITIES:

If Street Lighting facilities are removed either by Customer request or termination or breach of the agreement, the Customer shall pay FPL an amount equal to the original installed cost of the removed facilities less any salvage value and any depreciation (based on current depreciation rates as approved by the Florida Public Service Commission) plus removal cost.

MONTHLY RATE:

Luminaire Type		Lamp Size Initial Lumens	Watts	kWh/Mo. Estimate	Charge for FPL-Owned Unit ($) Fixtures	Mainte-nance	Energy Non-Fuel **	Total ***	Charge for Customer-Owned Unit $) Relamping/ Energy ****	Energy Only
High Pressure Sodium Vapor		~~5,800~~6,300	70	29	~~$3.91~~3.46	~~1.17~~1.62	~~0.79~~0.69	~~5.87~~5.77	~~1.38~~2.34	~~0.79~~0.69
" "		9,500	100	41	~~$3.98~~3.52	~~1.18~~1.63	~~1.12~~0.98	~~6.28~~6.13	~~1.73~~2.64	~~1.12~~0.98
" "		16,000	150	60	~~$4.11~~3.63	~~1.20~~1.66	~~1.63~~1.43	~~6.94~~6.72	~~2.23~~3.12	~~1.63~~1.43
" "		22,000	200	88	~~$6.22~~5.50	~~1.55~~2.12	~~2.39~~2.10	~~10.16~~9.72	~~3.16~~4.23	~~2.39~~2.10
" "		50,000	400	168	~~$6.29~~5.56	~~1.53~~2.13	~~4.57~~4.00	~~12.39~~11.69	~~5.35~~6.14	~~4.57~~4.00
	*	12,800	150	60	~~$4.27~~3.78	~~1.35~~1.86	~~1.63~~1.43	~~7.25~~7.07	~~2.37~~3.29	~~1.63~~1.43
" "	*	27,500	250	116	~~$6.61~~5.85	~~1.63~~2.31	~~3.16~~2.76	~~11.40~~10.92	~~3.97~~5.07	~~3.16~~2.76
" "	*	140,000	1,000	411	~~$9.95~~8.80	~~3.00~~4.14	~~11.18~~9.79	~~24.13~~22.73	~~12.98~~14.01	~~11.18~~9.79
Mercury Vapor	*	6,000	140	62	~~$3.09~~2.73	~~1.06~~1.46	~~1.69~~1.48	~~5.84~~5.67	~~2.28~~2.97	~~1.69~~1.48
" "	*	8,600	175	77	~~$3.13~~2.77	~~1.06~~1.46	~~2.10~~1.83	~~6.29~~6.06	~~2.70~~3.32	~~2.10~~1.83
" "	*	11,500	250	104	~~$5.23~~4.63	~~1.53~~2.11	~~2.83~~2.48	~~9.59~~9.22	~~3.47~~4.63	~~2.83~~2.48
" "	*	21,500	400	160	~~$5.21~~4.61	~~1.50~~2.07	~~4.35~~3.81	~~11.06~~10.49	~~4.97~~5.92	~~4.35~~3.81
" "	*	39,500	700	272	~~$7.37~~6.52	~~2.55~~3.52	~~7.40~~6.48	~~17.32~~16.52	~~7.44~~10.00	~~7.40~~6.48
" "	*	60,000	1,000	385	~~$7.54~~6.67	~~2.49~~3.44	~~10.48~~9.17	~~20.51~~19.28	~~11.33~~12.67	~~10.48~~9.17
Incandescent	*	1,000	103	36				~~7.78~~6.90	~~2.87~~4.16	~~0.98~~0.86
"	*	2,500	202	71				~~8.21~~7.30	~~3.83~~5.01	~~1.93~~1.69
"	*	4,000	327	116				~~9.79~~8.73	~~5.11~~6.18	~~3.16~~2.76
~~"~~	~~*~~	~~6,000~~	~~448~~	~~158~~				~~11.04~~	~~6.25~~	~~4.30"~~
~~*~~		~~10,000~~	~~690~~	~~244~~				~~13.56~~	~~8.73~~	~~6.64~~
Fluorescent	*	19,800	300	122				-	~~4.32~~4.67	~~3.32~~2.91
~~"~~	~~*~~	~~39,600~~	~~700~~	~~264~~					~~8.48~~	~~7.18~~

* These units are closed to new FPL installations.
** The non-fuel energy charge is ~~2.721~~2.383¢ per kWh.
*** Bills rendered based on "Total" charge. Unbundling of charges is not permitted.
**** New Customer installations of those units closed to FPL installations cannot receive relamping service.

Charges for other FPL-owned facilities:

Wood pole used only for the street lighting system	~~$2.80~~4.19
Concrete pole used only for the street lighting system	~~$3.85~~5.76
Fiberglass pole used only for the street lighting system	~~$4.55~~6.81
Steel pole used only for the street lighting system *	$5.76
Underground conductors not under paving	~~2.10~~3.29¢ per foot
Underground conductors under paving	~~5.14~~8.05¢ per foot

The Underground conductors under paving charge will not apply where a CIAC is paid pursuant to section "a)" under "Customer Contributions." The Underground conductors not under paving charge will apply in these situations.

(Continued on Sheet No. 8.717)

(Continued from Sheet No. 8.716)

On Customer-owned Street Lighting Systems, where Customer contracts to relamp at no cost to FPL, the Monthly Rate for non-fuel energy shall be ~~2.721~~2.383¢ per kWh of estimated usage of each unit plus adjustments. On Street Lighting Systems, where the Customer elects to install Customer-owned monitoring systems, the Monthly Rate for non-fuel energy shall be ~~2.721~~2.383¢ per kWh of estimated usage of each monitoring unit plus adjustments. The minimum monthly kWh per monitoring device will be 1 kilowatt-hour per month, and the maximum monthly kWh per monitoring device will be 5 kilowatt-hours per month.

During the initial installation period:
Facilities in service for 15 days or less will not be billed;
Facilities in service for 16 days or more will be billed for a full month.

WILLFUL DAMAGE:

Upon the **second** occurrence of willful damage to any FPL-owned facilities, the Customer will be responsible for the cost incurred for repair or replacement. If the lighting fixture is damaged, based on prior written instructions from the Customer, FPL will:

a) Replace the fixture with a shielded cutoff cobrahead. The Customer shall pay $280.00 for the shield plus all associated costs. However, if the Customer chooses to have the shield installed after the first occurrence, the Customer shall only pay the $280.00 cost of the shield; or

b) Replace with a like unshielded fixture. For this, and each subsequent occurrence, the Customer shall pay the costs specified under "Removal of Facilities"; or

c) Terminate service to the fixture.

Option selection shall be made by the Customer in writing and apply to all fixtures which FPL has installed on the Customer's behalf. Selection changes may be made by the Customer at any time and will become effective ninety (90) days after written notice is received.

Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

SPECIAL CONDITIONS:

Customers whose lights are turned off during sea turtle nesting season will receive a credit equal to the fuel charges associated with the fixtures that are turned off.

TERM OF SERVICE:

Initial term of ten (10) years with automatic, successive five (5) year extensions unless terminated in writing by either FPL or the Customer at least ninety (90) days prior to the current term's expiration.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service", the provision of this schedule shall apply.

PREMIUM LIGHTING

RATE SCHEDULE: PL-1

AVAILABLE:

In all territory served.

APPLICATION:

FPL-owned lighting facilities not available under rate schedule SL-1 and OL-1. To any Customer for the sole purpose of lighting streets, roadways and common areas, other than individual residential locations. This includes but is not limited to parking lots, homeowners association common areas, or parks.

SERVICE:

Service will be unmetered and will include lighting installation, lamp replacement and facilities maintenance for FPL-owned lighting systems. It will also include energy from dusk each day until dawn the following day.

The Company, while exercising reasonable diligence at all times to furnish service hereunder, does not guarantee continuous lighting and will not be liable for damages for any interruption, deficiency or failure of service, and reserves the right to interrupt service at any time for necessary repairs to lines or equipment.

LIMITATION OF SERVICE:

Installation shall be made only when, in the judgement of the Company, the location and the type of the facilities are, and will continue to be, easily and economically accessible to the Company equipment and personnel for both construction and maintenance.

Stand-by, non-firm, or resale service is not permitted hereunder.

TERM OF SERVICE:

The term of service is (20) twenty years. At the end of the term of service, the Customer may elect to execute a new agreement based on the current estimated replacement costs. The Company will retain ownership of these facilities.

FACILITIES PAYMENT OPTION:

The Customer will pay for the facilities in a lump sum in advance of construction. The amount will be the Company's total work order cost for these facilities times the Present Value Revenue Requirement (PVRR) multiplier of ~~1.4094.~~1.1941. Monthly Maintenance and Energy charges will apply for the term of service.

FACILITIES SELECTION:

Facilities selection shall be made by the Customer in writing by executing the Company's Premium Lighting Agreement.

(Continued on Sheet No. 8.721)

(Continued from Sheet No. 8.720)

MONTHLY RATE :

Facilities:

Paid in full:	Monthly rate is zero, for Customer's who have executed a Premium Lighting Agreement before March 1, 2010:
10 years payment option:	~~1.565~~1.362% of total work order cost.
20 years payment option:	~~1.038~~0.925% of total work order cost.
Maintenance:	FPL's estimated costs of maintaining lighting facilities.
Billing:	FPL reserves the right to assess a charge for the recovery of any dedicated billing system developed solely for this rate.
Energy:	KWH Consumption for fixtures shall be estimated using the following formula:

$$KWH = \frac{\text{Unit Wattage (usage)} \times 353.3 \text{ hours per month}}{1000}$$

Non-Fuel Energy	~~2.721~~2.383¢/kWh
Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

During the initial installation period:
Facilities in service for 15 days or less will not be billed;
Facilities in service for 16 days or more will be billed for a full month.

MINIMUM MONTHLY BILL:

The minimum monthly bill shall be the applicable Facilities Maintenance and Billing charges.

(Continued on Sheet No. 8.722)

(Continued from Sheet No. 8.721)

EARLY TERMINATION:

If the Customer no longer wishes to receive service under this schedule, the Customer may terminate the Premium Lighting Agreement by giving at least (90) ninety days advance written notice to the Company. Upon early termination of service, the Customer shall pay an amount computed by applying the following Termination Factors to the installed cost of the facilities, based on the year in which the Agreement was terminated. These Termination Factors will not apply to Customers who elected to pay for the facilities in a lump sum in lieu of a monthly payment.

FPL may also charge the Customer for the cost to the utility for removing the facilities.

Ten (10) Years Payment Option	Termination Factor	Twenty (20) Years Payment Option	Termination Factor
1	~~1.4094~~1.1941	1	~~1.4094~~1.1941
2	~~1.2216~~1.0306	2	~~1.2848~~1.0831
3	~~1.1198~~0.9473	3	~~1.2505~~1.0563
4	~~1.0108~~0.8575	4	~~1.2139~~1.0275
5	~~0.8941~~0.7608	5	~~1.1746~~0.9965
6	~~0.7692~~0.6565	6	~~1.1326~~,0.9630
7	~~0.6355~~0.5441	7	~~1.0876~~0.9269
8	~~0.4924~~0.4230	8	~~1.0395~~0.8880
9	~~0.3393~~0.2924	9	~~0.9880~~0.8461
10	~~0.1754~~0.1517	10	~~0.9328~~0.8009
>10	0.0000	11	~~0.8738~~0.7523
		12	~~0.8107~~0.6998
		13	~~0.74310~~0.6432
		14	~~0.6707~~0.5823
		15	~~0.5933~~0.5166
		16	~~0.5104~~0.4458
		17	~~0.4217~~0.3695
		18	~~0.3268~~0.2872
		19	~~0.2252~~0.1985
		20	~~0.1164~~0.1030
		>20	0.0000

WILLFUL DAMAGE:

In the event of willful damage to these facilities, FPL will provide the initial repair of each installed item at its expense. Upon the second occurrence of willful damage, and subsequent occurrence to these FPL-owned facilities, the Customer will be responsible for the cost for repair or replacement.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service", the provision of this schedule shall apply.

OUTDOOR LIGHTING

RATE SCHEDULE OL-1

AVAILABLE:

In all territory served.

APPLICATION:

For year-round outdoor security lighting of yards, walkways and other areas. Lights to be served hereunder shall be at locations which are easily and economically accessible to Company equipment and personnel for construction and maintenance.

It is intended that Company-owned security lights will be installed on existing Company-owned electric facilities, or short extension thereto, in areas where a street lighting system is not provided or is not sufficient to cover the security lighting needs of a particular individual or location. Where more extensive security lighting is required, such as for large parking lots or other commercial areas, the Customer will provide the fixtures, supports and connecting wiring; the Company will connect to the Customer's system and provide the services indicated below.

SERVICE:

Service includes lamp renewals, energy from approximately dusk each day until approximately dawn the following day, and maintenance of Company-owned facilities. The Company will replace all burned-out lamps and will maintain its facilities during regular daytime working hours as soon as practicable following notification by the Customer that such work is necessary. The Company shall be permitted to enter the Customer's premises at all reasonable times for the purpose of inspecting, maintaining, installing and removing any or all of its equipment and facilities.

The Company, while exercising reasonable diligence at all times to furnish service hereunder, does not guarantee continuous lighting and will not be liable for damages for any interruption, deficiency or failure of service, and reserves the right to interrupt service at any time for necessary repairs to lines or equipment.

LIMITATION OF SERVICE:

This schedule is not available for service normally supplied on the Company's standard street lighting schedules. Company-owned facilities will be installed only on Company-owned poles. Customer-owned facilities will be installed only on Customer-owned poles. Overhead conductors will not be installed in any area designated as an underground distribution area, or any area, premises or location served from an underground source. Stand-by or resale service not permitted hereunder.

MONTHLY RATE:

Luminaire Type	Lamp Size Initial Lumens/Watts		KWH/Mo. Estimate	Charge for Company-Owned Unit ($) Fixtures	Mainte-nance	Energy Non-Fuel **	Total	Charge for Customer-Owned Unit ($) Relamping/ Energy	Energy Only
High Pressure Sodium Vapor	~~5,800~~6,300	70	29	4.49	~~1.03~~1.64	~~0.85~~0.70	~~6.37~~6.83	~~0.97~~2.34	~~0.85~~0.70
" "	9,500	100	41	4.59	~~1.03~~1.64	~~1.20~~0.99	~~6.82~~7.22	~~1.16~~2.63	~~1.20~~0.99
" "	16,000	150	60	4.75	~~1.05~~1.67	~~1.76~~1.44	~~7.56~~7.86	~~1.44~~3.11	~~1.76~~1.44
" "	22,000	200	88	6.91	~~1.36~~2.16	~~2.58~~2.12	~~10.85~~11.19	~~1.88~~4.28	~~2.58~~2.12
" "	50,000	400	168	7.35	~~1.34~~2.13	~~4.93~~4.04	~~13.62~~13.52	~~3.12~~6.17	~~4.93~~4.04
" " *	12,000	150	60	5.10	~~1.20~~1.91	~~1.76~~1.44	~~8.06~~8.45	~~1.65~~3.35	~~1.76~~1.44
Mercury Vapor *	6,000	140	62	3.45	~~0.93~~1.48	~~1.82~~1.49	~~6.20~~6.42	~~1.47~~2.97	~~1.82~~1.49
" " *	8,600	175	77	3.47	~~0.93~~1.48	~~2.26~~1.85	~~6.66~~6.80	~~1.70~~3.33	~~2.26~~1.85
" " *	21,500	400	160	5.68	~~1.31~~2.08	~~4.69~~3.85	~~11.68~~11.61	~~2.98~~5.93	~~4.69~~ 3.85

* These units are closed to new Company installations.

** The non-fuel energy charge is ~~2.934~~2.405¢ per kWh.

(Continued on Sheet No. 8.726)

(Continued from Sheet No. 8.725)

Charges for other Company-owned facilities:

Wood pole and span of conductors:	~~$3.51~~8.62
Concrete pole and span of conductors:	~~$4.72~~11.64
Fiberglass pole and span of conductors:	~~$5.55~~13.67
Steel pole used only for the street lighting system *	$11.64
Underground conductors (excluding trenching)	~~$0.017~~0.069 per foot
Down-guy, Anchor and Protector	~~$2.04~~8.31

For Customer-owned outdoor lights, where the Customer contracts to relamp at no cost to FPL, the monthly rate for non-fuel energy shall be ~~2.934~~2.405¢ per kWh of estimated usage of each unit plus adjustments.

Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Clause	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

TERM OF SERVICE:

Not less than one year. In the event the Company installs any facilities for which there is an added monthly charge, the Term of Service shall be for not less than three years.

If the Customer terminates service before the expiration of the initial term of the agreement, the Company may require reimbursement for the total expenditures made to provide such service, plus the cost of removal of the facilities installed less the salvage value thereof, and less credit for all monthly payments made for Company-owned facilities.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service", the provision of this schedule shall apply.

COMPANY-OWNED FACILITIES:

Company-owned luminaires normally will be mounted on Company's existing distribution poles and served from existing overhead wires. The Company will provide one span of secondary conductor from existing secondary facilities to a Company-owned light at the Company's expense. When requested by the Customer, and at the option of the Company, additional spans of wire or additional poles or underground conductors may be installed by the Company upon agreement by the Customer to use the facilities for a minimum of three years and pay each month the charges specified under MONTHLY RATE.

The Customer will make a lump sum payment for the cost of changes in the height of existing poles or the installation of additional poles in the Company's distribution lines or the cost of any other facilities required for the installation of lights to be served hereunder.

At the Customer's request, the Company will upgrade to a higher level of illumination without a service charge when the changes are consistent with good engineering practices. The Customer will pay the Company the net costs incurred in making other lamp size changes. In all cases where luminaires are replaced, the Customer will sign a new service agreement. Billing on the rate for the new luminaire or lamp size will begin as of the next regular billing date. A luminaire may be relocated at the Customer's request upon payment by the Customer of the costs of removal and reinstallation.

The Company will not be required to install equipment at any location where the service may be objectionable to others. If it is found after installation that the light is objectionable, the Company may terminate the service.

(Continued on Sheet No. 8.727)

(Continued from Sheet No. 8.726)

When the Company relocates or removes its facilities to comply with governmental requirements, or for any other reason, either the Company or the Customer shall have the right, upon written notice, to discontinue service hereunder without obligation or liability.

SPECIAL CONDITIONS:

Customers whose lights are turned off during sea turtle nesting season will receive a credit equal to the fuel charges associated with the fixtures that are turned off.

CUSTOMER-OWNED FACILITIES:

Customer-owned luminaires and other facilities will be of a type and design specified by the Company to permit servicing and lamp replacement at no abnormal cost. The Customer will provide all poles, fixtures, initial lamps and controls, and circuits up to the point of connection to the Company's supply lines, and an adequate support for the Company-owned service conductors.

The Company will provide an overhead service drop from its existing secondary conductors to the point of service designated by the Company for Customer-owned lights. Underground service conductors will be installed in lieu of the overhead conductors at the Customer's request, and upon payment by the Customer of the installed cost of the underground conductors after allowance for the cost of equivalent overhead service conductors and any trenching and backfilling provided by the Customer.

DEFINITIONS:

A "Luminaire," as defined by the Illuminating Engineering Society, is a complete lighting unit consisting of a lamp (bulb), together with parts designed to distribute the light, to position and protect the lamp, and connect the lamp to the power supply.

A "Conventional" luminaire is supported by a bracket that is mounted on the side of an ordinary wood pole or an ornamental pole. This is the only type of luminaire offered where service is to be supplied from overhead conductors, although this luminaire may also be used when service is supplied from underground conductors.

A "Contemporary" luminaire is of modern design and is mounted on top of an ornamental pole. Underground conductors are required.

A "Traditional" luminaire resembles an Early American carriage lantern and is mounted on top of a pole. It requires an ornamental pole and underground conductors to a source of supply.

An "Ornamental" pole is one made of concrete or fiberglass.

RECREATIONAL LIGHTING

(Closed Schedule)

RATE SCHEDULE: RL-1

AVAILABLE:

In all territory served. Available to any customer, who, as of January 16, 2001, was either taking service pursuant to this schedule or had a fully executed Recreational Lighting Agreement with the Company.

APPLICATION:

For FPL-owned facilities for the purpose of lighting community recreational areas. This includes, but is not limitied to, baseball, softball, football, soccer, tennis, and basketball.

SERVICE:

Service will be metered and will include lighting installation, lamp replacement and facilities maintenance for FPL-owned lighting systems.

The Company, while exercising reasonable diligence at all times to furnish service hereunder, does not guarantee continuous lighting and will not be liable for damages for any interruption, deficiency or failure of service, and reserves the right to interrupt service at any time for necessary repairs to lines or equipment.

LIMITATION OF SERVICE:

Installation shall be made only when, in the judgement of the Company, the location and the type of the facilities are, and will continue to be, easily and economically accessible to the Company equipment and personnel for both construction and maintenance.

Stand-by, non-firm, or resale service is not permitted hereunder.

TERM OF SERVICE:

The term of service is (20) twenty years. At the end of the term of service, the Customer may elect to execute a new Agreement based on the current estimated replacement costs. The Company will retain ownership of these facilities.

FACILITIES PAYMENT OPTION:

The Customer will pay for the facilities in a lump sum in advance of construction. The amount will be the Company's total work order cost for these facilities times the Present Value Revenue Requirement (PVRR) multiplier of ~~1.4094~~1.1941. Monthly Maintenance and energy charges will apply for the term of service.

FACILITIES SELECTION:

Facilities selection shall be made by the Customer in writing by executing the Company's Recreational Lighting Agreement.

(Continued on Sheet No. 8.744)

(Continued from Sheet No. 8.743)

MONTHLY RATE :

Facilities:

Paid in full:	Monthly rate is zero.
10 years payment option:	~~1.565~~1.362% of total work order cost.*
20 years payment option:	~~1.038~~0.925% of total work order cost.*

* Both (10) ten and (20) twenty year payment options are closed to new service, and are only available for the duration of the term of service of those customers that have fully executed a Recreational Lighting Agreement with the Company before January 16, 2001.

Maintenance:	FPL's estimated costs of maintaining lighting facilities.
Billing:	FPL reserves the right to assess a charge for the recovery of any dedicated billing system developed solely for this rate.
Charge Per Month:	Company's otherwise applicable general service rate schedule.
Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

MINIMUM MONTHLY BILL:

As provided in the otherwise applicable rate schedule, plus the Facilities Maintenance and Billing charges.

(Continued on Sheet No. 8.745)

(Continued from Sheet No. 8.744)

EARLY TERMINATION:

If the Customer no longer wishes to receive service under this schedule, the Customer may terminate the Recreational Lighting Agreement by giving at least (90) ninety days advance written notice to the Company. Upon early termination of service, the Customer shall pay an amount computed by applying the following Termination Factors to the installed cost of the facilities, based on the year in which the Agreement was terminated. These Termination Factors will not apply to Customers who elected to pay for the facilities in a lump sum in lieu of a monthly payment.

FPL may also charge the Customer for the cost to the utility for removing the facilities.

Ten (10) Years Payment Option	Termination Factor	Twenty (20) Years Payment Option	Termination Factor
1	~~1.4094~~1.1941	1	~~1.4094~~1.1941
2	~~1.2216~~1.0306	2	~~1.2848~~1.0831
3	~~1.1198~~0.9473	3	~~1.2505~~1.0563
4	~~1.0108~~0.8575	4	~~1.2139~~1.0275
5	~~0.8941~~0.7608	5	~~1.1746~~0.9965
6	~~0.7692~~0.6565	6	~~1.1326~~.0.9630
7	~~0.6355~~0.5441	7	~~1.0876~~0.9269
8	~~0.4924~~0.4230	8	~~1.0395~~0.8880
9	~~0.3393~~0.2924	9	~~0.9880~~0.8461
10	~~0.1754~~0.1517	10	~~0.9328~~0.8009
>10	0.0000	11	~~0.8738~~0.7523
		12	~~0.8107~~0.6998
		13	~~0.74310~~0.6432
		14	~~0.6707~~0.5823
		15	~~0.5933~~0.5166
		16	~~0.5104~~0.4458
		17	~~0.4217~~0.3695
		18	~~0.3268~~0.2872
		19	~~0.2252~~0.1985
		20	~~0.1164~~0.1030
		>20	0.0000

WILLFUL DAMAGE:

In the event of willful damage to these facilities, FPL will provide the initial repair of each installed item at its expense. Upon the second occurrence of willful damage, and subsequent occurrence to these FPL-owned facilities, the Customer will be responsible for the cost for repair or replacement.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service", the provision of this schedule shall apply.

STANDBY AND SUPPLEMENTAL SERVICE

RATE SCHEDULE: SST-1

AVAILABLE:

In all territory served by the Company. Service under this rate schedule is on a customer by customer basis subject to the completion of arrangements necessary for implementation.

APPLICATION:

For electric service to any Customer, at a point of delivery, whose electric service requirements for the Customer's load are supplied or supplemented from the Customer's generation equipment at that point of service and require standby and/or supplemental service. For purposes of determining applicability of this rate schedule, the following definitions shall be used:

(1) "Standby Service" means electric energy or capacity supplied by the Company to replace energy or capacity ordinarily generated by the Customer's own generation equipment during periods of either scheduled (maintenance) or unscheduled (backup) outages of all or a portion of the Customer's generation.

(2) "Supplemental Service" means electric energy or capacity supplied by the Company in addition to that which is normally provided by the Customer's own generation equipment.

A Customer is required to take service under this rate schedule if the Customer's total generation capacity is more than 20% of the Customer's total electrical load and the Customer's generators are not for emergency purposes only.

Customers taking service under this rate schedule shall enter into a Standby and Supplemental Service Agreement ("Agreement"); however, failure to execute such an agreement will not pre-empt the application of this rate schedule for service.

SERVICE:

Three phase, 60 hertz, and at the available standard voltage. All service supplied by the Company shall be furnished through one metering point. Resale of service is not permitted hereunder.

Transformation Rider - TR, Sheet No. 8.820, does not apply to Standby Service.

MONTHLY RATE:

STANDBY SERVICE

Delivery Voltage:	Below 69 kV			69kV & Above
	SST-1(D1)	SST-1(D2)	SST-1(D3)	SST-1(T)
Contract Standby Demand:	Below 500 kW	500 to 1,999 kW	2,000 kW & Above	All Levels
Customer Charge:	~~$75.13~~$100.00	~~$75.13~~$100.00	~~$204.19~~$375.00	$1,451.71
Demand Charges:				
Base Demand Charges:				
Distribution Demand Charge per kW of Contract Standby Demand	~~$2.61~~$2.70	~~$4.31~~$2.70	~~$2.38~~ $2.70	none
Reservation Demand Charge per kW	~~$0.86~~$1.07	~~$0.86~~$1.07	~~$0.86~~$1.07	$1.03
Daily Demand Charge per kW for each daily maximum On-Peak Standby Demand	~~$0.41~~$0.52	~~$0.41~~$0.52	~~$0.41~~$0.52	$0.29

Capacity Payment and Conservation Charges See Sheet No. 8.030.1

(Continued on Sheet No. 8.751)

(Continued from Sheet No. 8.750)

Delivery Voltage:	Below 69 kV			69 kV & Above
	SST-1(D1)	SST-1(D2)	SST-1(D3)	SST-1(T)
Contract Standby Demand:	Below 500 kW	500 to 1,999 kW	2,000 kW & Above	All Levels
Non-Fuel Energy Charges:				
Base Energy Charges:				
On-Peak Period charge per kWh	~~0.624~~0.714¢	~~0.624~~0.714¢	~~0.624~~0.714¢	0.648 ¢
Off-Peak Period charge per kWh	~~0.624~~0.714¢	~~0.624~~0.714¢	~~0.624~~0.714¢	0.648¢

Environmental Charge See Sheet No. 8.030.1

Additional Charges:

Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the Base Demand Charges.

DEMAND CALCULATION:

The Demand Charge for Standby Service shall be (1) the charge for Distribution Demand **plus** (2) the greater of the sum of the Daily Demand Charges or the Reservation Demand Charge times the maximum On-Peak Standby Demand actually registered during the month **plus** (3) the Reservation Demand Charge times the difference between the Contract Standby Demand and the maximum On-Peak Standby Demand actually registered during the month.

SUPPLEMENTAL SERVICE

Supplemental Service shall be the total power supplied by the Company minus the Standby Service supplied by the Company during the same metering period. The charge for all Supplemental Service shall be calculated by applying the applicable retail rate schedule, excluding the customer charge.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

CONTRACT STANDBY DEMAND:

The level of Customer's generation requiring Standby Service as specified in the Agreement. This Contract Standby Demand will not be less than the maximum load actually served by the Customer's generation during the current month or prior 23-month period less the amount specified as the Customer's load which would not have to be served by the Company in the event of an outage of the Customer's generation equipment. For a Customer receiving only Standby Service as identified under Special Provisions, the Contract Standby Demand shall be maximum load actually served by the Company during the current month or prior 23-month period.

A Customer's Contract Standby Demand may be re-established to allow for the following adjustments:

1. Demand reduction resulting from the installation of FPL Demand Side Management Measures or FPL Research Project efficiency measures; or

(Continued on Sheet No. 8.752)

INTERRUPTIBLE STANDBY AND SUPPLEMENTAL SERVICE
(OPTIONAL)

RATE SCHEDULE: ISST-1

AVAILABLE:

In all territory served by the Company. Service under this rate schedule is on a customer by customer basis subject to the completion of arrangements necessary for implementation.

LIMITATION OF AVAILABILITY:

This schedule may be modified or withdrawn subject to determinations made under Commission Rule 25-6.0438, F.A.C., Non-Firm Electric Service - Terms and Conditions or any other Commission determination.

APPLICATION:

A Customer who is eligible to receive service under the Standby and Supplemental Service (SST-1) rate schedule may, as an option, take service under this rate schedule, unless the Customer has entered into a contract to sell firm capacity and/or energy to the Company, and the Customer cannot restart its generation equipment without power supplied by the Company, in which case the Customer may only receive Standby and Supplemental Service under the Company's SST-1 rate schedule.

Customers taking service under this rate schedule shall enter into an Interruptible Standby and Supplemental Service Agreement ("Agreement"). This interruptible load shall not be served on a firm service basis until service has been terminated under this rate schedule.

SERVICE:

Three phase, 60 hertz, and at the available standard voltage.

A designated portion of the Customer's load served under this schedule is subject to interruption by the Company. Transformation Rider-TR, where applicable, shall only apply to the Customer's Contract Standby Demand for delivery voltage below 69 kV. Resale of service is not permitted hereunder.

MONTHLY RATE:

STANDBY SERVICE		Distribution	Transmission
Delivery Voltage:		Below 69 kV ISST-1(D)	69 kV & Above ISST-1(T)
Customer Charge:		~~$200.00~~$375.00	$1,891.00
Demand Charges:			
Base Demand Charges:			
Distribution Demand Charge per kW of Contract Standby Demand		~~$2.59~~$2.70	none
Reservation Demand Charge per kW of Interruptible Standby Demand		~~$0.18~~$0.16	$0.16
Reservation Demand Charge per kW of Firm Standby Demand		~~$0.83~~$1.07	$0.81
Daily Demand Charge per kW for each daily maximum On-Peak Interruptible Standby Demand		~~$0.07~~$0.08	$0.07
Daily Demand Charge per kW for each daily maximum On-Peak Firm Standby Demand		~~$0.38~~$0.52	$0.38
Capacity Payment and Conservation Charges	See Sheet No. 8.030.1		
Non-Fuel Energy Charges:			
Base Energy Charges:			
On-Peak Period charge per kWh		~~0.643~~0.714¢	0.597¢
Off-Peak Period charge per kWh		~~0.643~~0.714¢	0.597¢
Environmental Charge	See Sheet No. 8.030.1		

(Continued on Sheet No. 8.761)

TRANSFORMATION RIDER - TR

AVAILABLE:

In all territory served.

APPLICATION:

In conjunction with any commercial or industrial rate schedule specifying delivery of service at any available standard voltage when Customer takes service from available primary lines of 2400 volts or higher at a single point of delivery.

MONTHLY CREDIT:

The Company, at its option, will either provide and maintain transformation facilities equivalent to the capacity that would be provided if the load were served at a secondary voltage from transformers at one location or, when Customer furnishes transformers, the Company will allow a monthly credit of $0.~~24~~27 per kW of Billing Demand. Any transformer capacity required by the Customer in excess of that provided by the Company hereunder may be rented by the Customer at the Company's standard rental charge.

The credit will be deducted from the monthly bill as computed in accordance with the provisions of the Monthly Rate section of the applicable Rate Schedule before application of any discounts or adjustments. No monthly bill will be rendered for an amount less than the minimum monthly bill called for by the Agreement for Service.

SPECIAL CONDITIONS:

The Company may change its primary voltage at any time after reasonable advance notice to any Customer receiving credit hereunder and affected by such change, and the Customer then has the option of changing its system so as to receive service at the new line voltage or of accepting service (without the benefit of this rider) through transformers supplied by the Company.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

SEASONAL DEMAND – TIME OF USE RIDER – SDTR
(OPTIONAL)

RIDER: SDTR

AVAILABLE:
In all territory served.

APPLICATION:
For electric service required for commercial or industrial lighting, power and any other purpose with a measured Demand in excess of 20 kW. This is an optional rate available to customers otherwise served under the GSD-1 GSDT-1, GSLD-1, GSLDT-1, GSLD-2 or GSLDT-2 Rate Schedules.

SERVICE:
Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:
OPTION A: Non-Seasonal Standard Rate

Annual Maximum Demand	SDTR-1 21-499 kW	SDTR-2 500-1,999 kW	SDTR-3 2,000 kW or greater
Customer Charge:	~~$22.77~~$24.00	~~$50.13~~$55.00	~~$179.19~~$195.00
Demand Charges:			
Seasonal On-peak Demand Charge Per kW of Seasonal On-peak Demand	~~$7.70~~$8.20	~~$8.55~~$8.90	~~$9.00~~$9.20
Non-Seasonal Demand Charge Per kW of Non- Seasonal Maximum Demand	~~$5.58~~6.70	~~$7.26~~$7.70	~~$7.22~~$8.10
Capacity Payment Charge:	See Sheet No. 8.030		
Conservation Charge:	See Sheet No. 8.030		
Energy Charges:			
Base Seasonal On-Peak Per kWh of Seasonal On-Peak Energy	~~5.627~~6.254¢	~~3.633~~4.267¢	~~2.965~~3.632¢
Base Seasonal Off-Peak Per kWh of Seasonal Off-Peak Energy	~~0.971~~1.000¢	~~0.641~~0.704¢	~~0.598~~0.633¢
Base Non-Seasonal Energy Charge Per kWh of Non-Seasonal Energy	~~1.401~~1.500¢	~~0.922~~1.056¢	~~0.861~~0.950¢
Environmental Charge:	See Sheet No. 8.030		
Additional Charges:			
Fuel Charge:	See Sheet No. 8.030		
Storm Charge:	See Sheet No. 8.040		
Franchise Fee:	See Sheet No. 8.031		
Tax Clause:	See Sheet No. 8.031		

(Continued from Sheet No. 8.830)

OPTION B: Non-Seasonal Time of Use Rate

Annual Maximum Demand	SDTR-1 21-499 kW	SDTR-2 500-1,999 kW	SDTR-3 2,000 kW or greater
Customer Charge:	~~$22.77~~$24.00	~~$50.13~~$55.00	~~$179.19~~$195.00
Demand Charges:			
Seasonal On-peak Demand Charge Per kW of Seasonal On-peak Demand	~~$7.70~~$8.20	~~$8.55~~$8.90	~~$9.00~~$9.20
Non-Seasonal Demand Charge Per kW of Non- Seasonal Peak Demand	~~$5.58~~$6.70	~~$7.26~~$7.70	~~$7.22~~$8.10
Capacity Payment Charge	See Sheet No. 8.030		
Conservation Charge	See Sheet No. 8.030		
Energy Charges:			
Base Seasonal On-Peak Per kWh of Seasonal On-Peak Energy	~~5.627~~6.254¢	~~3.633~~4.267¢	~~2.965~~3.632¢
Base Seasonal Off-Peak Per kWh of Seasonal Off-Peak Energy	~~0.971~~1.000¢	~~0.641~~0.704¢	~~0.598~~0.633¢
Base Non-Seasonal On-Peak Per kWh of Non-Seasonal On-Peak Energy	~~3.126~~3.232¢	~~1.884~~2.194¢	~~1.734~~2.010¢
Base Non-Seasonal Off-Peak Per kWh of Non-Seasonal Off-Peak Energy	~~0.971~~1.000¢	~~0.641~~0.704¢	~~0.598~~0.633¢
Environmental Charge	See Sheet No. 8.030		
Additional Charges:			
Fuel Charge	See Sheet No. 8.030		
Storm Charge	See Sheet No. 8.040		
Franchise Fee	See Sheet No. 8.031		
Tax Clause	See Sheet No. 8.031		

Minimum Charge: The Customer Charge plus the currently effective Demand Charges.

NON-SEASONAL RATING PERIODS (OPTION B only):

Non-Seasonal On-Peak Period:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through May 31 and October 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day.

Non-Seasonal Off-Peak Period:

All other hours.

(Continued On Sheet No. 8.832)

(Continued from Sheet No. 9.950)

1.04 "Incremental Base Revenue" is actual Base Revenue received during the Performance Guaranty Period for electric service rendered to the Premises in excess of Baseline Base Revenue.

1.05 "Incremental Capacity," as determined by Company, is the positive difference, if any, between Baseline Capacity and the amount of capacity (measured in kW) necessary to meet Applicant's projections of electric load at the Premises.

1.06 "Performance Guaranty Period" is the period of time commencing with the day on which the requested level of service is installed and available to Customer, as determined by Company, ("In-Service Date"), and ending on the third anniversary of the In-Service Date ("Expiration Date").

ARTICLE II - PERFORMANCE GUARANTY AMOUNT

2.01 For purposes of this Agreement, the derivation of Incremental Capacity is shown in the following table.

Incremental Capacity (1)	Existing Structure (2)	New Structure (3)	Total Structure (2)+(3)
a. Square Footage			
b. Requested watts/sq ft			
c. Baseline Capacity watts/sq ft			
d. Requested Capacity (in kW) (a * b / 1000)			
e. Baseline Capacity (in kW) (a * c / 1000)			
f. Incremental Capacity (in kW) (d - e)			

2.02 The amount of the Performance Guaranty is the cost, as determined by Company, of the Incremental Capacity multiplied by a factor of 1.51. The cost of the Incremental Capacity is the positive difference, if any, between Company's estimated cost of providing the requested level of capacity and Baseline Capacity. Applicant agrees to provide Company a Performance Guaranty in the amount specified in the table below prior to Company installing the facilities necessary to provide the Incremental Capacity to serve the Premises.

Performance Guaranty (1)	Existing Structure (2)	New Structure (3)	Total Structure (2 + 3)
a. Cost of requested capacity			
b. Cost of Baseline Capacity	-0-		
c. Incremental cost (a – b)			
d. Present value factor	~~1.51~~1.52	~~1.51~~1.52	~~1.51~~1.52
e. Performance Guaranty (c * d)			

(Continued on Sheet No. 9.952)

Appendix A

Distribution Substation Facilities
Monthly Rental and Termination Factors

The Monthly Rental Factor to be applied to the in-place value of the Distribution Substation Facilities as identified in the Long-Term Rental Agreement is as follows:

	Monthly Rental Factor
Distribution Substation Facilities	~~1.42~~1.67%

Termination Fee for Initial 20 Year Period

If the Long-Term Rental Agreement for Distribution Substation Facilities is terminated by Customer during the Initial Term, Customer shall pay to Company a Termination Fee, such fee shall be computed by applying the following Termination Factors to the in-place value of the Facilities based on the year in which the Agreement is terminated:

Year Agreement Is Terminated	Termination Factors %	Year Agreement Is Terminated	Termination Factors %	Year Agreement Is Terminated	Termination Factors %
1	~~3.55~~3.36	8	~~11.95~~11.16	15	~~6.22~~6.01
2	~~6.38~~6.03	9	~~11.67~~10.88	16	~~4.94~~4.87
3	~~8.50~~8.03	10	~~11.16~~10.40	17	~~3.65~~3.70
4	~~10.03~~9.47	11	~~10.46~~9.76	18	~~2.40~~2.48
5	~~11.06~~10.42	12	~~9.59~~8.97	19	~~1.18~~1.25
6	~~11.69~~10.98	13	~~8.58~~8.07	20	0
7	~~11.97~~11.21	14	~~7.45~~7.08		

Termination Fee for Subsequent Extension Periods

If the Long-Term Rental Agreement for Distribution Substation Facilities is terminated by Customer during an Extension, Customer shall pay to Company a Termination Fee, such fee shall be computed based on the net present value of the remaining payments under the extension period by applying the Termination Factor based on the month terminated to the monthly rental payment amount.

Month Terminated	Termination Factor	Month Terminated	Termination Factor	Month Terminated	Termination Factor	Month Terminated	Termination Factor
1	~~50.762~~49.896	16	~~39.687~~39.173	31	~~27.599~~27.359	46	~~14.404~~14.342
2	~~50.053~~49.213	17	~~38.914~~38.421	32	~~26.755~~26.530	47	~~13.482~~13.429
3	~~49.340~~48.526	18	~~38.136~~37.663	33	~~25.906~~25.696	48	~~12.555~~12.509
4	~~48.624~~47.834	19	~~37.354~~36.901	34	~~25.052~~24.856	49	~~11.623~~11.584
5	~~47.903~~47.138	20	~~36.567~~36.134	35	~~24.192~~24.010	50	~~10.685~~10.652
6	~~47.177~~46.437	21	~~35.775~~35.362	36	~~23.328~~23.160	51	~~9.742~~9.715
7	~~46.448~~45.731	22	~~34.979~~34.585	37	~~22.459~~22.303	52	~~8.793~~8.772
8	~~45.714~~45.021	23	~~34.178~~33.802	38	~~21.585~~21.441	53	~~7.839~~7.822
9	~~44.976~~44.307	24	~~33.372~~33.015	39	~~20.705~~20.574	54	~~6.879~~6.866
10	~~44.234~~43.588	25	~~32.662~~32.223	40	~~19.821~~19.701	55	~~5.913~~5.904
11	~~43.487~~42.864	26	~~31.747~~31.425	41	~~18.931~~18.822	56	~~4.942~~4.936
12	~~42.736~~42.135	27	~~30.927~~30.622	42	~~18.036~~17.938	57	~~3.965~~3.962
13	~~41.980~~41.402	28	~~30.102~~29.814	43	~~17.136~~17.047	58	~~2.983~~2.981
14	~~41.221~~40.664	29	~~29.273~~29.001	44	~~16.231~~16.151	59	1.994
15	~~40.456~~39.921	30	~~28.438~~28.183	45	~~15.320~~15.250	60	1.000

SERVICE CHARGES

A $14.88 service charge will be made for an initial connection.

A $17.66 Reconnection Charge will be made for the reconnection of service after disconnection for nonpayment or violation of a rule or regulation.

A $14.88 service charge will be made for the connection of an existing account.

A Returned Payment Charge as allowed by Florida Statute 68.065 shall apply for each check or draft dishonored by the bank upon which it is drawn. Termination of service shall not be made for failure to pay the Returned Payment Charge.

Charges for services due and rendered which are unpaid as of the past due date are subject to a Late Payment Charge of the greater of $6.00 or 1.5% applied to any past due unpaid balance of all accounts, except the accounts of federal, state, and local governmental entities, agencies, and instrumentalities. A Late Payment Charge shall be applied to the accounts of federal, state, and local governmental entities, agencies, and instrumentalities at a rate no greater than allowed, and in a manner permitted, by applicable law.

A $5.11 Field Collection Charge will be added to a customer's bill for electric service when a field visit is made and payment is collected on a delinquent account. If service is disconnected, or a current receipt of payment is shown at the time of the field visit, this charge will not be applied.

FPL may waive the Reconnection Charge, Returned Payment Charge, Late Payment Charge and Field Collection Charge for Customers affected by natural disasters or during periods of declared emergencies or once in any twelve (12) month period for any Customer who would otherwise have had a satisfactory payment record (as defined in 25-6.097(2) F.A.C.), upon acceptance by FPL of a reasonable explanation justifying a waiver. In addition, FPL may waive the charge for connection of an existing account and the charge for an initial connection for new or existing Customers affected by natural disasters or during periods of declared emergencies.

CONSERVATION INSPECTIONS AND SERVICES

Residential Dwelling Units:
A charge of $15.00 will be made for a computerized energy analysis in which a comprehensive on-site evaluation of the residence is performed.

Commercial/Industrial:
There is no charge for conservation inspections and services (Business Energy Services).

TEMPORARY/CONSTRUCTION SERVICE

APPLICATION:

For short term electric service to installations such as fairs, exhibitions, construction projects, displays and similar installations.

SERVICE:

Single phase or three phase, 60 hertz at the available standard secondary distribution voltage. This service is available only when the Company has existing capacity in lines, transformers and other equipment at the requested point of delivery. The Customer's service entrance electrical cable shall not exceed 200 Amp capacity.

CHARGE:

The non-refundable charge must be paid in advance of installation of such facilities which shall include service and metering equipment.

Installing and removing overhead service and meter	$297.00
Connecting and disconnecting Customer's service cable to Company's direct-buried underground facilities including installation and removal of meter	$175.00

MONTHLY RATE:

This temporary service shall be billed under the appropriate rate schedule applicable to commercial and industrial type installations.

SPECIAL CONDITIONS:

If specific electrical service other than that stated above is required, the Company, at the Customer's request, will provide such service based on the estimated cost of installing and removing such additional electrical equipment. This estimated cost will be a contribution in aid of construction payable in advance to the Company and subject to adjustment after removal of the required facilities. All Temporary/Construction services shall be subject to all of the applicable Rules, Regulations and Tariff charges of the Company, including Service Charges.

INDEX OF RATE SCHEDULES

GENERAL SERVICE DEMAND

RATE SCHEDULE: GSD-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose with a measured Demand in excess of 20 kW and less than 500 kW. Customers with a Demand of 20 kW or less may enter an agreement for service under this schedule based on a Demand Charge for a minimum of 21 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$18.00
Demand Charges:	
Base Demand Charge	$7.00 per kW
Capacity Payment Charge	See Sheet No. 8.030, per kW
Conservation Charge	See Sheet No. 8.030, per kW
Non-Fuel Energy Charges:	
Base Energy Charge	1.500¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of 20 kW or less who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 21 kW times the Base Demand Charge; therefore the minimum charge is $165.00.

DEMAND:

The Demand is the kW to the nearest whole kW, as determined from the Company's thermal type meter or, at the Company's option, integrating type meter for the 30-minute period of Customer's greatest use during the month as adjusted for power factor.

TERM OF SERVICE:

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

GENERAL SERVICE DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: GSDT-1

AVAILABLE:
In all territory served.

APPLICATION:
For electric service required for commercial or industrial lighting, power and any other purpose with a measured Demand in excess of 20 kW and less than 500 kW. Customers with Demands of less than 21 kW may enter an agreement for service under this schedule based on a Demand Charge for a minimum of 21 kW. This is an optional rate available to General Service Demand customers upon request subject to availability of meters.

SERVICE:
Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$24.00	
Demand Charges:		
Base Demand Charge	$7.00 per kW of Demand occurring during the On-Peak period.	
Capacity Payment Charge	See Sheet No. 8.030, per kW of Demand occurring during the On-Peak period.	
Conservation Charge	See Sheet No. 8.030, per kW of Demand occurring during the On-Peak period.	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	3.440¢ per kWh	0.710¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 21 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 21 kW times the Base Demand Charge.

If the Customer elects to make a lump sum payment to the Company for time of use metering costs of $360.00 the then Customer Charge and the Minimum Charge shall be $18.00 and $165.00, respectively.

RATING PERIODS:
On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.108)

GENERAL SERVICE CONSTANT USAGE

RATE SCHEDULE: GSCU-1

AVAILABLE:

In all territory served.

APPLICATION:

Available to General Service - Non Demand customers that maintain a relatively constant kWh usage, and a demand of 20 kW or less. Eligibility is restricted to General Service customers whose Maximum kWh Per Service Day, over the current and prior 23 months, is within 5% of their average monthly kWh per service days calculated over the same 24-month period. Customers under this Rate Schedule shall enter into a General Service Constant Use Agreement. This is an optional Rate Schedule available to General Service customers upon request.

SERVICE:

Single phase, 60 hertz and at any available standard voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$12.00
Non-Fuel Energy Charges:	
Base Energy Charge*	2.808¢ per Constant Usage kWh
Conservation Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.030
Capacity Payment Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.030
Environmental Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.030
Additional Charges:	
Fuel Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.030
Storm Charge*	Same as the SL-2 Rate Schedule; see Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

* The fuel, storm and non-fuel energy charges will be assessed on the Constant Usage kWh

TERM OF SERVICE:

Initial term of service under this rate schedule shall be not less than one (1) billing period, unless there is a termination of service due to a Customer's violation of the General Service Constant Usage Agreement. Upon the Customer's violation of any of the terms of the General Service Constant Usage Agreement, service under this Rate Schedule will be terminated immediately. To terminate service, either party must provide thirty (30) days written notice to the other party prior to the desired termination date. Absent such notice, the term of service shall automatically be extended another billing period. In addition, if service under this Rate Schedule is terminated by either the Customer or the Company, the account may not resume service under this Rate Schedule for a period of at least one (1) year.

DEFINITIONS:

kWh Per Service Day – the total kWh in billing month divided by the number of days in the billing month

Maximum kWh Per Service Day - the highest kWh Per Service Day experienced over the current and prior 23 month billing periods

Constant Usage kWh – the Maximum kWh Per Service Day multiplied by the number of service days in the current billing period

(Continued on Sheet 8.123)

RESIDENTIAL SERVICE

RATE SCHEDULE: RS-1

AVAILABLE:

In all territory served.

APPLICATION:

For service for all domestic purposes in individually metered dwelling units and in duplexes and triplexes, including the separately-metered non-commercial facilities of a residential Customer (i.e., garages, water pumps, etc.). Also for service to commonly-owned facilities of condominium, cooperative and homeowners' associations as set forth on Sheet No. 8.211, Rider CU.

SERVICE:

Single phase, 60 hertz at available standard voltage. Three phase service may be furnished but only under special arrangements. All residential service required on the premises by Customer shall be supplied through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$7.00
Non-Fuel Charges:	
Base Energy Charge:	
First 1,000 kWh	4.036¢ per kWh
All additional kWh	5.036¢ per kWh
Conservation Charge	See Sheet No. 8.030
Capacity Payment Charge	See Sheet No. 8.030
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Residential Load Management Program (if applicable)	See Sheet No. 8.207
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031
Minimum:	$7.00

TERM OF SERVICE:

Not less than one (1) billing period.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

RESIDENTIAL TIME OF USE RIDER – RTR-1
(OPTIONAL)

RIDER: RTR-1

AVAILABLE:
In all territory served.

APPLICATION:

For service for all domestic purposes in individually metered dwelling units and in duplexes and triplexes, including the separately-metered non-commercial facilities of a residential Customer (i.e., garages, water pumps, etc.). Also for service to commonly-owned facilities of condominium, cooperative and homeowners' associations as set forth on Sheet No. 8.211, Rider CU. This is an optional rider available to residential customers served under the RS-1 Rate Schedule subject to availability of meters. Customers taking service under RTR-1 are not eligible for service under Rate Schedule RLP.

SERVICE:
Single phase, 60 hertz at available standard voltage. Three phase may be supplied but only under special arrangements. All residential service required on the premises by Customer shall be supplied through one meter. Resale of service is not permitted hereunder.

Initial service under this rate schedule shall begin on the first scheduled meter reading date following the installation of the time of use meter. The Customer's first bill will reflect the lesser of the charges under Rate Schedule RS-1 or RTR-1.

MONTHLY RATE:

Except for the Customer Charge, all rates and charges under Rate Schedule RS-1 shall apply. In addition, the RTR-1 Customer Charge, the RTR-1 Base Energy and Fuel Charges and Credits applicable to on and off peak usage shall apply.

Customer Charge:	\$11.00	
Base Energy Charges/Credits:	On-Peak Period	Off-Peak Period
Base Energy Charge	8.391¢ per kWh	(3.656) ¢ per kWh
Additional Charges/Credits:		
RTR Fuel Charge/Credit	See Sheet No. 8.030	
Minimum:	\$11.00	

If the Customer elects to make a lump sum payment to the Company for time of use metering costs of \$240.00, then the Customer Charge and Minimum Charge shall be \$7.00.

RATING PERIODS:
On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

RESIDENTIAL SERVICE - TIME OF USE
(OPTIONAL) (Closed Schedule)

RATE SCHEDULE: RST-1

AVAILABLE:
In all territory served.

APPLICATION:

For service for all domestic purposes in individually metered dwelling units and in duplexes and triplexes, including the separately-metered non-commercial facilities of a residential Customer (i.e., garages, water pumps, etc.). Also for service to commonly-owned facilities of condominium, cooperative and homeowners' associations as set forth on Sheet No. 8.211, Rider CU. This is an optional rate available to residential customers, provided the customer was taking service pursuant to this schedule as of December 31, 2012.

SERVICE:
Single phase, 60 hertz at available standard voltage. Three phase may be supplied but only under special arrangements. All residential service required on the premises by Customer shall be supplied through one meter. Resale of service is not permitted hereunder.

Initial service under this rate schedule shall begin on the first scheduled meter reading date following the installation of the time of use meter. The Customer's first bill will reflect the lesser of the charges under Rate Schedule RS-1 or RST-1.

MONTHLY RATE:

Customer Charge:	$11.00	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	12.759¢ per kWh	0.712 per kWh
Conservation Charge	See Sheet No. 8.030	
Capacity Payment Charge	See Sheet No. 8.030	
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	
Minimum:	$11.00	

If the Customer elects to make a lump sum payment to the Company for time of use metering costs of $240.00 , then the Customer Charge and Minimum Charge shall be $7.00.

RATING PERIODS:
On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.206)

GENERAL SERVICE LARGE DEMAND

RATE SCHEDULE: GSLD-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose to any Customer with a measured demand of 500 kW and less than 2,000 kW. Customers with demands of less than 500 kW may enter an agreement for service under this Rate Schedule based on a Demand Charge for a minimum of 500 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$55.00
Demand Charges:	
Base Demand Charge	$8.00 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030
Conservation Charge	See Sheet No. 8.030
Non-Fuel Energy Charges:	
Base Energy Charge	1.056¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charges	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 500 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 500 kW times the Base Demand Charge; therefore the minimum charge is $4,055.00.

DEMAND:

The Demand is the kW to the nearest whole kW, as determined from the Company's thermal type meter or, at the Company's option, integrating type meter for the 30-minute period of Customer's greatest use during the month as adjusted for power factor.

TERM OF SERVICE:

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

GENERAL SERVICE LARGE DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE GSLDT-1

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose to any Customer with a measured demand of 500 kW and less than 2,000 kW. Customers with demands of less than 500 kW may enter an agreement for service under this schedule based on a Demand Charge for a minimum of 500 kW. This is an optional rate available to General Service Large Demand customers upon request subject to availability of meters.

SERVICE:

Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$55.00	
Demand Charges:		
Base Demand Charge	$8.00 per kW of Demand occurring during the On-Peak period.	
Capacity Payment Charge	See Sheet No. 8.030	
Conservation Charge	See Sheet No. 8.030	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	1.901¢ per kWh	0.704¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for currently effective Base Demand. For those Customers with a Demand of less than 500 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 500 kW times the Base Demand Charge; therefore the minimum charge is $4,055.00.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.321)

CURTAILABLE SERVICE
(OPTIONAL)

RATE SCHEDULE: CS-1

AVAILABLE:
In all territory served.

APPLICATION:
For any commercial or industrial Customer who qualifies for Rate Schedule GSLD-1 (500 kW - 1,999 kW) and will curtail this Demand by 200 kW or more upon request of the Company from time to time. Customers with demands of at least 200 kW but less than 500 kW may enter an agreement for service under this Rate Schedule based on a Demand Charge for a minimum of 500 kW.

SERVICE:
Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$80.00
Demand Charges:	
Base Demand Charge	$8.00 per kW of Demand.
Capacity Payment Charge	See Sheet No. 8.030
Conservation Charge	See Sheet No. 8.030
Non-Fuel Energy Charges:	
Base Energy Charge	1.056¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 500 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 500 kW times the Base Demand Charge; therefore the minimum charge is $4,080.00.

CURTAILMENT CREDITS:
A monthly credit of $1.72 per kW is allowed based on the current Non-Firm Demand. The Customer has the option to revise the Firm Demand once during the initial twelve (12) month period. Thereafter, subject to the Term of Service and/or the Provisions for Early Termination, a change to the Firm Demand may be made provided that the revision does not decrease the total amount of Non-Firm Demand during the lesser of: (i) the average of the previous 12 months; or (ii) the average of the number of billing months under this Rate Schedule.

CHARGES FOR NON-COMPLIANCE OF CURTAILMENT DEMAND:
If the Customer records a higher Demand during the current Curtailment Period than the Firm Demand, the Customer will be:

1. Rebilled at $1.72/kW for the prior 36 months or the number of months since the prior Curtailment Period, whichever is less, and
2. Billed a penalty charge of $3.70/kW for the current month.

The kW used for both the rebilling and penalty charge calculations is determined by taking the difference between the maximum Demand during the current Curtailment Period and the Firm Demand for a Curtailment Period.

(Continued on Sheet No. 8.331)

CURTAILABLE SERVICE - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: CST-1

AVAILABLE:
In all territory served.

APPLICATION:
For any commercial or industrial Customer who qualifies for Rate Schedule GSLD-1 (500 kW - 1,999 kW) and will curtail this Demand by 200 kW or more upon request of the Company from time to time. This is an optional Rate Schedule available to Curtailable General Service Customers upon request. Customers with demands of at least 200 kW but less than 500 kW may enter an agreement for service under this Rate Schedule based on a Demand Charge for a minimum of 500 kW

SERVICE:

Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$80.00	
Demand Charges:		
Base Demand Charge	$8.00 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030	
Conservation Charge	See Sheet No. 8.030	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	1.901¢ per kWh	0.704¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 500 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 500 kW times the Base Demand Charge; therefore the minimum charge is $4,080.00.

RATING PERIODS:

On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.341)

GENERAL SERVICE LARGE DEMAND

RATE SCHEDULE: GSLD-2

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose to any Customer with a measured demand of 2,000 kW or more. Customers with demands of less than 2,000 kW may enter an agreement for service under this schedule based on a demand charge for a minimum of 2,000 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$195.00
Demand Charges:	
Base Demand Charge	$8.30 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030
Conservation Charge	See Sheet No. 8.030
Non-Fuel Energy Charges:	
Base Energy Charge	0.950¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a demand of less than 2,000 kW who enter an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 2,000 kW times the Base Demand Charge; therefore the minimum charge is $16,795.00.

DEMAND:

The Demand is the kW to the nearest whole kW, as determined from the Company's metering equipment, for the 30-minute period of the Customer's greatest use during the month as adjusted for power factor.

TERM OF SERVICE:

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

GENERAL SERVICE LARGE DEMAND - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: GSLDT-2

AVAILABLE:

In all territory served.

APPLICATION:

For electric service required for commercial or industrial lighting, power and any other purpose to any Customer who has established a measured demand of 2,000 kW or more. Customers with demands of less than 2,000 kW may enter an agreement for service under this schedule based on a demand charge for a minimum of 2,000 kW.

SERVICE:

Three phase, 60 hertz and at any available standard secondary or distribution voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$195.00	
Demand Charges:		
Base Demand Charge	$8.30 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030	
Conservation Charge	See Sheet No. 8.030	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	1.620¢ per kWh	0.697¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a demand of less than 2,000 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 2,000 kW times the Base Demand Charge; therefore the minimum charge is $16,795.00.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.421)

HIGH LOAD FACTOR – TIME OF USE
(OPTIONAL)

RATE SCHEDULE: HLFT

AVAILABLE:
In all territory served.

APPLICATION:
For electric service required for commercial or industrial lighting, power and any other purpose with a measured Demand in excess of 20 kW. This is an optional rate schedule available to customers otherwise served under the GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, or GSLDT-2 Rate Schedules.

SERVICE:
Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:	HLFT-1	HLFT-2	HLFT-3
Annual Maximum Demand	21-499 kW	500-1,999 kW	2,000 kW or greater
Customer Charge:	$24.00	$55.00	$195.00
Demand Charges:			
On-peak Demand Charge	$8.40	$8.50	$8.50
Maximum Demand Charge	$1.90	$2.00	$2.00
Capacity Payment Charge	See Sheet No. 8.030, per kW of On-Peak Demand		
Conservation Charge	See Sheet No. 8.030, per kW of On-Peak Demand		
Non-Fuel Energy Charges:			
On-Peak Period per kWh	1.218¢	0.572¢	0.526¢
Off-Peak Period per kWh	0.710¢	0.572¢	0.526¢
Environmental Charge	See Sheet No. 8.030		
Additional Charges			
Fuel Charge	See Sheet No. 8.030		
Storm Charge	See Sheet No. 8.040		
Franchise Fee	See Sheet No. 8.031		
Tax Clause	See Sheet No. 8.031		

Minimum Charge: The Customer Charge plus the currently effective Demand Charges.

RATING PERIODS:
On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.426)

CURTAILABLE SERVICE
(OPTIONAL)

RATE SCHEDULE: CS-2

AVAILABLE:

In all territory served.

APPLICATION:

For any commercial or industrial Customer who qualifies for Rate Schedule GSLD-2 (2,000 kW and above) and will curtail this Demand by 200 kW or more upon request of the Company from time to time. Customers with demands of less than 2,000 kW may enter an Agreement for service under this schedule based on a Demand Charge for a minimum of 2,000 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	\$220.00
Demand Charges:	
Base Demand Charge	\$8.30 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030
Conservation Charge	See Sheet No. 8.030
Non-Fuel Energy Charges:	
Base Energy Charge	0.950¢ per kWh
Environmental Charge	See Sheet No. 8.030
Additional Charges:	
Fuel Charge	See Sheet No. 8.030
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 2,000 kW who enter an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 2,000 kW times the Base Demand Charge; therefore the minimum charge is \$16,820.00.

CURTAILMENT CREDITS:

A monthly credit of -\$1.72 per kW is allowed based on the current Non-Firm Demand. The Customer has the option to revise the Firm Demand once during the initial twelve (12) month period. Thereafter, subject to the Term of Service and/or the Provisions for Early Termination, a change to the Firm Demand may be made provided that the revision does not decrease the total amount of Non-Firm Demand during the lesser of: (i) the average of the previous 12 months; or (ii) the average of the number of billing months under this Rate Schedule.

CHARGES FOR NON-COMPLIANCE OF CURTAILMENT DEMAND:

If the Customer records a higher Demand during the current period than the Firm Demand, then the Customer will be:

1. Rebilled at \$1.72/kW for the prior 36 months or the number of months since the prior Curtailment Period, whichever is less, and
2. Billed a penalty charge of \$3.70/kW for the current month.

The kW used for both the rebilling and penalty charge calculations is determined by taking the difference between the maximum Demand during the current Curtailment Period and the contracted Firm Demand for a Curtailment Period.

(Continued on Sheet No. 8.433)

CURTAILABLE SERVICE - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: CST-2

AVAILABLE:
In all territory served.

APPLICATION:
For any commercial or industrial Customer who qualifies for Rate Schedule GSLDT-2 (2,000 kW and above) and will curtail this Demand by 200 kW or more upon request of the Company from time to time. Customers with demands of less than 2,000 kW may enter an agreement for service under this schedule based on a Demand Charge for a minimum of 2,000 kW.

SERVICE:

Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$220.00	
Demand Charges:		
Base Demand Charge	$8.30 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030	
Conservation Charge	See Sheet No. 8.030	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	1.620¢ per kWh	0.697¢ per kWh
Environmental Charge	See Sheet No. 8.030	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand. For those Customers with a Demand of less than 2,000 kW who have entered an agreement for service under this schedule, the minimum charge shall be the Customer Charge plus 2,000 kW times the Base Demand Charge; therefore the minimum charge is $16,820.00.

RATING PERIODS:

On-Peak:
November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:
All other hours.

(Continued on Sheet No. 8.441)

CURTAILABLE SERVICE - TIME OF USE
(OPTIONAL)

RATE SCHEDULE: CST-3

AVAILABLE:

In all territory served.

APPLICATION:

For any commercial or industrial Customer who qualifies for Rate Schedule GSLDT-3 and will curtail this Demand by 200 kW or more upon request of the Company from time to time.

SERVICE:

Three phase, 60 hertz at the available transmission voltage of 69 kV or higher. The Customer will provide and maintain all transformers and related facilities necessary for handling and utilizing the power and energy delivered hereunder. All service required by the Customer at each separate point of delivery served hereunder shall be furnished through one meter at, or compensated to, the available transmission voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$1,466.88	
Demand Charges:		
Base Demand Charge	$6.32 per kW of Demand occurring during the On-Peak Period.	
Capacity Payment Charge	See Sheet No. 8.030.1	
Conservation Charge	See Sheet No. 8.030.1	
Non-Fuel Energy Charges:	On-Peak Period	Off-Peak Period
Base Energy Charge	0.739¢ per kWh	0.604¢ per kWh
Environmental Charge	See Sheet No. 8.030.1	
Additional Charges:		
Fuel Charge	See Sheet No. 8.030.1	
Storm Charge	See Sheet No. 8.040	
Franchise Fee	See Sheet No. 8.031	
Tax Clause	See Sheet No. 8.031	

Minimum: The Customer Charge plus the charge for the currently effective Base Demand.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

(Continued on Sheet No. 8.543)

CURTAILABLE SERVICE
(OPTIONAL)

RATE SCHEDULE: CS-3

AVAILABLE:
In all territory served.

APPLICATION:
For any commercial or industrial Customer who qualifies for Rate Schedule GSLD-3 and will curtail this Demand by 200 kW or more upon request of the Company from time to time.

SERVICE:
Three phase, 60 hertz at the available transmission voltage of 69 kV or higher. The Customer will provide and maintain all transformers and related facilities necessary for handling and utilizing the power and energy delivered hereunder. All service required by the Customer at each separate point of delivery served hereunder shall be furnished through one meter at, or compensated to, the available transmission voltage. Resale of service is not permitted hereunder.

MONTHLY RATE:

Customer Charge:	$1,466.88
Demand Charges:	
Base Demand Charge	$6.32 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030.1
Conservation Charge	See Sheet No. 8.030.1
Non-Fuel Energy Charges:	
Base Energy Charge	0.640¢ per kWh
Environmental Charge	See Sheet No. 8.030.1
Additional Charges:	
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum Charge: The Customer Charge plus the charge for the currently effective Base Demand.

CURTAILMENT CREDITS:
A monthly credit of -$1.72 per kW is allowed based on the current Non-Firm Demand. The Customer has the option to revise the Firm Demand once during the initial twelve (12) month period. Thereafter, subject to the Term of Service and/or the Provisions for Early Termination, a change to the Firm Demand may be made provided that the revision does not decrease the total amount of Non-Firm Demand during the lesser of: (i) the average of the previous 12 months; or (ii) the average of the number of billing months under this Rate Schedule.

CHARGES FOR NON-COMPLIANCE OF CURTAILMENT DEMAND:

If the Customer records a higher Demand during the current Curtailment Period than the Firm Demand, then the Customer will be:

1. Rebilled at $1.72/kW for the prior 36 months or the number of months since the prior Curtailment Period, whichever is less, and
2. Billed a penalty charge of $3.70/kW for the current month.

The kW used for both the rebilling and penalty charge calculations is determined by taking the difference between the maximum Demand during the current Curtailment Period and the Firm Demand for a Curtailment Period.

(Continued on Sheet No. 8.546)

SPORTS FIELD SERVICE
(Closed Schedule)

RATE SCHEDULE: OS-2

AVAILABLE:

In all territory served.

APPLICATION:

This is a transitional rate available to municipal, county and school board accounts for the operation of a football, baseball or other playground, or civic or community auditorium, when all such service is taken at the available primary distribution voltage at a single point of delivery and measured through one meter, and who were active as of October 4, 1981. Customer may also elect to receive service from other appropriate rate schedules.

LIMITATION OF SERVICE:

Offices, concessions, businesses or space occupied by tenants, other than areas directly related to the operations above specified, are excluded hereunder and shall be separately served by the Company at utilization voltage. Not applicable when Rider TR is used.

MONTHLY RATE:

Customer Charge:	$103.00
Non-Fuel Energy Charges:	
Base Energy Charge	5.928¢ per kWh
Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Additional Charges:	
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031
Minimum Charge:	$103.00

TERM OF SERVICE:

Pending termination by Florida Public Service Commission Order.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

METROPOLITAN TRANSIT SERVICE

RATE SCHEDULE: MET

AVAILABLE:

For electric service to Metropolitan Dade County Electric Transit System (METRORAIL) at each point of delivery required for the operation of an electric transit system on continuous and contiguous rights-of-way.

APPLICATION:

Service to be supplied will be three phase, 60 hertz and at the standard primary voltage of 13,200 volts. All service required by Customer at each separate point of delivery served hereunder shall be furnished through one meter reflecting delivery at primary voltage. Resale of service is not permitted hereunder. Rider TR or a voltage discount is not applicable.

MONTHLY RATE:

Customer Charge:	$400.00
Demand Charges:	
Base Demand Charge	$10.60 per kW of Demand
Capacity Payment Charge	See Sheet No. 8.030.1
Conservation Charge	See Sheet No. 8.030.1
Non-Fuel Energy Charges:	
Base Energy Charge	1.248¢ per kWh
Environmental Charge	See Sheet No. 8.030.1
Additional Charges:	
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the charge for the currently effective Base Demand.

DEMAND:

The billing Demand is the kW, at each point of delivery, to the nearest whole kW, as determined from the Company's recording type metering equipment, for the period coincident with the 30-minute period of the electric rail transit system's greatest use supplied by the Company during the month adjusted for power factor.

BILLING:

Each point of delivery shall be separately billed according to the monthly charges as stated herein. All billing units related to charges under this rate schedule shall be determined from metering data on a monthly basis and determined for each point of delivery on the same monthly billing cycle day.

TERMS OF SERVICE

Not less than one year.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

(Continued from Sheet No. 8.650)

MONTHLY RATE:

Delivery Voltage Level	Distribution below 69 kV		69 kV & above
	CILC-1(G)	CILC-1(D)	CILC-1(T)
Maximum Demand Level	200-499 kW	500 kW & above	
Customer Charge:	$100.00	$150.00	$1,975.00
Demand Charges:			
Base Demand Charges:			
per kW of Maximum Demand	$3.40	$3.10	None
per kW of Load Control On-Peak Demand	$1.30	$1.30	$1.30
per kW of Firm On-Peak Demand	$7.31	$7.11	$7.25

Capacity Payment and Conservation Charge:

CILC-1(G)	See Sheet No. 8.030.1
CILC-1(D)	See Sheet No. 8.030.1
CILC-1(T)	See Sheet No. 8.030.1

Non-Fuel Energy Charges:			
Base Energy Charges:			
On-Peak Period charge per kWh	1.074¢	0.542¢	0.471¢
Off-Peak Period charge per kWh	1.074¢	0.542¢	0.471¢

Environmental Charge See Sheet No. 8.030.1

Additional Charges:

Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

Minimum: The Customer Charge plus the Base Demand Charges.

(Continued on Sheet No. 8.652)

COMMERCIAL/INDUSTRIAL DEMAND REDUCTION RIDER (CDR)
(OPTIONAL)

AVAILABLE:

In all territory served. Available to any commercial or industrial customer receiving service under Rate Schedules GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, GSLDT-2, GSLD-3, GSLDT-3, or HLFT through the execution of a Commercial/Industrial Demand Reduction Rider Agreement in which the load control provisions of this rider can feasibly be applied.

LIMITATION OF AVAILABILITY:

This Rider may be modified or withdrawn subject to determinations made under Commission Rules 25-17.0021(4), F.A.C., Goals for Electric Utilities and 25-6.0438, F.A.C., Non-Firm Electric Service - Terms and Conditions or any other Commission determination.

APPLICATION:

For electric service provided to any commercial or industrial customer receiving service under Rate Schedule GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, GSLDT-2, GSLD-3, GSLDT-3, or HLFT who as a part of the Commercial/Industrial Demand Reduction Rider Agreement between the Customer and the Company, agrees to allow the Company to control at least 200 kW of the Customer's load, or agrees to operate Backup Generation Equipment (see Definitions) and designate (if applicable) additional controllable demand to serve at least 200 kW of the Customer's own load during periods when the Company is controlling load. A Customer shall enter into a Commercial/Industrial Reduction Demand Rider Agreement with the Company to be eligible for this Rider. To establish the initial qualification for this Rider, the Customer must have had a Utility Controlled Demand during the summer Controllable Rating Period (April 1 through October 31) for at least three out of seven months of at least 200 kW greater than the Firm Demand level specified in Section 4 of the Commercial/Industrial Demand Reduction Rider Agreement. The Utility Controlled Demand shall not be served on a firm service basis until service has been terminated under this Rider.

LIMITATION OF SERVICE:

Customers participating in the General Service Load Management Program (FPL "Business On Call" Program) are not eligible for this Rider.

MONTHLY RATE:

All rates and charges under Rate Schedules GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, GSLDT-2, GSLD-3, GSLDT-3, HLFT shall apply. In addition, the applicable Monthly Administrative Adder and Utility Controlled Demand Credit shall apply.

MONTHLY ADMINISTRATIVE ADDER:

Rate Schedule	Adder
GSD-1	$75.00
GSDT-1, HLFT (21-499 kW)	$75.00
GSLD-1, GSLDT-1, HLFT (500-1,999 kW)	$125.00
GSLD-2, GSLDT-2, HLFT (2,000 kW or greater)	$50.00
GSLD-3, GSLDT-3	$475.00

UTILITY CONTROLLED DEMAND CREDIT:

A monthly credit of $7.30 per kW is allowed based on the Customer's Utility Controlled Demand.

UTILITY CONTROLLED DEMAND:

The Utility Controlled Demand for a month in which there are no load control events during the Controllable Rating Period shall be the sum of the Customer's kWh usage during the hours of the applicable Controllable Rating Period, divided by the total number of hours in the applicable Controllable Rating Period, less the Customer's Firm Demand.

In the event of Load Control occurring during the Controllable Rating Period, the Utility Controlled Demand shall be the sum of the Customer's kWh usage during the hours of the applicable Controllable Rating Period less the sum of the Customer's kWh usage during the Load Control Period, divided by the number of non-load control hours occurring during the applicable Controllable Rating Period, less the Customer's Firm Demand.

(Continued on Sheet No. 8.681)

(Continued from Sheet No. 8.681)

PROVISIONS FOR ENERGY USE DURING CONTROL PERIODS:

Customers notified of a load control event should not exceed their Firm Demand during periods when the Company is controlling load. However, electricity will be made available during control periods if the Customer's failure to meet its Firm Demand is a result of one of the following conditions:

1. Force Majeure events (see Definitions) which can be demonstrated to the satisfaction of the Company, or

2. maintenance of generation equipment necessary for the implementation of load control which is performed at a pre-arranged time and date mutually agreeable to the Company and the Customer (See Special Provisions), or

3. adding firm load that was not previously non-firm load to the Customer's facility, or

4. an event affecting local, state or national security, or

5. an event whose nature requires that space launch activities be placed in the critical mode (requiring a closed-loop configuration of FPL's transmission system) as designated and documented by the NASA Test Director at Kennedy Space Center and/or the USAF Range Safety Officer at Cape Canaveral Air Force Station.

The Customer's energy use (in excess of the Firm Demand) for the conditions listed above will be billed pursuant to the Continuity of Service Provision. For periods during which power under the Continuity of Service Provision is no longer available, the Customer will be billed, in addition to the normal charges provided hereunder, the greater of the Company's As-Available Energy cost, or the most expensive energy (calculated on a cents per kilowatt-hour basis) that FPL is purchasing or selling during that period, less the applicable class fuel charge. As-Available Energy cost is the cost calculated for Schedule COG-1 in accordance with FPSC Rule 25-17.0825, F.A.C.

If the Company determines that the Customer has utilized one or more of the exceptions above in an excessive manner, the Company will terminate service under this rider as described in TERM OF SERVICE.

If the Customer exceeds the Firm Demand during a period when the Company is controlling load for any reason other than those specified above, then the Customer will be:

1. billed a $7.30 charge per kW of excess kW for the prior sixty (60) months or the number of months the Customer has been billed under this rider, whichever is less, and

2. billed a penalty charge of $0.99 per kW of excess kW for each month of rebilling.

Excess kW for rebilling and penalty charges is determined by taking the difference between the Customer's kWh usage during the load control period divided by the number of hours in the load control period and the Customer's "Firm Demand". The Customer will not be rebilled or penalized twice for the same excess kW in the calculation described above.

(Continued on Sheet No. 8.683)

(Continued from Sheet No. 8.683)

In the event the Customer pays the Charges for Early Termination because no replacement Customer(s) is (are) available as specified in paragraph d. above, but the replacement Customer(s) does(do) become available within twelve (12) months from the date of termination of service under this Rider or FPL later determines that there is no need for the MW reduction in accordance with the FPL Numeric Commercial/Industrial Conservation Goals, then the Customer will be refunded all or part of the rebilling and penalty in proportion to the amount of MW obtained to replace the lost capacity less the additional cost incurred by the Company to serve those MW during any load control periods which may occur before the replacement Customer(s) became available.

Charges for Early Termination:

In the event that:

a) service is terminated by the Company for any reason(s) specified in this section, or

b) there is a termination of the Customer's existing service and, within twelve (12) months of such termination of service, the Company receives a request to re-establish service of similar character under a firm service or a curtailable service rate schedule, or under this rider with a shift from non-firm load to firm service,

   i) at a different location in the Company's service area, or

   ii) under a different name or different ownership, or

   iii) under other circumstances whose effect would be to increase firm demand on the Company's system without the requisite five (5) years' advance written notice, or

c) the Customer transfers the controllable portion of the Customer's load to "Firm Demand" or to a firm or a curtailable service rate schedule without providing at least five (5) years' advance written notice,

then the Customer will be:

1. rebilled $7.30 per kW of Utility Controlled Demand for the shorter of (a) the most recent prior sixty (60) months during which the Customer was billed for service under this Rider, or (b) the number of months the Customer has been billed under this Rider, and

2. billed a penalty charge of $0.99 per kW of Utility Controlled Demand times the number of months rebilled in No. 1 above.

SPECIAL PROVISIONS:

1. Control of the Customer's load shall be accomplished through the Company's load management systems by use of control circuits connected directly to the Customer's switching equipment or the Customer's load may be controlled by use of an energy management system where the firm demand level can be established or modified only by means of joint access by the Customer and the Company.

2. The Customer shall grant the Company reasonable access for installing, maintaining, inspecting, testing and/or removing Company-owned load control equipment.

3. It shall be the responsibility of the Customer to determine that all electrical equipment to be controlled is in good repair and working condition. The Company will not be responsible for the repair, maintenance or replacement of the Customer's electrical equipment.

4. The Company is not required to install load control equipment if the installation cannot be economically justified.

5. Credits under this Rider will commence after the installation, inspection and successful testing of the load control equipment.

6. Maintenance of equipment (including generators) necessary for the implementation of load control will not be scheduled during periods where the Company projects that it would not be able to withstand the loss of its largest unit and continue to serve firm service customers.

(Continued on Sheet No. 8.685)

(Continued from Sheet No. 8.715)

REMOVAL OF FACILITIES:

If Street Lighting facilities are removed either by Customer request or termination or breach of the agreement, the Customer shall pay FPL an amount equal to the original installed cost of the removed facilities less any salvage value and any depreciation (based on current depreciation rates as approved by the Florida Public Service Commission) plus removal cost.

MONTHLY RATE:

Luminaire Type		Lamp Size Initial Lumens	Watts	kWh/Mo. Estimate	Charge for FPL-Owned Unit ($) Fixtures	Mainte-nance	Energy Non-Fuel **	Total ***	Charge for Customer-Owned Unit $) Relamping/ Energy ****	Energy Only
High Pressure Sodium Vapor		6,300	70	29	$3.46	1.62	0.69	5.77	2.34	0.69
" "		9,500	100	41	$3.52	1.63	0.98	6.13	2.64	0.98
" "		16,000	150	60	$3.63	1.66	1.43	6.72	3.12	1.43
" "		22,000	200	88	$5.50	2.12	2.10	9.72	4.23	2.10
" "		50,000	400	168	$5.56	2.13	4.00	11.69	6.14	4.00
	*	12,800	150	60	$3.78	1.86	1.43	7.07	3.29	1.43
" "	*	27,500	250	116	$5.85	2.31	2.76	10.92	5.07	2.76
" "	*	140,000	1,000	411	$8.80	4.14	9.79	22.73	14.01	9.79
Mercury Vapor	*	6,000	140	62	$2.73	1.46	1.48	5.67	2.97	1.48
" "	*	8,600	175	77	$2.77	1.46	1.83	6.06	3.32	1.83
" "	*	11,500	250	104	$4.63	2.11	2.48	9.22	4.63	2.48
" "	*	21,500	400	160	$4.61	2.07	3.81	10.49	5.92	3.81
" "	*	39,500	700	272	$6.52	3.52	6.48	16.52	10.00	6.48
" "	*	60,000	1,000	385	$6.67	3.44	9.17	19.28	12.67	9.17
Incandescent	*	1,000	103	36				6.90	4.16	0.86
"	*	2,500	202	71				7.30	5.01	1.69
"	*	4,000	327	116				8.73	6.18	2.76
Fluorescent	*	19,800	300	122					4.67	2.91

* These units are closed to new FPL installations.
** The non-fuel energy charge is 2.383¢ per kWh.
*** Bills rendered based on "Total" charge. Unbundling of charges is not permitted.
**** New Customer installations of those units closed to FPL installations cannot receive relamping service.

Charges for other FPL-owned facilities:

Wood pole used only for the street lighting system	$4.19
Concrete pole used only for the street lighting system	$5.76
Fiberglass pole used only for the street lighting system	$6.81
Steel pole used only for the street lighting system *	$5.76
Underground conductors not under paving	3.29¢ per foot
Underground conductors under paving	8.05¢ per foot

The Underground conductors under paving charge will not apply where a CIAC is paid pursuant to section "a)" under "Customer Contributions." The Underground conductors not under paving charge will apply in these situations.

(Continued on Sheet No. 8.717)

(Continued from Sheet No. 8.716)

On Customer-owned Street Lighting Systems, where Customer contracts to relamp at no cost to FPL, the Monthly Rate for non-fuel energy shall be 2.383¢ per kWh of estimated usage of each unit plus adjustments. On Street Lighting Systems, where the Customer elects to install Customer-owned monitoring systems, the Monthly Rate for non-fuel energy shall be 2.383¢ per kWh of estimated usage of each monitoring unit plus adjustments. The minimum monthly kWh per monitoring device will be 1 kilowatt-hour per month, and the maximum monthly kWh per monitoring device will be 5 kilowatt-hours per month.

During the initial installation period:
Facilities in service for 15 days or less will not be billed;
Facilities in service for 16 days or more will be billed for a full month.

WILLFUL DAMAGE:

Upon the **second** occurrence of willful damage to any FPL-owned facilities, the Customer will be responsible for the cost incurred for repair or replacement. If the lighting fixture is damaged, based on prior written instructions from the Customer, FPL will:

a) Replace the fixture with a shielded cutoff cobrahead. The Customer shall pay $280.00 for the shield plus all associated costs. However, if the Customer chooses to have the shield installed after the first occurrence, the Customer shall only pay the $280.00 cost of the shield; or

b) Replace with a like unshielded fixture. For this, and each subsequent occurrence, the Customer shall pay the costs specified under "Removal of Facilities"; or

c) Terminate service to the fixture.

Option selection shall be made by the Customer in writing and apply to all fixtures which FPL has installed on the Customer's behalf. Selection changes may be made by the Customer at any time and will become effective ninety (90) days after written notice is received.

Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

SPECIAL CONDITIONS:

Customers whose lights are turned off during sea turtle nesting season will receive a credit equal to the fuel charges associated with the fixtures that are turned off.

TERM OF SERVICE:

Initial term of ten (10) years with automatic, successive five (5) year extensions unless terminated in writing by either FPL or the Customer at least ninety (90) days prior to the current term's expiration.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service", the provision of this schedule shall apply.

PREMIUM LIGHTING

RATE SCHEDULE: PL-1

AVAILABLE:

In all territory served.

APPLICATION:

FPL-owned lighting facilities not available under rate schedule SL-1 and OL-1. To any Customer for the sole purpose of lighting streets, roadways and common areas, other than individual residential locations. This includes but is not limited to parking lots, homeowners association common areas, or parks.

SERVICE:

Service will be unmetered and will include lighting installation, lamp replacement and facilities maintenance for FPL-owned lighting systems. It will also include energy from dusk each day until dawn the following day.

The Company, while exercising reasonable diligence at all times to furnish service hereunder, does not guarantee continuous lighting and will not be liable for damages for any interruption, deficiency or failure of service, and reserves the right to interrupt service at any time for necessary repairs to lines or equipment.

LIMITATION OF SERVICE:

Installation shall be made only when, in the judgement of the Company, the location and the type of the facilities are, and will continue to be, easily and economically accessible to the Company equipment and personnel for both construction and maintenance.

Stand-by, non-firm, or resale service is not permitted hereunder.

TERM OF SERVICE:

The term of service is (20) twenty years. At the end of the term of service, the Customer may elect to execute a new agreement based on the current estimated replacement costs. The Company will retain ownership of these facilities.

FACILITIES PAYMENT OPTION:

The Customer will pay for the facilities in a lump sum in advance of construction. The amount will be the Company's total work order cost for these facilities times the Present Value Revenue Requirement (PVRR) multiplier of 1.1941. Monthly Maintenance and Energy charges will apply for the term of service.

FACILITIES SELECTION:

Facilities selection shall be made by the Customer in writing by executing the Company's Premium Lighting Agreement.

(Continued on Sheet No. 8.721)

(Continued from Sheet No. 8.720)

MONTHLY RATE :

Facilities:

Paid in full:	Monthly rate is zero, for Customer's who have executed a Premium Lighting Agreement before March 1, 2010:
10 years payment option:	1.362% of total work order cost.
20 years payment option:	0.925% of total work order cost.

Maintenance: FPL's estimated costs of maintaining lighting facilities.

Billing: FPL reserves the right to assess a charge for the recovery of any dedicated billing system developed solely for this rate.

Energy: KWH Consumption for fixtures shall be estimated using the following formula:

$$KWH = \frac{\text{Unit Wattage (usage) x 353.3 hours per month}}{1000}$$

Non-Fuel Energy	2.383¢/kWh
Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

During the initial installation period:
Facilities in service for 15 days or less will not be billed;
Facilities in service for 16 days or more will be billed for a full month.

MINIMUM MONTHLY BILL:

The minimum monthly bill shall be the applicable Facilities Maintenance and Billing charges.

(Continued on Sheet No. 8.722)

(Continued from Sheet No. 8.721)

EARLY TERMINATION:

If the Customer no longer wishes to receive service under this schedule, the Customer may terminate the Premium Lighting Agreement by giving at least (90) ninety days advance written notice to the Company. Upon early termination of service, the Customer shall pay an amount computed by applying the following Termination Factors to the installed cost of the facilities, based on the year in which the Agreement was terminated. These Termination Factors will not apply to Customers who elected to pay for the facilities in a lump sum in lieu of a monthly payment.

FPL may also charge the Customer for the cost to the utility for removing the facilities.

Ten (10) Years Payment Option	Termination Factor	Twenty (20) Years Payment Option	Termination Factor
1	1.1941	1	1.1941
2	1.0306	2	1.0831
3	0.9473	3	1.0563
4	0.8575	4	1.0275
5	0.7608	5	0.9965
6	0.6565	6	0.9630
7	0.5441	7	0.9269
8	0.4230	8	0.8880
9	0.2924	9	0.8461
10	0.1517	10	0.8009
>10	0.0000	11	0.7523
		12	0.6998
		13	0.6432
		14	0.5823
		15	0.5166
		16	0.4458
		17	0.3695
		18	0.2872
		19	0.1985
		20	0.1030
		>20	0.0000

WILLFUL DAMAGE:

In the event of willful damage to these facilities, FPL will provide the initial repair of each installed item at its expense. Upon the second occurrence of willful damage, and subsequent occurrence to these FPL-owned facilities, the Customer will be responsible for the cost for repair or replacement.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service", the provision of this schedule shall apply.

OUTDOOR LIGHTING

RATE SCHEDULE OL-1

AVAILABLE:

In all territory served.

APPLICATION:

For year-round outdoor security lighting of yards, walkways and other areas. Lights to be served hereunder shall be at locations which are easily and economically accessible to Company equipment and personnel for construction and maintenance.

It is intended that Company-owned security lights will be installed on existing Company-owned electric facilities, or short extension thereto, in areas where a street lighting system is not provided or is not sufficient to cover the security lighting needs of a particular individual or location. Where more extensive security lighting is required, such as for large parking lots or other commercial areas, the Customer will provide the fixtures, supports and connecting wiring; the Company will connect to the Customer's system and provide the services indicated below.

SERVICE:

Service includes lamp renewals, energy from approximately dusk each day until approximately dawn the following day, and maintenance of Company-owned facilities. The Company will replace all burned-out lamps and will maintain its facilities during regular daytime working hours as soon as practicable following notification by the Customer that such work is necessary. The Company shall be permitted to enter the Customer's premises at all reasonable times for the purpose of inspecting, maintaining, installing and removing any or all of its equipment and facilities.

The Company, while exercising reasonable diligence at all times to furnish service hereunder, does not guarantee continuous lighting and will not be liable for damages for any interruption, deficiency or failure of service, and reserves the right to interrupt service at any time for necessary repairs to lines or equipment.

LIMITATION OF SERVICE:

This schedule is not available for service normally supplied on the Company's standard street lighting schedules. Company-owned facilities will be installed only on Company-owned poles. Customer-owned facilities will be installed only on Customer-owned poles. Overhead conductors will not be installed in any area designated as an underground distribution area, or any area, premises or location served from an underground source. Stand-by or resale service not permitted hereunder.

MONTHLY RATE:

Luminaire Type		Lamp Size Initial Lumens	Watts	KWH/Mo. Estimate	Charge for Company-Owned Unit ($) Fixtures	Mainte-nance	Energy Non-Fuel **	Total	Charge for Customer-Owned Unit ($) Relamping/ Energy	Energy Only
High Pressure Sodium Vapor		6,300	70	29	4.49	1.64	0.70	6.83	2.34	0.70
" "		9,500	100	41	4.59	1.64	0.99	7.22	2.63	0.99
" "		16,000	150	60	4.75	1.67	1.44	7.86	3.11	1.44
" "		22,000	200	88	6.91	2.16	2.12	11.19	4.28	2.12
" "		50,000	400	168	7.35	2.13	4.04	13.52	6.17	4.04
" "	*	12,000	150	60	5.10	1.91	1.44	8.45	3.35	1.44
Mercury Vapor	*	6,000	140	62	3.45	1.48	1.49	6.42	2.97	1.49
" "	*	8,600	175	77	3.47	1.48	1.85	6.80	3.33	1.85
" "	*	21,500	400	160	5.68	2.08	3.85	11.61	5.93	3.85

* These units are closed to new Company installations.

** The non-fuel energy charge is 2.405¢ per kWh.

(Continued on Sheet No. 8.726)

Issued by: S. E. Romig, Director, Rates and Tariffs
Effective: January 1, 2013

(Continued from Sheet No. 8.725)

Charges for other Company-owned facilities:

Wood pole and span of conductors:	$8.62
Concrete pole and span of conductors:	$11.64
Fiberglass pole and span of conductors:	$13.67
Steel pole used only for the street lighting system *	$11.64
Underground conductors (excluding trenching)	$0.069 per foot
Down-guy, Anchor and Protector	$8.31

For Customer-owned outdoor lights, where the Customer contracts to relamp at no cost to FPL, the monthly rate for non-fuel energy shall be 2.405¢ per kWh of estimated usage of each unit plus adjustments.

Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Clause	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

TERM OF SERVICE:

Not less than one year. In the event the Company installs any facilities for which there is an added monthly charge, the Term of Service shall be for not less than three years.

If the Customer terminates service before the expiration of the initial term of the agreement, the Company may require reimbursement for the total expenditures made to provide such service, plus the cost of removal of the facilities installed less the salvage value thereof, and less credit for all monthly payments made for Company-owned facilities.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service", the provision of this schedule shall apply.

COMPANY-OWNED FACILITIES:

Company-owned luminaires normally will be mounted on Company's existing distribution poles and served from existing overhead wires. The Company will provide one span of secondary conductor from existing secondary facilities to a Company-owned light at the Company's expense. When requested by the Customer, and at the option of the Company, additional spans of wire or additional poles or underground conductors may be installed by the Company upon agreement by the Customer to use the facilities for a minimum of three years and pay each month the charges specified under MONTHLY RATE.

The Customer will make a lump sum payment for the cost of changes in the height of existing poles or the installation of additional poles in the Company's distribution lines or the cost of any other facilities required for the installation of lights to be served hereunder.

At the Customer's request, the Company will upgrade to a higher level of illumination without a service charge when the changes are consistent with good engineering practices. The Customer will pay the Company the net costs incurred in making other lamp size changes. In all cases where luminaires are replaced, the Customer will sign a new service agreement. Billing on the rate for the new luminaire or lamp size will begin as of the next regular billing date. A luminaire may be relocated at the Customer's request upon payment by the Customer of the costs of removal and reinstallation.

The Company will not be required to install equipment at any location where the service may be objectionable to others. If it is found after installation that the light is objectionable, the Company may terminate the service.

(Continued on Sheet No. 8.727)

(Continued from Sheet No. 8.726)

When the Company relocates or removes its facilities to comply with governmental requirements, or for any other reason, either the Company or the Customer shall have the right, upon written notice, to discontinue service hereunder without obligation or liability.

SPECIAL CONDITIONS:

Customers whose lights are turned off during sea turtle nesting season will receive a credit equal to the fuel charges associated with the fixtures that are turned off.

CUSTOMER-OWNED FACILITIES:

Customer-owned luminaires and other facilities will be of a type and design specified by the Company to permit servicing and lamp replacement at no abnormal cost. The Customer will provide all poles, fixtures, initial lamps and controls, and circuits up to the point of connection to the Company's supply lines, and an adequate support for the Company-owned service conductors.

The Company will provide an overhead service drop from its existing secondary conductors to the point of service designated by the Company for Customer-owned lights. Underground service conductors will be installed in lieu of the overhead conductors at the Customer's request, and upon payment by the Customer of the installed cost of the underground conductors after allowance for the cost of equivalent overhead service conductors and any trenching and backfilling provided by the Customer.

DEFINITIONS:

A "Luminaire," as defined by the Illuminating Engineering Society, is a complete lighting unit consisting of a lamp (bulb), together with parts designed to distribute the light, to position and protect the lamp, and connect the lamp to the power supply.

A "Conventional" luminaire is supported by a bracket that is mounted on the side of an ordinary wood pole or an ornamental pole. This is the only type of luminaire offered where service is to be supplied from overhead conductors, although this luminaire may also be used when service is supplied from underground conductors.

A "Contemporary" luminaire is of modern design and is mounted on top of an ornamental pole. Underground conductors are required.

A "Traditional" luminaire resembles an Early American carriage lantern and is mounted on top of a pole. It requires an ornamental pole and underground conductors to a source of supply.

An "Ornamental" pole is one made of concrete or fiberglass.

RECREATIONAL LIGHTING

(Closed Schedule)

RATE SCHEDULE: RL-1

AVAILABLE:

In all territory served. Available to any customer, who, as of January 16, 2001, was either taking service pursuant to this schedule or had a fully executed Recreational Lighting Agreement with the Company.

APPLICATION:

For FPL-owned facilities for the purpose of lighting community recreational areas. This includes, but is not limitied to, baseball, softball, football, soccer, tennis, and basketball.

SERVICE:

Service will be metered and will include lighting installation, lamp replacement and facilities maintenance for FPL-owned lighting systems.

The Company, while exercising reasonable diligence at all times to furnish service hereunder, does not guarantee continuous lighting and will not be liable for damages for any interruption, deficiency or failure of service, and reserves the right to interrupt service at any time for necessary repairs to lines or equipment.

LIMITATION OF SERVICE:

Installation shall be made only when, in the judgement of the Company, the location and the type of the facilities are, and will continue to be, easily and economically accessible to the Company equipment and personnel for both construction and maintenance.

Stand-by, non-firm, or resale service is not permitted hereunder.

TERM OF SERVICE:

The term of service is (20) twenty years. At the end of the term of service, the Customer may elect to execute a new Agreement based on the current estimated replacement costs. The Company will retain ownership of these facilities.

FACILITIES PAYMENT OPTION:

The Customer will pay for the facilities in a lump sum in advance of construction. The amount will be the Company's total work order cost for these facilities times the Present Value Revenue Requirement (PVRR) multiplier of 1.1941. Monthly Maintenance and energy charges will apply for the term of service.

FACILITIES SELECTION:

Facilities selection shall be made by the Customer in writing by executing the Company's Recreational Lighting Agreement.

(Continued on Sheet No. 8.744)

(Continued from Sheet No. 8.743)

MONTHLY RATE :

Facilities:

Paid in full:	Monthly rate is zero.
10 years payment option:	1.362% of total work order cost.*
20 years payment option:	0.925% of total work order cost.*

* Both (10) ten and (20) twenty year payment options are closed to new service, and are only available for the duration of the term of service of those customers that have fully executed a Recreational Lighting Agreement with the Company before January 16, 2001.

Maintenance:	FPL's estimated costs of maintaining lighting facilities.
Billing:	FPL reserves the right to assess a charge for the recovery of any dedicated billing system developed solely for this rate.
Charge Per Month:	Company's otherwise applicable general service rate schedule.
Conservation Charge	See Sheet No. 8.030.1
Capacity Payment Charge	See Sheet No. 8.030.1
Environmental Charge	See Sheet No. 8.030.1
Fuel Charge	See Sheet No. 8.030.1
Storm Charge	See Sheet No. 8.040
Franchise Fee	See Sheet No. 8.031
Tax Clause	See Sheet No. 8.031

MINIMUM MONTHLY BILL:

As provided in the otherwise applicable rate schedule, plus the Facilities Maintenance and Billing charges.

(Continued on Sheet No. 8.745)

(Continued from Sheet No. 8.744)

EARLY TERMINATION:

If the Customer no longer wishes to receive service under this schedule, the Customer may terminate the Recreational Lighting Agreement by giving at least (90) ninety days advance written notice to the Company. Upon early termination of service, the Customer shall pay an amount computed by applying the following Termination Factors to the installed cost of the facilities, based on the year in which the Agreement was terminated. These Termination Factors will not apply to Customers who elected to pay for the facilities in a lump sum in lieu of a monthly payment.

FPL may also charge the Customer for the cost to the utility for removing the facilities.

Ten (10) Years Payment Option	Termination Factor	Twenty (20) Years Payment Option	Termination Factor
1	1.1941	1	1.1941
2	1.0306	2	1.0831
3	0.9473	3	1.0563
4	0.8575	4	1.0275
5	0.7608	5	0.9965
6	0.6565	6	0.9630
7	0.5441	7	0.9269
8	0.4230	8	0.8880
9	0.2924	9	0.8461
10	0.1517	10	0.8009
>10	0.0000	11	0.7523
		12	0.6998
		13	0.6432
		14	0.5823
		15	0.5166
		16	0.4458
		17	0.3695
		18	0.2872
		19	0.1985
		20	0.1030
		>20	0.0000

WILLFUL DAMAGE:

In the event of willful damage to these facilities, FPL will provide the initial repair of each installed item at its expense. Upon the second occurrence of willful damage, and subsequent occurrence to these FPL-owned facilities, the Customer will be responsible for the cost for repair or replacement.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service", the provision of this schedule shall apply.

STANDBY AND SUPPLEMENTAL SERVICE

RATE SCHEDULE: SST-1

AVAILABLE:

In all territory served by the Company. Service under this rate schedule is on a customer by customer basis subject to the completion of arrangements necessary for implementation.

APPLICATION:

For electric service to any Customer, at a point of delivery, whose electric service requirements for the Customer's load are supplied or supplemented from the Customer's generation equipment at that point of service and require standby and/or supplemental service. For purposes of determining applicability of this rate schedule, the following definitions shall be used:

(1) "Standby Service" means electric energy or capacity supplied by the Company to replace energy or capacity ordinarily generated by the Customer's own generation equipment during periods of either scheduled (maintenance) or unscheduled (backup) outages of all or a portion of the Customer's generation.

(2) "Supplemental Service" means electric energy or capacity supplied by the Company in addition to that which is normally provided by the Customer's own generation equipment.

A Customer is required to take service under this rate schedule if the Customer's total generation capacity is more than 20% of the Customer's total electrical load and the Customer's generators are not for emergency purposes only.

Customers taking service under this rate schedule shall enter into a Standby and Supplemental Service Agreement ("Agreement"); however, failure to execute such an agreement will not pre-empt the application of this rate schedule for service.

SERVICE:

Three phase, 60 hertz, and at the available standard voltage. All service supplied by the Company shall be furnished through one metering point. Resale of service is not permitted hereunder.

Transformation Rider - TR, Sheet No. 8.820, does not apply to Standby Service.

MONTHLY RATE:

STANDBY SERVICE

Delivery Voltage:	Below 69 kV			69kV & Above
	SST-1(D1)	SST-1(D2)	SST-1(D3)	SST-1(T)
Contract Standby Demand:	Below 500 kW	500 to 1,999 kW	2,000 kW & Above	All Levels
Customer Charge:	$100.00	$100.00	$375.00	$1,451.71
Demand Charges:				
Base Demand Charges:				
Distribution Demand Charge per kW of Contract Standby Demand	$2.70	$2.70	$2.70	none
Reservation Demand Charge per kW	$1.07	$1.07	$1.07	$1.03
Daily Demand Charge per kW for each daily maximum On-Peak Standby Demand	$0.52	$0.52	$0.52	$0.29

Capacity Payment and Conservation Charges See Sheet No. 8.030.1

(Continued on Sheet No. 8.751)

(Continued from Sheet No. 8.750)

Delivery Voltage:	Below 69 kV			69 kV & Above
	SST-1(D1)	SST-1(D2)	SST-1(D3)	SST-1(T)
Contract Standby Demand:	Below 500 kW	500 to 1,999 kW	2,000 kW & Above	All Levels
Non-Fuel Energy Charges:				
Base Energy Charges:				
On-Peak Period charge per kWh	0.714¢	0.714¢	0.714¢	0.648¢
Off-Peak Period charge per kWh	0.714¢	0.714¢	0.714¢	0.648¢

Environmental Charge See Sheet No. 8.030.1

Additional Charges:
Fuel Charge See Sheet No. 8.030.1
Storm Charge See Sheet No. 8.040
Franchise Fee See Sheet No. 8.031
Tax Clause See Sheet No. 8.031

Minimum: The Customer Charge plus the Base Demand Charges.

DEMAND CALCULATION:

The Demand Charge for Standby Service shall be (1) the charge for Distribution Demand **plus** (2) the greater of the sum of the Daily Demand Charges or the Reservation Demand Charge times the maximum On-Peak Standby Demand actually registered during the month **plus** (3) the Reservation Demand Charge times the difference between the Contract Standby Demand and the maximum On-Peak Standby Demand actually registered during the month.

SUPPLEMENTAL SERVICE

Supplemental Service shall be the total power supplied by the Company minus the Standby Service supplied by the Company during the same metering period. The charge for all Supplemental Service shall be calculated by applying the applicable retail rate schedule, excluding the customer charge.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

CONTRACT STANDBY DEMAND:

The level of Customer's generation requiring Standby Service as specified in the Agreement. This Contract Standby Demand will not be less than the maximum load actually served by the Customer's generation during the current month or prior 23-month period less the amount specified as the Customer's load which would not have to be served by the Company in the event of an outage of the Customer's generation equipment. For a Customer receiving only Standby Service as identified under Special Provisions, the Contract Standby Demand shall be maximum load actually served by the Company during the current month or prior 23-month period.

A Customer's Contract Standby Demand may be re-established to allow for the following adjustments:

1. Demand reduction resulting from the installation of FPL Demand Side Management Measures or FPL Research Project efficiency measures; or

(Continued on Sheet No. 8.752)

INTERRUPTIBLE STANDBY AND SUPPLEMENTAL SERVICE
(OPTIONAL)

RATE SCHEDULE: ISST-1

AVAILABLE:

In all territory served by the Company. Service under this rate schedule is on a customer by customer basis subject to the completion of arrangements necessary for implementation.

LIMITATION OF AVAILABILITY:

This schedule may be modified or withdrawn subject to determinations made under Commission Rule 25-6.0438, F.A.C., Non-Firm Electric Service - Terms and Conditions or any other Commission determination.

APPLICATION:

A Customer who is eligible to receive service under the Standby and Supplemental Service (SST-1) rate schedule may, as an option, take service under this rate schedule, unless the Customer has entered into a contract to sell firm capacity and/or energy to the Company, and the Customer cannot restart its generation equipment without power supplied by the Company, in which case the Customer may only receive Standby and Supplemental Service under the Company's SST-1 rate schedule.

Customers taking service under this rate schedule shall enter into an Interruptible Standby and Supplemental Service Agreement ("Agreement"). This interruptible load shall not be served on a firm service basis until service has been terminated under this rate schedule.

SERVICE:

Three phase, 60 hertz, and at the available standard voltage.

A designated portion of the Customer's load served under this schedule is subject to interruption by the Company. Transformation Rider-TR, where applicable, shall only apply to the Customer's Contract Standby Demand for delivery voltage below 69 kV. Resale of service is not permitted hereunder.

MONTHLY RATE:

STANDBY SERVICE		Distribution	Transmission
Delivery Voltage:		Below 69 kV ISST-1(D)	69 kV & Above ISST-1(T)
Customer Charge:		$375.00	$1,891.00
Demand Charges:			
Base Demand Charges:			
Distribution Demand Charge per kW of Contract Standby Demand		$2.70	none
Reservation Demand Charge per kW of Interruptible Standby Demand		$0.16	$0.16
Reservation Demand Charge per kW of Firm Standby Demand		$1.07	$0.81
Daily Demand Charge per kW for each daily maximum On-Peak Interruptible Standby Demand		$0.08	$0.07
Daily Demand Charge per kW for each daily maximum On-Peak Firm Standby Demand		$0.52	$0.38
Capacity Payment and Conservation Charges	See Sheet No. 8.030.1		
Non-Fuel Energy Charges:			
Base Energy Charges:			
On-Peak Period charge per kWh		0.714¢	0.597¢
Off-Peak Period charge per kWh		0.714¢	0.597¢
Environmental Charge	See Sheet No. 8.030.1		

(Continued on Sheet No. 8.761)

Issued by: S. E. Romig, Director, Rates and Tariffs
Effective: January 1, 2013

TRANSFORMATION RIDER - TR

AVAILABLE:

In all territory served.

APPLICATION:

In conjunction with any commercial or industrial rate schedule specifying delivery of service at any available standard voltage when Customer takes service from available primary lines of 2400 volts or higher at a single point of delivery.

MONTHLY CREDIT:

The Company, at its option, will either provide and maintain transformation facilities equivalent to the capacity that would be provided if the load were served at a secondary voltage from transformers at one location or, when Customer furnishes transformers, the Company will allow a monthly credit of $0.27 per kW of Billing Demand. Any transformer capacity required by the Customer in excess of that provided by the Company hereunder may be rented by the Customer at the Company's standard rental charge.

The credit will be deducted from the monthly bill as computed in accordance with the provisions of the Monthly Rate section of the applicable Rate Schedule before application of any discounts or adjustments. No monthly bill will be rendered for an amount less than the minimum monthly bill called for by the Agreement for Service.

SPECIAL CONDITIONS:

The Company may change its primary voltage at any time after reasonable advance notice to any Customer receiving credit hereunder and affected by such change, and the Customer then has the option of changing its system so as to receive service at the new line voltage or of accepting service (without the benefit of this rider) through transformers supplied by the Company.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

SEASONAL DEMAND – TIME OF USE RIDER – SDTR
(OPTIONAL)

RIDER: SDTR

AVAILABLE:
In all territory served.

APPLICATION:
For electric service required for commercial or industrial lighting, power and any other purpose with a measured Demand in excess of 20 kW. This is an optional rate available to customers otherwise served under the GSD-1 GSDT-1, GSLD-1, GSLDT-1, GSLD-2 or GSLDT-2 Rate Schedules.

SERVICE:
Single or three phase, 60 hertz and at any available standard voltage. All service required on premises by Customer shall be furnished through one meter. Resale of service is not permitted hereunder.

MONTHLY RATE:
OPTION A: Non-Seasonal Standard Rate

Annual Maximum Demand	SDTR-1 21-499 kW	SDTR-2 500-1,999 kW	SDTR-3 2,000 kW or greater
Customer Charge:	$24.00	$55.00	$195.00
Demand Charges:			
Seasonal On-peak Demand Charge Per kW of Seasonal On-peak Demand	$8.20	$8.90	$9.20
Non-Seasonal Demand Charge Per kW of Non- Seasonal Maximum Demand	$6.70	$7.70	$8.10
Capacity Payment Charge:	See Sheet No. 8.030		
Conservation Charge:	See Sheet No. 8.030		
Energy Charges:			
Base Seasonal On-Peak Per kWh of Seasonal On-Peak Energy	6.254¢	4.267¢	3.632¢
Base Seasonal Off-Peak Per kWh of Seasonal Off-Peak Energy	1.000¢	0.704¢	0.633¢
Base Non-Seasonal Energy Charge Per kWh of Non-Seasonal Energy	1.500¢	1.056¢	0.950¢
Environmental Charge:	See Sheet No. 8.030		
Additional Charges:			
Fuel Charge:	See Sheet No. 8.030		
Storm Charge:	See Sheet No. 8.040		
Franchise Fee:	See Sheet No. 8.031		
Tax Clause:	See Sheet No. 8.031		

(Continued from Sheet No. 8.830)

OPTION B: Non-Seasonal Time of Use Rate

Annual Maximum Demand	SDTR-1 21-499 kW	SDTR-2 500-1,999 kW	SDTR-3 2,000 kW or greater
Customer Charge:	$24.00	$55.00	$195.00
Demand Charges:			
Seasonal On-peak Demand Charge Per kW of Seasonal On-peak Demand	$8.20	$8.90	$9.20
Non-Seasonal Demand Charge Per kW of Non- Seasonal Peak Demand	$6.70	$7.70	$8.10
Capacity Payment Charge	See Sheet No. 8.030		
Conservation Charge	See Sheet No. 8.030		
Energy Charges:			
Base Seasonal On-Peak Per kWh of Seasonal On-Peak Energy	6.254¢	4.267¢	3.632¢
Base Seasonal Off-Peak Per kWh of Seasonal Off-Peak Energy	1.000¢	0.704¢	0.633¢
Base Non-Seasonal On-Peak Per kWh of Non-Seasonal On-Peak Energy	3.232¢	2.194¢	2.010¢
Base Non-Seasonal Off-Peak Per kWh of Non-Seasonal Off-Peak Energy	1.000¢	0.704¢	0.633¢
Environmental Charge	See Sheet No. 8.030		
Additional Charges:			
Fuel Charge	See Sheet No. 8.030		
Storm Charge	See Sheet No. 8.040		
Franchise Fee	See Sheet No. 8.031		
Tax Clause	See Sheet No. 8.031		

Minimum Charge: The Customer Charge plus the currently effective Demand Charges.

NON-SEASONAL RATING PERIODS (OPTION B only):

Non-Seasonal On-Peak Period:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through May 31 and October 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day.

Non-Seasonal Off-Peak Period:

All other hours.

(Continued On Sheet No. 8.832)

(Continued from Sheet No. 9.950)

1.04 "Incremental Base Revenue" is actual Base Revenue received during the Performance Guaranty Period for electric service rendered to the Premises in excess of Baseline Base Revenue.

1.05 "Incremental Capacity," as determined by Company, is the positive difference, if any, between Baseline Capacity and the amount of capacity (measured in kW) necessary to meet Applicant's projections of electric load at the Premises.

1.06 "Performance Guaranty Period" is the period of time commencing with the day on which the requested level of service is installed and available to Customer, as determined by Company, ("In-Service Date"), and ending on the third anniversary of the In-Service Date ("Expiration Date").

ARTICLE II - PERFORMANCE GUARANTY AMOUNT

2.01 For purposes of this Agreement, the derivation of Incremental Capacity is shown in the following table.

Incremental Capacity (1)	Existing Structure (2)	New Structure (3)	Total Structure (2)+(3)
a. Square Footage			
b. Requested watts/sq ft			
c. Baseline Capacity watts/sq ft			
d. Requested Capacity (in kW) (a * b / 1000)			
e. Baseline Capacity (in kW) (a * c / 1000)			
f. Incremental Capacity (in kW) (d - e)			

2.02 The amount of the Performance Guaranty is the cost, as determined by Company, of the Incremental Capacity multiplied by a factor of 1.51. The cost of the Incremental Capacity is the positive difference, if any, between Company's estimated cost of providing the requested level of capacity and Baseline Capacity. Applicant agrees to provide Company a Performance Guaranty in the amount specified in the table below prior to Company installing the facilities necessary to provide the Incremental Capacity to serve the Premises.

Performance Guaranty (1)	Existing Structure (2)	New Structure (3)	Total Structure (2 + 3)
a. Cost of requested capacity			
b. Cost of Baseline Capacity	-0-		
c. Incremental cost (a – b)			
d. Present value factor	1.52	1.52	1.52
e. Performance Guaranty (c * d)			

(Continued on Sheet No. 9.952)

Appendix A

Distribution Substation Facilities
Monthly Rental and Termination Factors

The Monthly Rental Factor to be applied to the in-place value of the Distribution Substation Facilities as identified in the Long-Term Rental Agreement is as follows:

	Monthly Rental Factor
Distribution Substation Facilities	1.67%

Termination Fee for Initial 20 Year Period

If the Long-Term Rental Agreement for Distribution Substation Facilities is terminated by Customer during the Initial Term, Customer shall pay to Company a Termination Fee, such fee shall be computed by applying the following Termination Factors to the in-place value of the Facilities based on the year in which the Agreement is terminated:

Year Agreement Is Terminated	Termination Factors %	Year Agreement Is Terminated	Termination Factors %	Year Agreement Is Terminated	Termination Factors %
1	3.36	8	11.16	15	6.01
2	6.03	9	10.88	16	4.87
3	8.03	10	10.40	17	3.70
4	9.47	11	9.76	18	2.48
5	10.42	12	8.97	19	1.25
6	10.98	13	8.07	20	0
7	11.21	14	7.08		

Termination Fee for Subsequent Extension Periods

If the Long-Term Rental Agreement for Distribution Substation Facilities is terminated by Customer during an Extension, Customer shall pay to Company a Termination Fee, such fee shall be computed based on the net present value of the remaining payments under the extension period by applying the Termination Factor based on the month terminated to the monthly rental payment amount.

Month Terminated	Termination Factor	Month Terminated	Termination Factor	Month Terminated	Termination Factor	Month Terminated	Termination Factor
1	49.896	16	39.173	31	27.359	46	14.342
2	49.213	17	38.421	32	26.530	47	13.429
3	48.526	18	37.663	33	25.696	48	12.509
4	47.834	19	36.901	34	24.856	49	11.584
5	47.138	20	36.134	35	24.010	50	10.652
6	46.437	21	35.362	36	23.160	51	9.715
7	45.731	22	34.585	37	22.303	52	8.772
8	45.021	23	33.802	38	21.441	53	7.822
9	44.307	24	33.015	39	20.574	54	6.866
10	43.588	25	32.223	40	19.701	55	5.904
11	42.864	26	31.425	41	18.822	56	4.936
12	42.135	27	30.622	42	17.938	57	3.962
13	41.402	28	29.814	43	17.047	58	2.981
14	40.664	29	29.001	44	16.151	59	1.994
15	39.921	30	28.183	45	15.250	60	1.000

FLORIDA POWER & LIGHT COMPANY

Revenue Requirement Associated With Additional Infrastructure-Related Costs Since FPL's Last Rate Case Updated Based on FPL's Post-Hearing Brief

Test Year Ending December 31, 2013

(Dollar Amounts in $000)

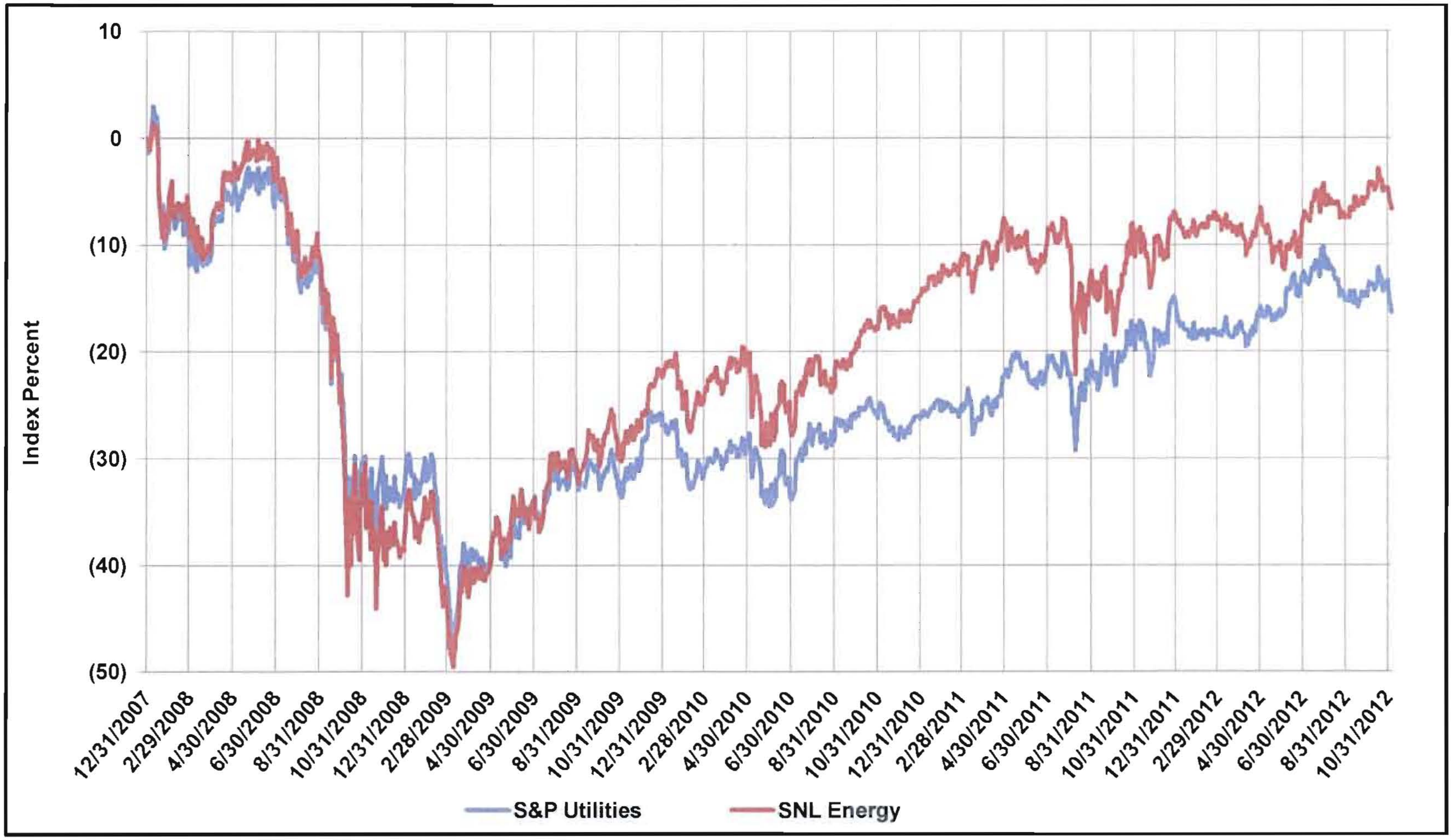
Line	Description	Incremental Infrastructure Costs
		(1)
1	Jurisdictional Adjusted Rate Base	$3,663,266
2	Pre-Tax Return at 10.70% ROE	9.65%
3	Return and Associated Taxes	$353,322
4	Property Insurance	$5,266
5	Depreciation (excluding Decommissioning)	$22,667
6	Property Tax	$9,483
7	Revenue Deficiency	$390,738
8	Settlement Base Revenue Increase	$378,000

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 702
PARTY FIPUG; Jeffry Pollock (JP-19); Incremental
DESCRIPTION Infrastructure Costs
DATE

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 703
PARTY FIPUG; Jeffry Pollock (JP-20)
DESCRIPTION Return on Equity
DATE

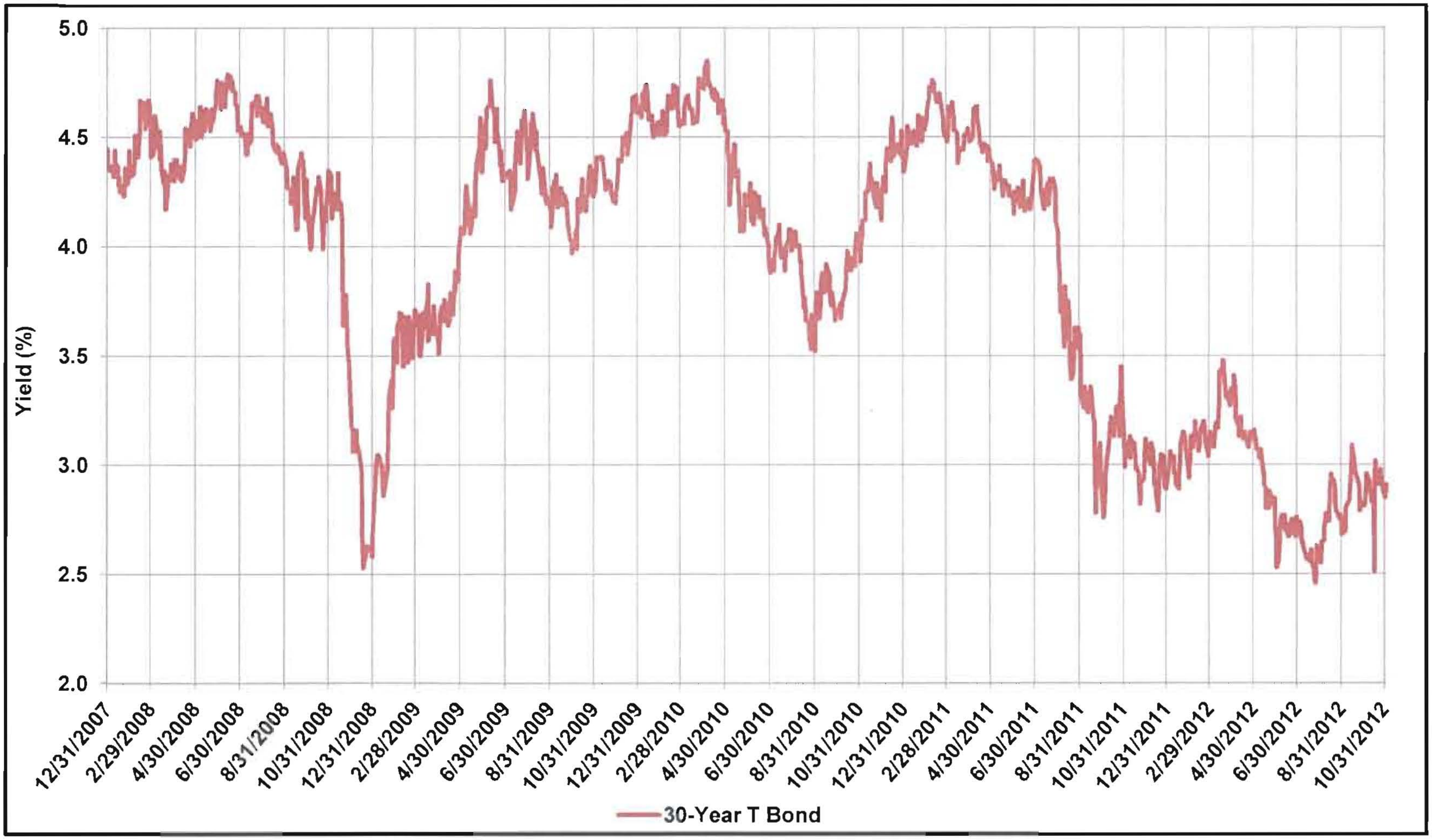
Docket No. 120015-EI
Return on Equity
Exhibit JP- 20

LORIDA POWER & LIGHT COMPANY
S&P Utility and SNL Energy Index Prices
2008 to Present



Source: SNL Financial

FLORIDA POWER & LIGHT COMPANY
30-Year Treasury Bond Yields
2008 to Present



Source: SNL Financial

FLORIDA POWER & LIGHT COMPANY
Revenue Requirement Associated With
Additional Infrastructure-Related Costs
Since FPL's Last Rate Case
Test Year Ending December 31, 2013
(Dollar Amounts in $000)

Line	Description	Incremental Infrastructure Costs
		(1)
1	Jurisdictional Adjusted Rate Base	$3,480,006
2	Pre-Tax Return at 10.70% ROE	9.78%
3	Return and Associated Taxes	$340,245
4	Property Insurance	$5,266
5	Depreciation (excluding Decommissioning)	$16,769
6	Property Tax	$9,483
7	Revenue Deficiency	$371,764
8	Settlement Base Revenue Increase	$378,000

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 704
PARTY FIPUG; Jeffry Pollock (JP-21)
DESCRIPTION Incremental Infrastructure Cost
DATE (Errata to JP-15)

EXHIBIT NO. 705

DOCKET NO: 120015-EI

WITNESS: Terry Deason

PARTY: Signatories

DESCRIPTION: Order No. PSC-05-0902-S-EI

(2005 FPL Stipulation Order)

DOCUMENTS:

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 1200015-EI EXHIBIT 705
PARTY Office of Public Counsel
DESCRIPTION 2005 FPL Stipulation Order
Order No. PSC-05-0902-S-EI

BEFORE THE PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company.	DOCKET NO. 050045-EI
In re: 2005 comprehensive depreciation study by Florida Power & Light Company.	DOCKET NO. 050188-EI ORDER NO. PSC-05-0902-S-EI ISSUED: September 14, 2005

The following Commissioners participated in the disposition of this matter:

BRAULIO L. BAEZ, Chairman
J. TERRY DEASON
RUDOLPH "RUDY" BRADLEY
LISA POLAK EDGAR

ORDER APPROVING STIPULATION AND SETTLEMENT

BY THE COMMISSION:

I. BACKGROUND

On March 22, 2005, Florida Power & Light Company (FPL) filed a petition for approval of a permanent increase in rates and charges sufficient to generate additional total annual revenues of $430,198,000 beginning January 1, 2006, and for approval of an adjustment to 2007 base rates to produce additional annual revenues of $122,757,000 beginning 30 days following the commercial in-service date of Turkey Point Unit 5 projected to occur in June 2007. In support of its petition, FPL filed new rate schedules, testimony, Minimum Filing Requirements (MFRs), and other schedules. FPL's petition was assigned Docket No. 050045-EI. By Order No. PSC-05-0619-PCO-EI, issued June 6, 2005, we suspended FPL's proposed new rate schedules to allow our staff and intervenors sufficient time to adequately and thoroughly examine the basis for the proposed new rates.

On March 17, 2005, FPL filed a depreciation study for this Commission's review. The depreciation study was assigned Docket No. 050188-EI. By Order No. PSC-05-0499-PCO-EI, issued May 9, 2005, we consolidated Docket Nos. 050188-EI and 050045-EI for all purposes.

As part of this consolidated proceeding, we conducted service hearings at the following locations in FPL's service territory: Daytona Beach, Viera, West Palm Beach, Ft. Lauderdale, Miami, Sarasota, and Ft. Myers. A formal administrative hearing was scheduled for August 22 - 26 and August 31 - September 2, 2005. The Office of Public Counsel (OPC), Office of the Attorney General (AG), Florida Industrial Power Users Group (FIPUG), Florida Retail Federation (FRF), Commercial Group (CG), AARP, Federal Executive Agencies (FEA), and

South Florida Hospital and Healthcare Association (SFHHA) were granted intervenor status. Common Cause Florida and seven individual customers filed a petition to intervene on August 15, 2005.

On August 22, 2005, the parties filed a joint motion for approval of a Stipulation and Settlement[1] among all parties to resolve all matters in this consolidated proceeding.[2] The Stipulation and Settlement was presented at the start of our hearing on August 22. The hearing was recessed to allow our staff to thoroughly review the Stipulation and Settlement and provide its analysis to us on August 24, when the hearing was reconvened for our vote.

By this Order, we approve the Stipulation and Settlement. Jurisdiction over these matters is vested in this Commission by various provisions of Chapter 366, Florida Statutes, including Sections 336.04, 366.05, and 366.06, Florida Statutes.

II. STIPULATION AND SETTLEMENT

The major elements contained in the Stipulation and Settlement are as follows:

- The Stipulation and Settlement is effective for a minimum term of four years - January 1, 2006, through December 31, 2009 - and thereafter will remain in effect until new base rates and charges become effective by order of the Commission. (Paragraph 1)

- With the exception of certain new and modified rate schedules specified in the Stipulation and Settlement, FPL's retail base rates and charges will remain unchanged on January 1, 2006, when the currently operative stipulation governing FPL's base rates and charges expires. (Paragraph 2)

- No party will petition for a change in FPL's base rates and charges to take effect prior to the minimum term of the Stipulation and Settlement, and, except as provided for in the Stipulation and Settlement, FPL will not petition for any new surcharges to recover costs that traditionally would be, or are presently, recovered through base rates. (Paragraph 3)

- A revenue sharing plan similar to the one contained in FPL's currently operative rate settlement will be implemented through the term of the Stipulation and Settlement. Retail base rate revenues between specified sharing threshold amounts and revenue caps will be shared as follows: FPL's shareholders will receive a 1/3 share, and FPL's retail customers will receive a 2/3 share. Retail base rate revenues above the specified revenue caps will be refunded to retail customers on an annual basis. (Paragraphs 4 and 5)

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[1] The Stipulation and Settlement is attached hereto as Attachment A and is incorporated herein by reference.

[2] Although Common Cause Florida and the individual customers had not been granted intervenor status, they signed the stipulation and settlement along with all parties. Under these circumstances and without objection from any party, we found at the August 22 hearing that it was not necessary to make a ruling on the petition to intervene filed by Common Cause Florida and the individual customers.

- If FPL's retail base rate earnings fall below a 10% ROE as reported on a Commission-adjusted or pro-forma basis on an FPL monthly earnings surveillance report during the term of the Stipulation and Settlement, FPL may petition to amend its base rates, and parties to the Stipulation are not precluded from participating in such a proceeding. This provision does not limit FPL from any recovery of costs otherwise contemplated by the Stipulation. (Paragraph 6)

- FPL has the option to amortize up to $125,000,000 annually as a credit to depreciation expense and a debit to the bottom line depreciation reserve over the term of the Stipulation and Settlement and as specified therein. Depreciation rates and/or capital recovery schedules will be established pursuant to the comprehensive depreciation studies as filed in March 2005 and will not be changed during the term of the Stipulation and Settlement. (Paragraph 8)

- Subject to review for prudence and reasonableness, FPL is permitted clause recovery of incremental costs associated with establishment of a Regional Transmission Organization or costs arising from an order of this Commission or the Federal Energy Regulatory Commission addressing any alternative configuration or structure to address independent transmission system governance or operation. (Paragraph 9)

- No party will appeal the Commission's final order in Docket No. 041291-EI addressing recovery of 2004 storm recovery costs. FPL will suspend its current accrual to its storm reserve effective January 1, 2006. Through a separate proceeding, a target level for FPL's storm reserve will be set. Replenishment of the storm reserve to that target level shall be accomplished through securitization under Section 366.8260, Florida Statutes, or through a separate surcharge that is independent of and incremental to retail base rates, as approved by the Commission. (Paragraph 10)

- FPL will suspend its current nuclear decommissioning accrual effective September 1, 2005, and at least through the minimum term of the Stipulation and Settlement. (Paragraph 11)

- New capital costs for expenditures recovered through the Environmental Cost Recovery Clause will be allocated, for the purpose of clause recovery, on a demand basis. (Paragraph 13)

- All post-September 11, 2001, incremental security costs will be recovered through the Capacity Cost Recovery Clause. (Paragraph 14)

- FPL will continue to operate without an authorized ROE range for the purpose of addressing earnings levels, but an ROE of 11.75% shall be used for all other regulatory purposes. (Paragraph 16)

- For any power plant that is approved through the Power Plant Siting Act and that achieves commercial operation within the term of the Stipulation and Settlement, the

> costs of which are not recovered fully through a clause or clauses, FPL's base rates will increase by the annualized base revenue requirement for the first 12 months of operation, reflecting the costs upon which the cumulative present value revenue requirements were or are predicated and pursuant to which a need determination was granted by the Commission. This base rate adjustment will be reflected on FPL's customer bills by increasing base charges and non-clause recoverable credits by an equal percentage and will apply to meter readings made on and after the commercial in-service date of the plant. (Paragraph 17)

Most of the terms of the Stipulation and Settlement appear to be self-explanatory. Still, we believe that several provisions merit comment or clarification so that as full an understanding of the parties' intent can be reflected in this Order before the Stipulation and Settlement is implemented. Based on the parties' discussions with our staff and discussions during our August 24 vote to approve the Stipulation and Settlement, we understand that the parties agree with the clarifications discussed below.

Paragraph 2

Under Paragraph 2, the parties agree that FPL will implement three new tariff offerings: an optional High Load Factor Time-of-Use rate with an adjustment to reflect a 65% load factor breakeven point by class; a Seasonal Demand Time-of-Use rate; and a General Service Constant Use rate. Further, the parties agree that FPL will eliminate the 10 kW exemption from its current rate schedules. We note that these changes are revenue neutral across FPL's demand-metered rate classes but are not revenue neutral within each such class.

Further, the parties agree that the inversion point on FPL's RS-1 (residential service) rate will be raised from 750 kWh to 1,000 kWh. We note that this change is revenue neutral within FPL's residential rate class.

The parties also agree that all gross receipts taxes will be shown as and collected through a separate gross receipts tax line item on bills. Thus, the portion of gross receipts taxes currently embedded in base rates will be removed and consolidated with the portion of gross receipts taxes currently shown separately.

Paragraph 5

Paragraph 5 describes and defines the revenue sharing plan agreed to by the parties. Part c of this paragraph states that the revenue sharing plan and the corresponding revenue sharing thresholds and revenue caps are intended to relate only to retail base rate revenues based on FPL's current structure and regulatory framework. Further, part c indicates that incremental revenues attributable to a business combination or acquisition involving FPL, its parent, or its affiliates will be excluded in determining retail base rate revenues for purposes of the revenue sharing plan. The parties clarified that in the event that a portion of FPL's system is sold or municipalized, appropriate adjustments would be made to account for the associated revenue reduction before application of FPL's annual average growth rate upon which the revenue sharing thresholds and revenue cap are calculated.

Paragraph 10

Under Paragraph 10, the parties agree that FPL will suspend its current base rate accrual of $20.3 million to its storm reserve account effective January 1, 2006. Further, the parties agree that a target for FPL's storm reserve account will be established in a separate proceeding and that funding the account to the target level will be achieved by either or both of two means: (1) a separate surcharge independent of and incremental to retail base rates; and (2) through the recently enacted provisions of Section 366.8260, Florida Statutes. FPL has committed to pursue continued funding of its storm reserve account within six months.

Paragraph 11

Pursuant to Paragraph 11, the parties agree that FPL will file a nuclear decommissioning study on or before December 12, 2005, but the study shall have no impact on FPL's base rates or charges or the terms of the Stipulation and Settlement. The parties clarified that the filing of this study is intended only for informational purposes and that no Commission action on the study is contemplated.

Paragraph 13

We note that Paragraph 13 reflects a change in practice with respect to the allocation of capital costs recovered through the Environmental Cost Recovery Clause (ECRC). These costs historically have been allocated to customer classes on an energy basis. Under the Stipulation and Settlement, the parties agree that new capital costs for environmental expenditures recovered through the ECRC will be allocated on a demand basis instead, consistent with the treatment of capital costs in a base rate cost of service study.

Paragraph 14

Currently, post-September 11, 2001, incremental security costs related only to power plant security are recovered through the Capacity Cost Recovery Clause (Capacity Clause). Pursuant to Paragraph 14, all post-September 11, 2001, incremental security costs – both power plant and non-plant security costs – will be recovered through the Capacity Clause.

Paragraph 17

The parties clarified that in the event the actual capital cost of a generation project subject to Paragraph 17 is lower than the projected cost, the difference will be reflected as a one-time credit through the Capacity Clause.

Other Matters

Pursuant to a stipulation approved in Order No. PSC-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI, FPL currently recovers incremental hedging costs through the Fuel Cost Recovery Clause (Fuel Clause). In its petition for a rate increase, FPL proposed to recover these costs through base rates instead. The Stipulation and Settlement is silent on how incremental hedging costs will be recovered. The parties clarified that they intended for recovery of these costs to continue through the Fuel Clause during the term of the Stipulation and Settlement. Because the Stipulation is silent in this regard, the parties indicated that they would take action to memorialize their intent in this year's Fuel Clause proceedings.

The parties also clarified their intent that, upon approval of this Stipulation and Settlement, Docket No. 050494-EI should be closed. Docket No. 050494-EI was assigned to a joint petition for a decrease in FPL's base rates and charges filed July 19, 2005, by several of the intervenors in this docket.

III. FINDINGS

Upon review and consideration, we find that the Stipulation and Settlement provides a reasonable resolution of the issues in this proceeding with respect to FPL's rates and charges and its depreciation rates and capital recovery schedules. The Stipulation and Settlement appears to provide FPL's customers with a degree of stability and predictability with respect to their electricity rates while allowing FPL to maintain the financial strength to make investments necessary to provide customers with safe and reliable power. Further, the Stipulation and Settlement extends through 2009 a revenue sharing plan which, since its inception in 1999, has resulted in refunds to customers of over $225 million to date. In addition, we recognize that the Stipulation and Settlement reflects the agreement of a broad range of interests: FPL, OPC, the Attorney General, and residential, commercial, industrial, and governmental customers of FPL.

In conclusion, we find that the Stipulation and Settlement establishes rates that are fair, just, and reasonable and that approval of the Stipulation and Settlement is in the public interest. Therefore, we approve the Stipulation and Settlement. As with any settlement we approve, nothing in our approval of this Stipulation and Settlement diminishes this Commission's ongoing authority and obligation to ensure fair, just, and reasonable rates. Nonetheless, this Commission has a long history of encouraging settlements, giving great weight and deference to settlements, and enforcing them in the spirit in which they were reached by the parties.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the Stipulation and Settlement filed August 22, 2005, which is attached hereto as Attachment A and incorporated herein by reference, is approved. It is further

ORDERED that FPL shall file, for administrative approval, revised tariff sheets to reflect the terms of the Stipulation and Settlement. It is further

ORDERED that Docket Nos. 050045-EI, 050188-EI, and 050494-EI shall be closed.

By ORDER of the Florida Public Service Commission this 14th day of September, 2005.

BLANCA S. BAYÓ, Director
Division of the Commission Clerk
and Administrative Services

By: Kay Flynn
Kay Flynn, Chief
Bureau of Records

(S E A L)

WCK

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: (1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of the Commission Clerk and Administrative Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or (2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Director, Division of the Commission Clerk and Administrative Services and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company.	Docket No. 050045-EI
In re: 2005 comprehensive depreciation study by Florida Power & Light Company.	Docket No. 050188-EI

STIPULATION AND SETTLEMENT

WHEREAS, pursuant to its petition filed March 22, 2005, Florida Power & Light Company (FPL) has petitioned the Florida Public Service Commission (FPSC or Commission) for an increase in base rates and other related relief;

WHEREAS, the Office of the Attorney General (AG), the Office of Public Counsel (OPC), The Florida Industrial Power Users Group (FIPUG), AARP, Florida Retail Federation (FRF), the Commercial Group (CG), the Federal Executive Agencies (FEA), and South Florida Hospital and Healthcare Association (SFHHA) have intervened, and have signed this Stipulation and Settlement (unless the context clearly requires otherwise, the term Party or Parties means a signatory to this Stipulation and Settlement);

WHEREAS, FPL and the Parties to this Stipulation and Settlement recognize that this is a period of unprecedented world energy prices and that this Stipulation and Settlement will mitigate the impact of high energy prices;

WHEREAS, FPL has provided the minimum filing requirements (MFRs) as required by the FPSC and such MFRs have been thoroughly reviewed by the FPSC Staff and the Parties to this proceeding;

WHEREAS, FPL has filed comprehensive testimony in support of and detailing its MFRs;

WHEREAS, on March 16, 2005, FPL filed comprehensive depreciation studies in accordance with FPSC Rule 25-6.0436(8)(a), Florida Administrative Code;

WHEREAS, the parties in this proceeding have conducted extensive discovery on the MFRs, depreciation studies, and FPL's testimony;

WHEREAS, the discovery conducted has included the production and opportunity to inspect more than 315,000 pages of information regarding FPL's costs and operations;

WHEREAS, the Parties to this Stipulation and Settlement have undertaken to resolve the issues raised in these proceedings so as to maintain a degree of stability to FPL's base rates and charges, and to provide incentives to FPL to continue to promote efficiency through the term of this Stipulation and Settlement;

WHEREAS, FPL is currently operating under a stipulation and settlement agreement agreed to by OPC and other parties, and approved by the FPSC by Order PSC-02-0501-AS-EI, issued April 11, 2002, in Docket Nos. 001148-EI and 020001-EI (2002 Agreement);

WHEREAS, previous to the 2002 Agreement, FPL operated under a stipulation and settlement agreement approved by the FPSC in Order No. PSC 99-0519-AS-EI (1999 Agreement);

WHEREAS, the 1999 and 2002 Agreements, combined, provided for a reduction of $600 million in FPL's base rates, and include revenue sharing plans that have resulted in refunds to customers to date in excess of $225 million;

WHEREAS, the 1999 and 2002 Agreements and revenue sharing plans have provided significant benefits to customers, resulting in approximately $4 billion in total savings to FPL's customers through the end of 2005;

WHEREAS, during 2005 FPL has added two new power plants in Martin and Manatee Counties at installed costs totaling approximately $887 million without increasing base rates;

WHEREAS, FPL must make substantial investments in the construction of new electric generation and other infrastructure for the foreseeable future in order to continue to provide safe and reliable power to meet the growing needs of retail customers in the state of Florida; and

WHEREAS, an extension of the revenue sharing plan and preservation of the benefits for customers of the $600 million reduction in base rates provided for in the 1999 and 2002 Agreements during the period in which this Stipulation and Settlement is in effect, and other provisions as set forth herein, including the provision for the incremental base rate recovery of costs associated with the addition of electric generation, will further be beneficial to retail customers;

NOW THEREFORE, in consideration of the foregoing and the covenants contained herein, the Parties hereby stipulate and agree:

1. Upon approval and final order of the FPSC, this Stipulation and Settlement will become effective on January 1, 2006 (the "Implementation Date"), and shall continue through December 31, 2009 (the "Minimum Term"), and thereafter shall remain in effect until terminated on the date that new base rates become effective pursuant to order of the FPSC following a formal administrative hearing held either on the FPSC's own motion or on request made by any of the Parties to this Stipulation and Settlement in accordance with Chapter 366, Florida Statutes.

2. FPL's retail base rates and base rate structure shall remain unchanged, except as otherwise permitted in this Stipulation and Settlement. The following tariff changes shall be approved and implemented:

a. (i) As reflected in FPL's MFR E-14, institution of the optional High Load Factor Time-of-Use rate with an adjustment to reflect a 65% load factor breakeven point by rate class, the Seasonal Demand Time-of-Use rate, and the General Service Constant Use Rate;

(ii) Elimination of the 10 kW exemption from rates.

(iii) The combined adjustments to implement (i) and (ii) above shall be made on a revenue neutral basis with reference to the 2006 forecast reflected in MFR E-13(c) at present base rates.

b. Raising the inversion point on the RS-1 rate from 750 kWh to 1,000 kWh, on a revenue neutral basis with reference to the 2006 forecast reflected in MFR E-13(c) at present base rates.

c. Consolidation and collection of all gross receipts taxes, including existing gross receipts taxes embedded in base rates, through the separate gross receipts tax line item on bills, on a revenue neutral basis with reference to the 2006 forecast reflected in MFR E-13(c) at present base rates.

d. At any time during the term of the Stipulation and Settlement and subject to Commission approval, any new or revised tariff provisions or rate schedules requested by FPL, provided that such tariff request does not increase any existing base rate component of a tariff or rate schedule during the term of the

Stipulation and Settlement unless the application of such new or revised tariff or rate schedule is optional to the utility's customers.

3. Except as provided in Section 1, no Party to this Stipulation and Settlement will request, support, or seek to impose a change in the application of any provision hereof. AG, OPC, FIPUG, AARP, FRF, FEA, CG, and SFHHA will neither seek nor support any reduction in FPL's base rates and charges, including interim rate decreases, to take effect prior to the end of the Minimum Term of this Stipulation and Settlement unless a reduction request is initiated by FPL. FPL will not petition for an increase in its base rates and charges, including interim rate increases, to take effect for meter readings before the end of the Minimum Term except as provided for in Section 6. During the term of this Stipulation and Settlement, except as otherwise provided for in this Stipulation and Settlement, or except for unforeseen extraordinary costs imposed by government agencies relating to safety or matters of national security, FPL will not petition for any new surcharges, on an interim or permanent basis, to recover costs that are of a type that traditionally and historically would be, or are presently, recovered through base rates.

4. During the term of this Stipulation and Settlement, revenues which are above the levels stated herein below in Section 5 will be shared between FPL and its retail electric utility customers -- it being expressly understood and agreed that the mechanism for earnings sharing herein established is not intended to be a vehicle for "rate case" type inquiry concerning expenses, investment, and financial results of operations.

5. Commencing on the Implementation Date and for the calendar years 2006, 2007, 2008 and 2009, and continuing thereafter until terminated, FPL will be under a Revenue Sharing Incentive Plan as set forth below. For purposes of this Revenue Sharing Incentive Plan, the following retail base rate revenue threshold amounts are established:

a. Sharing Threshold - Retail base rate revenues between the sharing threshold amount and the retail base rate revenue cap as defined in Section 5(b) below will be divided into two shares on a 1/3, 2/3 basis. FPL's shareholders shall receive the 1/3 share. The 2/3 share will be refunded to retail customers. The sharing threshold for 2006 will be established by using the 2005 sharing threshold of $3,880 million in retail base rate revenues, increased by the average annual growth rate in retail kWh sales for the ten year period ending December 31, 2005. For each succeeding calendar year or portion thereof during which the Stipulation and Settlement is in effect, the succeeding calendar year retail base rate revenue sharing threshold amounts shall be established by increasing the prior year's threshold by the sum of the following two amounts: (i) the average annual growth rate in retail kWh sales for the ten calendar year period ending December 31 of the preceding year multiplied by the prior year's retail base rate revenue sharing threshold and (ii) the amount of any incremental GBRA revenues in that year. The GBRA is described in Section 17.

b. Revenue Cap - Retail base rate revenues above the retail base rate revenue cap will be refunded to retail customers on an annual basis. The retail base rate revenue cap for 2006 will be established by using the 2005 cap of $4,040 million in retail base rate revenues, increased by the average annual growth rate in retail kWh sales for the ten calendar year period ending December 31, 2005. For each succeeding calendar year or portion thereof during which the Stipulation and Settlement is in effect, the succeeding calendar year retail base rate revenue cap amounts shall be established by increasing the prior year's cap by the sum of the following two amounts: (i) the average annual growth rate in retail kWh sales for the ten calendar year period ending December 31 of the preceding year multiplied by the prior year's retail base rate revenue cap amount and (ii) the amount of any incremental GBRA revenues in that year.

c. Revenue exclusions - The Revenue Sharing Incentive Plan and the corresponding revenue sharing thresholds and revenue caps are intended to relate only to retail base rate revenues of FPL based on its current structure and regulatory framework. Thus, for example, incremental revenues attributable to a business combination or acquisition involving FPL, its parent, or its affiliates, whether inside or outside the state of Florida, or revenues from any clause, surcharge or other recovery mechanism other than retail base rates, shall be excluded in determining retail base rate revenues for purposes of revenue sharing under this Stipulation and Settlement.

d. Refund mechanism - Refunds will be paid to customers as described in Section 7.

e. Calculation of sharing threshold and revenue cap for partial calendar years – In the event that this Stipulation and Settlement is terminated other than at the end of a calendar year, the sharing threshold and revenue cap for the partial calendar year shall be determined at the end of that calendar year by (i) dividing the retail kWh sales during the partial calendar year by the retail kWh for the full calendar year, and (ii) applying the resulting fraction to the sharing threshold and revenue cap for the full calendar year that would have been calculated as set forth in Sections 5(a) and 5(b) above.

f. Calculation of annual average growth rate - For purposes of this Section 5, the average annual growth rate shall be calculated by summing the percentage change in retail kWh sales for each year in the relevant ten year period and dividing by 10.

6. If FPL's retail base rate earnings fall below a 10% ROE as reported on an FPSC adjusted or pro-forma basis on an FPL monthly earnings surveillance report during the term of this Stipulation and Settlement, FPL may petition the FPSC to amend its base rates notwithstanding the provisions of Section 3, either as a general rate proceeding or as a limited proceeding under Section 366.076, Florida Statutes. Parties to this Stipulation and Settlement are not precluded from participating in such a proceeding, and, in the event that FPL petitions to initiate a limited proceeding under this Section 6, any Party may petition to initiate any proceeding otherwise permitted by Florida law. This Stipulation and Settlement shall terminate upon the effective date of any Final Order issued in such proceeding that changes FPL's base rates. This paragraph shall not be construed to bar or limit FPL from any recovery of costs otherwise contemplated by this Stipulation and Settlement.

7. All revenue-sharing refunds will be paid with interest at the 30-day commercial paper rate to retail customers of record during the last three months of each applicable refund period based on their proportionate share of base rate revenues for the refund period. For purposes of calculating interest only, it will be assumed that revenues to be refunded were collected evenly throughout the preceding refund period. All refunds with interest will be in the form of a credit on the customers' bills beginning with the first day of the first billing cycle of the second month after the end of the applicable refund period (or, in the case of a partial calendar year refund, after the end of that calendar year). Refunds to former customers will be completed as expeditiously as reasonably possible.

8. Starting with the effective date of this Stipulation and Settlement, FPL may, at its option, amortize up to $125,000,000 annually as a credit to depreciation expense and a debit to the bottom line depreciation reserve over the term of this Stipulation and Settlement. Any such

reserve amount will be applied first to reduce any reserve excesses by account, as determined in FPL's depreciation studies filed after the term of this Stipulation and Settlement, and thereafter will result in reserve deficiencies. Any such reserve deficiencies will be allocated to individual reserve balances based on the ratio of the net book value of each plant account to total net book value of all plant. The amounts allocated to the reserves will be included in the remaining life depreciation rate and recovered over the remaining lives of the various assets. Additionally, depreciation rates and/or capital recovery schedules shall be established pursuant to the comprehensive depreciation studies as filed March 16, 2005 and will not be changed for the term of this Stipulation and Settlement.

9. FPL will be permitted clause recovery of prudently incurred incremental costs associated with the establishment of a Regional Transmission Organization or any other costs arising from an order of the FPSC or the Federal Energy Regulatory Commission addressing any alternative configuration or structure to address independent transmission system governance or operation. Any Party to this Stipulation and Settlement may participate in any proceeding relating to the recovery of costs contemplated in this section for the purpose of challenging the reasonableness and prudence of such costs, but not for the purpose of challenging FPL's right to clause recovery of such costs.

10. No Party to this Stipulation and Settlement shall appeal the FPSC's Final Order in Docket No. 041291-EI. Further, Parties agree to the following provisions relative to the target level and funding of Account No. 228.1 and recovery of any deficits in such Account:

a. The target level for Account No. 228.1 shall be as established by the Commission, whether on its own motion, upon petition by FPL, or in conjunction with a proceeding held in accordance with Section 366.8260, Florida Statutes. FPL will be permitted to recover prudently incurred costs associated with events covered by Account No. 228.1 and replenish Account No. 228.1 to a target level through charges to customers, that are approved by the Commission, that are independent of and incremental to base rates and without the application of any form of earnings test or measure. The fact that insufficient funds have been accumulated in Account No. 228.1 to cover costs associated with events covered by that Account shall not be evidence of imprudence or the basis of a disallowance. Replenishment of Account No. 228.1 to a target level approved by the Commission and/or the recovery of any costs incurred in excess of funds accumulated in Account No. 228.1 and insurance shall be accomplished through Section 366.8260, Florida Statutes, and/or through a separate surcharge that is independent of and incremental to retail base rates, as approved by the Commission. Parties to this Stipulation and Settlement are not precluded from participating in such a proceeding, nor precluded from challenging the amount of such target level or whether recovery should be accomplished either through Section 366.8260, Florida Statutes or through a separate surcharge.

b. The current base rate accrual to Account No. 228.1 of $20.3 million is suspended effective January 1, 2006.

c. No revenues contemplated by this Section 10 shall be included in the computation of retail base rate revenues for purposes of revenue sharing under this Stipulation and Settlement.

11. The current decommissioning accrual of $78,516,937 (jurisdictional) approved in Order No. PSC-02-0055-PAA-EI shall be suspended effective September 1, 2005 and shall remain suspended through the Minimum Term and, at the Company's option, for any additional period during which this Stipulation and Settlement remains in effect. FPL's decommissioning study to be filed on or before December 31, 2005 shall have no impact on FPL's base rates, charges, or the terms of this Stipulation and Settlement.

12. The portion of St. Johns River Power Park ("SJRPP") capacity costs and certain capacity revenues that are currently embedded in base rates shall continue to be recovered through base rates in the current manner as contemplated by Order No. PSC-92-1334-FOF-EI.

13. New capital costs for environmental expenditures recovered through the Environmental Cost Recovery Clause will be allocated, for the purpose of clause recovery, consistent with FPL's current cost of service methodology.

14. Post-September 11, 2001 incremental security costs shall remain in and be recovered through the Capacity Clause.

15. For surveillance reporting requirements and all regulatory purposes, FPL's ROE will be calculated based upon an adjusted equity ratio as follows. FPL's adjusted equity ratio will be capped at 55.83% as included in FPL's projected 1998 Rate of Return Report for surveillance purposes. The adjusted equity ratio equals common equity divided by the sum of common equity, preferred equity, debt and off-balance sheet obligations. The amount used for off-balance sheet obligations will be calculated per the Standard & Poor's methodology.

16. Effective on the Implementation Date, FPL will continue to operate without an authorized Return on Equity (ROE) range for the purpose of addressing earnings levels, and the

revenue sharing mechanism herein described will be the appropriate and exclusive mechanism to address earnings levels, but an ROE of 11.75% shall be used for all other regulatory purposes.

17. For any power plant that is approved pursuant to the Florida Power Plant Siting Act (PPSA) and achieves commercial operation within the term of this Stipulation and Settlement, the costs of which are not recovered fully through a clause or clauses, FPL's base rates will be increased by the annualized base revenue requirement for the first 12 months of operation, reflecting the costs upon which the cumulative present value revenue requirements (CPVRR) were or are predicated, and pursuant to which a need determination was granted by the FPSC, such adjustment to be reflected on FPL's customer bills by increasing base charges, and non-clause recoverable credits, by an equal percentage. FPL will begin applying the incremental base rate charges required by this Stipulation and Settlement to meter readings made on and after the commercial in service date of any such power plant. Such adjustment shall be referred to as a Generation Base Rate Adjustment (GBRA). The GBRA will be calculated using an 11.75% ROE and the capital structure as per Section 15 above. FPL will calculate and submit for Commission confirmation the amount of the GBRA using the Capacity Clause projection filing for the year that the plant is to go into service. In the event that the actual capital costs of generation projects are lower than were or are projected in the need determination proceeding, the difference will be flowed back via a true-up to the Capacity Clause. In the event that actual capital costs for such power plant are higher than were projected in the need determination proceeding, FPL at its option may initiate a limited proceeding per Section 366.076, Florida Statutes, limited to the issue of whether FPL has met the requirements of Rule 25-22.082(15), Florida Administrative Code. If the Commission finds that FPL has met the requirements of Rule 25-22.082(15), FPL shall increase the GBRA by the corresponding incremental revenue

requirement due to such additional capital costs. However, FPL's election not to seek such an increase in the GBRA shall not preclude FPL from booking any incremental costs for surveillance reporting and all regulatory purposes subject only to a finding of imprudence or disallowance by the Commission. Upon termination of the Stipulation and Settlement, FPL's base rate levels, including the effects of any GBRA, shall continue in effect until next reset by the Commission. Any Party to this Stipulation and Settlement may participate in any such limited proceeding for the purpose of challenging whether FPL has met the requirements of Rule 25-22.082(15). A GBRA shall be implemented upon commercial operation of Turkey Point Unit 5, currently projected to occur in mid-2007, by increasing base rates by the estimated annual revenue requirement exclusive of fuel of the costs upon which the CPVRR for Turkey Point Unit 5 were predicated, and pursuant to which a need determination was granted by the FPSC in Order No. PSC-04-0609-FOF-EI, such adjustment to be reflected on FPL's customer bills by increasing base charges and non-clause recoverable credits, by an equal percentage. FPL will begin applying the incremental base rate charges required by this Stipulation and Settlement to meter readings made on and after the commercial in service date of Turkey Point Unit 5.

18. This Stipulation and Settlement is contingent on approval in its entirety by the FPSC. This Stipulation and Settlement will resolve all matters in these Dockets pursuant to and in accordance with Section 120.57(4), Florida Statutes. This Docket will be closed effective on the date the FPSC Order approving this Stipulation and Settlement is final.

19. All Parties to this Stipulation and Settlement agree to endorse and support the Stipulation and Settlement before the FPSC and any other administrative or judicial tribunal, and in any other forum.

20. This Stipulation and Settlement dated as of August 22, 2005 may be executed in counterpart originals, and a facsimile of an original signature shall be deemed an original.

In Witness Whereof, the Parties evidence their acceptance and agreement with the provisions of this Stipulation and Settlement by their signature.

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Common Cause, Florida
+ individual customers

DOCKET NO: **120015-EI** **EXHIBIT NO.** 706

WITNESS: **RENAE B. DEATON**

PARTY: **FLORIDA POWER & LIGHT COMPANY**

DESCRIPTION: **The Free Dictionary - definition of "Public Interest".**

PROFFERED BY: **THOMAS SAPORITO**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 706
PARTY Thomas Saporito
DESCRIPTION The Free Dictionary - defiinition of "Public Interest"

thefreedictionary.com

Anything affecting the rights, health, or finances of the public at large.

Public interest is a common concern among citizens in the management and affairs of local, state, and national government. It does not mean mere curiosity but is a broad term that refers to the body politic and the public weal. A public utility is regulated in the public interest because private individuals rely on such a company for vital services.

DOCKET NO: **120015-EI** **EXHIBIT NO.** 707

WITNESS: **RENAE B. DEATON**

PARTY: **FLORIDA POWER & LIGHT COMPANY**

DESCRIPTION: **FPL, key customer advocacy groups ask PSC to approve proposed rate settlement that would help secure low rates for FPL customers for four years.**

PROFFERED BY: **THOMAS SAPORITO**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 707
PARTY Thomas Saporito
DESCRIPTION FPL, key custiner advocacy groups ask PSC to approve proposed rate settlement that would help

FPL, key customer advocacy groups ask PSC to approve proposed rate settlement that would help secure low rates for FPL customers for four years

Compared with current rates among Florida's 55 utilities, FPL's typical 1,000-kWh residential bill projected to remain the lowest in the state through 2016

On Sept. 27, 2012, the Florida Public Service Commission is scheduled to begin reviewing a proposed settlement agreement in Florida Power & Light Company's 2013 base rate proceeding. The settlement, if approved, is expected to help secure low rates for FPL customers through the end of 2016 while supporting FPL's ability to provide safe, highly reliable service.

"Compared with current rates for Florida's 55 electric utilities, our residential customers are projected to continue to have the lowest typical bills in the state under the proposed settlement, along with reliability, an emissions profile and customer service that are among the best in the country," said FPL President Eric Silagy. "We believe this four-year agreement makes sense for all of our customers and provides a predictable, stable rate structure that will help FPL plan for the future and keep investing in Florida."

In January, FPL notified the PSC of the company's need for a base rate increase in 2013. The formal request was filed in March. In August, FPL joined key customer advocacy groups to file a proposed settlement designed to limit the impact to customers while maintaining FPL's financial strength and ability to invest billions of dollars in Florida's infrastructure in the coming years.

The settlement agreement is supported by FPL, the Florida Industrial Power Users Group, the South Florida Hospital and Healthcare Association, the Federal Executive Agencies and Algenol Biofuels. If the PSC does not approve the settlement agreement, a decision on FPL's original request would likely be made in November.

As part of the proposed settlement, FPL agreed that it would reduce its January 2013 revenue request by about 25 percent, from $517 million to $378 million, primarily through a reduction in the company's requested return on equity (ROE) from 11.5 percent to 10.7 percent. This is slightly below the average allowed ROE of 10.75 percent for Florida's other investor-owned utilities and well below the average allowed ROE of 11.52 percent for other investor-owned utilities in the southeastern coastal United States.

The agreement would also provide for appropriate base rate increases covering the capital and operating costs of new, highly efficient power plants at Cape Canaveral, Riviera Beach and Port Everglades when these plants go into service, which is expected in 2013, 2014 and 2016, respectively. The costs and benefits of these projects were carefully considered by the PSC in prior proceedings that resulted in approval of these power plants. In addition, when these plants go into service, customers are expected to see decreases in the fuel portion of their bills that would significantly offset the base rate increases due to the plants' advanced efficiency improvements. Combined, the more efficient power plants are projected to save customers more than $1 billion in fuel and other costs during their operating lifetimes over and above the plants' cost of construction.

Also, except as contemplated in the agreement, FPL would not seek any additional base rate increases for the four-year term of the settlement agreement, provided its earnings remain within 100 basis points of the allowed 10.7 percent ROE midpoint.

2013 Customer Bills

Today, FPL's typical residential customer bill is down approximately 13 percent compared with 2006 as a result of investments in more efficient power generation, the beneficial impact of lower fuel prices and the company's strong cost controls. FPL's typical commercial customer bills are down 14 percent over the same period.

Under FPL's original request, the company's typical 1,000-kWh residential customer bill would increase by roughly $2.50 a month, or about 8 cents a day, in 2013, including the impact of FPL's latest projections for fuel and other charges. The proposed settlement would reduce the net increase in 2013 for FPL's typical residential customer by about 40 percent, to roughly $1.50 a month, or about 5 cents a day.

This net increase of less than 2 percent compared with current rates would keep FPL's typical bill the lowest in the state, based on current rates for other utilities, and more than 10 percent less than it was in 2006.

FPL's Typical Residential Customer Bill – Proposed Settlement Agreement

1,000-kWh Residential	January 2012	January 2013	June 2013	Increase/Decrease
Base Rate	$43.26	$47.36	$49.03	Increase of $5.77/month *($4.10 in January, $1.67 in June)*

Fuel Charge	$33.43	$27.89	$26.33	Decrease of $7.10/month *(-$5.54 in January, -$1.56 in June)*
All Other Charges*	$17.93	$20.73	$20.82	Increase of $2.89/month *($2.80 in January, $0.09 in June)*
TOTAL BILL	**$94.62**	**$95.98**	**$96.18**	**Net increase of $1.56/month or 5 cents/day in 2013**

**"All Other Charges" include FPL's filed projections for capacity, environmental and conservation clause recovery, West County Energy Center 3 recovery, the storm charge, base rate increase for completed nuclear upgrades and state gross receipts tax. All of these rates require PSC approval and are subject to change until approved. All January 2013 rates are expected to be finalized by early December 2012 and will be posted at www.FPL.com.*

Under the proposed settlement agreement, total typical bills for most commercial customers are projected to be flat to down 3 percent in 2013.

For small businesses on FPL's standard non-demand commercial rate – approximately 80 percent of FPL's business customers – there would be no base rate increase in January 2013. Because FPL has filed to reduce its fuel charge, a typical small business using 1,200-kWh/month would see its total bill decrease by approximately 2.5 percent in 2013.

Indeed, lower projected fuel costs are expected to reduce the overall impact for all customer classes. While FPL cannot control future fuel prices, its investments in efficient new power generation reduce overall fuel usage, which, in turn, lowers overall bills no matter what the price of fuel may be. Industry experts agree that dramatic increases in the supply of natural gas in the U.S. are likely to keep natural gas prices moderate for many years to come. More than half of FPL's fuel supply is comprised of natural gas.

As part of the agreement, FPL would increase its energy conservation credits to large commercial/industrial customers for load interruptions. As a result, total bills for customers who participate in the Commercial and Industrial Load Control and Commercial Demand Reduction programs are projected to decrease by up to 10 percent, including the impact of lower fuel costs. These programs benefit all customers by helping FPL avoid the necessity of building costly additional peaking facilities.

Parties to the proposed settlement have noted that the agreement would benefit Florida's consumers and economy by keeping bills low, reliability high and promoting economic development.

"The settlement agreement is a win for all of our customers and for the state of Florida. It reduces the base rate increase for all business and residential customers while maintaining FPL's ability to continue investing in the infrastructure to keep reliability high and bills low for the long term," Silagy said. "Smaller businesses would see their bills decrease, and most larger business customers would see their bills remain flat or decrease, helping to support their ability to continue to invest in our economic recovery and create jobs."

FPL's projected 2013 rates for fuel and other components of the bill are subject to change until reviewed and approved by the PSC in November. For more information, FPL customers can visit www.FPL.com/answers, which features frequently asked questions and an online bill calculator that shows residential customers how much their 2013 bills would be based on their actual kilowatt-hour usage and the company's latest projections.

Florida Power & Light Company

Florida Power & Light Company is the largest electric utility in Florida and one of the largest rate-regulated utilities in the United States. FPL serves approximately 4.6 million customer accounts and is a leading Florida employer with approximately 10,000 employees. The company consistently outperforms national averages for service reliability while its typical residential customer bills, based on data available in December 2011, are about 25 percent below the national average. A clean energy leader, FPL has one of the lowest emissions profiles and one of the leading energy efficiency programs among utilities nationwide. FPL is a subsidiary of Juno Beach, Fla.-based NextEra Energy, Inc. (NYSE: NEE). For more information, visit www.FPL.com.

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Cautionary Statements and Risk Factors That May Affect Future Results

This press release contains "forward-looking statements" within the meaning of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. Forward-looking statements are not statements of historical facts, but instead represent the current expectations of NextEra Energy, Inc. (NextEra Energy) and Florida Power & Light Company (FPL) regarding future operating results and other future events, many of which, by their nature, are inherently uncertain and outside of NextEra Energy's and FPL's control. In some cases, you can identify the forward-looking statements by words or phrases such as "will," "will likely result," "expect," "anticipate," "believe," "intend," "plan," "seek," "aim," "potential," "projection," "forecast," "predict," "goals," "target," "outlook," "should," "would" or similar words or expressions. You should not place undue reliance on these forward-looking statements, which are not a guarantee of future performance. The future results of NextEra Energy and FPL are subject to risks and uncertainties that could cause their actual results to differ materially from those expressed or implied in the forward-looking statements. These risks and uncertainties include, but are not limited to, the following: effects of extensive regulation of NextEra Energy's and FPL's business operations; inability of NextEra Energy and FPL to recover in a timely manner any significant amount of costs, a return on certain assets or an appropriate return on capital through base rates, cost recovery clauses, other regulatory mechanisms or otherwise; impact of political, regulatory and economic factors on regulatory decisions important to NextEra Energy and FPL; risks of disallowance of cost recovery by FPL based on a finding of imprudent use of derivative instruments; effect of any reductions to or elimination of governmental incentives that support renewable energy projects of NextEra

Energy Resources, LLC and its affiliated entities (NextEra Energy Resources); impact of new or revised laws, regulations or interpretations or other regulatory initiatives on NextEra Energy and FPL; effect on NextEra Energy and FPL of potential regulatory action to broaden the scope of regulation of OTC financial derivatives and to apply such regulation to NextEra Energy and FPL; capital expenditures, increased cost of operations and exposure to liabilities attributable to environmental laws and regulations applicable to NextEra Energy and FPL; effects on NextEra Energy and FPL of federal or state laws or regulations mandating new or additional limits on the production of greenhouse gas emissions; exposure of NextEra Energy and FPL to significant and increasing compliance costs and substantial monetary penalties and other sanctions as a result of extensive federal regulation of their operations; effect on NextEra Energy and FPL of changes in tax

laws and in judgments and estimates used to determine tax-related asset and liability amounts; impact on NextEra Energy and FPL of adverse results of litigation; effect on NextEra Energy and FPL of failure to proceed with projects under development or inability to complete the construction of (or capital improvements to) electric generation, transmission and distribution facilities, gas infrastructure facilities or other facilities on schedule or within budget; impact on development and operating activities of NextEra Energy and FPL resulting from risks related to project siting, financing, construction, permitting, governmental approvals and the negotiation of project development agreements; risks involved in the operation and maintenance of electric generation, transmission and distribution facilities, gas infrastructure facilities and other facilities; effect on NextEra Energy and FPL of a lack of growth or slower growth in the number of customers or in customer usage; impact on NextEra Energy and FPL of severe weather and other weather conditions; risks associated with threats of terrorism and catastrophic events that could result from terrorism, cyber attacks or other attempts to disrupt NextEra Energy's and FPL's business or the businesses of third parties; risk of lack of availability of adequate insurance coverage for protection of NextEra Energy and FPL against significant losses; risk to NextEra Energy Resources of increased operating costs resulting from unfavorable supply costs necessary to provide NextEra Energy Resources' full energy and capacity requirement services; inability or failure by NextEra Energy Resources to hedge effectively its assets or positions against changes in commodity prices, volumes, interest rates, counterparty credit risk or other risk measures; potential volatility of NextEra Energy's results of operations caused by sales of power on the spot market or on a short-term contractual basis; effect of reductions in the liquidity of energy markets on NextEra Energy's ability to manage operational risks; effectiveness of NextEra Energy's and FPL's hedging and trading procedures and associated risk management tools to protect against significant losses; impact of unavailability or disruption of power transmission or commodity transportation facilities on sale and delivery of power or natural gas by FPL and NextEra Energy Resources; exposure of NextEra Energy and FPL to credit and performance risk from customers, hedging counterparties and vendors; risks to NextEra Energy and FPL of failure of counterparties to perform under derivative contracts or of requirement for NextEra Energy and FPL to post margin cash collateral under derivative contracts; failure or breach of NextEra Energy's and FPL's information technology systems; risks to NextEra Energy and FPL's retail businesses of compromise of sensitive customer data; risks to NextEra Energy and FPL of volatility in the market values of derivative instruments and limited liquidity in OTC markets; impact of negative publicity; inability of NextEra Energy and FPL to maintain, negotiate or renegotiate acceptable franchise agreements with municipalities and counties in Florida; increasing costs of health care plans; lack of a qualified workforce or the loss or retirement of key employees; occurrence of work strikes or stoppages and increasing personnel costs; NextEra Energy's ability to successfully identify, complete and integrate acquisitions; environmental, health and financial risks associated with NextEra Energy's and FPL's ownership of nuclear generation facilities; liability of NextEra Energy and FPL for significant retrospective assessments and/or retrospective insurance premiums in the event of an incident at certain nuclear generation facilities; increased operating and capital expenditures at nuclear generation facilities of NextEra Energy or FPL resulting from orders or new regulations of the Nuclear Regulatory Commission; inability to operate any of NextEra Energy Resources' or FPL's owned nuclear generation units through the end of their respective operating licenses; liability of NextEra Energy and FPL for increased nuclear licensing or compliance costs resulting from hazards posed to their owned nuclear generation facilities; risks associated with outages of NextEra Energy's and FPL's owned nuclear units; effect of disruptions, uncertainty or volatility in the credit and capital markets on NextEra Energy's and FPL's ability to fund their liquidity and capital needs and meet their growth objectives; inability of NextEra Energy, FPL and NextEra Energy Capital Holdings, Inc. to maintain their current credit ratings; risk of impairment of NextEra Energy's and FPL's liquidity from inability of creditors to fund their credit commitments or to maintain their current credit ratings; poor market performance and other economic factors that could affect NextEra Energy's and FPL's defined benefit pension plan's funded status; poor market performance and other risks to the asset values of NextEra Energy's and FPL's nuclear decommissioning funds; changes in market value and other risks to certain of NextEra Energy's investments; effect of inability of NextEra Energy subsidiaries to upstream dividends or repay funds to NextEra Energy or of NextEra Energy's performance under guarantees of subsidiary obligations on NextEra Energy's ability to meet its financial obligations and to pay dividends on its common stock; and effect of disruptions, uncertainty or volatility in the credit and capital markets of the market price of NextEra Energy's common stock. NextEra Energy and FPL discuss these and other risks and uncertainties in their annual report on Form 10-K for the year ended December 31, 2011 and other SEC filings, and this press release should be read in conjunction with such SEC filings made through the date of this press release. The forward-looking statements made in this press release are made only as of the date of this press release and NextEra Energy and FPL undertake no obligation to update any forward-looking statements.

SOURCE Florida Power & Light Company
For further information: Florida Power & Light Co. Media Line, +1-305-552-3888

EXHIBIT NO. 708

DOCKET NO: 120015-EI

WITNESS: Jeffry Pollock

PARTY: FIPUG

DESCRIPTION: Excerpt of July 16, 2009 Testimony of Jeffrey Pollock in Docket No. 080677-EI & 090130-EI (Florida Power & Light) Before the Florida Public Service Commission

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 708
PARTY Office of Public Counsel
DESCRIPTION Excerpt of 07/16/09 Testimony of Jeffery Pollock in Dkt. No. 080677-EI & 090130-EI (FP&L before the FPSC

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Increase in Rates by Florida Power & Light Company.	DOCKET NO. 080677-EI
In re: 2009 Depreciation and Dismantlement Study by Florida Power & Light Company.	DOCKET NO. 090130-EI Filed: July 16, 2009

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TESTIMONY AND EXHIBITS OF JEFFRY POLLOCK

ON BEHALF OF THE FLORIDA INDUSTRIAL POWER USERS GROUP

J. POLLOCK
INCORPORATED

COM ___
ECR ___
GCL 2
OPC ___
RCP 1
SSC 1
SGA 1
ADM ___
CLK 4, Rep.

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3. CAPITAL STRUCTURE

Q WHAT CAPITAL STRUCTURE IS FPL PROPOSING IN THIS PROCEEDING?

A FPL's proposed regulatory capital structure is shown in the first column of the chart below:

Component	MFR Schedule D-4	FPL Adjusted (AP-7)	Excluding Imputed PPAS
Long-Term Debt	31.52%	43.1%	39.20%
Short-Term Debt	0.95%	1.1%	1.18%
Common Equity	47.93%	55.8%	59.62%
Customer Deposits	3.31%		
Deferred Taxes	15.96%		
Investment Tax Credits	0.33%		

The second column is the adjusted capital structure that FPL claims to be achieving, according to FPL witness Mr. Pimental. The adjusted capital structure excludes customer deposits, deferred income taxes, investment tax credits and imputes to debt the obligations under various firm Purchased Power Agreements (PPAs). The third column shows FPL's adjusted capital structure excluding the imputed PPAs.

Q WHAT IS THE PROPOSED ADJUSTMENT FOR PURCHASED POWER OBLIGATIONS?

A FPL's adjusted capital structure includes $949,260,000 of imputed debt for purchased power obligations. As can be seen in the third column of the above chart, without this imputed debt, FPL's equity ratio would approach 60%. This would make FPL among the least leveraged regulated electric utilities in the nation. For the reasons explained below, the Commission should set rates based on an adjusted capital structure (1) excluding imputed debt and (2) consisting of not more than 50% common equity.

<u>**Imputed Debt for Purchased Power Obligations**</u>

Q WHY DOES FPL IMPUTE $949.3 MILLION OF DEBT RELATED TO PPAS?

A FPL asserts that the financial community commonly takes into account obligations associated with PPAs. Since FPL has certain long-term PPAs, it is obligated to make certain fixed payments, which, it asserts, the rating agencies regard as equivalent to long-term debt (*Direct Testimony and Exhibits of Armando Pimental* at 34). According to FPL, long-term PPAs are those agreements that have a term of at least one year (*FPL's Response to SFHHA's Interrogatory No. 281*).

Q DO YOU AGREE WITH THIS ADJUSTMENT?

A No. It is unnecessary to impute debt for PPA obligations. The Commission's approval of PPAs is governed by Rule 25-17.0832 Florida Administrative Code (for standard offer and negotiated contracts). Once approved, FPL is allowed full and direct recovery of firm energy and purchased power capacity costs under the Fuel and Capacity Cost Recovery (CCR) clauses. Though such contracts are reviewed in the annual fuel adjustment proceeding, there is minimal recovery risk associated with PPAs.

Second, Moody's does not treat PPAs in the same way as Standard & Poor's (S&P).

Finally, the Commission has very recently addressed precisely this issue. In Tampa Electric's (TECO's) most recent rate case, TECO made the same argument that FPL puts forth here and it was rejected by the Commission.

Q **DO ALL RATING AGENCIES IMPUTE THE FIXED OBLIGATIONS UNDER PPAS IN EVALUATING A UTILITY'S FINANCIAL STRENGTH?**

A No. FPL's imputed debt adjustment reflects the methodology outlined by S&P. It is noteworthy that another ratings agency, Moody's, does not make a similar adjustment.

Q **HOW DOES S&P RECOGNIZE THE DEBT EQUIVALENT OF PPAS?**

A S&P quantifies the debt equivalent as the product of (1) a risk factor and (2) the net present value of the remaining capacity payments under each PPA. The risk factor is based primarily on the method of recovery of capacity payments.

Q **WHAT RISK FACTOR HAS FPL USED IN ITS IMPUTED DEBT ADJUSTMENT?**

A FPL has used a 25% risk factor (*Testimony and Exhibits of Armando Pimental* at 35-36). This choice is based on general criteria explained by S&P:

> If a regulator has established a power cost adjustment mechanism that recovers all prudent PPA costs, a risk factor of 25% is employed, because the recovery hurdle is lower than it is for a utility that must litigate time and again its right to recovery costs. (Standard & Poor's, *Corporate Credit Ratings 2008* at 75).

Q **DOES THIS ACCURATELY REFLECT THE RISKS ASSOCIATED WITH THE RECOVERY OF PURCHASED POWER CAPACITY COSTS IN FLORIDA?**

A No. Purchased power capacity costs are subject to dollar-for-dollar recovery through the CCR. This includes a true-up procedure that establishes a forward-looking charge, which is then reconciled based on actually incurred costs, with interest. The recovery mechanism is nearly identical to FPL's Fuel Charge.

Q **DOES S&P RECOGNIZE THE RELATIONSHIP BETWEEN RISK AND THE TYPE OF COST RECOVERY MECHANISM?**

A Yes. S&P states that:

> The calculated PV [present value] is adjusted to reflect the benefits of regulatory or legislative cost recovery mechanisms. The adjustment reduces the debt-equivalent amount by multiplying the PV by a specific risk factor that pertains to each contract. The stronger the recovery mechanisms, the smaller the risk factor. These risk factors typically range between 0% and 50%, but can be as high as 100%. (*Id.*)

Thus, S&P does not provide an objective standard for determining the appropriate risk factor. Dollar-for-dollar recovery of purchased power capacity costs is a very strong mechanism with no practical risk. The PPAs in question have been previously approved for recovery. In fact, the above discussion from S&P in conjunction with the policies and previous findings in Florida strongly suggest that the obligations under Commission-approved PPAs are risk free, so long as the utility properly manages the contracts.

Q **DOES MOODY'S CONSIDER PPAS AS INHERENTLY MORE RISKY FOR ELECTRIC UTILITIES?**

A No. Moody's specifically recognizes that the risk of PPAs is specifically related to the applicable cost recovery mechanism as well as market dynamics:

> Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly Moody's regards these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive, the ability to pass through costs may decrease and, as circumstances change, Moody's treatment of PPA obligations will alter accordingly. (Moody's, *Rating Methodology: Global Regulated Electric Utilities*, March 2005 at 9.)

Thus, it is clear that Moody's does not regard PPAs as inherently risky and thus it imputes no debt for these contracts where recovery is guaranteed.

Q DOES FPL HAVE THE ABILITY TO PASS THROUGH THE COSTS OF ITS PPAS?

A Yes. As explained earlier, FPL has the ability to directly pass through purchased power capacity costs. In the case of certain purchases mandated by state statute, such as those from renewable energy sources, up-front approval is required for non-standard offer contracts, while standard offer contracts are considered reasonable.

Q DO FPL PPAS CONTAIN ANY CLAUSES FURTHER MITIGATING RISK?

A Yes. FPL recently included a clause in a PPA stating that if the Commission does not allow recovery of contract costs from ratepayers, FPL does not have an obligation to pay under the agreement.

> Notwithstanding anything to the contrary in this Amended Agreement, if FPL, at any time during the Term of this Amended

> Agreement, fails to obtain or is denied the authorization of the FPSC, or the authorization of any other legislative, administrative, judicial or regulatory body which now has, or in the future may have, jurisdiction over FPL's rates and charges, to recover from its customers all of the payments required to be made to the Authority under the terms of this Amended Agreement or any subsequent amendment hereto, FPL may, at its sole option, adjust the payments made under this Amended Agreement to the amount(s) which FPL is authorized to recover from its customers. (Negotiated Contract with The Solid Waste Authority of Palm Beach County, paragraph 16.4, which was submitted for approval on March 25, 2009 in Docket No. 090150-EQ)

This makes FPL's "risk" virtually non-existent.

Q DOES MOODY'S CONSIDER PPAS AS BEING LESS RISKY IN CERTAIN CIRCUMSTANCES?

A Yes. Unlike S&P, Moody's recognizes that PPAs can be less risky for a utility:

> Risk management: An overarching principle is that PPAs have been used by utilities as a risk management tool and Moody's recognizes that this is the fundamental reason for their existence. Thus, Moody's will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature. (*Id.*)

Q ARE YOU SAYING THAT MOODY'S WILL NOT IMPUTE DEBT ASSOCIATED WITH PPAS?

A No. Moody's states:

> *Methods of accounting for PPAs in our analysis*
>
> According to the weighting and importance of the PPA to each utility and the level of disclosure, Moody's may analytically assess the total obligations for the utility using one of the methods discussed below.

> Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, Moody's may view the PPA as being most akin to an operating cost. In this circumstance, there most likely will be no imputed adjustment to the obligations of the utility.

Based on the above statements by Moody's, it seems unlikely that debt will be imputed to FPL based on the cost recovery mechanisms applicable to purchased power capacity costs.

Q IS THE DEBT THAT FPL PROPOSES TO IMPUTE FOR PPA OBLIGATIONS ACTUAL DEBT ON THE COMPANY'S BOOKS AND RECORDS?

A No. FPL does not reflect its PPA obligations as debt in the normal course of accounting.

Q HAS THE COMMISSION PREVIOUSLY RULED ON THIS ISSUE IN A RECENT CASE?

A Yes. The Commission rejected TECO's proposal to impute additional equity in determining its capital structure to recognize the so-called risks associated with PPAs. The Commission stated that:

> The pro forma adjustment to equity proposed by TECO is not an actual equity investment in the utility. If this adjustment is approved for purposes of setting rates in this proceeding, the Company would essentially be allowed to earn a risk-adjusted equity return without having actually made the equity investment. The revenue requirement impact of recognizing this pro forma adjustment to equity in the capital structure is approximately $5 million per year. (*Order No. PSC-09-0283-FOF-EI* at 35)

The Commission went on to find:

> Companies with PPAs are not required by the rating agencies to make the pro forma adjustment in question. As the following passage explains, the Standard & Poors' (S&P) practice with

> respect to PPAs described in witness Gillette's testimony is strictly for the rating agency's own analytical purposes:
>
> We adjust utilities' financial metrics, incorporating PPA fixed obligations, so that we can compare companies that finance and build generation capacity and those that purchase capacity to satisfy customer needs. The analytical goal of our financial adjustments for PPAs is to reflect fixed obligations in a way that depicts the credit exposure that is added by PPAs. That said, PPAs also benefit utilities that enter into contracts with suppliers because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build. The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates. (*Id.* at 35)

Further, in rejecting TECO's adjustment, the Commission held:

> With this proposed adjustment, we find that the Company is attempting to take a portion of S&P's consolidated credit assessment methodology and use it for a purpose it was never intended. (*Id.* at 36).

Q **SHOULD DEBT ASSOCIATED WITH PPAS BE IMPUTED IN ASSESSING THE PROPER CAPITAL STRUCTURE FOR FPL?**

A No. For all of the reasons stated above, imputed debt should not be included in assessing the reasonableness of FPL's capital structure.

<u>Common Equity Ratio</u>

Q **DOES FPL PROPOSE TO ADJUST ITS EQUITY RATIO TO RECOGNIZE IMPUTED DEBT?**

A No. Unlike TECO, FPL does not propose a specific adjustment. Instead, FPL seeks to use the imputation argument to support its excessively high common equity ratio. As discussed below, without this adjustment, FPL is one of the least leveraged regulated electric utilities in the nation. Thus, the Commission should reduce the amount of common equity in determining FPL's cost of capital.

Q HOW DOES FPL'S COMMON EQUITY RATIO COMPARE WITH OTHER ELECTRIC UTILITIES?

A Exhibit JP-2 is a comparison of common equity ratios for the 2006 to 2009 (1^{st} Quarter) time frame published by SNL Financial. For this period, average common equity ratios for all electric utilities range from 46.1% to 47.6% (line 85). On a comparable basis, FPL's proposed 2010 common equity ratio is 59.6%, far above the average. Thus, FPL proposes a common equity ratio that is over 1,200 basis points higher than the electric utility average.

Q WHAT IS THE CONSEQUENCE OF USING MORE EQUITY AND LESS DEBT TO FINANCE THE UTILITY'S RATE BASE?

A Common equity is more expensive than debt. In this instance, FPL is asking for a common equity return that is nearly 700 basis points higher than its embedded cost of long-term debt. A utility having too much equity in its capital structure has a higher cost of capital than a utility with a more balanced common equity ratio. All else being equal, the higher the overall common equity ratio, the higher the rates all FPL ratepayers will bear.

Q IS A NEARLY 60% COMMON EQUITY RATIO NECESSARY TO MAINTAIN FPL'S CURRENT BOND RATING?

A No. FPL is currently rated "A1" by Moody's and "A" by both Fitches and S&P. The chart below provides a comparison of the common equity ratios for other A-rated electric utilities. I included all electric utilities that had "A" or equivalent bond ratings from at least two of the three bond rating agencies.

Year	All Electric Utilities	A-Rated Electric Utilities
2006	47.6%	50.9%
2007	47.3%	51.0%
2008	46.4%	49.5%
2009 (Q1)	46.1%	49.5%
Average	46.9%	50.2%

Thus, FPL's 59.6% proposed (unadjusted) common equity would be 940 basis points higher than comparably rated electric utilities.

Q **WHAT IS YOUR RECOMMENDATION FOR A COMMON EQUITY RATIO FOR FPL?**

A FPL's common equity ratio should be reduced to 50.2% on an adjusted basis for setting its cost of capital in this proceeding. This translates into a 40.36% regulatory common equity ratio. Reducing the regulatory common equity ratio to 40.36% lowers FPL's requested 2010 base revenue increase by about $192.9 million, as shown in **Exhibit JP-3**.

EXHIBIT NO. 709

DOCKET NO: 120015-EI

WITNESS: Jeffry Pollock

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 709
PARTY Office of Public Counsel; JP-15,
DESCRIPTION Incremental Infrastructure Costs (Originally JP-1)
With Columns C-G Expanded

PARTY: FIPUG

DESCRIPTION: Incremental Infrastructure Costs Exhibit JP-15 (Originally JP-1) With Columns C – G Expanded

[Provided in Response to OPC 1st POD to FIPUG as Exhibit JP-1]

DOCUMENTS: Rule 26-6.1351

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

Docket No. 120015-EI
Incremental Infrastructure Costs
Exhibit JP-15 (Originally JP-1)
With Columns C-G Expanded

FLORIDA POWER & LIGHT COMPANY

Revenue Requirement Associated With Additional Infrastructure-Related Costs Since FPL's Last Rate Case
Test Year Ending December 31, 2013
(Dollar Amounts in $000)

Line	Description	D. 080677-EI Final Order	Proposed	Proposed With CC Increase	Increase Since Last Rate Case	WCEC 3	Incremental Infrastructure Costs
							(1)
1	Jurisdictional Adjusted Rate Base	$16,787,430	$21,036,823	$21,858,148	$5,070,718	$787,873	$4,282,845
2	Pre-Tax Return at 10.70% ROE						9.78%
3	Return and Associated Taxes						$418,740
4	Property Insurance	$8,531	$14,321	$15,569	$7,039	$524	$6,515
5	Depreciation (excluding Decommissioning)	$753,237	$803,912	$835,414	$82,177	$33,266	$48,911
6	Property Tax	$297,735	$321,817	$339,487	$41,752	$15,130	$26,622
7	Revenue Deficiency						$500,788
	Amortize Remaining Surplus Depreciation				-$190,918		
8	Over 18 Months				-$114,834		-$114,800
9	Adjusted Revenue Deficiency						$385,988
10	Settlement Base Revenue Increase						$378,000

Source: Excel worksheet provided by email dated 11/7/12 in response to OPC's 1st POD to FIPUG Exhibit JP-1 Settlement.xls.

EXHIBIT NO. 710

DOCKET NO: 120015-EI – Settlement Hearing

WITNESS: JEFFRY POLLOCK

PARTY: FIPUG

DESCRIPTION: Excerpts from FPL's Last Rate Case
Final Order No. PSC-10-0153-FOF-EI
Docket No. 080677-EI and 090130-EI

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 1200015-EI EXHIBIT 710
PARTY Office of Public Counsel
DESCRIPTION Excerpts from FPL's Last Rate Case Final Order No. PSC-10-0153-FOF-EI Docket No.080677-EI & 090130-EI

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for increase in rates by Florida Power & Light Company.	DOCKET NO. 080677-EI
In re: 2009 depreciation and dismantlement study by Florida Power & Light Company.	DOCKET NO. 090130-EI ORDER NO. PSC-10-0153-FOF-EI ISSUED: March 17, 2010

The following Commissioners participated in the disposition of this matter:

NANCY ARGENZIANO, Chairman
LISA POLAK EDGAR
NATHAN A. SKOP
DAVID E. KLEMENT
BEN A. "STEVE" STEVENS III

APPEARANCES:

R. WADE LITCHFIELD, MITCHELL S. ROSS, JOHN T. BUTLER, BRYAN S. ANDERSON, and JESSICA A. CANO, ESQUIRES, 700 Universe Boulevard, Juno Beach, Florida 33408-0420; and
SUSAN F. CLARK., Radey Thomas Yon & Clark, P.A., 301 South Bronough Street, Suite 200, Tallahassee, Florida 32301
On behalf of FLORIDA POWER & LIGHT COMPANY (FPL).

JOSEPH A. McGLOTHLIN, CHARLIE BECK, PATRICIA A. CHRISTENSEN, ESQUIRES, Office of the Public Counsel, c/o the Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
On behalf of THE CITIZENS OF THE STATE OF FLORIDA (OPC).

STEPHANIE ALEXANDER, ESQUIRE, Tripp Scott, P.A.., 200 West College Avenue, Suite 216, Tallahassee, Florida 32301
On behalf of the FLORIDA ASSOCIATION FOR FAIRNESS IN RATE MAKING (AFFIRM)

CECILIA BRADLEY, Office of the Attorney General, The Capitol – PL01, Tallahassee, FL 32399
On behalf of the ATTORNEY GENERAL FOR THE CITIZENS OF FLORIDA (AG)

FPL argued that amortization of the remaining reserve surplus over any time period other than the remaining life results in intergenerational unfairness to the ratepayers of yesterday versus those of tomorrow. OPC, on the other hand, argued that the existence of a reserve imbalance indicates that there are intergenerational inequities in that current and past customers paid more than they should have, thereby subsidizing future customers. We agree with OPC's position that intergenerational unfairness already exists, as witnessed by the existence of such a significant reserve imbalance. Therefore, we are of the opinion that amortizing the remainder of the reserve surplus is the most appropriate remedy to eliminate the intergenerational inequity the surplus created. The only question remaining is how long it should take to correct the situation.

Accordingly, we find that the remaining reserve surplus amount of $894.6 million shall be amortized over a four-year period. This is consistent with our policy with respect to reserve imbalances, which has been to correct them as soon as possible without adversely impacting the company's ability to earn a fair and reasonable return.[35] We find that there is substantial evidence in the record to show that the company's ability to earn a fair and reasonable return will not be adversely affected. Furthermore, our decision is consistent with past orders in which we have amortized reserve imbalances over periods shorter than the remaining life.[36] And we note that we will be reviewing FPL's depreciation reserve again when FPL files its next depreciation study.

In conclusion, each account's book reserve shall be brought to its calculated theoretically correct level. Of the $1,208.8 million bottom-line reserve surplus, $314.2 million shall be used to offset the unrecovered costs associated with the capital recovery schedules of near-term retiring investments. The remaining reserve surplus of $894.6 million shall be amortized over a 4-year period, beginning January 1, 2010. As part of FPL's next depreciation study, to be filed no later than March 16, 2013, FPL's reserve position will be reviewed and assessed for any other necessary action.

Implementation date for revised depreciation rates, capital recovery schedules and amortization schedules

FPL proposed an implementation date of January 1, 2010. All the parties, except SFHHA, agreed with FPL's proposed implementation date. SFHHA argued that the implementation date for revised depreciation rates, capital recovery schedules, and amortization schedules should correspond with the implementations of rates resulting from this proceeding. We disagree with SFHHA's proposed implementation date. The implementation date for the

[35] Order No. PSC-01-2270-PAA-EI, issued on November 19, 2001, in Docket No. 010699-EI, In re: Request for approval of implementation date of January 1, 2002, for new depreciation rates for Marianna Electric Division by Florida Public Utilities, p. 2.

[36] Order No. PSC-96-0461-FOF-EI, issued on April 2, 1996, in Docket No. 950359-EI, In Re: Petition to establish amortization schedule for nuclear generating units to address potential for stranded investment by Florida Power & Light Company; Order No. PSC-06-0307-FOF-TP, issued April 20, 2006, in Docket No. 041269-TP, In re: Petition to establish generic docket to consider amendments to interconnection agreements resulting from changes in law, by BellSouth Telecommunications, Inc.; and Order No. PSC-98-1723-FOF-EI, issued on December 18, 1998, in Docket No. 971570-EI, In re: 1997 Depreciation Study by Florida Power Corporation.

expenditure reductions were provided for aviation costs and deferred or delayed projects with the corresponding depreciation expense for 2010 in the amount of $2,303,009. When discussing levels of plant in service, we also reviewed SFHHA's proposal of an annualized adjustment for 2010 plant in service in the amount of $784,000,000 and declined to make that adjustment. Based on the foregoing, the total capital expenditure reductions for 2010 is $17,239,009. These reductions for depreciation expense are included with all other depreciation reductions in Table 24 on the following page.

Depreciation expense adjustment

We were asked to determine what adjustments, if any, should be made to depreciation expense. Our decision on what adjustments is a culmination of our other decisions in this docket. As shown in the table below, we identified all of the adjustments to depreciation expense that we have made. Each adjustment for depreciation expense corresponds to adjustments we made for: jurisdictional separation; depreciation study, capital recovery schedules and reserve surplus; fossil dismantlement study; plant in service; aviation costs; customer information system-CIS3; and correction of errors by the Company. In addition, based on the results of the depreciation study, we developed the composite depreciation rates that were used for the 2010 test year depreciation expense calculation.

TABLE 24

2010 Adjustments to Depreciation Expense			
Description	FPL	OPC	Commission
Issue 15 SLB-26 Revised-Jurisdictional Separation Factor–Transmission Services			
Issue 108: EXH 358-Item 4-DOE Settlement	($747,000)	0	($747,000)
Issue 129: EXH 358-Item 12 CIS III	($435,000)	0	($435,000)
EXH 358 Issue 16 Account 354 correction	($3,419,000)		($3,419,000)
Issue 15: EXH 358-Item 21-Transmission Services–jurisdictional factor	($10,335,000)	0	($10,335,000)
Issue 50: EXH 418-Deferred Projects	0	0	($211,000)
Issue 94: Aviation Costs	($2,092,009)	0	($2,092,009)
Issue 19C and 19D: Depreciation Study	0		($82,735,000)
Issue19E and 19F: Allocation of Reserve Surplus			($223,695,000)
Issue 121: Fossil Dismantlement Study			$2,640,568
Total Reductions	($17,028,009)	($560,659,000)	($321,028,441)

Accordingly, based on the adjustments reflected in the table above, the appropriate adjustment to depreciation expense for 2010 shall be a reduction of $321,028,441. The effect of the adjustments for the 2010 test year is a depreciation expense of $753,236,559.

SCHEDULE 1

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 080677-EI
13-MONTH AVERAGE RATE BASE
DECEMBER 2010 TEST YEAR

Issue No.		Plant in Service	Accumulated Depreciation	Net Plant in Service	CWIP	Plant Held for Future Use	Nuclear Fuel - No AFUDC (Net)	Net Plant	Working Capital	Total Rate Base
	Adjusted per Company	28,288,080,000	(12,590,521,000)	15,697,559,000	707,530,000	74,502,000	374,733,000	16,854,324,000	209,262,000	17,063,586,000
	Commission Adjustments:									
14	WCEC 3 - No GBRA	0	0	0	0	0	0	0	0	0
15	Transmission Investments and Costs	(386,896,000)	144,299,000	(242,597,000)	(18,623,000)	(4,200,000)	0	(265,420,000)	3,700,000	(261,720,000)
16	Jurisdictional Separation	0	0	0	0	0	0	0	0	0
42	Fossil Dismantlement Accrual	0	(1,320,284)	(1,320,284)	0	0	0	(1,320,284)	0	(1,320,284)
46	Cost Recovery Clause Over-Recovery	0	0	0	0	0	0	0	(101,971,000)	(101,971,000)
47	Advanced Metering Infrastructure	0	0	0	0	0	0	0	0	0
50	Plant in Service Level	(785,187,189)	460,387,189	(324,800,000)	0	0	0	(324,800,000)	0	(324,800,000)
51	Accumulated Depreciation	0	469,416,500	469,416,500	0	0	0	469,416,500	0	469,416,500
52	Florida EnergySecure Line	0	0	0	0	0	0	0	0	0
53-S	ECRC Capital Items	0	0	0	0	0	0	0	0	0
55	Construction Work in Progress	0	0	0	(1,264,000)	0	0	(1,264,000)	0	(1,264,000)
56	Property Held for Future Use	0	0	0	0	0	0	0	0	0
57-S	Fuel Inventories	0	0	0	0	0	0	0	0	0
58	Nuclear End of Life and Last Core	0	0	0	0	0	0	0	0	0
59	Nuclear Fuel In Rate Base	0	0	0	0	0	0	0	0	0
60	Nuclear Fuel Level	0	0	0	0	0	(3,771,000)	(3,771,000)	0	(3,771,000)
61	Glades Power Park Amortization	0	0	0	0	0	0	0	0	0
62	Working Capital Level	0	0	0	0	0	0	0	4,078,000	4,078,000
63	Total Rate Base	0	0	0	0	0	0	0	0	0
83	SJRPP Transfer to CCRC	0	0	0	0	0	0	0	0	0
94	Aviation Costs	(53,268,205)	27,853,907	(25,414,298)	0	0	0	(25,414,298)	0	(25,414,298)
108	Department of Energy Settlement	(25,866,000)	252,000	(25,614,000)	(828,000)	0	0	(26,442,000)	0	(26,442,000)
120	Storm Damage Reserve	0	0	0	0	0	0	0	0	0
122	Rate Case Expense	0	0	0	0	0	0	0	(2,948,000)	(2,948,000)
173	Nuclear Uprates	0	0	0	0	0	0	0	0	0
---	Total Commission Adjustments	(1,251,217,394)	1,100,888,312	(150,329,082)	(20,715,000)	(4,200,000)	(3,771,000)	(179,015,082)	(97,141,000)	(276,156,082)
63	Commission Adjusted Rate Base	27,036,862,606	(11,489,632,688)	15,547,229,918	686,815,000	70,302,000	370,962,000	16,675,308,918	112,121,000	16,787,429,918

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 080677-EI
NET OPERATING INCOME
DECEMBER 2010 TEST YEAR

SCHEDULE 3

Issue No.		Operating Revenues	O&M - Fuel & Purchased Power	O&M Other	Depreciation and Amortization	Taxes Other Than Income	Total Income Taxes and ITCs	(Gain)/Loss on Disposal of Plant	Total Operating Expenses	Net Operating Income
	Adjusted per Company	4,114,727,000	27,505,000	1,694,367,000	1,074,265,000	350,370,000	243,338,000	(1,002,000)	3,388,844,000	725,883,000
	Commission Adjustments:									
3	2010 Customer, kWh & kW Forecast	0	0	0	0	0	0	0	0	0
7	2011 Customer, kWh & kW Forecast	0	0	0	0	0	0	0	0	0
14	WCEC 3 - No GBRA	0	0	0	0	0	0	0	0	0
15	Transmission Investments and Costs	(33,639,000)	0	(10,462,000)	(10,335,000)	(4,918,000)	(3,056,683)	0	(28,771,683)	(4,867,317)
16	Jurisdictional Separation	0	0	0	0	0	0	0	0	0
58	Nuclear End of Life and Last Core	0	0	(6,137,000)	0	0	2,367,348	0	(3,769,652)	3,769,652
61	Glades Power Park Amortization	0	0	0	0	0	0	0	0	0
82	Customer Growth and Inflation Factors	0	0	0	0	0	0	0	0	0
83	SJRPP Transfer to CCRC	0	0	0	0	0	0	0	0	0
84	FAC Revenues & Expenses	0	0	0	0	0	0	0	0	0
85	ECCR Revenues & Expenses	0	0	0	0	0	0	0	0	0
86	CCRC Revenues & Expenses	0	0	0	0	0	0	0	0	0
87	ECRC Revenues & Expenses	0	0	0	0	0	0	0	0	0
88	C/I Demand Reduction Rider	0	0	0	0	0	0	0	0	0
89	Late Payment Revenues	18,390,146	0	0	0	13,241	7,088,891	0	7,102,132	11,288,014
90	Revenue Forecast	36,969,000	0	0	0	26,618	14,250,524	0	14,277,142	22,691,858
91	Total Operating Revenues	0	0	0	0	0	0	0	0	0
92	Charitable Contibutions	0	0	0	0	0	0	0	0	0
93	Historical Museum	0	0	(45,470)	0	0	17,540	0	(27,930)	27,930
94	Aviation Costs	0	0	(1,633,916)	(2,092,009)	0	1,437,276	0	(2,288,649)	2,288,649
95	Advanced Metering Infrastructure	0	0	0	0	0	0	0	0	0
96	Bad Debt Expense	0	0	3,805,000	0	0	(1,467,779)	0	2,337,221	(2,337,221)
97	FAC Bad Debt Expense	0	0	16,893,000	0	0	(6,516,475)	0	10,376,525	(10,376,525)
98-S	Advertising Expenses	0	0	0	0	0	0	0	0	0
99-S	Lobbying Expenses	0	0	0	0	0	0	0	0	0
100	Unfilled Positions and Overtime	0	0	(15,392,467)	0	(882,729)	6,278,157	0	(9,997,039)	9,997,039
101	Productivity Improvements	0	0	0	0	0	0	0	0	0
102	Nuclear Production Staffing	0	0	0	0	0	0	0	0	0
103	Salaries and Employee Benefits	0	0	(49,510,136)	0	0	19,098,535	0	(30,411,601)	30,411,601
106	Pension Expense	0	0	0	0	0	0	0	0	0
107	Environmental Insurance Refund	0	0	0	0	0	0	0	0	0
108	Department of Energy Settlement	0	0	(6,084,000)	(747,000)	(109,000)	2,677,105	0	(4,262,895)	4,262,895
109	Affiliated Companies Transactions	0	0	(4,555,224)	0	(510,000)	1,953,910	0	(3,111,314)	3,111,314
116A	Gain on Sale	0	0	0	0	0	0	0	0	0
119	FPL-NED Assets	0	0	0	0	0	0	0	0	0
120	Storm Damage Accrual	0	0	(148,666,500)	0	0	57,348,102	0	(91,318,398)	91,318,398
121	Fossil Dismantlement Accrual	0	0	0	2,640,568	0	(1,018,599)	0	1,621,969	(1,621,969)
122	Rate Case Expense	0	0	(217,250)	0	0	83,804	0	(133,446)	133,446
123-S	Atrium	0	0	0	0	0	0	0	0	0
124	ECCR Payroll in Base Rates	0	0	1,582,000	0	0	(610,257)	0	971,744	(971,744)
125	CCRC Payroll in Base Rates	0	0	427,000	0	0	(164,715)	0	262,285	(262,285)
126	Hedging Costs in FAC	0	0	650,000	0	0	(250,738)	0	399,263	(399,263)
127-S	Orange Grove Operations	0	0	0	0	0	0	0	0	0
128	Level of O&M Expenses	0	0	0	0	0	0	0	0	0
129	Customer Information System	0	0	0	(435,000)	0	167,801	0	(267,199)	267,199
130	Capital Expenditures Reduction	0	0	0	0	0	0	0	0	0
131	Depreciation Expense	0	0	0	(310,060,000)	0	119,605,645	0	(190,454,355)	190,454,355
132	Taxes Other Than Income	0	0	0	0	972,000	(374,949)	0	597,051	(597,051)
133	American Recovery & Reinvestment Ac	0	0	0	0	0	0	0	0	0
134	Income Tax Expense	0	0	0	0	0	0	0	0	0
173	Nuclear Uprates	0	0	0	0	0	0	0	0	0
	Interest Synchronization	0	0	0	0	0	4,292,628	0	4,292,628	(4,292,628)
	Total Commission Adjustments	21,720,146	0	(219,346,963)	(321,028,441)	(5,407,870)	223,207,072	0	(322,576,202)	344,296,348
135	Commission Adjusted NOI	4,136,447,146	27,505,000	1,475,020,037	753,236,559	344,962,130	466,545,072	(1,002,000)	3,066,267,798	1,070,179,348

SCHEDULE 5

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 080677-EI
DECEMBER 2010 PROJECTED TEST YEAR
OPERATING REVENUE INCREASE CALCULATION

Line No.		As Filed	Commission Adjusted
1.	Rate Base	$ 17,063,586,000	$16,787,429,918
2.	Overall Rate of Return	8.00%	6.65%
3.	Required Net Operating Income (1)x(2)	1,364,748,000	1,116,364,090
4.	Achieved Net Operating Income	725,883,000	1,070,179,348
5.	Net Operating Income Deficiency (3)-(4)	638,865,000	46,184,742
6.	Net Operating Income Multiplier	1.63342	1.63411
7.	Operating Revenue Increase (5)x(6)	$1,043,535,000	$75,470,948

EXHIBIT NO. 711

DOCKET NO: 120015-EI

WITNESS: Jeffry Pollock

PARTY: FIPUG

DESCRIPTION: 2013 MFR Schedules B-1 Adjusted Rate Base and C-1 Adjusted Jurisdictional NOI from Docket No. 120015-EI

DOCUMENTS:

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 1200015-EI EXHIBIT 711
PARTY Office of Public Counsel
DESCRIPTION 2013 MFR Schedules B-1 Adjustred Rate Base and C-1 Adjusted Jurisdictional NOI from Docket No. 1200015-EI

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 120015-EI

EXPLANATION: Provide a schedule of the 13-month average adjusted rate base for the test year, the prior year and the most recent historical year. Provide the details of all adjustments on Schedule B-2.

TYPE OF DATA SHOWN:
X PROJECTED TEST YEAR ENDED 12/31/13
__ PRIOR YEAR ENDED __/__/__
__ HISTORICAL TEST YEAR ENDED __/__/__
Witness: Kim Ousdahl

($000)

LINE NO.	(1) DESCRIPTION	(2) PLANT IN SERVICE	(3) ACCUMULATED PROVISION FOR DEPRECIATION & AMORTIZATION	(4) NET PLANT IN SERVICE (2 - 3)	(5) CWIP	(6) PLANT HELD FOR FUTURE USE	(7) NUCLEAR FUEL	(8) NET UTILITY PLANT	(9) WORKING CAPITAL ALLOWANCE	(10) OTHER RATE BASE ITEMS	(11) TOTAL RATE BASE
1	UTILITY PER BOOK	35,230,269	13,439,198	21,791,071	2,427,629	237,400	576,317	25,032,417	(589,043)	0	24,443,374
2	SEPARATION FACTOR	0.979180	0.919267	1.016129	0.978072	0.969640	0.980759	1.011183	2.311219	0	0.979855
3	JURIS UTILITY	34,496,759	12,354,217	22,142,542	2,374,395	230,192	565,229	25,312,358	(1,361,408)	0	23,950,951
4	COMMISSION ADJUSTMENTS	(3,482,540)	(438,820)	(3,043,720)	(1,872,719)	0	0	(4,916,439)	2,573,792	0	(2,342,647)
5	COMPANY ADJUSTMENTS	(589,992)	(13,686)	(576,306)	0	0	0	(576,306)	4,826	0	(571,481)
6	TOTAL ADJUSTMENTS	(4,072,532)	(452,506)	(3,620,026)	(1,872,719)	0	0	(5,492,745)	2,578,617	0	(2,914,128)
7	JURIS ADJ UTILITY	30,424,227	11,901,711	18,522,516	501,676	230,192	565,229	19,819,614	1,217,209	0	21,036,823
8											
9											
10											
11											
12	NOTE: TOTALS MAY NOT ADD DUE TO ROUNDING.										

Supporting Schedules: B-3, B-2, B-6 Recap Schedules: A-1

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY AND SUBSIDIARIES

DOCKET NO.: 120015-EI

EXPLANATION: Provide the calculation of jurisdictional net operating income for the test year, the prior year and the most recent historical year.

TYPE OF DATA SHOWN:
X PROJECTED TEST YEAR ENDED 12/31/13
__ PRIOR YEAR ENDED _/_/_
__ HISTORICAL TEST YEAR ENDED _/_/_
WITNESS: Kim Ousdahl

($000)

LINE NO.	(1) DESCRIPTION	(2) TOTAL COMPANY PER BOOKS	(3) NON-ELECTRIC UTILITY	(4) TOTAL ELECTRIC (2)-(3)	(5) JURISDICTIONAL FACTOR	(6) JURISDICTIONAL AMOUNT (4) X (5)	(7) JURISDICTIONAL COMMISSION ADJUSTMENTS (SCHEDULE C-2)	(8) JURISDICTIONAL ADJUSTED PER COMMISSION (6) + (7)	(9) JURISDICTIONAL COMPANY ADJUSTMENTS	(10) JURISDICTIONAL ADJUSTED AMOUNT (8) + (9)
1										
2	REVENUE FROM SALES	10,220,581	0	10,220,581	0.986442	10,082,008	(5,815,392)	4,266,616	0	4,266,616
3										
4	OTHER OPERATING REVENUES	186,174	0	186,174	0.801202	149,163	(8,526)	140,637	0	140,637
5										
6	TOTAL OPERATING REVENUES	10,406,755	0	10,406,755	0.983128	10,231,171	(5,823,918)	4,407,253	0	4,407,253
7										
8	OTHER O&M	1,830,599	0	1,830,599	0.984380	1,802,005	(245,771)	1,556,233	(13,911)	1,542,322
9										
10	FUEL & INTERCHANGE	3,259,952	0	3,259,952	0.979035	3,191,607	(3,168,140)	23,466	0	23,466
11										
12	PURCHASED POWER	963,410	0	963,410	0.979598	943,754	(943,754)	0	0	0
13										
14	DEFERRED COSTS	137,248	0	137,248	1.000000	137,248	(137,248)	0	0	0
15										
16	DEPRECIATION & AMORTIZATION	1,132,186	0	1,132,186	0.983223	1,113,192	(276,178)	837,013	(34,253)	802,761
17										
18	TAXES OTHER THAN INCOME TAXES	1,115,886	0	1,115,886	0.992939	1,108,008	(724,982)	383,026	(11,316)	371,710
19										
20	INCOME TAXES	591,888	0	591,888	0.984182	582,526	(92,198)	490,328	22,948	513,276
21										
22	(GAIN)/LOSS ON DISPOSAL OF PLANT	(3,185)	0	(3,185)	0.996604	(3,175)	534	(2,641)	0	(2,641)
23										
24	TOTAL OPERATING EXPENSES	9,027,984	0	9,027,984	0.983073	8,875,164	(5,587,738)	3,287,426	(36,532)	3,250,894
25										
26	NET OPERATING INCOME	1,378,771	0	1,378,771	0.983490	1,356,007	(236,180)	1,119,827	36,532	1,156,359
27										
28										
29	TOTALS MAY NOT ADD DUE TO ROUNDING.									
30										

Supporting Schedules: C-2, C-3, C-4

Recap Schedules: A-1

EXHIBIT NO. 712

DOCKET NO: 120015-EI

WITNESS: Jeffry Pollock

PARTY: FIPUG

DESCRIPTION: Incremental Infrastructure Costs Exhibit JP-21 (Errata to Exh JP-15) With Columns C – G Expanded

[Provided in Response to OPC 1st POD to FIPUG as Exhibit JP-7 (Errata to Exhibit JP-1)]]

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 712
PARTY Office of Public Counsel
DESCRIPTION Incremental Infrastructure Costs Exhibit JP-21 (Erratta to Exh -15) with Columns C - G Expanded

Docket No. 120015-EI
Incremental Infrastructure Costs
Exhibit JP-7
(Errata to Exhibit JP-1)
(Indentifed as Exhibit JP-21 Errata to Exh JP-15)
With Columns C - G Expanded

FLORIDA POWER & LIGHT COMPANY

Revenue Requirement Associated With Additional Infrastructure-Related Costs Since FPL's Last Rate Case

Test Year Ending December 31, 2013
(Dollar Amounts in $000)

Line	Description	D. 080677-EI Final Order	Proposed	Proposed With CC Increase	Increase Since Last Rate Case	WCEC 3	Incremental Infrastructure Costs
							(1)
1	Jurisdictional Adjusted Rate Base	$16,787,430	$21,036,823	$21,858,148	$4,249,393	$769,387	$3,480,006
2	Pre-Tax Return at 10.70% ROE						9.78%
3	Return and Associated Taxes						$340,245
4	Property Insurance	$8,531	$14,321	$15,569	$5,790	$524	$5,266
5	Depreciation (excluding Decommissioning)	$753,237	$803,912	$835,414	$50,675	$33,906	$16,769
6	Property Tax	$297,735	$321,817	$339,487	$24,082	$14,599	$9,483
7	Revenue Deficiency						$371,764
8	Settlement Base Revenue Increase						$378,000

Source: Excel worksheet provided by email dated 11/7/12 in response to OPC's 1st POD to FIPUG Exhibit JP-7 Settlement.xls.

EXHIBIT NO. 713

DOCKET NO: 120015-EI – Settlement Hearing

WITNESS: JEFFRY POLLOCK

PARTY: FIPUG

DESCRIPTION: Exhibit JP-21 Modified to Remove Depreciation Surplus Amortization Impacts from Line 5

Source: Response to OPC's 1st POD to FIPUG Exhibit JP-7 Settlement.xls.

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 713
PARTY Office of Public Counsel
DESCRIPTION Exh JP-21 Modified to Remove Depreciation Surplus Amortization Impacts from Line 5

Docket No. 120015-EI
Incremental Infrastructure Costs
Sheet1
(Errata to Exhibit JP-1)
(Indentifed as Exhibit JP-21 Errata to Exh JP-15)
With Columns C - G Expanded

FLORIDA POWER & LIGHT COMPANY
Revenue Requirement Associated With
Additional Infrastructure-Related Costs
Since FPL's Last Rate Case
Test Year Ending December 31, 2013

Exhibit JP-21 Modified to Remove Depreciation Surplus Amortization Impacts from Line 5

Line	Description	D. 080677-EI Final Order	Proposed	Proposed With CC Increase	Increase Since Last Rate Case	WCEC 3	Incremental Infrastructure Costs	Depreciation Impacts
							(1)	
1	Jurisdictional Adjusted Rate Base	$16,787,430	$21,036,823	$21,858,148	$4,249,393	$769,387	$3,480,006	
2	Pre-Tax Return at 10.70% ROE						9.78%	
3	Return and Associated Taxes						$340,245	
4	Property Insurance	$8,531	$14,321	$15,569	$5,790	$524	$5,266	
5	Depreciation (excluding Decommissioning)	$753,237	$803,912	$835,414	$50,675	$33,906		$16,769
5a	Surplus Depreciation Amortization in Above	-$223,695	-$190,918		$32,777			$32,777
5b	Depreciation excluding surplus amortization	$976,932	$994,830		$17,898	$33,906	-$16,008	-$16,008
6	Property Tax	$297,735	$321,817	$339,487	$24,082	$14,599	$9,483	
7	Revenue Deficiency with No Surplus Depreciation Amortization Impact						$338,986	
8	Remaining Surplus Depreciation Owed to Ratepayers, per FPL filing						-$190,918	
9	Revenue Deficiency with Remaining Surplus Depreciation being Amortized						$148,068	
10	Settlement Base Revenue Increase						$378,000	

Source: Excel worksheet provided by email dated 11/7/12 in response to OPC's 1st POD to FIPUG Exhibit JP-7 Settlement.xls.

EXHIBIT NO. 714

DOCKET NO: 120015-EI

WITNESS: Sam Forrest

PARTY: FPL

DESCRIPTION: Florida Power & Light Company's 2012 Ten Year Power Plant Site Plan (Pages 95 and 96)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 714
PARTY Office of Public Counsel; Sam Forest, FPL's
DESCRIPTION 2012 Ten-Year Site Plan (pages 95 and 96)

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

Jessica Cano
Principal Attorney
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420
(561) 304-5226
(561) 691-7135 (Facsimile)

April 2, 2012

VIA HAND DELIVERY

Ms. Ann Cole
Division of the Commission Clerk and
Administrative Services
Florida Public Service Commission
Betty Easley Conference Center
2540 Shumard Oak Boulevard, Room 110
Tallahassee, FL 32399-0850

RECEIVED-FPSC
12 APR -2 PM 3:5
COMMISSION
CLERK

120000-OT

RE: Florida Power & Light Company's 2012 Ten Year Power Plant Site Plan

Dear Ms. Cole:

In accordance with Rule 25-22.071, F.A.C., please find enclosed for filing the original and twenty-five (25) copies of Florida Power & Light Company's 2012-2021 Ten Year Power Plant Site Plan.

Sincerely,

Jessica Cano

Jessica A. Cano

Enclosure

COM ____
APA ____
ECR ____
GCL 2
RAD 22
SRC ____
ADM ____
OPC ____
CLK 1-original

Florida Power & Light Company
700 Universe Boulevard, Juno Beach, FL 33408

DOCUMENT NUMBER-DATE
01983 APR-2 12
FPSC-COMMISSION CLERK

Ten Year Power Plant Site Plan
2012 – 2021

FPL

DOCUMENT NUMBER-DATE
01983 APR-2 12
FPSC-COMMISSION CLERK

Schedule 7.3
Projection of Generation - Only Reserves
At Time Of Summer Peak (Assuming PEEC in 2016 but no 2021 PPA)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
					Total			Firm					
	Firm	Firm	Firm		Firm	Total		Summer	Reserve			Reserve	
	Installed	Capacity	Capacity	Firm	Capacity	Peak		Peak	Margin Before		Scheduled	Margin After	
August of	Capacity	Import	Export	QF	Available	Demand	DSM	Demand	Maintenance		Maintenance	Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2012	23,502	1,733	0	635	25,870	21,623	0	21,623	4,246	19.6	745	3,501	16.2
2013	24,208	1,303	0	635	26,146	21,931	0	21,931	4,214	19.2	826	3,388	15.5
2014	25,482	1,303	0	635	27,420	23,243	0	23,243	4,176	18.0	826	3,350	14.4
2015	25,553	1,303	0	635	27,491	23,786	0	23,786	3,704	15.6	0	3,704	15.6
2016	26,434	375	0	705	27,514	24,315	0	24,315	3,199	13.2	0	3,199	13.2
2017	26,434	0	0	705	27,139	24,529	0	24,529	2,609	10.6	0	2,609	10.6
2018	26,434	0	0	705	27,139	24,674	0	24,674	2,465	10.0	0	2,465	10.0
2019	26,434	0	0	705	27,139	25,041	0	25,041	2,097	8.4	0	2,097	8.4
2020	26,434	0	0	705	27,139	25,499	0	25,499	1,640	6.4	0	1,640	6.4
2021	26,434	0	0	705	27,139	25,960	0	25,960	1,179	4.5	0	1,179	4.5

Col. (2) represents capacity additions and changes, **assuming no generation additions in 2021.**
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).
Col. (7) reflects the load forecast without incremental DSM or cumulative load management.
Col. (8) shows zero contribution from DSM in order to calculate FPL's reserves that are supplied only by generation resourc
Col. (10) = Col. (6) - Col. (9)
Col. (11) = Col.(10) / Col.(9)
Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Summer peak period. This value is comprised of: (i) 745 MW (at St. Lucie Unit 2) of nuclear capacity that will be out-of-service
during part of Summer in 2012 due to an extended planned outage as part of the capacity uprates project; and (ii) an additional
826 MW of fossil-fueled capacity that will be out-of-service in the Summer of 2013 (at Martin Unit 1) and in the Summer of 2014 (at M
due to the installation of electrostatic precipitators
Col. (13) = Col. (10) - Col. (12)
Col. (14) = Col (13) / Col (9)

Schedule 7.4
Projection of Generation - Only Reserves
At Time Of Summer Peak (Assuming PEEC in 2016 and 2021 PPA)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
					Total			Firm					
	Firm	Firm	Firm		Firm	Total		Summer	Reserve			Reserve	
	Installed	Capacity	Capacity	Firm	Capacity	Peak		Peak	Margin Before		Scheduled	Margin After	
August of	Capacity	Import	Export	QF	Available	Demand	DSM	Demand	Maintenance		Maintenance	Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2012	23,502	1,733	0	635	25,870	21,623	0	21,623	4,246	19.6	745	3,501	16.2
2013	24,208	1,303	0	635	26,146	21,931	0	21,931	4,214	19.2	826	3,388	15.5
2014	25,482	1,303	0	635	27,420	23,243	0	23,243	4,176	18.0	826	3,350	14.4
2015	25,553	1,303	0	635	27,491	23,786	0	23,786	3,704	15.6	0	3,704	15.6
2016	26,434	375	0	705	27,514	24,315	0	24,315	3,199	13.2	0	3,199	13.2
2017	26,434	0	0	705	27,139	24,529	0	24,529	2,609	10.6	0	2,609	10.6
2018	26,434	0	0	705	27,139	24,674	0	24,674	2,465	10.0	0	2,465	10.0
2019	26,434	0	0	705	27,139	25,041	0	25,041	2,097	8.4	0	2,097	8.4
2020	26,434	0	0	705	27,139	25,499	0	25,499	1,640	6.4	0	1,640	6.4
2021	26,684	0	0	705	27,389	25,960	0	25,960	1,429	5.5	0	1,429	5.5

Col. (2) represents capacity additions and changes, assuming a 250 MW PPA is added in 2021.
Col. (6) = Col.(2) + Col.(3) - Col.(4) + Col.(5).
Col. (7) reflects the load forecast without incremental DSM or cumulative load management.
Col. (8) shows zero contribution from DSM in order to calculate FPL's reserves that are supplied only by generation resourc
Col. (10) = Col. (6) - Col. (9)
Col. (11) = Col.(10) / Col.(9)
Col. (12) indicates the capacity of units projected to be out-of-service for planned maintenance during the Summer peak period. This value is comprised of: (i) an additional 745 MW (at St. Lucie Unit 2) of nuclear capacity that will be out-of-service
during part of Summer in 2012 due to an extended planned outage as part of the capacity uprates project; and (ii) an additional
826 MW of fossil-fueled capacity that will be out-of-service in the Summer of 2013 (at Martin Unit 1) and in the Summer of 2014 (at M
due to the installation of electrostatic precipitators.
Col. (13) = Col. (10) - Col. (12)
Col. (14) = Col (13) / Col.(9)

EXHIBIT NO. 715

DOCKET NO: 120015-EI

WITNESS: Sam Forrest

PARTY: FPL

DESCRIPTION: August 15th document (Pages 12-15)

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 715
PARTY OPC; Sam Forrest; August 15th
DESCRIPTION Document, Pages 12-15.

maintain in each such 12-month period a return on equity of 9.70% (measured on an FPSC actual, adjusted basis); and (iii) FPL may not amortize Reserve Amount in an amount that results in FPL achieving a return on equity of greater than 11.70% (measured on an FPSC actual, adjusted basis) in any such 12-month period as measured by surveillance reports submitted by FPL during the Term. FPL shall not satisfy the requirement of Paragraph 9 that its actual adjusted earned return on equity must fall below 9.70% on a monthly surveillance report before it may initiate a petition to increase base rates during the Term unless FPL first uses any of the Reserve Amount that remains available for the purpose of increasing its earned return on equity to at least 9.70% for the period in question.

11. Notwithstanding any requirements of Rules 25-6.0436 and 25-6.04364, F.A.C., FPL shall not be required during the Term to file any depreciation study or dismantlement study. The depreciation rates and dismantlement accrual rates in effect as of the Implementation Date shall remain in effect throughout the Term. The Parties agree that the provisions of Rules 25-6.0436 and 25-6.04364 pursuant to which depreciation and dismantlement studies are generally filed at least every four years will not apply to FPL during the Term.

12. (a) In order to create additional value for customers by FPL engaging in both wholesale power purchases and sales, as well as all forms of asset optimization, the Parties agree that FPL will be subject to the following mechanism, effective on the Implementation Date (the "Incentive Mechanism"):

(i) FPL will file each year as part of its fuel cost recovery clause ("Fuel Clause") final true-up filing a schedule showing its gains in the prior calendar year on short-term wholesale sales, short-term wholesale purchases (including purchases that are reported on Schedule A-7), and all forms of asset optimization that it undertook in that year (the "Total Gains Schedule").[2] FPL's final true-up filing will include a description of each asset optimization measure for which gain is included on the Total Gains Schedule for the prior year, and such measures shall be subject to review by the Commission to determine that they are eligible for inclusion in the Incentive Mechanism.

(ii) For the purposes of the Incentive Mechanism, "asset optimization" includes but is not limited to:

- Gas storage utilization (FPL could release contracted storage space or sell stored gas during non-critical demand seasons);
- Delivered city-gate gas sales using existing transport (FPL could sell gas to Florida customers, using FPL's existing gas transportation capacity during periods when it is not needed to serve FPL's native load);
- Production (upstream) area sales (FPL could sell gas in the gas-production areas, using FPL's existing gas transportation capacity during periods when it is not needed to serve FPL's native load);

[2] For the purpose of this Agreement, "short-term" is intended to refer to non-separated wholesale sales and purchases. Order No. PSC-97-0262-FOF-EI defined "non-separated" sales as "sales that are non-firm or less than one year in duration."

- Capacity Release of gas transport and electric transmission (FPL could sell idle gas transportation and/or electric transmission capacity for short periods when it is not needed to serve FPL's native load;
- Asset Management Agreement ("AMA") (FPL could outsource optimization function such as those described above to a third party through assignment of transportation and/or storage rights in exchange for a premium to be paid to FPL).

(iii) On an annual basis, FPL customers will receive 100% of the gain described in Paragraph 12(b)(i), up to a threshold of $36 million ("Customer Savings Threshold"). In addition, FPL customers will receive 100% of the gain described in Paragraph 12(b)(i) for the first $10 million above the Customer Savings Threshold ("Additional Customer Savings"). Incremental gains above the total of the Customer Savings Threshold and the Additional Customer Savings (i.e., above a gain of $46 million) will be shared between FPL and customers as follows: FPL will retain 70% and customers will receive 30% of incremental gains between $46 million and $75 million; FPL will retain 60% and customers will receive 40% of incremental gains between $75 million and $100 million; and FPL will retain 50% and customers will receive 50% of all incremental gains in excess of $100 million. The customers' portion of all gains will be reflected as a reduction to fuel costs recovered through the Fuel Clause. FPL agrees that it will not require any native load customer to be interrupted in order to initiate or maintain an economy sale, whether that sale is firm or non-firm.

(b) FPL will be entitled to recover through the Fuel Clause the following types of reasonable and prudent incremental O&M costs incurred in implementing its expanded short-term wholesale purchases and sales programs as well as the asset optimization measures (the "Incremental Optimization Costs"):

(i) incremental personnel, software and associated hardware costs incurred by FPL to manage the expanded short-term wholesale purchases and sales programs and the asset optimization measures; and

(ii) variable power plant O&M costs[3] incurred by FPL to generate additional output in order to make wholesale sales, to the extent that the level of such sales exceed 514,000 MWh (*i.e.*, the level of sales assumed for the purpose of forecasting 2013 test year power plant O&M costs in the MFRs filed with the 2012 Rate Petition), with such costs determined by multiplying the sales above that threshold times the monthly weighted average variable power plant O&M cost per MWh reflected in the 2013 test year MFRs.

FPL's final true-up filing will separately state and describe the Incremental Optimization Costs that it incurred in the prior year, and such costs shall be subject to review and approval by the Commission.

13. No Party to this Agreement will request, support, or seek to impose a change in the application of any provision hereof. Except as provided in Paragraph 9, a Party to this Agreement will neither seek nor support any reduction in FPL's base rates, including limited, interim or any other rate decreases, that would take effect prior to the first billing cycle for January 2017, except for any such reduction requested by FPL or as otherwise

[3] For the purpose of this Agreement, "variable power plant O&M costs" includes non-fuel O&M expenses and costs for capital replacement parts that vary as a function of a power plant's output.

EXHIBIT NO. 716

DOCKET NO: 120015-EI

WITNESS: Lane Kollen

PARTY: Signatories

DESCRIPTION: Excerpt from July 2009 Testimony
(Dkt. No. 080677-EI)

DOCUMENTS:

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 716
PARTY OPC; Lane Kollen; Excerpt from July 2009
DESCRIPTION Testimony (Docket 080677)

ORIGINAL

Public Disclosure Version

BEFORE THE FLORIDA
PUBLIC SERVICE COMMISSION

IN RE:

PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY	))	DOCKET NO. 080677-EI

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

J. KENNEDY AND ASSOCIATES, INC
ROSWELL, GEORGIA

JULY 2009

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July 16, 2009

VIA FEDEX

Ann Cole, Commission Clerk
Office of the Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: *Docket No. 080677-EI - Florida Power & Light Company; South Florida Hospital & Healthcare Association's Prefiled Testimony and Exhibits*

Dear Ms. Cole:

Please find enclosed an original and fifteen (15) copies of the public version of the Direct Testimony and Exhibits for each of the following witnesses on behalf of South Florida Hospital & Healthcare Association in Docket No. 080677-EI: Stephen J. Baron, Richard A. Baudino, and Lane Kollen. Also enclosed in sealed envelopes marked "CONFIDENTIAL DO NOT RELEASE" is one confidential copy of each of the testimonies of Messrs. Baudino and Kollen. Attached to the confidential copy of their testimonies is Florida Power & Light Company's Notice of Intent to Request Confidential Classification of those testimonies and a transmittal letter from Florida Power & Light Company for its Notice. Two extra copies of the cover pages for each of the public versions of the testimonies are also enclosed. Please date-stamp these copies and send them back to me in the self-addressed, stamped envelope that has been provided.

Please call me if you have any questions.

Very truly yours,

Kenneth L. Wiseman
Mark F. Sundback
Jennifer L. Spina
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Andrews Kurth LLP
1350 I Street, NW
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Attorneys for South Florida Hospital & Healthcare Association

COM 5
ECR
GCL 1
OPC
RCP 1
SSC 1
SGA 1
ADM
CLK 1

WAS:153425.1

BEFORE THE FLORIDA
PUBLIC SERVICE COMMISSION

IN RE:

PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY)	DOCKET NO. 080677-EI

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BEFORE THE FLORIDA
PUBLIC SERVICE COMMISSION

IN RE:

PETITION FOR RATE INCREASE BY) DOCKET NO. 080677-EI
FLORIDA POWER & LIGHT COMPANY)

DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Qualifications

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with Kennedy and Associates.

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Business Administration in Accounting degree and a Master of Business Administration degree, both from the University of Toledo. I also earned a Master of Arts degree from Luther Rice University. I am a Certified

Public Accountant, with a practice license, and a Certified Management Accountant.

I have been an active participant in the utility industry for more than thirty years, both as a consultant and as an employee. Since 1986, I have been a consultant with Kennedy and Associates, providing services to consumers of utility services and state and local government agencies in the areas of utility planning, ratemaking, accounting, taxes, financial reporting, financing and management decision-making. From 1983 to 1986, I was a consultant with Energy Management Associates, providing services to investor and consumer owned utility companies in the areas of planning, financial reporting, financing, ratemaking and management decision-making. From 1976 to 1983, I was employed by The Toledo Edison Company in a series of positions providing services in the areas of planning, accounting, financial and statistical reporting and taxes.

I have appeared as an expert witness on utility planning, ratemaking, accounting, reporting, financing, and tax issues before state and federal regulatory commissions and courts on nearly two hundred occasions. In many of those proceedings, I have represented state and local ratemaking agencies or their Staffs, including the Louisiana Public Service Commission, Georgia Public Service Commission and various groups of Cities with original rate jurisdiction in Texas. I also have appeared before the Florida Public Service Commission

("Commission") in numerous proceedings, including the two most recent Florida Power & Light Company ("FPL" or "Company") base rate proceedings in Docket Nos. 050045-EI (2005) and 001148-EI (2002). I have developed and presented papers at various industry conferences on ratemaking, accounting, and tax issues. My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

Summary

Q. On whose behalf are you testifying?

A. I am offering testimony on behalf of the South Florida Hospital and Healthcare Association ("SFHHA") and individual healthcare institutions (collectively, the "Hospitals") taking electric service on the FPL system.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the Company's proposed series of base rate and recovery clause increases and to make recommendations on the appropriate rate increase amounts.

Q. Please summarize your testimony.

A. The Company has requested an unprecedented series of rate increases in this proceeding of more than $1,550 million, the magnitude of which may not be immediately evident, and which would represent a radical change in the Commission's ratemaking process. These increases consist of a base rate increase of $1,044 million on January 1, 2010, another series of increases on January 1, 2010 summing to $77 million through various recovery clauses due to transfers in the recovery of such costs between base rates and the clauses, another base rate increase of $247 million on January 1, 2011, an estimated initial base rate increase of $182 million through a Generation Base Rate Adjustment ("GBRA") mechanism for West County Energy Center Unit 3 ("WCEC 3") on June 1, 2011 and another series of unknown future base rate increases through the GBRA for future generation costs.

I recommend that the Commission reject the Company's proposals in this proceeding for all base rate increases after January 1, 2010. Instead, the Company should file for future base rate increases closer to the effective dates of such increases using then current costs and assumptions. The Commission realistically cannot determine at this time the reasonable level of revenues and costs that should be recovered through base rates some three or more years into the future, particularly given the present economic uncertainty. Further, the Commission should not adopt a GBRA that provides the Company an almost unfettered ability to automatically impose base rate increases to recover selective increases in certain costs without consideration of increases in revenues and reductions in all other costs.

In addition, I recommend that the Commission reduce the Company's base rates by at least $336.338 million (net of transfers of costs between base rates and various recovery clauses) on January 1, 2010 compared to the Company's requested increase of $1,044 million. My recommendation reflects the SFHHA adjustments to remove the excessive and inappropriate costs that affect the rate base, operating income and rate of return that are included in the Company's request. I have summarized the effects of the SFHHA recommendations on the following table.

FLORIDA POWER AND LIGHT BASE RATE INCREASE
SUMMARY OF SFHHA RECOMMENDATIONS
TEST YEAR ENDING DECEMBER 31, 2010
($ MILLIONS)

	Amount
FPL Requested Base Rate Increase	**$ 1,043.535**
Operating Income Adjustments:	
Reduce O&M Expenses - Other (Maintain Status Quo)	(169.256)
Reduce O&M Expenses - DOE Settlement Refunds	(9.030)
Reduce O&M Expenses - AMI Deployment Savings	(5.685)
Reduce O&M Expenses - Development of New CIS	(7.274)
Remove Annual Storm Damage Expense Accrual	(149.162)
Reduce O&M Labor, Payroll Taxes, and Fringe Benefits - Productivity Improvements	(36.641)
Reduce O&M Labor, Payroll Taxes, and Fringe Benefits - Nuclear Staffing	(21.925)
Remove Depreciation Expense - Development of New CIS	(0.506)
Reduce Depreciation Expense - Capital Cost Reductions	(26.719)
Reduce Depreciation Expense - Five Year Amortization of Depreciation Reserve Surplus	(247.556)
Reduce Depreciation Expense - No Acceleration of Capital Recovery Costs	(63.605)
Reduce Depreciation Expense - Forty Year Service Life for Combined Cycle Gas Units	(123.730)
Reduce Depreciation Expense - Economic Stimulus Grants for AMI Deployment	(1.584)
Rate Base Adjustments:	
Reflect Capitalization/Deferral of CIS O&M Expenses	0.428
Reduce Plant for Capital Expenditure Reductions	(92.520)
Restate Accum Depr to Reflect Capital Expenditure Reductions	3.668
Restate Accum Depr to Reflect Five Year Amortization of Depreciation Reserve Surplus	14.559
Restate Accum Depr to Adjust Amortization Periods for Capital Recovery Costs	3.741
Restate Accum Depr to Reflect Forty Year Service Lives for Combined Cycle Gas Units	7.276
Restate Gross Plant and Accum Depr to Reflect Economic Stimulus for AMI Deployment	(2.267)
Capital Structure and Rate of Return Adjustments:	
Rebalance Common Equity and Debt in Capital Structure	(121.424)
Rebalance Long and Short Term Debt in Capital Structure	(11.018)
Eliminate FIN 48 Adjustment to Accumulated Deferred Income Tax	(17.643)
Reallocate Pro Rata Adjustments to Exclude Cust Deposits, ADIT, ITC	(48.695)
Increase ADIT for Depreciation Changes	(8.909)
Restate ROE at 10.4%	(232.610)
Restate Short Term Debt Interest Rate	(11.785)
Total SFHHA Adjustments	**($1,379.873)**
SFHHA Recommendation for Base Rate Change on January 1, 2010	**($336.338)**

The remainder of my testimony is structured to follow the sequence of my summary. In the next section, I address the Company's proposed base rate increases effective on January 1, 2011 and beyond and why the Commission should reject those increases in this proceeding. In the subsequent sections, I focus on the Company's proposed base rate increase effective on January 1, 2010 and the appropriate adjustments to that proposed increase by major ratemaking component (operating income, rate base, and capitalization and rate of return) and by issue affecting each of those major ratemaking components.

Economic Uncertainty and Requested Base Increase on January 1, 2011 and GBRA Increase on June 1, 2011

Q. Should the Commission approve a second base rate increase to be effective on January 1, 2011 based on a "subsequent" test year of 2011?

A. No. First, the Commission cannot determine at this time what the reasonable revenues and costs will be in 2011 given the present economic uncertainty. It will be difficult enough to determine the reasonable level of revenues and costs for the 2010 test year, which itself is two years removed from actual experience and is based on a budgeting process covering 2009 and 2010, but which began in mid-2008 prior to the meltdown in the financial markets and the recession. Since 2008, the Company has engaged in extensive cost reductions compared to its 2009 budget, thus rendering the 2009 budget unreliable as the basis for the 2010 test year forecast, and even more so for the 2011 subsequent test year forecast. I subsequently describe the Company's cost reductions in both capital expenditures and operating expenses compared to 2008 actual amounts and compared to the Company's 2009 budget.

Second, there is no evidence that there will be actual savings to ratepayers resulting from the avoidance of a separate proceeding sometime in 2010 for rates that will be effective in 2011. Company witness Ms. Kim Ousdahl asserts that the Commission should determine the 2011 rate increase in this proceeding to "avoid the cost and distraction for all parties of back-to-back rate proceedings." [Ousdahl Direct at 12]. However, if the Company's 2011 test year costs are reduced as the result of the Company's cost cutting efforts compared to the projections in the Company's 2011 subsequent year forecasts in this proceeding, then the cost of a separate proceeding in 2010 or in some future year is likely to pale against the effect of such savings in a subsequent proceeding. It would be far better to incur the cost of another rate proceeding in 2010 or later and to endure the alleged "distraction" of such a proceeding in order to avoid an excessive increase for 2011 that is not merited and that cannot be reasonably determined at this time. The reasonable levels of revenues and costs in 2011 are not known and measurable today.

Third, the Company is not harmed if the Commission rejects the proposed 2011 subsequent year increase because it can file another case in 2010 using more current assumptions and data. Company witness Ms. Ousdahl recognizes that the

Commission may reject the Company's request for the January 1, 2011 base rate increase and concludes that this may result in another rate filing. [Ousdahl Direct at 4]. That may be and the Commission can consider such a request after it is filed, if one is filed. Regardless, Ms. Ousdahl does not claim that the Company will harmed if it must make a subsequent filing, nor could it reasonably make such a claim.

Fourth, it may very well be that the Company will not file another case in 2010 if it continues to reduce its costs through additional reductions in capital expenditures and operating expenses as it addresses the lack of growth in sales and revenues due to the economic recession. In any event, it is premature both for the Commission and the Company to make a determination at this time as to the Company's revenue requirement in 2011 given the present uncertainty.

Q. Should the Commission approve the Company's proposed GBRA?

A. No. The Company's proposed GBRA mechanism represents a radical departure from the traditional ratemaking process and should be rejected for several reasons. First, the Company's proposed GBRA will be a permanent mechanism that will operate to automatically implement significant future base rate increases as the Company adds new generation. The Company effectively will self-implement those base rate increases without the normal regulatory scrutiny and resulting cost-control discipline that accompanies the filing, review and adjudication of a comprehensive base rate case. The proposed GBRA will not be limited only to the West County Energy Center Unit 3 revenue requirement, but also will include all future generation and related transmission costs.

Second, the circumstances and nature of the proposed GBRA differ from those of the expiring GBRA. The expiring GBRA was implemented in conjunction with a settlement in Docket Nos. 050045-EI and 050188-EI, which provided for no base rate increases for the next four years except for costs recovered through various adjustment mechanisms, including the GBRA and various clauses, unless the Company's earnings fell below a threshold level. In addition, the GBRA mechanism was temporary and will expire at the end of this year unless it is re-established in this proceeding.

Third, the proposed GBRA mechanism constitutes a single issue and one-way base rate increase mechanism that fails to consider cost reductions that the Company may achieve in other areas. For example, the proposed mechanism will not reflect cost reductions due to the continued depreciation on or retirement of existing production plant investment as acknowledged by the Company in response to SFHHA Interrogatory 112. The proposed GBRA mechanism allows the Company to retain the savings resulting from ongoing recoveries of existing plant investment through depreciation from ratepayers, the cost free capital resulting from ongoing accelerated tax depreciation, increases in revenues due to customer and usage growth and capital expenditure and expense cost reductions. This fundamental flaw will be accentuated the longer the period between comprehensive base rate proceedings. I have attached a copy of the Company's response to SFHHA Interrogatory 112 as my Exhibit___(LK-2)

Third, the GBRA recovery will be based on the Company's first year estimate of the revenue requirement of the new generation and related transmission when that revenue requirement is at its peak level. Once the Company self-implements a base rate increase when a new project enters commercial operation, that rate increase will be permanent and remain at the level when implemented, at least until the next comprehensive base rate proceeding. Once the increase is implemented, base revenues will not be revised downward as the underlying rate base amount declines due to increases in accumulated depreciation or as the related cost of capital declines due to increases in cost-free accumulated deferred income taxes and apparently never is trued-up to actual. This approach allows the Company to increase base rates when the revenue requirement is at the maximum level and then to retain any savings due to the declining rate base or actual expenses that are less than initially projected until the next comprehensive base rate proceeding. This approach also will allow the Company to avoid or at least defer a voluntary comprehensive review of its base rates absent growth in its other base rate costs that exceeds such savings.

Fourth, the GBRA mechanism is not even a proposed tariff even though it is self-implementing. There is no proposed tariff to review. There is not even a detailed description of the mechanism and the revenue requirement computations in the testimony of any FPL witness. Company witness Ms. Ousdahl simply refers to the existing GBRA in her testimony. However, the description of the existing GBRA mechanism in paragraph 17 of the settlement agreement in Docket Nos. 050045-EI and 050188-EI and approved by the Commission in Order No. PSC-05-0902-S-EI is not sufficiently detailed for a permanent self-implementing base rate increase mechanism. I have attached a copy of the settlement agreement in that proceeding as my Exhibit___(LK-3) for ease of reference.

Fifth, based on the Company's computation of the proposed West County Energy Center 3 revenue requirement, there are serious computational problems in the Company's proposed GBRA, all of which serve to improperly increase the Company's revenue requirement.

Q. Please describe the computational problems with the Company's proposed GBRA.

A. There are numerous problems that are evident from a review of the Company's separate computation of the WCEC 3 revenue requirement for the first year of its operation that the Company provided in this proceeding. The Commission should not allow the use (or misuse) of a GBRA to provide the Company with excessive revenues. First, the proposed rate of return is overstated due to an excessive common equity ratio of 55.80%. A reasonable capital structure consists of 50.0% common equity and 50.0% debt for rating agency reporting purposes and 53.46%

common equity and 46.54% debt for ratemaking purposes, according to SFHHA witness Mr. Richard Baudino's testimony in this proceeding.

Second, the proposed rate of return is overstated due to the Company's use of the so-called "incremental" cost of debt rather than the weighted average cost of debt outstanding. For example, the Company's computations reflect a 6.43% cost of debt on Schedule D-1a for the WCEC 3 revenue requirement compared to the 5.81% weighted average cost of debt on Schedule D-1a for the 2011 subsequent test year revenue requirement.

Third, the proposed rate of return is overstated due to the failure to include low-cost short term debt in the capital structure. If the WCEC 3 rate base investment was included in the rate base for the base revenue requirement, then the return applied to the rate base investment would include short-term debt.

Fourth, the rate of return is overstated because it does not include any cost-free ADIT in the capital structure. The Company should not be allowed to retain this benefit by computationally assuming that it does not exist.

Fifth, the depreciation expense is overstated because it is based on a 25 year life for the WCEC 3 facility. Such a facility has a reasonable service life of 40 years and depreciation expense should be based on the reasonable service life, not an accelerated life established only to accelerate and increase near-term ratemaking recovery. I address the appropriate service lives for depreciation expense in the Operating Income section of my testimony.

Q. How should the Company recover its costs associated with the West County Energy Center Unit 3 and future generation facilities?

A. If the Company believes that it has or will have a revenue deficiency for 2011, then it should file a request to increase its base rates some time in 2010. Similarly, if the Company believes that it has or will have a revenue deficiency in years after 2011, then it should file requests to increase its base rates in those years.

EXHIBIT NO. 717

DOCKET NO: 120015-EI

WITNESS: Lane Kollen

PARTY: Signatories

DESCRIPTION: Excerpt from Order No. PSC-10-0153-FOF-EI

DOCUMENTS:

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 717
PARTY OPC, Lane Kollen; Excerpt from Order
DESCRIPTION No. PSC-10-0153-FOF-EI

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for increase in rates by Florida Power & Light Company.	DOCKET NO. 080677-EI
In re: 2009 depreciation and dismantlement study by Florida Power & Light Company.	DOCKET NO. 090130-EI ORDER NO. PSC-10-0153-FOF-EI ISSUED: March 17, 2010

The following Commissioners participated in the disposition of this matter:

NANCY ARGENZIANO, Chairman
LISA POLAK EDGAR
NATHAN A. SKOP
DAVID E. KLEMENT
BEN A. "STEVE" STEVENS III

APPEARANCES:

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SUSAN F. CLARK., Radey Thomas Yon & Clark, P.A., 301 South Bronough Street, Suite 200, Tallahassee, Florida 32301
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JOSEPH A. McGLOTHLIN, CHARLIE BECK, PATRICIA A. CHRISTENSEN, ESQUIRES, Office of the Public Counsel, c/o the Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
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On behalf of ASSOCIATED INDUSTRIES OF FLORIDA (AIF)

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On behalf of the CITY OF SOUTH DAYTONA (CSD)

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On behalf of Federal Executive Agencies (FEA)

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On behalf of the South Florida Hospital and Healthcare Association (SFHHA)

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On behalf of IBEW System-Council U-4 (SCU-4)

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On behalf of Mr. Richard Unger (UNGER)

LISA C. BENNETT, MARTHA CARTER BROWN, JEAN HARTMAN, ANNA WILLIAMS, KEINO YOUNG, and KATHRYN COWDERY, ESQUIRES, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
On behalf of the Florida Public Service Commission (STAFF).

MARY ANNE HELTON, Deputy General Counsel, SAMANTHA CIBULA, ADAM TEITZMAN, and JENNIFER BRUBAKER, ESQUIRES, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
Advisors to the Florida Public Service Commission.

ORDER DENYING IN PART, AND GRANTING IN PART, FLORIDA POWER & LIGHT COMPANY'S REQUEST FOR A PERMANENT RATE INCREASE AND SETTING DEPRECIATION AND DISMANTLEMENT RATES AND SCHEDULES

BY THE COMMISSION:

BACKGROUND

This proceeding commenced on March 18, 2009, with the filing of a petition for a permanent rate increase by Florida Power & Light Company (FPL or Company). The Company is engaged in business as a public utility providing electric service as defined in Section 366.02, Florida Statutes (F.S.), and is subject to our jurisdiction. FPL provides electric service to approximately 4.5 million retail customers in all or parts of 35 Florida counties.

FPL requested an increase in its retail rates and charges to generate $1.044 billion in additional gross annual revenues, effective January 4, 2010. If granted, this increase would have allowed the Company to earn an overall rate of return of 8.00 percent or a 12.50 percent return on equity, with a range of 11.50 percent to 13.50 percent. The Company based its request on a projected test year ending December 31, 2010. FPL also requested a $247.4 million subsequent year base rate increase effective January 2011. This additional increase would have allowed the Company to earn an overall rate of return of 8.18 percent or a 12.50 percent return on equity (range 11.50 percent to 13.50 percent). The Company based its subsequent year request on a projected test year ending December 31, 2011. In addition to its 2010 and 2011 rate increases, FPL requested approval of a Generation Base Rate Adjustment (GBRA) mechanism that would allow FPL to increase base rates for revenue requirements associated with new generating additions approved under the Power Plant Siting Act at the time the plants enter commercial service. FPL did not request any interim rate relief. Order No. PSC-09-0351-PCO-EI, issued May 22, 2009, in this docket, suspended the proposed final rates.

The Office of Public Counsel (OPC), the Office of the Attorney General (AG), the Florida Industrial Power Users Group (FIPUG), The Florida Retail Federation (FRF), the Florida Association for Fairness in Rate Making (AFFIRM), the Federal Executive Agencies (FEA), the South Florida Hospital and Healthcare Association (SFHHA), the Associated Industries of Florida (AIF), the City of South Daytona, Florida (South Daytona), the I.B.E.W. System Council U-4 (SCU-4), the FPL Employee Intervenors (Employee Intervenors), and Richard Unger (Unger) intervened in this proceeding. OPC, AG, FIPUG, FRF, AFFIRM, FEA, SFHHA, South Daytona and Mr. Unger objected to FPL's petition for rate increase. OPC, FIPUG, and SFHHA filed testimony supporting a rate decrease.

Pursuant to Florida Statutes, we conducted 9 customer service hearings at the following locations and dates: Sarasota and Ft. Myers, June 19, 2009; Daytona Beach, June 23, 2009; Melbourne and West Palm Beach, June 24, 2009; Ft. Lauderdale and Miami, June 25, 2009; and Miami Gardens and Plantation, June 26, 2009. The Technical Hearing was held in Tallahassee on August 24-28 and 31, 2009, September 2-5, 16 and 17, 2009, and October 21-23, 2009. During the hearing, we approved several stipulated issues, which are reflected in Appendix A to this Order.

On January 13, 2010, at a Special Agenda Conference, we considered the revenue requirements and rate design for FPL. At a January 29, 2010, Special Agenda Conference, we considered the rates to be charged to FPL's customers. This Order reflects our decisions in these dockets. We have jurisdiction over this matter pursuant to Chapter 366, F.S., including Sections 366.041, 366.06, 366.07, and 366.076, F.S.

2010 PROPOSED TEST PERIOD

Legal authority to approve base rate increase

The parties requested that we rule on whether we had the legal authority to use a projected test year in setting rates. In 1983, the Florida Supreme Court, in a telecommunications case, settled that question:

> Section 364.035(1), Florida Statutes (1981) [telecommunications], provides that the Commission has the authority to fix "just, reasonable, and compensatory rates." Nothing in the decisions of this Court or any legislative act prohibits the use of a projected test year by the Commission in setting a utility's rates. We agree with the Commission that it may allow the use of a projected test year as an accounting mechanism to minimize regulatory lag. The projected test period established by the Commission is a ratemaking tool which allows the Commission to determine, as accurately as possible, rates which would be just and reasonable to the customer and properly compensatory to the utility.

Southern Bell Tel. & Tel. Co. v. Public Service Commission, 443 So. 2d 92, 97 (Fla. 1983) (Southern Bell). As we had the authority in telecommunications to use a projected test year, so also do we have the authority to fix "just, reasonable, and compensatory rates" for investor-owned electric utilities. See Section 366.041(1), F.S. A comparison of Section 364.035(1) to

366.041(1), F.S., reveals virtually identical language for the two different industries. In 1985, in an investor-owned electric utility case, the Florida Supreme Court acknowledged our inherent authority to combat regulatory lag by considering and recognizing factors which affect future rates and to grant rate increases based on those factors. Floridians United for Safe Energy, Inc. v. Public Service Commission, 475 So. 2d 241, 242 (Fla. 1985) (Floridians United).

By adopting Rule 25-6.140, Florida Administrative Code (F.A.C.), we codified the Supreme Court's decisions in Southern Bell and Floridians United by requiring an investor-owned electric utility to give an explanation for the test year if the utility chooses to select a projected test year. We have on numerous occasions over the past 20 years used the projected test year method of accounting to set rates for electric utilities. Accordingly, we determine that we have the legal authority to approve a base rate increase using a 2010 projected test year.

Projected Test Period

FPL proposed to utilize a fully projected 2010 test year as the basis for its overall jurisdictional revenue requirement calculation. Generally, the periods covered in FPL's Minimum Filing Requirements (MFRs) in support of its application were the 2008 historical year, 2009 Prior Year, and 2010 Test Year. FPL filed its MFRs based upon forecasts completed in late 2008. The accuracy of FPL's 2010 forecasts is discussed more extensively in our consideration of forecasts of customers, below.

As we have acknowledged in prior dockets, there are primarily two options we may use in evaluating a utility's rate case. The two options are the historic test year and the projected test year. Both options have strengths and weaknesses. In determining to use the projected test year for Gulf[1] in its 2001 rate request, we stated:

> The historical test year has the advantage of using actual data for much of rate base, NOI, and capital structure; however, the pro forma adjustments usually do not represent all the changes that occur from the end of the historical period to the time new rates are in effect. Therefore, this option generally does not present as complete an analysis of the expected financial operations as a projected test year.
>
> The main advantage of a projected test year is that it includes all information related to rate base, NOI, and capital structure for the time new rates will be in effect. However, the data is projected and its accuracy depends on the Company's ability to use the forecast for setting rates.

In granting Gulf's request for the use of the projected test year, we acknowledged that extensive discovery was conducted on the forecasts, and, with adjustments, was appropriate.

In this docket, we find that the projected test year of the twelve months ended December 31, 2010, provides the best opportunity for a proper matching of revenues, expenses, and rate

[1] Order No. PSC-02-0787-FOF-EI, issued June 10, 2002, in Docket No. 010949-EI, In re: Request for rate increase by Gulf Power Company.

base investment for 2010. Accordingly, we accept FPL's proposed 2010 year proposed, with the adjustments discussed below.

Forecasts of customers

FPL's 2010 forecast of customers, kilowatt hours (kWh), and kilowatts (kW) by rate class are consistent with the sales and customer forecast by revenue class and reflect the particular billing determinants specified in each rate schedule if certain adjustments are made to the forecast. Both FPL and OPC suggested changes to FPL's load forecast.

FPL's 2010 forecast of customers, kWh, and kW was sponsored by FPL witnesses Rosemary Morley and Philip Q. Hanser. The two primary elements of FPL's projections were its forecasts of the total number of customers and the Net Energy for Load (NEL). FPL forecasted the total number of customers with an econometric model using population and seasonal factors as explanatory variables. FPL forecasted NEL per customer with an econometric model based upon the level of economic activity, weather, and the price of electricity. NEL was then projected by multiplying the customer forecasts by the NEL per customer forecasts. FPL relied upon independent sources for its forecast assumptions such as the University of Florida's Bureau of Economic and Business Research (BEBR) for its population projections, and Global Insight, Moody's Economy.com, and the Florida Legislature for its economic projections.

These aggregate forecasts were then broken down into separate revenue class forecasts (e.g. Residential, Commercial, Industrial, etc.) for the number of customers and kWh sales by revenue class. These projections were ultimately used to determine the level of test year revenues FPL would earn in 2010 under its current rates and, together with the Company's revenue requirement for 2010, determine the amount of rate relief FPL was requesting in its petition.

FPL's forecast was prepared in late 2008 and used historical monthly data from 1990 through October 2008 for its customer forecast, and historical monthly data from 1998 through October 2008 for its NEL per customer forecast. FPL's customer forecast relied upon the University of Florida's October 2008 population projections. FPL's economic assumptions used in its NEL model were based upon economic forecasts formulated in the latter half of 2008 from Global Insight, Economy.com and other sources. In light of the current economic conditions, we have concern over the use of historic data to guide us in this current economy and believe adjustments are necessary.

In an attempt to reflect current economic conditions not captured in the historic data, FPL made several adjustments to the output of its NEL per customer econometric model. First, FPL adjusted for the impact of two wholesale contracts. Second, FPL reduced its NEL forecast to capture the influence of changes in the appliance stock and new energy efficiency standards. Third, after adjusting the NEL forecast for these two effects, FPL made a "re-anchoring" adjustment to the output of its NEL model so that the output of the model equaled the latest available actual 2008 level of sales. Fourth, FPL adjusted its NEL per customer forecast to capture the impact of the recent escalation in the number of homes left vacant due to the housing crisis. Many of these vacant homes were still active accounts although they consumed only a small amount of electricity. Because FPL believed that the impact of these vacant homes was not fully reflected in the historical data used to estimate the econometric models, FPL adjusted downwards its NEL per customer forecasts to reflect the presence of these "minimal use customers" during 2009, 2010, and 2011. As a result, FPL projected the number of customers to increase by 0.2 percent in 2009, and increase by 0.6 percent in 2010. FPL projects NEL per customer to decrease by 1.7 percent in 2009, and increase by 0.1 percent in 2010.

We agree with the first two adjustments made by FPL. However, as to the third and fourth adjustments suggested by FPL, we disagree. While FPL's third and fourth suggested adjustments were made to reflect the impact of changing economic times, we believe that OPC witness's Brown's methodology more appropriately incorporates this uncertainty into the load forecast.

With respect to FPL's third suggested adjustment, the "re-anchoring" adjustment, we agree that such an adjustment is appropriate. However, since the increase in the number of "minimal use customers" began prior to 2008, we agree with OPC witness Brown that it is appropriate to apply the "minimal use customer" adjustment to the 2008 output of FPL's NEL model prior to making the "re-anchoring" adjustment.

With respect to FPL's adjustment for "minimal use customers," we find that the measurement of the percentage of customers who normally use a minimal amount of electricity should be based upon data spanning a longer period, such as from September 2002 through December 2007, instead of the shorter time period of August 2003 through December 2004 used by FPL. The use of the longer time period results in increasing the percentage of normally occurring "minimal use customers" from FPL's suggested 7.0 percent to 7.42 percent.

Based on the foregoing, we adopt FPL's load forecast and its first and second adjustments made to account for the impact of two wholesale contracts and to capture the influence of changes in the appliance stock and new energy efficiency standards. We also adjust FPL's load forecast for minimal use customers to reflect a 7.42 percent historical average and find that it is appropriate to perform the "minimal use customer" adjustment to the 2008 output of FPL's NEL model before performing the "re-anchoring" adjustment. As a result of the forecasts and adjustments, in 2010, FPL's revised net energy for load is 111,299,656,865 kWh. This adjustment to FPL's load forecast increases test year revenues by $36,969,000.

2011 PROPOSED SUBSEQUENT YEAR TEST PERIOD

Legal authority to approve base rate increase

FPL petitioned for a $247 million increase in revenue requirements beginning in 2011 in addition to its petitioned for 2010 revenue increase. The 2011 requested increase was based upon a 2011 subsequent test year. As a preliminary matter, the parties asked us to determine whether we have the legal authority to approve a 2011 subsequent year increase such as that asked for by FPL. The parties next asked us to address whether we should, from a policy perspective and from a factual perspective, approve a 2011 subsequent year adjustment.

Our legal ability to use a subsequent year adjustment has previously been confirmed by the Legislature, by the Florida Supreme Court, and by us. In 1983, the Legislature enacted the following amendment to Chapter 366, F.S.:

> The commission may adopt rules for the determination of rates in full revenue requirement proceedings which rules provide for adjustments of rates based on revenues and costs during the period new rates are to be in effect and for incremental adjustments in rates for subsequent periods.

Section 366.076(2), F.S. In 1987, we adopted Rule 25-6.0425, F.A.C., allowing us in a full revenue requirements proceeding to approve incremental adjustments for periods subsequent to the initial period in which new rates will be in effect.

The Florida Supreme Court, in the case of Floridians United, held that even without the authority of Section 366.076, F.S., we had the authority to approve subsequent year adjustments. The Floridians United case was an appeal from our prior order granting FPL a 1984 rate increase and a subsequent year adjustment for 1985. While the appellants challenged the constitutionality of the statute (Section 366.076, F.S.) that we relied upon as authority to grant the subsequent year adjustment, the Court never reached that issue. Rather, the Supreme Court agreed that we had authority to grant subsequent year adjustments even prior to the legislative enactment of Section 366.076(2), F.S:

> We agree that PSC's authority to grant subsequent year adjustments predated the enactment of chapter 83-222 and it is therefore unnecessary to address the constitutionality of the chapter. [citations omitted]

Id.

We have used subsequent year adjustments in prior proceedings. In addition to the 1985 subsequent year adjustment for FPL considered in Floridians United, we approved a request by Tampa Electric Company for a projected test year of 1993 and a subsequent test year of 1994. In that docket, we stated that we had authority to do so and that the facts supported our approval of the 1994 subsequent year adjustment for TECO. See Order No. PSC-93-0165-FOF-EI, issued February 2, 1993, in Docket No. 920324-EI, In re: Application for a rate increase by Tampa Electric Company.

Based on the foregoing, we determine that we have the legal authority to grant a subsequent year adjustment if the facts warrant such an adjustment. We next address whether FPL has supported its petition for a 2011 subsequent year adjustment.

Policy decision for subsequent year adjustment

OPC asserted that it did not object to the concept of a subsequent test year on legal grounds per se. Rather, OPC disputed the validity of the application of a subsequent test year to this particular docket. Although each of the intervenors objected to our ability to make a subsequent year adjustment, the basis of their objections appeared to be that from a policy and a factual standpoint, FPL did not prove that a 2011 subsequent year adjustment was appropriate. Having acknowledged that we have the legal authority to grant FPL's request for a 2011 subsequent year adjustment, we next examine whether granting FPL's request is appropriate from a policy perspective.

We believe that back-to-back rate increases should be allowed only in extraordinary circumstances. Historically, we have used the test year concept for setting rates. Under this concept, the test year is deemed to be representative of the future, and used to set rates that will allow the utility the opportunity to earn a rate of return within an allowed range. If the test year is truly representative of the future, then the utility should earn a return within the allowed range for at least the first 12 months of new rates.

FPL witness Olivera explained that the Company was requesting a subsequent year increase in base rates effective January 1, 2011, to address the deterioration in earnings that will take place during 2010. According to witness Olivera, the subsequent year adjustment allows us, as well as the Company, and all parties to address in a single proceeding both the 2010 and 2011 needs, avoiding the time and expense of a separate rate proceeding for 2011. FPL witness Barrett testified that:

> Given the significant time and financial resource commitments involved in fully litigated base rate proceedings, the Commission, the Company, and other stakeholders would benefit by minimizing the frequency of these costly proceedings. One mechanism by which the Commission can address this issue is through the use of a Subsequent Year Adjustment for 2011, the year following the Test Year.

According to SFHHA witness Kollen, there is no evidence that there will be actual savings to ratepayers resulting from the avoidance of a separate proceeding sometime in 2010 for rates that will be effective in 2011. If the Company's 2011 test year costs are reduced as the result of the Company's cost cutting efforts compared to its projections for 2011, then the cost of a separate proceeding in 2010 is likely to pale against the effect of such savings in a subsequent proceeding.

We agree with SFHHA that there is no evidence that ratepayers would receive any savings by avoiding a separate rate proceeding sometime in 2010 for rates that would be effective in 2011. FPL witness Barrett admitted that FPL did not perform a cost-benefit analysis to examine whether the costs of a rate case outweighed savings that could result from re-examining changing costs.

The subsequent increase requested in this case is based on a second projected test year of 2011 and is in fact a second full rate case filing. FPL claims that this second case is necessary "to address the deterioration in earnings that will take place during 2010." However, it is important to note here that filing two general rate cases with back-to-back projected test years deprives us and deprives the Company's ratepayers of the benefit of an additional twelve months of actual economic data and operating history of the Company. This additional data could be used to validate whether an additional increase is truly necessary and whether the second test year is really representative of the future.

The Company's ratepayers deserve a full investigation into the cause of FPL's claimed deterioration of its earnings. Two general rate increases that are barely twelve months apart justify the time and expense of a second separate proceeding. Two back-to-back general rate increases are especially of concern when one considers that the need for base rate increases has already been reduced for FPL due to the effect of the cost recovery clauses. Cost recovery clauses provide for approximately 61 percent of FPL's revenue and reduce the risk of under-recovery of a substantial portion of FPL's operating costs. The recovery of costs through the clauses should limit the need and frequency of full rate cases for FPL.

States that make use of a projected test year, like Florida, typically only attempt to look one year into the future. FPL is asking us to look far beyond the horizon, into 2011, and raise consumers' rates not only in 2010 based on a 2010 projected test year, but to raise consumers rates again in 2011 based on speculative and untested projections for a 2011 subsequent projected test year. These test years were developed in 2008. As one reaches farther into the future, predictions and projections of future economic conditions become less certain and more subject to the vagaries of changing variables. This is particularly true given that for 2010, FPL projected results based upon the assumption of a "down economy," and for 2011 projected results based upon a "down economy just beginning to recover."

Because of unpredictable changes in the economy, it is certainly possible that FPL's perceived need for a 2011 base rate increase could be offset by changes in sales growth, billing determinants, additional Stimulus Bill of the American Recovery and Reinvestment Act of 2009 (Stimulus Bill) benefits, and other cost-decreasing measures. At a time when Florida's ratepayers have been hit hard by the downturn in the economy, it makes sense to wait and see if a subsequent rate case is justified. FPL's claim that it will need a rate increase in 2011 simply is too speculative, and is hereby rejected.

<u>Factual support for 2011 subsequent year adjustment</u>

We realize that our decision on the policy of whether a subsequent year adjustment is appropriate incorporates many of the facts from the case. However, we think it important to address in more detail the appropriateness of the 2011 test year and whether the facts in this docket support the use of a 2011 subsequent year adjustment. FPL witness Barrett explained that the Company provided forecasted information for 2009, 2010, and 2011 for use in this proceeding. The Company included 2011 year data in support of its requested Subsequent Year Adjustment. According to witness Barrett, FPL applied the same rigor to its forecast of 2011 as it did for 2009 and 2010, to be confident that the costs proposed were appropriate for setting rates in this proceeding.

FPL witness Barrett stated that final approvals for these forecasts were made in late 2008 and reflected the Company's best assessment of the business environment. Discussing the prevailing business environment at the time the forecasts were being finalized, witness Barrett testified that "All of these factors have combined to plunge Florida into an economic deterioration not seen since the early 1970s. [. . .] Every major assumption used in the forecast reflects the severe economic downturn."

We are concerned with the reliability of the forecasted data used to develop the 2011 test year and subsequent rate increase. FPL has stretched its forecasts far into the future during a period when "every major assumption used in the forecast reflects the effects of the most severe economic downturn since the early 1970's." OPC witness Brown testified that "[t]he farther into the future that a utility attempts to project data, there is a greater amount of uncertainty and the data becomes less reliable." Witness Brown further noted that "This is particularly of concern as our country and the customers in FPL's service territory are facing the current economic crisis. Projections of when and how economic recovery will occur are extremely speculative."

The forecasted 2011 test year was prepared in late 2008, when the economic environment was extremely volatile. The last month of the 2011 test year was at least 36 months away from the last actual historical data point when the forecast was prepared. Even in times of economic stability, projections this far in the future strain the reliability and accuracy of data that is needed to set rates.

SFHHA witness Kollen testifed that the record was insufficient for us to determine what the reasonable revenues and costs would be in 2011, given the present economic uncertainty:

> First, the Commission cannot determine at this time what the reasonable revenues and costs will be in 2011 given the present economic uncertainty. It will be difficult enough to determine the reasonable level of revenues and costs for the 2010 test year, which itself is two years removed from actual experience and is based on a budgeting process covering 2009 and 2010, but which began in mid-2008 prior to the meltdown in the financial markets and the recession. Since 2008, the Company has engaged in extensive cost reductions compared to its 2009 budget, thus rendering the 2009 budget unreliable as the basis for the 2010 test year forecast, and even more so for the 2011 subsequent test year forecast.

In the first four months of 2009, the Company experienced a $38 million budget variance in O&M expenses and a $169 million budget variance in capital projects. Both of these variances were favorable and were explained by FPL witness Barrett. However, variances of this magnitude, in the very beginning of a forecast, when projections should be the most accurate, show how unpredicted events and management's reactions to the actual business conditions can make projections inaccurate. The further those projections go into the future, the less predictable the underlying assumptions become.

Forecast of customers

Above, we addressed FPL's overall projections for 2011 and stated our concern for their accuracy. We now address the appropriateness of FPL's 2011 forecast of customers, kWh, and kW which were sponsored by FPL witnesses Rosemary Morley and Philip Q. Hanser.

FPL used the same methodology for its 2011 forecast by revenue and rate classes, as it did for its 2010 forecast. OPC witness Brown testified that, due to the uncertainty associated with the current economic downturn, economic projections of when an economic recovery will occur are extremely speculative. She also noted that if the economic recovery was either faster or greater than expected under FPL's assumptions, there would be a potential for excess earnings at ratepayers' expense. She concluded by saying that although OPC was willing to accept the uncertainty associated with a 2010 test year, the 2011 test year projections incorporate an unacceptable additional level of uncertainty and should be rejected.

We share OPC witness Brown's concern that economic projections formulated in late 2008 and extending through 2011 incorporate an unacceptable level of uncertainty for the purpose of setting rates. Hearing Exhibit 412 is illustrative of our concern. This exhibit showed the Low, Medium, and High Case scenarios for the University of Florida's population forecast used in FPL's customer growth model. As this exhibit showed, as the forecast horizon extended further into the future, the range between the Low and High Case scenarios became wider. We believe that this wider range is indicative of the University of Florida's acknowledgement that its forecast for population growth is subject to more variability as the forecast horizon extends further into the future. Furthermore, as acknowledged by FPL witness Morley under cross examination, the University of Florida revised its population forecast "with some frequency" during 2008. These revisions, which extended into 2009, added an additional degree of variability to the population projections as the forecast bands shifted either upward or downward. Because the population projection from the University of Florida was the primary driver in FPL's customer model, increased variability in the 2011 population projection led to increased variability in the number of customers in 2011. Because of the way FPL's models were structured, an increase in the variability of the number of customers in 2011 flowed through to total NEL, and ultimately to the number of customers and kWh sales by revenue class.

Because there was no empirical data (such as stabilized customer growth rates) in the record to indicate that the uncertainty associated with the current economic downturn was nearing an end, we are concerned that during the twelve months of 2010, additional economic volatility could cause the number of customers and kWh sales in 2011 to deviate significantly from FPL's projections.

In conclusion, while we recognize that we have the legal authority to grant a subsequent year adjustment when the facts so warrant, we decline to do so in the present case. FPL's 2011 subsequent test year and its forecasts of customers, kWh, and kW by revenue and rate classes for the 2011 projected test year are too speculative and are therefore not appropriate for rate setting purposes. The projection period is too far in the future and was developed in times of great economic instability to have confidence in the integrity of the data. Actual events in 2009 have already shown the potential for significant variance from the projections. In denying FPL's petition for a 2011 subsequent year adjustment, we recognize that if the Company is unable to earn within its allowed range of return, it has the option of filing for a base rate increase including a request for interim rate relief. Accordingly, we find that FPL's projected subsequent test year of 2011 is not appropriate and we deny FPL's request for a subsequent increase in January 2011 based on this record.

GENERATION BASE RATE ADJUSTMENT

For the reasons explained in detail below, we do not approve FPL's request for a Generation Base Rate Adjustment (GBRA) mechanism that would authorize FPL to increase base rates for revenue requirements associated with new generating additions approved under the Power Plant Siting Act at the time they enter commercial service. The existing ratemaking procedure provided by Florida Statutes and our rules provides for a more rigorous and thorough review of the costs and earnings associated with new generating units. Section 366.06(2), F.S., provides that when approved rates charged by a utility do not provide reasonable compensation for electrical service, the utility may request that we hold a public hearing and determine reasonable rates to be charged by the utility. Section 366.071, F.S., provides expedited approval of interim rates until issuance of a final order for a rate change. Rule 25-0243, F.A.C., establishes the minimum filing requirements for utilities in a rate case. These procedures have been sufficient in the past for FPL and other regulated utilities wishing to recover capital expenditures when a new generating facility begins commercial service. We find that the GBRA shall expire as scheduled when new rates are established as delineated in this Order.

GBRA Background

The GBRA was one of several elements of a negotiated settlement agreement between the parties that we approved in FPL's 2005 rate case, Order No. PSC-05-0902-S-EI, issued September 14, 2005, in Docket No. 050045-EI, In re: Petition for rate increase by Florida Power & Light Company (2005 Settlement Order). The GBRA permitted FPL to increase base rates to recover capital costs associated with new generation facilities as they entered commercial service. The stipulation specified the basis for the costs, as well as the return on equity and capital structure to be used in the calculation of the cost factor to be submitted for our approval using the Capacity Clause projection filing for any necessary true-up. Other elements of the settlement agreement prohibited FPL from petitioning for an increase in retail base rates during the term of the agreement, and established a revenue sharing arrangement between FPL's shareholders and customers. The conditions under which we approved the negotiated settlement agreement are far different from the proposal to establish the GBRA in this case.

Differences From the 2005 Stipulation

FPL's current request to permanently establish the GBRA differs markedly from the 2005 negotiated settlement agreement that we approved.[2] Acceptance of the GBRA provision of the settlement agreement was contingent upon several provisions, a result of the "give-and-take" in negotiating the agreement. First, the stipulation specified the term of the agreement as effective for a minimum of four years – January 1, 2006, through December 31, 2009 – and to remain in effect until new base rates and charges become effective by order of the Commission.[3] FPL's current request to continue the GBRA specifies no end date. Second, FPL's base rates could not change during the term of the settlement agreement; FPL's current request to continue the GBRA specifies no restriction on changes to base rates. Third, the negotiated agreement provided a

[2] Id.
[3] Ibid., Attachment A, page 3.

revenue sharing plan between shareholders and customers. FPL's current request to continue the GBRA specifies no such revenue sharing arrangement. To date, FPL has flowed $386,928,000 through the GBRA mechanism for three generating units as a result of the stipulated settlement.[4] If the GBRA is made permanent, the amount that FPL proposes to add to rate base under the GBRA mechanism is $3.2 billion over the next five years.[5]

FPL witness Ousdahl acknowledged that the GBRA is materially different from a rate case, because it is an interim base rate measure. We agree that the GBRA specified in the settlement agreement is an interim measure because it has an ending date, and costs would be rolled into base rates at the next rate case. The GBRA mechanism that FPL has asked us to approve in this docket would have no such limit. It has no ending date, and it is intended to cover the costs of all future power plants that receive need determination approval. As FPL witness Barrett acknowledged, the GBRA mechanism would allow FPL to recover such costs without regard to whether earnings were sufficient to cover the addition of a new plant.

Existing Ratemaking Policy and the Proposed GBRA

Parties are in agreement that rate cases are often costly and administratively burdensome. For example, the expenses associated with FPL's rate case in this docket were estimated at $4 – 5 million during the hearing. Comparatively, the cumulative total rate increase that FPL requested is approximately $1.5 billion. FPL's requested rate increase included new power plants, transmission and distribution projects, administrative costs, operation and maintenance expenses, and other expenses.

The record indicates that FPL built several generating units since 1985 without seeking a rate increase. FPL witness Barrett also acknowledged that if economic conditions or other factors changed, it was possible that FPL's base rates could be sufficient to cover the cost of a new generating unit in whole or in part without the application of a GBRA. Other factors, such as the addition of new customers and increased electricity sales tend to offset the additional costs of new power plants. FPL witness Barrett testified that under certain hypothetical circumstances, with a GBRA mechanism in place, customers' bills could go up as a result of adding new generation, though FPL's earnings would remain unaffected.

According to FPL, we should approve continuation of the GBRA because it is "reasonable, cost-based and sends the appropriate price signals to customers." While the term "cost-based" may accurately describe the GBRA, a rate case proceeding provides more of an opportunity to rigorously review costs and earnings as a whole. Regarding the price signals, we agree that implementation of the GBRA may link reductions in fuel costs to increases in base rates that may occur as a new plant is put in service. However, a traditional base rate proceeding could also be timed (based on the Company's request) to coincide with the in-service date of a new plant, thus achieving the same result. FPL witness Barrett testified that it is possible for the Company to structure the timing of a rate request associated with a new plant so that both the

[4] The jurisdictional revenue requirements $121,310,000 for Turkey Point 5, $138,519,000 for West County 1, and $127,099,000 for West County 2.
[5] Representing costs of FPL's West County Unit 3, Cape Canaveral, and Riviera Beach projects.

plant's costs and its fuel savings benefits are received by the customer at the same time. FPL witness Pimentel stated that "the reason that we're requesting the GBRA, first and foremost, is as we build generation that's been approved by this Commission in need determinations, we're trying to match the customer savings and fuel efficiency with the actual capital that we are putting into the business." This goal could be achieved within the process of a traditional rate case.

Another of FPL's arguments for the GBRA mechanism was that it has the potential to avoid the need for a rate case. It is not possible for us or interested parties to examine projected costs at the same level of detail during a need determination proceeding as we would be able to do in a traditional rate case proceeding. A need determination examines costs only in comparison to alternative sources of generation. It does not allow for a review of the full scope of costs and earnings, as a rate case does. FPL witness Barrett acknowledged that the GBRA mechanism would be a limited-scope proceeding focused only on the GBRA, and intervenors would not be able to raise other cost issues in such a proceeding. SFHHA witness Kollen also argued against the GBRA because FPL would have the ability to impose a base rate increase for new generation and transmission projects without consideration of other revenues and costs. OPC witness Brown explained that if the GBRA is approved and the economy subsequently recovers, FPL's shareholders may earn greater returns that could be sufficient to cover the cost of new generating units without increasing base rates. According to OPC, having a GBRA mechanism in place would mean FPL would have less incentive to control overall costs. Witness Brown also pointed out that under the GBRA, FPL would essentially be "imposing a surcharge on customers' bills to cover the costs associated with a single component of its overall costs of providing service," and we would not have the ability to evaluate whether FPL's existing base rates were sufficient to cover some or all of the costs.

The time period required for a traditional rate case proceeding differs from that required for need determination proceedings that the GBRA mechanism would utilize. Rate cases generally take at least eight months to complete and include five months devoted to discovery prior to hearing, in accordance with Section 366.06, F.S. Need determination proceedings are required to be completed within 135 days from the date a petition is filed per Section 403.519 (4), F.S. Witness Barrett stated that the GBRA mechanism protects customers "in the event that we're able to bring in a unit less than the costs that were estimated for that unit and approved through the need process, so there would be an automatic true-up for customers." Witness Barrett also acknowledged, however, that a rate case serves as the ultimate true-up, and a rate case is generally beneficial for regulators and customers.

Witness Ousdahl agreed with the statement that "One of the benefits of a base rate proceeding from a consumer's perspective is that a base rate proceeding would examine a utility's entire cost of service to determine whether reductions in rate base may offset capital additions." Witness Ousdahl also agreed that as part of a base rate proceeding we have the opportunity to examine whether a utility's accumulated depreciation or increases in a utility's billing determinants would result in a decrease in its rate base. One criticism that SFHHA witness Kollen had of the GBRA mechanism is that "it provides the Company an almost unfettered ability to automatically impose base rate increases to recover selective increases in certain costs without consideration of increases in revenues and reductions in all other costs."

Witness Kollen was also concerned that the GBRA mechanism that FPL asked us to approve was not clearly defined. Witness Kollen pointed out that "the GBRA mechanism is not even a proposed tariff even though it is self-implementing. There is no proposed tariff to review. There is not even a detailed description of the mechanism and the revenue requirement computations in the testimony of any FPL witness." FPL is currently building several new power plants, West County 3, Riviera Beach, and Cape Canaveral. Witness Deaton acknowledged that between 2010 and 2015, FPL will be adding $3.255 billion in capital costs to rate base for these power plants if we approve the GBRA. This suggests that in the absence of the GBRA, FPL may file a rate case in 2013 for the next new plant.

The record shows that FPL already collects about 61 percent of its total revenues through various "pass-through" mechanisms and cost recovery clauses. We are not convinced that adding another such mechanism, by permanently implementing a GBRA for FPL, would provide advantages over traditional rate case procedures found in Section 366.06, F.S. We find no justification in the record for approving a cost-recovery mechanism for FPL's new generation that is different from what applies to all other investor-owned electric utilities. Approving a GBRA for FPL on a permanent basis would constitute a significant change in our general ratemaking policies. As we said in Order No. PSC-09-0283-FOF-EI: "[a]cceptance of a settlement among parties is not the same as establishing a generic policy." [6] FPL witness Ousdahl stated: "We are asking the Commission to formalize its policy with regard to GBRA." We are not inclined to formalize our policy with regard to GBRA in the manner FPL requested. There is no record evidence, beyond FPL's suggestion, supporting adoption of a GBRA-like procedure for other utilities. We do not want to set such a precedent here.

We deny FPL's request to continue the GBRA mechanism. It is not possible for us to exercise as adequate a level of economic oversight within the context of a GBRA mechanism as we can exercise within the context of a traditional rate case proceeding. Furthermore, a policy change of this magnitude, which would ultimately affect other utilities, deserves a more thorough review through a separate generic proceeding.

JURISDICTIONAL SEPARATION

FPL's witness Ender testified that the Company's 2010 transmission service revenues were allocated as credits to offset retail jurisdictional revenues consistent with our order in FPL's last fully litigated rate case, but witness Ender did note that, historically, we have required utilities to separate, not credit back, any costs and revenues associated with firm wholesale transmission sales that last over one year in duration.

According to OPC's witness Brown, FPL created a revenue credit methodology that charged the retail jurisdiction with all costs of transmission, and provided an offsetting revenue

[6] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company, p. 126.

credit for transmission revenues received from non-retail jurisdictional customers. Witness Brown contended that while FPL's approach might be appropriate for non-firm or short-term transmission services, revenue crediting for long term contracts could create a subsidy for long-term firm transmission service customers. To remove the effect of this revenue credit method, witness Brown stated that FPL would need to reduce its requested jurisdictional revenue requirements by $18.5 million in 2010.

In his rebuttal testimony, witness Ender indicated that FPL did not oppose OPC's method of addressing transmission related costs and revenues for long-term firm non-jurisdictional transmission service contracts, but the actual revenue amount that should be separated was approximately $23.0 million. OPC agreed with the adjusted amount.

We agree with OPC's position on this matter. Separating all revenues and costs associated with forecasted long-term firm non-jurisdictional transmission service contracts ensures that jurisdictional customers will not subsidize non-jurisdictional transactions. We also agree that the information concerning the costs and revenues associated with these sales is more accurately presented, based on forecasted transactions for 2010, by FPL.

Based on the above, we find that all costs and revenues associated with long-term firm non-jurisdictional transmission service contracts shall be separated. We make the following jurisdictional adjustments to remove the effects of the revenue crediting method employed by FPL: reduce plant in service by $386,896,000; reduce accumulated depreciation by $144,299,000; reduce plant held for future use by $4,200,000; reduce construction work in progress by $18,623,000; increase working capital by $3,700,000; decrease operating revenues by $33,639,000; decrease O&M expenses by $10,462,000; decrease depreciation and amortization by $10,352,000; decrease taxes other than income by $4,918,000 and increase amortization of regulatory asset by $17,000. We also find that FPL appropriately separated all other costs and revenues between the wholesale and retail jurisdictions.

QUALITY OF SERVICE

FPL provides electric service to about 4.4 million customers. FPL's service territory covers 28,000 square miles, uses 67,000 miles of electrical conductor consisting of 42,000 miles of overhead wires and about 25,000 miles of underground cable, 1.1 million poles, and approximately 800,000 transformers. The distribution business unit is divided into five regions (North, East, West, Broward, and Miami-Dade), which are further divided into seventeen management areas with 35 service centers.

The quality and reliability of the electric service provided by a utility is objectively measured through the use of electric industry reliability indices and the number and types of customer complaints. We have established specific reporting requirements and reliability indices in Rule 25-6.0455, F.A.C., which are used to analyze the quality and reliability of an electric utility's distribution system. The reliability indices track the duration and frequency of power interruptions and are typically examined at a system level. The System Average Interruption Duration Index (SAIDI), the System Average Interruption Frequency Index (SAIFI), and the Customer Average Interruption Duration Index (CAIDI) are the most common indices. In effect,

EXHIBIT NO. 718

DOCKET NO: 120015-EI

WITNESS: Lane Kollen

PARTY: Signatories

DESCRIPTION: SFHHA Petition to Intervene & Order Granting Intervention

DOCUMENTS:

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 718
PARTY OPC, Lane Kollen; SFHHA Petition to Intervene
DESCRIPTION & Order Granting Intervention

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company	§ § § §	**Docket No.: 120015-EI** **Filed: March 9, 2012**

PETITION TO INTERVENE OF SOUTH FLORIDA HOSPITAL AND HEALTHCARE ASSOCIATION

The South Florida Hospital and Healthcare Association ("SFHHA"), pursuant to Chapter 120, Florida Statutes, and Rules 25-22.039, 28-106.201 and 28-106.205 of the Florida Administrative Code, hereby petitions the Florida Public Service Commission ("Commission") to intervene in the captioned docket regarding the rates and charges proposed to be charged by Florida Power & Light Company ("FPL"). FPL is a public utility that is subject to the Commission's jurisdiction over the rates and service of public utilities in Florida.

In support of their Petition to Intervene, SFHHA states as follows:

1. The name and address of SFHHA is:

   South Florida Hospital and Healthcare Association
   6030 Hollywood Blvd
   Suite 140
   Hollywood, Florida 33024
   Phone: (954) 964-1660
   Fax: (954) 962-1260

2. All pleadings, orders and correspondence should be directed to Petitioners' representatives as follows:

Kenneth L. Wiseman
Mark F. Sundback
Lisa M. Purdy
William M. Rappolt
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3. The agency affected by this Petition to Intervene is:

Florida Public Service Commission
2540 Shumard Oak Blvd
Tallahassee, Florida 32399-0850

4. SFHHA is a regional healthcare provider association acting as an advocate, facilitator and educator for its members, and a voice for improving the health status of its community. Particularly, SFHHA advocates the interests, and encourages involvement, of its member organizations in communications with the public, to elected and government officials, and to the business community and engages in cost-effective projects and programs that benefit, or add value to the services offered by, its member organizations.

5. The individual healthcare institutions that are members of SFHHA are engaged in providing, *inter alia*, acute healthcare services. They receive electric power from and pay the rates of FPL. The healthcare institutions, because of the services they render, their

load profile, and their concern with reliable, consistent levels of service, have important concerns regarding FPL's services and rates.

6. **SFHHA Standing:** Under Florida law, to establish standing as an association representing its members' substantial interests, an association such as SFHHA must demonstrate three things:

a. that a substantial number of its members, although not necessarily a majority, are substantially affected by the agency's decisions;

b. that the intervention by the association is within the association's general scope of interest and activity; and

c. that the relief requested is of a type appropriate for an association to obtain on behalf of its members.[1]

7. SFHHA satisfies all of these "associational standing" requirements. First, substantially all of SFHHA's members are located in FPL's service area and receive their electric service from FPL, for which they are charged FPL's applicable service rates. As such, they will be substantially affected by the Commission's determination of FPL's rates. Second, SFHHA exists, as previously noted, to act as an advocate, facilitator and educator for its members and advocates the interests of its member organizations to elected and government officials, such as the Commission. SFHHA was, in fact, an intervenor in FPL's two prior general rate cases and a signatory to the 2010 and 2005 settlements that resolved the issues in each docket, respectively. Therefore, intervention is within the association's general scope of interest and activity. Third, the relief

[1] Florida Home Builders Ass'n v. Dep't of Labor and Employment Security, 412 So. 2d 351, 353-54 (Fla. 1982).

requested -- intervention, and with it, the right to seek the lowest rates consistent with the Commission's governing law and policy -- is across-the-board relief that will apply to all of SFHHA's members in the same manner, according to the rate schedules under which they receive service. Therefore, the requested relief is of a type appropriate for an association to obtain on behalf of its members. As demonstrated, SFHHA has established standing as an association representing its members' substantial interests.

8. **Statement of Substantial Interests Affected:** This docket was initiated by a letter dated January 17, 2012 from FPL informing the Commission of FPL's intent to file a petition this spring for authority to increase its base rates effective on the first billing cycle day of January 2013. FPL's letter also indicated that FPL will request a subsequent based rate step adjustment to be effective when the Cape Canaveral power plant becomes operational in June 2013.

9. The proceeding in this docket thus will examine the rates that FPL will be authorized to charge to its customers. The Commission will necessarily have to decide whether any rate increases or decreases are justified, and if so, the Commission also will have to approve rates and charges in order to implement such increases or decreases. Thus, the disposition of this case will affect the rates charged by FPL, as well as the terms and conditions of service, impacting FPL's customers, including SFHHA's members that are connected to FPL's facilities. SFHHA's members require reliable, consistent and reasonably-priced electricity. Because SFHHA and its members will be directly and substantially affected by any action the Commission takes in FPL's current

docket, SFHHA has a substantial interest in the proceeding that is not adequately represented by other parties to this proceeding.[2]

10. For a potential intervenor to demonstrate that its substantial interests will be affected by a proceeding, the potential intervenor must show: (a) it will suffer injury in fact as a result of the agency action contemplated in the proceeding that is of sufficient immediacy to entitle it to a hearing; and (b) the injury suffered is a type against which the proceeding is designed to protect.[3] SFHHA satisfies these provisions. SFHHA seeks to protect its members' substantial interests as they will be affected by the Commission's decision in this case, and they face immediate injury if the Commission were to approve FPL's proposed rates, which are not just and reasonable and would be unduly discriminatory. SFHHA's participation in this rate case is designed to protect against that injury. If granted leave to intervene, SFHHA will be able to attempt to protect its members' substantial interests, including the ability to receive reliable and consistent electricity at fair, just and reasonable rates.

11. **Disputed Issues of Material Fact:** Disputed issues of material fact in this proceeding may include, but will not necessarily be limited to, the issues listed below. The following statement of issues is general in nature and SFHHA reserves the right to identify and develop additional issues and refine those listed below as this docket progresses in accordance with the Commission's rules. SFHHA expects that, as in past rate cases, numerous additional, specific issues will be identified and developed as this docket progresses.

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2 Insofar as this is a petition for intervention and because there is presently no agency decision pending in this docket, SFHHA states that Rule 28-106.201(c) of the Florida Administrative Code is not applicable.

3 See Ameristeel Corp. v. Clark, 691 So. 2d 473, 477 (Fla. 1997).

Issue 1: Determining appropriate jurisdictional levels of FPL's Plant in Service, Accumulated Depreciation, and Rate Base for setting FPL's rates.

Issue 2: Determining appropriate jurisdictional values of FPL's operation and maintenance expenses for setting FPL's rates.

Issue 3: Determining whether FPL's expenditures sought to be included in the derivation of the cost of service were prudently incurred.

Issue 4: Determining the appropriate capital structure for FPL for the purpose of setting FPL's rates.

Issue 5: Determining the appropriate rate of return on equity for FPL for the purpose of setting FPL's rates.

Issue 6: Determining the appropriate allocation of FPL's costs of providing retail electric service among FPL's retail customer classes

Issue 7: Determining the appropriate rates to be charged by FPL for its services to each customer class.

Issue 8: Determining the appropriate amount to be included in FPL's base rates for storm restoration accrual.

Issue 9: Designing rates for recovery of revenue requirements.

Issue 10: Determining the propriety of FPL's proposed projected twelve-month period ending December 31, 2013 as the test year for the permanent rate increase.

Issue 11: Determining the propriety of FPL's proposed base rate step adjustment based on the in-service date of its new Cape Canaveral plant.

12. **Ultimate Facts Alleged:** Because SFHHA and the institutions supporting this filing have substantial interests that are subject to determination in this docket, SFHHA is entitled to intervene and participate in the proceeding which will determine the fair, just, and reasonable rates to be charged by FPL upon the expiration of 2010 settlement rates on the last billing cycle day of December 2012.

13. **Specific Statutes and Rules**: The applicable statutes and rules, include, but are not limited to:

- Chapters 120 and 366 of the Florida Statutes
- Florida Administrative Code Chapters 25-22 and 28-106

14. **Relation of Alleged Facts to the Statutes and Rules**: Chapter 120 of the Florida Statutes relates to agency decisions which affect the substantial interests of a participant and related procedures.[4] Chapter 366 of the Florida Statutes declares the Commission's jurisdiction over FPL's rates and provides the Commission the statutory mandate to ensure that FPL's rates are fair, just and reasonable, and that those rates are not unduly discriminatory. The facts alleged here demonstrate that: (1) the Commission's decisions herein will have a significant impact on FPL's rates and charges; (2) FPL's customers represented by SFHHA will be directly impacted by the Commission's decisions regarding FPL's rates and charges herein; and (3) accordingly, that the statutes herein, among others, provide the basis for the relief requested by SFHHA.

15. Rules 25-22.039 and 28-106.205 provide that persons whose substantial interests are subject to determination or will be affected through an agency proceeding are entitled to, and may petition for, leave to intervene. Both rules also state that the petition to intervene must conform with subsection 28-106.201(2) of the Florida Administrative Code. Because SFHHA's members are FPL electricity customers, they have a substantial interest in the rates determined by the Commission and will be affected by the Commission's decisions in this docket. Accordingly, as the representative association of its members who are FPL customers, SFHHA, is entitled to intervene.

4 See Sections 120.569 and 120.57(1), Florida Statutes.

16. **Conclusion:** Consistent with the purposes of the SFHHA and the substantial interests of its members, SFHHA seeks to intervene in this general rate case docket. Because SFHHA has satisfied the elements necessary for standing as an association and because SFHHA's members have a substantial interest in FPL's proposed rates and charges which will be affected by the proceeding, the Commission should allow the intervention of SFHHA, as prayed herein.

17. **Relief Requested:** WHEREFORE, SFHHA respectfully requests that the Commission grant this Petition to Intervene. SFHHA also respectfully requests that the Commission require that all parties to this proceeding serve copies of all pleadings, notices, and other documents on the SFHHA representatives indicated in paragraph 2 above.

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Attorneys for the South Florida Hospital and Healthcare Association

March 12, 2012

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been served by electronic mail, U.S. Mail, or Federal Express, this 12th day of March, 2012, to the following:

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/s/ George E. Humphrey
George E. Humphrey

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for increase in rates by Florida Power & Light Company.	DOCKET NO. 120015-EI ORDER NO. PSC-12-0137-PCO-EI ISSUED: March 23, 2012

ORDER GRANTING PETITION TO INTERVENE

On January 17, 2012, Florida Power & Light Company (FPL) filed a test year letter, as required by Rule 25-6.140, Florida Administrative Code (F.A.C.), notifying this Commission of its intent to file a petition in the Spring of 2012 for an increase in rates effective January, 2013. Pursuant to the provisions of Chapter 366, Florida Statutes (F.S.), and Rules 25-6.0425 and 25-6.043, F.A.C., FPL filed the petition for an increase in rates on March 19, 2012.

Petition for Intervention

By petition dated March 12, 2012, the South Florida Hospital and Healthcare Association (SFHHA) requested permission to intervene in this proceeding. SFHHA states that it is a regional healthcare provider association which advocates, facilitates, and educates its members, and seeks to improve the health status of its community. SFHHA states that its members are individual healthcare institutions which are FPL customers. SFHHA contends that its members have important concerns regarding FPL's services and rates due to the nature of the services they render and their concern with reliable, consistent levels of service. No party has filed an objection to SFHHA's Petition, and the time for doing so has expired.

Standards for Intervention

Pursuant to Rule 25-22.039, F.A.C., persons, other than the original parties to a pending proceeding, who have a substantial interest in the proceeding, and who desire to become parties may petition for leave to intervene. Petitions for leave to intervene must be filed at least five (5) days before the final hearing, conform with Rule 28-106.201(2), F.A.C., and include allegations sufficient to demonstrate that the intervenor is entitled to participate in the proceeding as a matter of constitutional or statutory right or pursuant to Commission rule, or that the substantial interests of the intervenor are subject to determination or will be affected through the proceeding. Intervenors take the case as they find it.

To have standing, the intervenor must meet the two-prong standing test set forth in Agrico Chemical Company v. Department of Environmental Regulation, 406 So. 2d 478, 482 (Fla. 2nd DCA 1981). The intervenor must show that (1) he will suffer injury in fact which is of sufficient immediacy to entitle him to a Section 120.57, F.S., hearing, and (2) this substantial injury is of a type or nature which the proceeding is designed to protect. The first aspect of the test deals with the degree of injury. The second deals with the nature of the injury. The "injury in fact" must be both real and immediate and not speculative or conjectural. International Jai-Alai Players Assn. v. Florida Pari-Mutuel Commission, 561 So. 2d 1224, 1225-26 (Fla. 3rd DCA

1990). See also, Village Park Mobile Home Assn., Inc. v. State Dept. of Business Regulation, 506 So. 2d 426, 434 (Fla. 1st DCA 1987), rev. den., 513 So. 2d 1063 (Fla. 1987) (speculation on the possible occurrence of injurious events is too remote).

Further, the test for associational standing was established in Florida Home Builders v. Dept. of Labor and Employment Security, 412 So. 2d 351 (Fla. 1982), and Farmworker Rights Organization, Inc. v. Dept. of Health and Rehabilitative Services, 417 So. 2d 753 (Fla. 1st DCA 1982), which is also based on the basic standing principles established in Agrico. Associational standing may be found where: (1) the association demonstrates that a substantial number of an association's members may be substantially affected by the Commission's decision in a docket; (2) the subject matter of the proceeding is within the association's general scope of interest and activity; and (3) the relief requested is of a type appropriate for the association to receive on behalf of its members.

Analysis & Ruling

It appears that SFHHA meets the two-prong standing test in Agrico as well as the three-prong associational standing test established in Florida Home Builders. SFHHA argues that the Commission's decision in this case will affect its members' substantial interests and that its members face immediate injury if the Commission approves FPL's proposed rates. SFHHA contends that its members are FPL ratepayers. SFHHA further asserts that this is the type of proceeding designed to protect its members' interests. Therefore, SFHHA's members meet the two-prong standing test of Agrico.

With respect to the first prong of the associational standing test, SFHHA asserts that all of its members are located in FPL's service area and receive electric service from FPL, for which they are charged FPL's applicable service rates. Accordingly, SFHHA states that its members will be substantially affected by this Commission's determination in this rate proceeding. With respect to the second prong of the associational standing test, the subject matter of the proceeding appears to be within SFHHA's general scope of interest and activity. SFHHA is a regional healthcare provider association which acts as an advocate on behalf of its member healthcare institutions. As for the third prong of the associational standing test, SFHHA seeks intervention in this docket to represent the interests of its members, as FPL customers, in seeking reliable service and the lowest rates possible. The relief requested by SFHHA is of a type appropriate for an association to obtain on behalf of its members.

Because SFHHA meets the two-prong standing test established in Agrico as well as the three-prong associational standing test established in Florida Home Builders, SFHHA's petition for intervention shall be granted. Pursuant to Rule 25-22.039, F.A.C., SFHHA takes the case as it finds it.

Based on the foregoing, it is

ORDERED by Commissioner Art Graham, as Prehearing Officer, that the Petition to Intervene filed by the South Florida Hospital and Healthcare Association (SFHHA) is hereby granted as set forth in the body of this Order. It is further

ORDERED that all parties to this proceeding shall furnish copies of all testimony, exhibits, pleadings and other documents which may hereinafter be filed in this proceeding to:

Kenneth L. Wiseman kwiseman@andrewskurth.com
Mark F. Sundback msundback@andrewskurth.com
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By ORDER of Commissioner Art Graham, as Prehearing Officer, this 23rd day of March, 2012.

ART GRAHAM
Commissioner and Prehearing Officer
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770
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Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

KY

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing.

Any party adversely affected by this order, which is preliminary, procedural or intermediate in nature, may request: (1) reconsideration within 10 days pursuant to Rule 25-22.0376, Florida Administrative Code; or (2) judicial review by the Florida Supreme Court, in the case of an electric, gas or telephone utility, or the First District Court of Appeal, in the case of a water or wastewater utility. A motion for reconsideration shall be filed with the Office of Commission Clerk, in the form prescribed by Rule 25-22.0376, Florida Administrative Code. Judicial review of a preliminary, procedural or intermediate ruling or order is available if review of the final action will not provide an adequate remedy. Such review may be requested from the appropriate court, as described above, pursuant to Rule 9.100, Florida Rules of Appellate Procedure.

Eric Fryson

From: Hayes, Annisha [AnnishaHayes@andrewskurth.com]
Sent: Monday, March 12, 2012 3:54 PM
To: Filings@psc.state.fl.us
Subject: 120015-EI Petition to Intervene of South Florida Hospital and Healthcare Association
Attachments: SFHHA Petition to Intervene.pdf

Electronic Filing

a. Person responsible for this electronic filing:
George Humphrey
Florida Reg. No. 0007943
Andrews Kurth LLP
600 Travis, Suite 4200
Houston, TX 77002-3090
713-220-4200 (phone)
713-220-4285 (fax)

b. Docket No. 120015-EI.

c. Document being filed on behalf of South Florida Hospital and Healthcare Association (SFHHA).

d. There is a total of 9 pages.

e. The document attached for electronic filing is Petition to Intervene of South Florida Hospital and Healthcare Association
(See attached SFHHA Petition to Intervene.pdf)

Thank you for your attention and cooperation to this request.

Regards.
Annisha Hayes
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Parties updated
3/12/12
- om

DOCUMENT NUMBER-DATE
01424 MAR 12
FPSC-COMMISSION CLERK

part of its contents to any other person. Thank you.

EXHIBIT NO. 719

DOCKET NO: **1200015-EI**

WITNESS: N/A

PARTY: N/A

DESCRIPTION: Sales by Rate Class

PROFFERED BY: FPL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 719
PARTY FPL; Sales by Rate Class
DESCRIPTION
DATE

FLORIDA POWER & LIGHT COMPANY
SALES BY RATE CLASS

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Rate Class	Signatories to Settlement[1]	Description	Size	Customer Types	Total Delivered Sales (MWH)	% of Total
1	CILC-1D	x	CI Load Control	Medium/Large CI >500 kW	Hospital, large grocery, large school, water/wastewater, large department stores	2,865,110	2.77%
2	CILC-1G	x	CI Load Control	Small CI 200-499 kW	Small manufacturing, large department stores, military, other, misc.	177,813	0.17%
3	CILC-1T	x	CI Load Control	Large CI Transmission >2000 kW	Manufacturing, military bases, other industrial	1,342,962	1.30%
4	GS(T)-1	x	General Service	Very Small Non-Demand < 21 kW	Small storefronts, pumps, billboards	5,851,293	5.66%
5	GSD(T)-1	x	General Service Demand	Small CI 21-499 kW	Small manufacturing, bank, small grocery, school, retailer	25,106,279	24.30%
6	GSLD(T)-1	x	General Service Large Demand	Medium/Large CI 500-1999 kW	Hospital, large grocery, large school, water/wastewater	11,323,170	10.96%
7	GSLD(T)-2	x	General Service Large Demand	Large CI >2000 kW	Manufacturing, large hospitals, large offices	2,453,405	2.37%
8	GSLD(T)-3	x	General Service Large Demand	Large CI Transmission >2000 kW	Industrial, military bases	199,704	0.19%
9	RS(T)-1		Residential			53,081,852	51.38%
10	Other					913,076	0.88%
11	**Total**					**103,314,664**	**100.00%**

[1] Classes under which the signatories to the Proposed Settlement Agreement take service total 48% of Total Delivered Sales

EXHIBIT NO. 720

DOCKET NO: 120015-EI

WITNESS: Moray Dewhurst

PARTY: FPL

DESCRIPTION: Reports Provided by FPL in Response to OPC's 14th Request for PODs No. 105.

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 720
PARTY OPC;witness Dewhurst, Reports provided
DESCRIPTION by FPL in Response to OPC's 14th Request
DATE for PODs, No. 105

2 October 2012

Company Note | Company Update

Utilities

ATLANTIC EQUITIES

NextEra Energy Inc

Rate case catalyst, reiterate overweight

Overweight

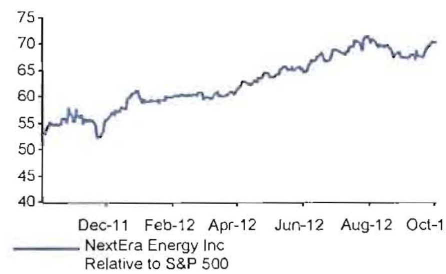
Price Target $76.00

We reiterate that NEE remains the best option in our coverage universe given 1) potential positive catalysts in the next several months, and 2) the valuation discount to other US Utilities despite having better than average fundamentals.

- **Resolution of its Florida rate case within the next six weeks could be a significant positive.** We continue to believe that regulatory risk is one of the main reasons why the shares trade at a discount to its peers given 1) the poor outcome in its prior rate case and 2) the significant (24%) rate base increase requested. So far, the rate case developments have been better than we expected and it is possible that this case could be resolved earlier with a better outcome than we originally expected.
- **Recovery in Florida housing could be a positive for the stock**. After years of languishing demand due to a difficult housing market, there appears to be a nascent up tick in the Florida real estate market. If customer growth returns to the 10 year historical average of adding over 100,000 customers per year vs ~25,000 this year, we estimate that NEE's long term EPS growth could rise by as much as 2% percentage points annually.
- **Share buybacks/dividend increases likely in next 12 months.** Given the likely slowdown in renewable spending as well as a reduced risk profile following the completion of the rate case, we continue to expect NEE's management will announce measures to return cash to shareholders in 2013. We calculate that the company has a potential of returning about $1.5bn (or 5%) annually by 2014.
- **Discount valuation is not warranted**. We do not believe that the company's current 5% 2013 PE discount to other regulated utilities will persist given 1) NEE probably has the best opportunity in the industry to increase its dividend growth rate and/or announce a share buy back given its industry leading free cash flow profile and below average payout ratio, 2) Current dividend growth of 10% annually ranks in industry top quintile, 3) EPS growth of 7% is about double industry growth of 3%, 4) Above average balance sheet (A- vs BBB+ avg debt rating), 5) Diminished regulatory risk following conclusion of rate case, and 6) Business risk is lower than average as regulated and long term contracted businesses represent ~85% of 2014e EBITDA, a higher than average proportion. Also expectations for its deregulated subsidiaries have been ratcheted down considerably.

Ticker (NYSE)	**NEE**
Price	**$70.15**
Market Capitalisation	**$29,656m**
12 Month Range	**$51.33 - $72.22**
YTD Change	**15.2%**
Annualised Dividend	**$2.40**
Dividend Yield	**3.42%**
S&P500 YTD Change	**14.9%**
S5UTIL YTD Change	**.6%**

Price Performance Chart



Y/E Dec	2011A	2012E	2013E
EPS ($)			
Q1	0.94	1.02	--
Q2	1.18	1.26	--
Q3	1.31	1.41E	--
Q4	0.93	0.96E	--
FY	**4.39**	**4.65E**	**5.10**
P/E (x)	**16.0**	**15.1**	**13.8**

[IMPORTANT DISCLOSURES ARE INCLUDED AT THE END OF THIS REPORT]

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OPC 305031
FPL RC-12

Rate case nearing resolution, potential catalyst

NextEra's regulated utility, FPL, is currently in a rate case and it is increasingly likely that the final outcome will be better than our base case. Based on statutory limitations and the potential for acceptance of a tentative settlement/stipulation, the rate case could be concluded by the middle of November. Whilst we expect that by the end of this week, we will have better clarity around the procedural schedule. The details of FPL's original filing, major tenets of an August settlement with large industrial and commercial customers, and outcome of its last rate case are on table 1 below.

Table 1: Highlights of FP&L rate case

	Present Case		Previous Case
	Requested by Company 3/19/2012	Stipulation 8/15/2012	Authorized by Commission 3/17/2010
Rate Change Amount ($)	690,372,000	378,000,000	75,470,948
Rate Change/ Revenue (%)	NA	NA	0.80
Rate Case Test Year End Date	12/31/2013	12/31/2013	12/31/2010
Rate Base ($)	21,858,148,000	NA	16,787,429,918
Rate Base Valuation Method	Average	NA	Average
Return on Equity (%)	11 50	10.70	10 00
Common Equity to Total Capital (%)	46 03	NA	47.00
Rate of Return (%)	7	NA	6 65

Source: SNL, NEE

Overall, it appears that FP&L is on track to receive approval to earn an average ROE of around 10.7%, which is about 70bp above our base case of 10.0%. In a supportive move, the Florida regulator ruled last week that the company's settlement stipulation/agreement with some large commercial and industrial customers would not be dismissed despite the objections of the Office of Public Council (OPC), the influential body that represents residential customers in the state, and Florida's Retail Federation. Whilst the Florida regulators have never approved a settlement without OPC's approval before, it does appear that regulators are pushing the remaining objectors to settle which is a positive.

A constructive resolution of this rate case will likely be viewed favourably by investors. Given how adverse the ruling was in FPL's last rate case, we believe that some investors remain nervous and as a result, the shares continue to trade at a discount (for more details on the last rate case, please refer to our report "*Downgrade to Underweight due to slowing growth in wind and rate case risk*" dated 22 October 2009). If the rate case is decided with a reasonable outcome which it is on course to be, then investors' perception of regulatory risk will likely diminish and NEE's valuation could benefit as a result.

Some reasons why we remain cautiously optimistic about this rate case:

1) This rate case is not in a gubernatorial election year for Florida and, so far, the amount of press is a fraction of what the prior rate case received. It also helps that the net total rate increase for the average customer is only about 2% which is considerably lower than the 30%+ increase in certain areas that Florida residents were facing in the last rate case.

2) New utility regulators – 4 of the 5 commissioners are new and so far have rendered relatively constructive rulings. For example, Southern Company's Gulf Power received about 67% of its revenue request and a 10.25% ROE in its rate case decided in February 2012. In addition, Duke Power's Florida Power utility has had a lot of support following a very serious delamination event at a nuclear plant. It appears that the newly comprised commission has been much fairer, focusing on the details and the application of existing law.

3) Expectations are low. Based on implied EPS estimates, it appears that the consensus ROE is for about 10%, in line with the past rate case. It does appear that the risk is low of FPL receiving an outcome worst than this which limits the downside risk.

OPC 305032
FPL RC-12

Valuation still attractive

Despite being the best performing utility in our coverage list by a significant amount over the past year (+22.3 percentage points of outperformance vs S&P 500 Utility index), NEE still is one of the best bargains in the group. As seen on table 2 below, NEE's 2013 PE is at a 5% discount to the average of a group of large cap low risk utilities. In fact, the stock has one of the lowest valuations of any utility.

Whilst our current price target of $76/share assumes the stock trades at parity to the group, there is reason to be even more optimistic considering

1) NEE probably has the best opportunity in the industry to increase its dividend growth rate and/or announce a share buy back given its industry leading free cash flow profile and below average payout ratio,

2) Current dividend growth of 10% annually ranks in industry top quintile,

3) EPS growth of 7% is about double industry growth of 3%,

4) Above average balance sheet (A- vs BBB+ avg debt rating),

5) Diminished regulatory risk following conclusion of rate case, and

6) Business risk is lower than average as regulated and long term contracted businesses represent ~85% of 2014e EBITDA, a higher than average proportion. Also expectations for its deregulated subsidiaries have been ratcheted down considerably.

Table 2: NEE & utility peer valuation table

Name	Tkr	Share Price 10/1	Div Payout 2012	Div Yld	PER '11A	'12E	'13E	'14E	S&P Sr. Uns Debt Rating
NextEra Energy Inc	NEE	70.73	53%	3.4%	16.2	15.6	14.3	13.7	A-
T&D									
CenterPoint Energy Inc	CNP	21.22	64%	3.6%	18.6	18.0	16.7	15.8	BBB+
Con Ed	ED	59.83	64%	4.0%	16.7	15.9	15.5	15.3	A-
Northeast Utilities	NU	38.54	60%	3.6%	16.5	16.8	15.2	14.4	A-
ITC Holdings Corp	ITC	75.46	38%	2.0%	22.7	18.9	15.5	13.7	BBB+
Avg T&D			60%	3.6%	17.6	16.7	15.7	15.0	
Regulated Utilities									
Alliant Energy Corp	LNT	43.43	61%	4.1%	15.4	14.7	13.9	13.4	BBB+
American Electric Power Co Inc	AEP	44.21	62%	4.2%	14.2	14.5	14.1	13.4	BBB
Ameren Corp	AEE	32.74	66%	4.9%	13.0	13.6	16.8	16.1	BBB-
CMS Energy Corp	CMS	23.60	62%	4.1%	16.2	15.3	14.4	13.6	BBB-
Dominion Resources Inc/VA	D	53.24	67%	4.0%	17.1	16.9	15.6	14.8	A-
Duke Energy Corp	DUK	65.01	72%	4.7%	15.3	15.2	14.7	14.0	BBB+
DTE Energy	DTE	59.98	65%	4.1%	16.5	15.7	15.0	14.2	BBB+
OGE Energy Corp	OGE	55.53	44%	2.8%	16.2	15.6	14.9	14.1	BBB+
PG&E Corp	PCG	42.55	57%	4.3%	12.0	13.4	14.2	12.6	BBB
Pinnacle West Capital Corp	PNW	52.97	61%	4.0%	18.2	15.5	14.9	14.5	BBB
NV Energy Inc	NVE	17.95	55%	3.8%	21.3	14.6	14.3	13.8	BB+
Southern Co.	SO	46.09	74%	4.3%	18.0	17.4	16.3	15.5	A
TECO Energy Inc	TE	17.71	62%	4.3%	13.6	14.5	14.2	13.5	BBB+
Wisconsin Energy Corp	WEC	37.63	52%	3.2%	17.7	16.3	15.7	15.0	A-
Xcel Energy Inc	XEL	27.63	61%	3.9%	15.9	15.6	14.6	14.0	A-
Regulated Utilities			61%	4.0%	16.2	15.4	15.0	14.2	
Total Utility Average (ex IPPs)		42.0	59%	4.0%	15.2	15.1	14.7	14.1	

Source: Bloomberg, Atlantic Equities

OPC 305033
FPL RC-12

NextEra Energy Inc

IMPORTANT DISCLOSURES

Recommendation History

Initiation at Neutral on 16 March 2009

Downgrade to Underweight from Neutral on 22 October 2009

Upgrade to Neutral on 24 March 2010

Upgrade to Overweight on 13 August 2011

Stocks under the analyst's coverage

CenterPoint [CNP], Dominion Resources [D], Duke Energy [DUK], Exelon [EXC], NextEra Energy [NEE], PSEG [PEG], Southern Company [SO], Spectra [SE], Wisconsin Energy [WEC]

Risks

Rising or falling electricity prices due to changes in commodity prices. NEE's earnings are influenced directly by the price of electricity and, indirectly, by natural gas prices. Every $1/mmbtu change in natural gas price equals little less than 1% of 2012 EPS.

Governmental subsidies for renewable energy (specifically Production and Investment Tax Credit). Without governmental subsidies (currently the production tax credit), it is often not economic to build a wind farm. If the federal government did not extend the production tax credit, NEE's capex budget for wind development would likely be below average. In the past decade the PTC has lapsed on three occasions. Each time, there was a significant drop in new wind capacity added that year (average drop of ~70%), which underlines the importance of government subsidies for renewable energy growth.

Regulatory risk - FP&L is currently in a rate case. A reduction in the allowed ROE or other negative developments would likely cause the stock to decline.

Consensus Estimates

Where used, consensus numbers have been sourced from Bloomberg.

ANALYST CERTIFICATION

Nathan Judge CFA, hereby certifies that the views expressed in this research report accurately reflects his/her personal views about the subject Security and Issuer as of the date of this report. He/She further certifies that no part of his/her compensation was, is, or will be directly, or indirectly, related to the specific recommendations or views contained in this research report.

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Investment opinions are based on a stock's total return potential:

"Overweight" stocks are the most attractive stocks under the analyst's coverage over the next 12 months.

"Underweight" stocks are deemed to be particularly unattractive stocks over the next 12 months.

"Neutral" stocks are those stocks which are neither classified as "Overweight" nor "Underweight".

Stocks covered are subject to continuous review. Updates will be provided whenever a change in recommendation is to be made or, at the discretion of the analyst, whenever there is news worthy of note. It is anticipated that a report for each company covered will be produced at least once per annum.

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OPC 305034
FPL RC-12

BARCLAYS

EQUITY RESEARCH | INSTANT INSIGHTS 16 August 2012

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NEE: Settlement Reached in Florida

Stock Rating/Industry View: Overweight / Neutral
Price Target: $75
Price (16-Aug-2012): $69.23
Potential Upside/Downside: 12%
Ticker: NEE

After the market close on Wednesday, NEE's FP&L utility announced a non-unanimous settlement in its electric rate case in Florida. If approved, the settlement would allow a $378 million rate increase, premised upon a 10.7% ROE. It would also allow a generation base rate adjustment rider similar to the one allowed in its 2005 rate case. On balance, we believe the settlement is fair to both ratepayers and shareholders, in that it allows for rate base growth at ROEs that may look very reasonable over the 4-year plan.

More specifically, the settlement calls for a 10.7% baseline ROE, with an allowance for FP&L to file a case if their earned returns fall below 9.70%, and for intervenors to require a filing if FP&L's earnings exceed 11.7%. The generation base rate adjustor allows for the Cape Canaveral, Riviera Beach, and Port Everglades plant modernizations to be placed into rates without subsequent rate filings. Those plants are scheduled to come on line in 2013, 2014, and 2016, respectively.

The settlement also allows FP&L to amortize its excess depreciation - as well as a piece of its fossil dismantlement costs - over the term of the agreement. In aggregate, that amount cannot exceed $400 million, and we believe will help to preserve earnings at a rate similar to FP&L's current design. In addition, the deal allows for future storm costs to be recovered on an interim basis beginning 60 days after the event, in an amount not to exceed $800 million in a calendar year (exceeding this amount would require an additional recovery filing). Finally, there is an off system sales sharing mechanism that will incent FPL to utilize its fleet, including the new efficient ones, in a way that minimizes customer bills while incenting management with some profit retention.

We would note that the Office of Public Counsel and Florida Retail Federation were not parties to the deal, suggesting some concern over rate design and ROE levels may be an issue when hearings convene on August 20. We do not expect it to be approved by FP&L's requested August 31 timeline given the unsigned parties and tight time period involved. Ultimately, we think the deal is constructive, and are hopeful that it - or something close to it - may be approved this fall.

BARCLAYS

EQUITY RESEARCH | INSTANT INSIGHTS 28 September 2012

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NEE: More Testimony Required to Support FP&L Settlement

Stock Rating/Industry View: Overweight / Neutral
Price Target: $75
Price (27-SEP-2012): $70.14
Potential Upside/Downside: 10%
Ticker: NEE

On Thursday, the Florida PSC held hearings on FP&L's non-unanimous settlement pertaining to its 2012 rate case. The settlement, which would grant FP&L a 10.7% ROE and allow rate increases for the Cape Canaveral, Riviera Beach, and Port Everglades power plants to be added to customer rates over the next 3 years without subsequent rate case filings, is being contested by the state's Office of Public Counsel, which is effectively the watchdog for residential customers in the state.

More specifically, the OPC is objecting to the 10.7% ROE in the settlement as being too high, and requested that the FPSC reject the settlement because there were new issues raised in the settlement - the generation base rate adjuster (GBRA), asset management/optimization process, reallocation of the fossil plant dismantlement reserve, and the timing of the next depreciation study chief among these topics - that have not been introduced into the record. OPC has promised a court challenge if this record issue is not resolved, and would prefer that the settlement be dismissed and the FPSC issues a ruling on the rate case request itself on the normal timeline.

The FPSC chose instead to allow supplemental testimony to be filed in support of, and in opposition to, the settlement's novel items. It is obvious that the commission would prefer not to approve the settlement without OPC's participation in it, but the strenuousness of OPC's objections to that settlement's 10.7% ROE, and their own request for a 8.5-9.0% ROE (depending on the FP&L capital structure) suggest that two sides are far apart at the moment.

We would again point to the fact that recent rate cases in the state have allowed 10.25-10.5% ROEs, for smaller utilities with less risky asset bases and locations, and therefore continue to expect a similar outcome for FP&L. FP&L declined to waive the statutory deadline for the case in November, and so we believe a final ruling should be expected in that general timeframe. We don't believe slippage of a few days would cause any problems for the parties, if it came to that, and with FP&L's ability to put interim rates into effect while it awaits a final ruling, we don't expect any adverse financial impact for the company. A new schedule for producing testimony on the above items is expected shortly, after which the FPSC will host a hearing on those items to build and clarify the record further.

We expect a ruling on either the settlement or the case itself by the end of November, and believe the final result will be constructive versus the current 10% ROE that FP&L is currently allowed.

EXHIBIT NO. 721

DOCKET NO: 120015-EI

WITNESS: JAMES DANIEL

PARTY: OPC

DESCRIPTION: ERRATA TO EXHIBIT JWD-2

PROFFERED BY: OFFICE OF PUBLIC COUNSEL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 721
PARTY OPC; witness James Daniel; Errata to Exhibit
DESCRIPTION JWD-2
DATE

Florida Public Service Commission
Docket No. 120015-E1

Increase in FPL Profits
If Proposed Incentive Mechanism
Had Been In Effect Since 2001

				Customer's Share of Claimed Benefits				FPL's Share of Claimed Benefits			
				Current Incentive Mechanism		Proposed Incentive Mechanism		Current Incentive Mechanism		Proposed Incentive Mechanism	
Line No.	Year	Proposed Incentive Mechanism: Total Claimed Benefits*	Proposed Claimed Benefits less Threshold of $46,000,000	Amount	% of Total	Amount	% of Total	Amount	% of Total	Amount	% of Total
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	2003	$47,939,149	$1,939,149	$47,939,149	100.00%	$46,581,745	97.17%	$0	0.00%	$1,357,404	2.83%
2	2005	$49,612,011	$3,612,011	$48,481,777	97.72%	$47,083,603	94.90%	$1,130,234	2.28%	$2,528,408	5.10%
3	2009	$50,452,089	$4,452,089	$50,452,089	100.00%	$47,335,627	93.82%	$0	0.00%	$3,116,462	6.18%
4	2010	$82,738,350	$36,738,350	$82,738,350	100.00%	$57,795,340	69.85%	$0	0.00%	$24,943,010	30.15%
5	2011	$69,563,423	$23,563,423	$69,563,423	100.00%	$53,069,027	76.29%	$0	0.00%	$16,494,396	23.71%
6	Total	$300,305,022	$70,305,022	$299,174,788	99.62%	$251,865,342	83.87%	$1,130,234	0.38%	$48,439,680	16.13%

* From FPL's Exhibit SF-2, page 1 of 1

EXHIBIT NO. 722

DOCKET NO. 120015-EI

WITNESS: James W. Daniel

PARTY: Florida Power & Light Co.

DESCRIPTION: Incentive Mechanism Performance 2001 - 2011 (3 Pages)

PROFERRED BY: Florida Power & Light Co.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI **EXHIBIT** 722
PARTY FPL; witness Jame W. Daniel; Incentive
DESCRIPTION Mechanism Performance 2001-2011 (3pgs)
DATE

Incentive Mechanism Comparison

Line No.	Year	Proposed Incentive Mechanism: Total Claimed Benefits	Proposed Claimed Benefits less Threshold of $46,000,000	Customer's Share of Claimed Benefits: Current Incentive Mechanism Amount	% of Total	Customer's Share: Proposed Incentive Mechanism Amount	% of Total	FPL's Share of Claimed Benefits: Current Incentive Mechanism Amount	% of Total	FPL's Share: Proposed Incentive Mechanism Amount	% of Total
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	2001	$32,443,426	$0	$32,443,426	100.00%	$32,443,426	100.00%	$0	0.00%	$0	0.00%
2	2002	$30,725,727	$0	$30,725,727	100.00%	$30,725,727	100.00%	$0	0.00%	$0	0.00%
3	2003	$47,939,149	$1,939,149	$47,939,149	100.00%	$46,581,745	97.17%	$0	0.00%	$1,357,404	2.83%
4	2004	$36,130,609	$0	$35,445,641	98.10%	$36,130,609	100.00%	$684,968	1.90%	$0	0.00%
5	2005	$49,612,011	$3,612,011	$48,481,777	97.72%	$47,083,603	94.90%	$1,130,234	2.28%	$2,528,408	5.10%
6	2006	$36,464,381	$0	$36,403,936	99.83%	$36,464,381	100.00%	$60,445	0.17%	$0	0.00%
7	2007	$34,820,289	$0	$34,820,289	100.00%	$34,820,289	100.00%	$0	0.00%	$0	0.00%
8	2008	$31,889,308	$0	$31,889,308	100.00%	$31,889,308	100.00%	$0	0.00%	$0	0.00%
9	2009	$50,452,089	$4,452,089	$50,452,089	100.00%	$47,335,627	93.82%	$0	0.00%	$3,116,462	6.18%
10	2010	$82,738,350	$36,738,350	$82,738,350	100.00%	$57,795,340	69.85%	$0	0.00%	$24,943,010	30.15%
11	2011	$69,563,423	$23,563,423	$69,563,423	100.00%	$53,069,027	76.29%	$0	0.00%	$16,494,396	23.71%
	Total	**$502,778,762**	**$70,305,022**	**$500,903,115**	**99.63%**	**$454,339,082**	**90.37%**	**$1,875,647**	**0.37%**	**$48,439,680**	**9.63%**

Florida Public Service Commission
Docket No. 120015-E1

Increase in FPL Profits
If Proposed Incentive Mechanism
Had Been In Effect Since 2001

Line No.	Year	Proposed Incentive Mechanism: Total Claimed Benefits*	Proposed Claimed Benefits less Threshold of $46,000,000	Customer's Share of Claimed Benefits: Current Incentive Mechanism Amount	% of Total	Customer's Share of Claimed Benefits: Proposed Incentive Mechanism Amount	% of Total	FPL's Share of Claimed Benefits: Current Incentive Mechanism Amount	% of Total	FPL's Share of Claimed Benefits: Proposed Incentive Mechanism Amount	% of Total
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	2003	$47,939,149	$1,939,149	$47,939,149	100.00%	$46,581,745	97.17%	$0	0.00%	$1,357,404	2.83%
2	2005	$49,612,011	$2,481,777	$48,481,777	97.72%	$46,744,533	94.22%	$1,130,234	2.28%	$1,737,244	3.50%
3	2009	$50,452,089	$4,452,089	$50,452,089	100.00%	$47,335,627	93.82%	$0	0.00%	$3,116,462	6.18%
4	2010	$82,738,350	$36,738,350	$82,738,350	100.00%	$57,795,340	69.85%	$0	0.00%	$24,943,010	30.15%
5	2011	$69,563,423	$23,563,423	$69,563,423	100.00%	$53,069,027	76.29%	$0	0.00%	$16,494,396	23.71%
6	Total	$300,305,022	$69,174,788	$299,174,788	99.62%	$251,526,271	83.76%	$1,130,234	0.38%	$47,648,517	15.87%

* From FPL's Exhibit SF-2, page 1 of 1

Years Not Included in JWD-2

Line No.	Year	Proposed Incentive Mechanism: Total Claimed Benefits	Proposed Claimed Benefits less Threshold of $46,000,000	Customer's Share of Claimed Benefits — Current Incentive Mechanism: Amount	% of Total	Customer's Share — Proposed Incentive Mechanism: Amount	% of Total	FPL's Share of Claimed Benefits — Current Incentive Mechanism: Amount	% of Total	FPL's Share — Proposed Incentive Mechanism: Amount	% of Total
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	2001	$32,443,426	$0	$32,443,426	100.00%	$32,443,426	100.00%	$0	0.00%	$0	0.00%
2	2002	$30,725,727	$0	$30,725,727	100.00%	$30,725,727	100.00%	$0	0.00%	$0	0.00%
3	2004	$36,130,609	$0	$35,445,641	98.10%	$36,130,609	100.00%	$684,968	1.90%	$0	0.00%
4	2006	$36,464,381	$0	$36,403,936	99.83%	$36,464,381	100.00%	$60,445	0.17%	$0	0.00%
5	2007	$34,820,289	$0	$34,820,289	100.00%	$34,820,289	100.00%	$0	0.00%	$0	0.00%
6	2008	$31,889,308	$0	$31,889,308	100.00%	$31,889,308	100.00%	$0	0.00%	$0	0.00%
	Total	**$202,473,740**	**$0**	**$201,728,327**	**99.63%**	**$202,473,740**	**100.00%**	**$745,413**	**0.37%**	**$0**	**0.00%**

EXHIBIT NO. 723

DOCKET NO. 120015-EI

WITNESS: Donna Ramas

PARTY: Florida Power & Light Co.

DESCRIPTION: PEF and Gulf rate increases as percentage of total revenue (2 pages)

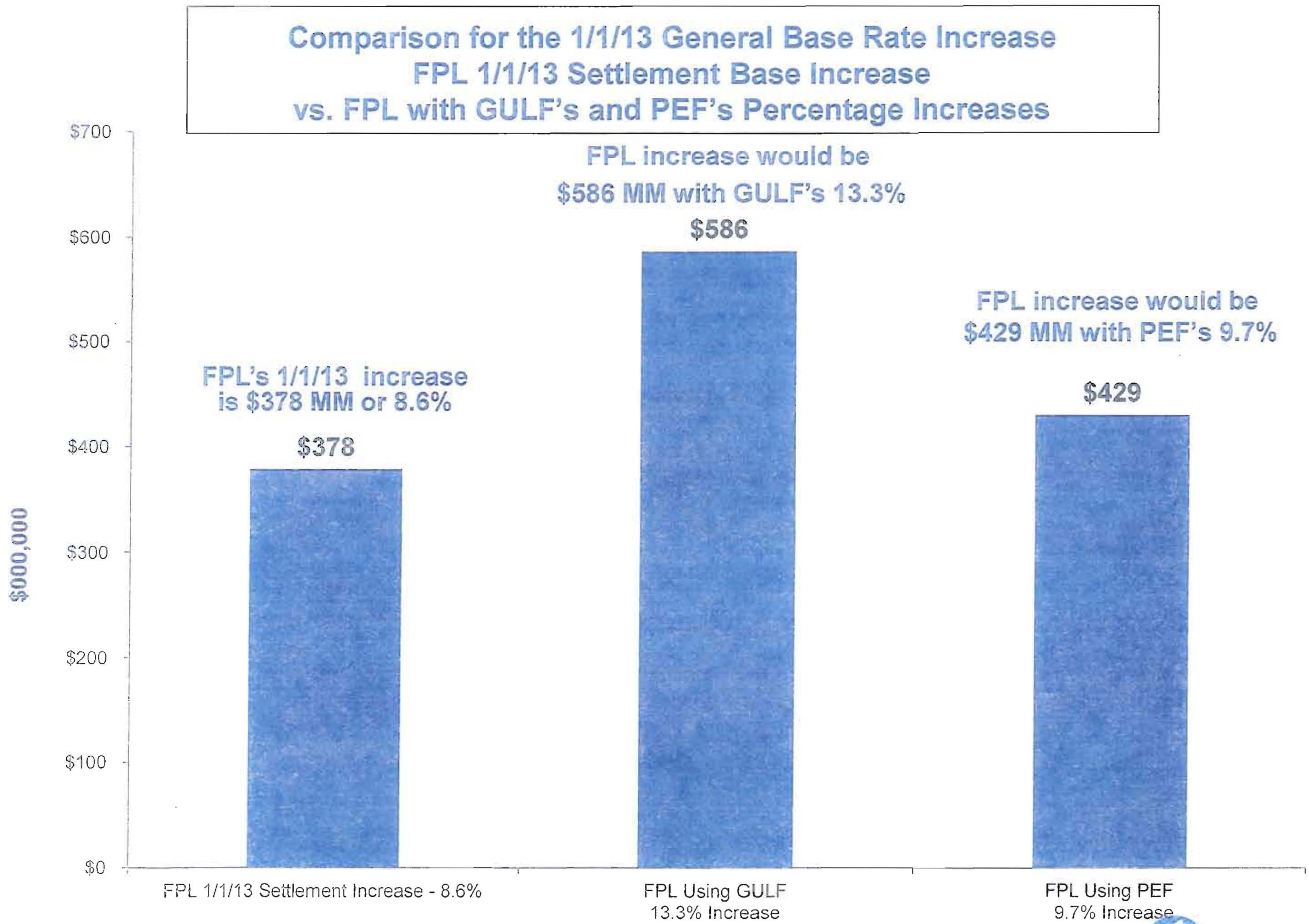
PROFERRED BY: Florida Power & Light Co.

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120015-EI **EXHIBIT** 723

PARTY Florida Power & Light Co./Donna Ramas

DESCRIPTION PEF and Gulf rate increases as percentage of total revenue (2 pages)



Comparison for the 1/1/13 General Base Rate Increase
FPL 1/1/13 Settlement Base Increase
vs. FPL with GULF's and PEF's Percentage Increases
$000,000
$700
$600
$500
$400
$300
$200
$100
$0
FPL's 1/1/13 increase
is $378 MM or 8.6%
$378
FPL increase would be
$586 MM with GULF's 13.3%
$586
FPL increase would be
$429 MM with PEF's 9.7%
$429
FPL 1/1/13 Settlement Increase - 8.6%
FPL Using GULF
13.3% Increase
FPL Using PEF
9.7% Increase

FPL

Revenue Increases as a Percent of Total Operating Revenue:

	Base Rate Increase	Projected Total Operating Revenue	Calculated Percent Increase	FPL Increase Using PEF and Gulf Percent
FPL Settlement Docket 120015-EI	$378,000,000 Settlement Exhibit A	$4,407,253,000 FPL MFR C-1	8.6%	NA
PEF Settlement Docket 120022-EI	$150,000,000 Order No. PSC-12-0104-FOF-EI, Exhibit A, pp. 19-20, 36.	$1,541,643,000 Exhibit A, p.36	9.7%	$4,407,253,000 X 9.7% = $429,000,000
Gulf Rate Case Docket 110138-EI	$64,101,662 Order No. PSC-12-0179-FOF-EI, p. 3.	$481,909,000 Gulf MFR C-1	13.3%	$4,407,253,000 X 13.3% = $586,000,000

EXHIBIT NO. 724

DOCKET NO. 120015-EI

WITNESS: John Hendricks

PARTY: Florida Power & Light Co.

DESCRIPTION: Excerpt from Joskow *Incentive Regulation and Its Application to Electricity Networks* (1 page)

PROFERRED BY: Florida Power & Light Co.

CLK note: Entire artical was admitted. (attached)

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 120015-EI **EXHIBIT** 724

PARTY Florida Power & Light Co./John Hendricks

DESCRIPTION Excerpt from Joskow *Incentive Regulation and Its Application to Electricity Networks*

EXH 724

Incentive Regulation and Its Application to Electricity Networks

PAUL L. JOSKOW *

Alfred P. Sloan Foundation and Department of Economics, MIT

Abstract

This paper examines developments since the publication of *The Economics of Regulation* in the theory of incentive regulation and its application to the regulation of unbundled electricity transmission and distribution networks. Conceptual mechanism design issues that arise when regulators are imperfectly informed and there is asymmetric information about costs, managerial effort, and quality of service are discussed. The design and application of price cap mechanisms and related quality of service incentives in the UK are explained. The limited literature that measures the effects of incentive regulation applied to electricity networks is reviewed.

1 Introduction

Alfred Kahn began to write what became *The Economics of Regulation* while I was an undergraduate at Cornell. He was my teacher and academic advisor at Cornell and is the one who stimulated my interest in both economics and the economics of regulation. Much has changed since *The Economics of Regulation* was published in 1970/71 (Volume 1 in 1970 and Volume 2 in 1971). Most of the industries that were thought to be "natural monopolies" and were subject to price, entry and service quality regulation at that time (for example, telecommunication, electricity, natural gas transportation, cable television, etc.) have been restructured and competition introduced into one or more of their horizontal segments.[1] Other industries, where the economic case for pervasive price and entry regulation was already increasingly being recognized as dubious by 1970, and where regulation and competition were often mixed together (for example, trucking, airlines, railroads, natural gas production), have been completely deregulated. The expanse of the economy in the U.S. and most other countries that is subject to price, entry and service quality regulation today has shrunk considerably since 1970.

There are many reasons for this trend, including changes in technology, poor performance exhibited by some regulated industries, changes in the political economy of regulation and associated changes in the power of different interest groups, and broader

* President, Alfred P. Sloan Foundation, 630 Fifth Avenue, Suite 2550, New York, NY. E-mail: joskow@sloan.org This paper is based on a longer study "Incentive Regulation in Theory and Practice: Electric Distribution and Transmission," Joskow (2006a) prepared for the National Bureau of Economic Research regulation project. http://econ-www.mit.edu/files/1181. See also Joskow (2006b). The views expressed here are my own and do not reflect the views of the Alfred P. Sloan Foundation, MIT or any other organization with which I am associated.

[1] Competition in Electricity remains a work in progress in the U.S. See Joskow (2006c).

ideological shifts favoring markets over regulation and state-owned enterprises. While the pendulum may be shifting back in some sectors (for example, financial market regulation, health and safety regulation, access of content providers to communications networks, etc.) the broad changes in the mix of regulated and competitive segments that we have observed in the last 30 years is unlikely to be reversed.

Even in countries that have gone the farthest in "liberalizing" previously regulated and state-owned enterprises, certain network segments of some of the historically regulated "natural monopoly" industries continue to be subject to price, entry and service quality regulation. These industries include electricity transmission and distribution networks, natural gas transmission and distribution networks, and water supply networks. In the case of electricity and natural gas transmission and distribution networks, the regulatory mechanisms applied to these networks have important implications for supporting wholesale competition (electricity generation, natural gas production, and associated wholesale marketing activities) and retail competition (competition to supply end-users) since they serve as platforms upon which competing wholesale and retail suppliers depend and also implement market and non-market mechanisms to maintain network reliability. Thus, good performance of the competitive segments depends on good performance of the remaining regulated network segments.

The application of sound regulatory mechanisms that affect the terms and conditions of network connections, network delivery prices, network investment, and network service quality have been important components of all successful electricity sector liberalization programs around the world. The benefits of a good regulatory framework include lower network service costs, improvements in service quality, investment to expand the network to support changes in supply and demand for network services, and the development of efficient network platforms to support robust competitive wholesale and retail markets. While many of the basic regulatory principles discussed in *The Economics of Regulation* still apply to these remaining regulated monopoly network segments, there have been important advances in both theory and application since those volumes were published as well.

Volume 1 of *The Economics of Regulation* focuses on the principles for pricing regulated services supplied by firms that are subject to budget or break-even constraints. While there have certainly been theoretical advances associated with the second-best pricing of services supplied by regulated monopoly firms since 1970, especially with regard to the design and welfare properties of non-linear prices to meet budget constraints, the application of these basic pricing principles at the retail level has not advanced very far. So, for example, except for large retail customers, time of day pricing and real time pricing for electricity and natural gas has not spread quickly at all, despite the fact that the information available from wholesale markets about generation and natural gas prices makes it even easier to apply these concepts today than in 1970. At the wholesale level, in those places where prices have been deregulated, the market naturally leads to the load varying prices whose basic economic principles are developed in detail in Volume 1.

The problem of designing rewards and incentives for efficient production by firms subject to cost-of-service or rate-of-return regulation is discussed briefly in Volume 1 (pages 53-54) and in (the more rarely read) Volume 2 (Chapters 2 and 3). The discussion in Volume II of *The Economics of Regulation* in particular raises the right issues:

> ...the central institutional questions have to do with the nature and adequacy of the incentives and pressures that influence private management in making the critical economic decisions. (Volume II, page 47)

…[rate of return regulation] creates strong incentives to pad their expenses." (Volume II, page 48)

It also has several insights into how incentives might be introduced into the regulatory process to improve performance:

> Freezing rates for the period of the [regulatory] lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards for the opposites …

From an overall economic efficiency perspective, these production cost and service quality inefficiencies are likely to be more important than are failures to adopt the most efficient (second best given budget constraints) pricing structures. This is the case because the efficiency losses from excessive costs lead to "first order" efficiency losses ("rectangles") while the pricing inefficiencies are likely to be second order (Harberger "triangles"). The historical focus on efficient price structures, rather than cost control and service quality incentives, likely flows in part from the political concerns about monopoly power, excessive prices, and price discrimination that played an important political role leading to the creation of regulated legal monopolies and oligopolies in the first place. But we must recognize as well that in the last fifteen or twenty years there have been major advances in imperfect and asymmetric information theory, and in the theories of incentive mechanisms and associated contractual arrangements generally that have now made it possible to develop relevant theories and then to apply them.

At the time *The Economics of Regulation* was written, there was relatively little formal theoretical development of the properties of alternative incentive regulation mechanisms that provide incentives to regulated firms to control costs, to offer appropriate levels of service quality, and to find it in their interest to set efficient (second-best) price structures. Absent relevant theory, it was difficult to develop applications that could be applied in the real world, though experiments with incentive regulation go back to the 19th century (Joskow, 2007). At the time *The Economics of Regulation* was published, the primary theoretical analysis that focused on the incentive properties of rate of return regulation was the Averch-Johnson (or as Kahn refers to it in his book, the Averch, Johnson, and Wellisz or A-J-W effect, to recognize the less widely cited paper by Stanislaw Wellisz that identified similar potential distortions from rate of return regulation (Averch and Johnson, 1962; Wellisz, 1963)). The A-J-W effect turns on the incentives created by a characterization of rate of return regulation that effectively reduces the regulated firm's effective cost of capital inputs (r) by creating a profit margin on increases in capital input while leaving fixed the price of other inputs ("labor" in the A-J model) since these input costs are assumed (that is, asymmetrically vis-à-vis capital costs) to be passed through dollar for dollar into regulated prices. This in turn leads a profit maximizing regulated firm subject to this type of regulation to make long run production decisions that use a higher capital/labor ratio than would be cost-minimizing given the firm's production function and true input costs. This theory ignores many attributes of real regulatory institutions and it has little if any empirical support (Joskow, 1974, 2007; Joskow and Rose, 1989), but for many years it was "the" positive theory of regulation. However, in the last fifteen or twenty years there have been significant advances in the theory of "incentive regulation" or "performance-based regulation" and these concepts are beginning to be applied in the regulation of electricity and gas transmission and distribution networks in a number of countries (Joskow 2006a, 2006b, 2007).

The rest of this paper identifies the key elements associated with the development of modern incentive regulation theory and then examines the application of alternative types of "incentive" or "performance-based" regulation of electricity distribution and transmission network price levels, price structures and service quality. The discussion will assume that effective electricity sector restructuring and unbundling mechanisms have been put in place so that there are clearly defined distribution and transmission network entities offering unbundled delivery and network support services to market participants (as in the UK and portions of the U.S.). I will also assume that electricity networks are regulated monopolies[2] and that an independent regulator with adequate staff resources has been created to oversee the regulation of the distribution and transmission networks.

2 Theoretical considerations

The primary goal of regulation in the public interest is to stimulate the regulated firm to produce output efficiently from cost and quality (including reliability) perspectives, to price the associated services efficiently, and to achieve these goals consistent with satisfying a break-even or budget-balance constraint for the regulated firm that allows the firm to covered its costs of providing service while restraining its ability to exercise its market power to exploit consumers by charging excessive prices. Much of the older theoretical literature on optimal (first and second-best) pricing of services provided by regulated monopolies (for example, Boiteux, Steiner, Turvey) assumes implicitly that regulators are perfectly informed about the regulated firm's cost opportunities and demand patterns and can effectively enforce cost minimization on the regulated firm.[3] The literature then focuses on first and second-best pricing of the services provided by the regulated firm given defined cost functions, demand attributes and budget balance constraints (for example, Ramsey-Boiteux pricing, non-linear pricing, etc.).[4] The older literature did not focus on incentives to minimize costs or improve other dimensions of firm performance (for example, service quality attributes), aside from making the general observation that firms insulated from competition and subject to cost-based regulation were likely to be inefficient and the limited formal theoretical developments of the A-J-W effect discussed above.

In reality, regulators care (or at least should care) as well (or more) about the production efficiency and service quality implications of the regulatory mechanisms they choose. Regulators are neither completely informed nor completely uninformed about relevant cost, quality, and demand attributes faced by the regulated firm. Regulators have *imperfect* information about these firms and market attributes and the regulated firm generally has more information about these attributes than does the regulator. Furthermore, managers have discretion to make choices not only about input proportions (as in the A-J-W models) but on how hard they will work to minimize the firm's costs or in choosing the levels of service quality. Accordingly, the regulated firm may use its information advantage (*asymmetric information)* strategically to exploit the regulatory process to

[2] The economic attributes of unregulated "merchant" transmission network investment are discussed in Joskow and Tirole (2005).

[3] An exception is the extensive theoretical and limited empirical literature following Averch and Johnson (1962), and especially after Baumol and Klevorick (1970) that examines potential distortions in input proportions caused by rate-of-return constraints. The empirical foundations for these theories are discussed in Joskow and Rose (1989).

[4] Brauetigam (1989).

increase its profits or to pursue other managerial goals, to the disadvantage of consumers (Laffont and Tirole, 1993, Chapter 1).

This creates potential moral hazard (for example, too little managerial effort resulting in excessive costs) and adverse selection (for example, prices that are too high relative to production costs) problems that effective regulatory mechanism design must address. The recent theoretical literature on incentive regulation focuses on devising regulatory mechanisms to respond to these moral hazard and adverse selection problems (Laffont and Tirole, 1993; Armstrong and Sappington, 2007).

Consider a situation in which the regulator is uncertain about the firm's true underlying costs and its opportunities further to reduce costs, the regulator cannot observe the level of managerial effort expended by the firm, but the regulator can monitor accurately the firm's realized costs ex post in regulatory hearings and through audits. The regulated firm knows its true cost opportunities, its managerial effort, and the effects of managerial effort on costs. Following Laffont and Tirole (1993, pp.10-19), under these assumptions we can think of two polar case regulatory mechanisms that may be applied to a monopoly firm producing a single product with a fixed quality. The first regulatory mechanism involves setting a fixed price ex ante that the regulated firm will be permitted to charge going forward (that is, effectively forever). In a dynamic setting this is equivalent to a pricing formula that starts with a particular price and then adjusts this price for exogenous changes in input price indices and other exogenous indices of cost drivers (again, effectively forever). This type of regulatory mechanism can be characterized as a fixed price regulatory contract or, in a dynamic setting, a price cap regulatory mechanism.

Because prices are fixed with this mechanism (or vary based only on exogenous indices of cost drivers) and do not respond to changes in managerial effort or ex post cost realizations, the firm and its managers keep 100% of any cost reductions they realize by increasing effort. Accordingly, and ignoring service quality and investment considerations for now, this mechanism provides incentives to induce efficient levels of managerial effort and in turn cost reduction. This effect is a first order "rectangle" efficiency gain. However, because the regulator must ensure that any regulatory mechanism it imposes on the regulated firm meets a budget balance constraint, when the regulator is uncertain about the regulated firm's true cost opportunities she will have to set a relatively high fixed price (or dynamic price cap) to ensure that *if* the firm is indeed inherently high cost, the prices under the fixed price contract or price cap will be high enough to cover the firm's (efficient but high) realized costs. Accordingly, while a fixed price mechanism does well from the perspective of providing incentives to reduce costs it is potentially very poor at "rent extraction" for the benefit of consumers and society because prices may be too high relative to the firm's true cost opportunities. The social value of rent extraction depends upon the social welfare function applied to the distribution of these rents between consumers and producers (Armstrong and Sappington, 2007) or the cost of public funds in a public procurement theoretical framework (Laffont and Tirole, 1993).

At the other extreme, the regulator could implement a simplistic pure "cost of service" regulatory contract where the firm is assured that it will be compensated for all of the costs of production that it actually incurs and no more. After the firm produces, the regulator's uncertainty about whether the firm is a relatively high or a low cost opportunity firm will be resolved. And since the regulator compensates the firm only for its realized costs, there is no "rent" left to the firm or its managers in the form of excess profits. This solves the "rent extraction" or "adverse selection" problem that would arise under a fixed price contract. However, this kind of cost of service regulatory mechanism does not provide any incentives for the management to exert optimal (indeed any) effort. Even though there are no "excess profits" left to the firm, the actual costs incurred by the firm may be inefficiently high as a result of too little managerial effort. Managers now retain 0% of any cost savings they achieve and have no incentive to exert cost-reducing effort. Accordingly, consumers may now be paying higher prices than they would have to pay if the management could be induced to exert more effort to reduce costs. Indeed, it is this kind of managerial slack and associated x-inefficiencies that most policymakers have in mind when they discuss the "inefficiencies" associated with regulated firms.

Conceptually, fixed-price contracts (or price caps) are good at providing incentives for managerial efficiency and cost minimization, but bad at extracting the benefits of the lower costs for consumers. Cost of service contracts are good at aligning prices and costs but the costs will be excessive due to suboptimal managerial effort. Perhaps not surprisingly, the optimal regulatory mechanism in the presence of imperfect and asymmetric information will lie somewhere between these two extremes. It will have a form similar to a *profit sharing* contract or a *sliding scale* regulatory mechanism where the price that the regulated firm can charge is *partially* responsive to or contingent on changes in realized costs and *partially* fixed ex ante (Schmalensee, 1989; Lyon, 1996). (I should note that Volume II of *The Economics of Regulation* discusses some early profit sharing or sliding scale plans and performance benchmarking mechanisms (pp.61-63), but expresses some skepticism about the regulator's ability to apply these mechanisms effectively.) More generally, by offering the regulated firm a *menu* of cost-contingent regulatory contracts with different cost sharing provisions, the regulator can do even better than if it offers only a single profit sharing contract (Laffont and Tirole, 1993).

3 Price cap mechanisms in practice

While the theoretical literature on incentive regulation is quite rich, it still provides relatively little direct guidance for practical application in real-world circumstances. In practice, well-designed incentive regulation programs have adopted fairly simple mechanisms that reflect some of the basic theoretical principles discussed above.

A particular form of incentive regulation was introduced for the regulated segments of the privatized electric gas, telephone and water utilities in the UK, New Zealand, Australia, and portions of Latin American as well as in the regulated segments of the telecommunications industry in the U.S.[5] This mechanism chosen is the "price cap" (Beesley and Littlechild, 1989; Brennan, 1989; Armstrong, Cowan and Vickers, 1994; Isaac, 1991). Price cap regulation is a form of institutionalized regulatory lag. Under price cap regulation the regulator sets an initial price p_0 (or a vector of prices for multiple products). This price (or a weighted average of the prices allowed for firms supplying multiple products or different types of customers) is then adjusted from one year to the next for changes in inflation (rate of input price increase or RPI) and a target productivity change factor "x."[6] Accordingly, the price p_1 in period 1 is given by:

[5] The U.S. is behind many other countries in the application of incentive regulation principles to electric distribution and transmission, though their use is slowly spreading in the U.S. beyond telecommunications.
[6] Many implementations of price cap regulation also have "z" factors. Z factors reflect cost elements that cannot be controlled by the regulated firm and are passed through in retail prices. For example, in the UK,

(1) $$p_1 = p_o (1 + RPI - x)$$

In theory, a "forever" price cap mechanism is a high-powered "fixed price" regulatory contract which provides powerful incentives for the firm to reduce costs. Moreover, if the price cap mechanism is applied to a (properly) weighted average of the revenues the firm earns from each product it supplies, the firm has an incentive to set the second-best prices for each service (Laffont and Tirole, 2000) given the level of the price cap. So to speak, it kills two birds with one stone. As already noted, however, when the regulator has imperfect information about the firm's cost opportunities and must meet a budget balance constraint, pure "forever" price cap mechanisms are not optimal from the perspective of an appropriate tradeoff between efficiency incentives and rent extraction (Schmalensee, 1989) and would leave too much rent to the firm with "average" cost characteristics. Finally, any incentive regulation mechanism that provides incentives only for cost reduction also potentially creates incentives inefficiently to reduce service quality when service quality and costs are positively correlated with one another.

In practice, "forever" price caps are not typically used in the regulation of distribution and transmission network price levels. Some form of cost-based regulation is used to set an initial value for p_o. The price cap mechanism then operates for a pre-established time period (for example, five years). At the end of this period a new starting price p_o and a new x factor are established after another cost-of-service and prudence or efficiency review of the firm's costs. That is, there is a pre-scheduled regulatory process to reset or "ratchet" prices based partially on costs realized during the previous period. In addition, price caps are often only one component of a larger portfolio of incentive mechanisms that include quality of service incentives, as discussed in the next section. Finally, regulated electric distribution and transmission network firms' ability to determine the structure of prices for different types of customers or for services provided at different locations on the network under an overall revenue cap is typically limited. As a result, the applications of price caps in practice are properly thought of as cost and quality incentive mechanism not as a mechanism to induce optimal second-best pricing of various network services. So, in practice the incentive mechanisms are only targeted at one bird rather than two.

A natural question to ask about price cap mechanisms is where does "x' (and perhaps p_o) come from or, more generally, how does one choose the correct starting value for p_o and the proper dynamic price trajectory? The difficulty of answering this question in practice is one of the sources of skepticism about formal incentive mechanisms expressed in Volume II of *The Economics of Regulation.* In England and Wales and some other countries, statistical benchmarking methods have come to be used to help to determine the relative efficiency of individual firms' <u>operating</u> costs and service quality compared to their peers. This information can then be used as an input to setting values for both p_o and x (Jamasb and Pollitt, 2001, 2003; OFGEM, 2004a) to provide incentives for those far from the efficiency frontier to move toward it and to reward the most efficient firms in order to induce them to stay on the efficiency frontier, in a fashion that is effectively an application of yardstick regulation (Shleifer, 1985).

Although it is not discussed too much in the theoretical or empirical literature on price caps, capital-related cost are handled quite differently from operating costs in the

the charges distribution companies pay for connections to the transmission network are treated as pass-throughs. Changes in property tax rates are also often treated as pass-throughs.

establishment and resetting of p_o and x. The limited attention paid to capital-related costs in the academic literature on price cap regulation provides a potentially misleading picture of the challenges associated with implementing a price-cap mechanism effectively. This is the case for several reasons. First, in practice, the p_o and x values must be developed based not only on a review of the relative efficiency of each firm's operating costs, but also based on the value of the firm's current capital stock or rate base, forecasts of future capital additions required to provide target levels of service quality, and the application of depreciation rates, estimates of the cost of the firm's debt and equity capital, assumptions about the firm's dept/equity ratio, tax allowances and other variables to turn capital stocks into prices for capital services over time. The capital cost related allowances represent a large fraction of the total price (p_o) of supplying unbundled electricity network services so the choices of these parameters for defining capital user charges are very important.

Second, allowances for capital-related costs are typically established by regulators using incentive regulation mechanisms through more traditional utility planning and cost-of-service regulatory accounting methods including the specification of a rate base (or regulatory asset value), depreciation rates, debt and equity costs, debt/equity ratios, tax allowances, etc. This is the case because the kinds of statistical benchmarking techniques that have been applied to operating costs have not been developed for capital-related costs, due to significant heterogeneity between firms in terms of the age of assets, geography, service quality, lumpiness of capital investments and other considerations. Third, the efficiency properties of a regulatory mechanism that mixes competitive benchmarking with more traditional forward-looking rate of return regulation are more complex than first meets the eye (Acemoglu and Finkelstein, 2006).

In principle, operating and capital costs could be integrated and associated benchmarks determined using total factor productivity measures. This is the approach taken by the initial price caps applied to telecom companies in the U.S. by the Federal Communications Commission. In electricity, this approach has been rejected largely because of the diversity in the capital stock, much of which is several decades old, and the associated difficulties of coming up with accurate total productivity measures. The application of price caps in England and Wales and other countries in Europe that have adopted this mechanism, benchmark a firm's performance against industry specific "best practice" (production frontier analysis using data for other firms in the industry).

Thus, the implementation of price cap mechanisms is more complicated and their efficiency properties more difficult to evaluate than is often implied and places a significant information collection, auditing and analysis burden on regulators. This is precisely the source of the skepticism about formal incentive mechanisms expressed in Volume II of *The Economics of Regulation*. In practice, modern applications of incentive regulation concepts involve the application of elements of traditional cost of service regulation, yardstick regulation, and high-powered "fixed price" incentives.

The challenge of forecasting future investment needs and costs for electricity network firms has historically been a rather contentious process, sometimes yielding significant differences between what the regulated firm's claim they need and what the regulator claims they need to meet their legal responsibilities to provide safe and reliable service efficiently. There is clearly a very serious asymmetric information problem here. In the 2004 review of electricity distribution prices in the UK, the regulator adopted an innovative "menu" of sliding scale mechanisms approach to resolve the asymmetric information problem faced by the regulator as she tries to deal with differences between the firms' claims and the regulator's consultants' claims (OFGEM, 2004b) about future capital investment requirements to meet reliability targets. The sliding scale menu allows firms to choose between getting a lower capital expenditure allowance but a higher powered incentive (and a higher expected return on investment) that allows them to retain more of the cost reduction if they can beat the target expenditure levels or a higher capital expenditure allowance combined with a lower powered sliding scale mechanism and lower expected return. (OFGEM, 2004b). This is an application of Laffont and Tirole's menu of cost-contingent contracts mechanism and provides a more effective way to deal with the imperfect and asymmetric information conditions and associated adverse selection problems than the traditional approach of offering a single regulatory contract.

An example of the use of a profit-sharing or cost-contingent form of incentive regulatory mechanism can be found in the incentive mechanism that has been applied to the costs of the transmission system operator (SO) in England and Wales (which is also the transmission owner (TO), though there are separate regulatory mechanisms for SO and TO functions). Each year forward targets are established for the costs of system balancing services and system losses (OFGEM, 2005). A sharing or sliding scale formula is specified which places the TO at risk for a fraction (for example 30%) of deviations from this benchmark (up or down) with caps on profits and losses. There is also a cap and a floor. In recent years the SO was given a menu of three alternative incentive arrangements with different sharing fractions and different caps and floors (with costs of service as a default) from which to choose. If the SO were to choose the cost-of-service default it would suggest that in constructing the menu, the regulator had underestimated the range of the SO's future cost realizations.

4 Service quality incentives

As noted earlier, any incentive regulation mechanism that provides incentives only for cost reduction also potentially creates incentives to reduce service quality when service quality and costs are positively related to one another. The higher powered are the incentives to reduce costs, the greater the incentive to reduce quality when cost and quality are correlated. Accordingly, price cap mechanisms are increasingly accompanied by a set performance standards and associated penalties and rewards for the regulated firm for falling above or below these performance norms. Similar mechanisms are used by several U.S. states and in other countries that have liberalized their electricity sectors (for example, New Zealand, Netherlands, and Argentina).

In the UK, the regulator (OFGEM) has developed several incentive mechanisms targeted at various dimensions of distribution network service quality (OFGEM, 2004b, 2004c). OFGEM uses statistical and engineering benchmarking studies and forecasts of planned maintenance outages to develop targets for the number of customer outages and the average number of minutes per outage for each distribution company.

Until recently in the UK, there was no formal incentive mechanism that applied to transmission system reliability – network failures that lead to administrative customer outages or "unsupplied energy". In 2005, a new incentive mechanism that focuses on the reliability of the transmission network as measured by the quantity of "unsupplied energy" resulting from transmission network outages went into effect (OFGEM, 2004d). NGC is assessed penalties or received rewards when outages fall outside of a "deadband" of +/- 5%

defined by the distribution of historical outage experience (and with potential adjustments for extreme weather events), using a sliding scale with a cap and a floor on the revenue impact.

5 Performance attributes

The information burden to implement incentive regulation mechanisms well is certainly no less than for traditional cost of service regulation. Incentive regulation in practice requires a good accounting system for capital and operating costs, cost reporting protocols, data collection and reporting requirements for dimensions of performance other than costs. Capital cost accounting rules are necessary, a rate base for capital must still be defined, depreciation rates specified, and an allowed rate of return on capital determined. Comprehensive "rate cases" or "price reviews" are still required to implement "simple" price cap mechanisms. Planning processes for determining needed capital additions are an important part of the process of setting total allowed revenues and associated prices going forward. Performance benchmarks must be defined and the power of the relevant incentive mechanisms determined. What distinguishes incentive regulation in practice from traditional cost of service regulation is that this information is used more effectively because it can rely on advances in incentive regulation theory to organize and apply it. Whether the extra effort is worth it depends on whether the performance improvements justify the additional effort.

Unfortunately, there are been relatively little systematic analysis of the effects of the application of incentive regulation mechanisms on the performance of electric distribution and transmission companies.[7] Improvements in labor productivity and service quality have been documented for electric distribution systems in England and Wales, Argentina, Chile, Brazil, Peru, New Zealand and other countries (Newbery and Pollitt, 1997; Rudnick and Zolezzi, 2001; Bacon and Besant-Jones, 2001; Estache and Rodriguez-Pardina, 1998; and Pollitt, 2004). However, most of these studies have focused on developing countries where the pre-reform levels of performance were especially poor prior to restructuring. Moreover, it is difficult to disentangle the effects of privatization, restructuring and incentive regulation from one another.

The most comprehensive study of the post reform performance of the regional electricity distribution companies in the UK (distribution and supply functions) has been done by Domah and Pollitt (2001). They find significant overall increases in productivity over the period 1990 to 2000 and lower real "controllable" distribution costs compared to a number of benchmarks. However, controllable costs and overall prices first rose in the early years of the reforms before falling dramatically after 1995. Moreover, the first application of price cap mechanisms to the distribution networks in 1990 was too generous (average of RPI+ 2.5%) and a lot of rent was initially left on the table for the RECs' initial owners (who cleverly soon sold out to foreign buyers). Distribution service quality in the UK, at least as measured by supply interruptions per 100 customers and average minutes of service lost per customer, has improved as well since the restructuring and privatization initiative in 1990. This suggests that incentive regulation has not led, as some had feared,

[7] There is a much more extensive body of empirical work that examines the effects of incentive regulation mechanisms, primarily price caps, on the performance of telecommunications firms. Examples are Ai and Sappington (2004), Sappington (2003), Ai, Martinez and Sappington (2005).

to deterioration in these dimensions of service quality. This is likely to have been the case because quality standards and associated mechanisms were included in the portfolio of incentive regulation mechanisms adopted in the UK.

The experience with the transmission system operator (SO) incentive mechanism in England and Wales also provides a good example of how incentive regulation can improve performance. During the first few years following the restructuring of the electricity sector in England and Wales in 1990, the SO recovered the costs of system balancing, including managing congestion and other network constraints, through a simple cost pass-through mechanism. The SO's costs escalated rapidly, growing from about \$75 million per year in 1990/91 to almost \$400 million per year in 1993/94. After the introduction of the SO incentive scheme in 1994, these costs fell to about \$25 million in 1999/2000. OFGEM estimates that NGC's system operating costs fell by about £400 million (\$600 million at current exchange rates) between 1994 and 2001. A new SO incentive scheme was introduced when NETA went into operation in early 2001. The SO's costs have fallen by nearly 20% over the three year period since the new scheme was introduced (OFGEM, 2003).

While the empirical evidence on the effects incentive regulation mechanisms applied to electric distribution and transmission system in practice is still limited, the experience so far is very encouraging.

6 Conclusion

As we look back at developments in the theory and practice of regulating firms that have been given de facto monopoly franchises since the publication of *The Economics of Regulation* in 1970 and 1971, we can come to a number of conclusions. First, the overall economic importance of getting the theory and application of "natural monopoly" regulation right has become less important over time since a smaller fraction of the economy is subject to these types of economic regulation as competition has replaced regulated monopoly in so many industries. Moreover, even in those industries where price, entry and service quality regulation continues, it is typically being applied to a smaller number of truly natural monopoly network segments of those industries as competition has been introduced into other horizontal segments that rely on the regulated network platform. The basic theory of efficient pricing (first and second best) under the assumption that the regulator is fully informed has not changed very much over the years, except perhaps for a better understanding of the properties of non-linear pricing for regulated firms subject to budget constraints. The major advances in the theory and practice of regulation have relied on formalizing the information structure that characterizes the real world. Regulators are imperfectly informed, regulated firms have better information about the cost and demand attributes they face, and regulated firms will use this information advantage to their benefit. This situation leads to adverse selection and moral hazard problems that have been incorporated into the modern theory of incentive regulation. While applying this theory in practice must confront numerous empirical challenges, the available evidence from their application to electricity distribution and transmission systems suggests that they can help to resolve what Kahn called "the central institutional question" that confronts economic regulation.

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Docket No. 120015-EI
Incremental Infrastructure Costs
Exhibit REB-17

FLORIDA POWER & LIGHT COMPANY

Revenue Requirement Associated With
Additional Infrastructure-Related Costs
Since FPL's Last Rate Case

Test Year Ending December 31, 2013

RAMAS SUPPLEMENTAL DIRECT EXHIBIT CORRECTED TO INCLUDE SURPLUS AMORTIZATION CONSISTENTLY IN ALL PERIODS

Line	Description	D.080677-EI Final Order	Proposed	Proposed With CC Increases	Increase Since Last Rate Case	WCEC 3	Incremental Infrastructure Costs	Depreciation Impacts
1	Jurisdictional Adjusted Rate Base	$16,787,430	$21,036,823	$21,858,148	$4,249,393	$769,387	$3,480,006	
2	Pre-Tax Return at 10.70% ROE						9.78%	
3	Return and Associated Taxes						$340,245	
4	Property Insurance	$8,531	$14,321	$15,569	$5,790	$524	$5,266	
5	Depreciation (excluding Decommissioning)	$753,237	$803,912	$835,414	$50,675	$33,906		$16,769
5a	Surplus Depreciation Amortization in Above	-$223,695	-$190,918		$32,777			$32,777
5b	Depreciation excluding surplus amortization	$976,932	$994,830		$17,898	$33,906	-$16,008	-$16,008
6	Property Tax	$297,735	$321,817	$339,487	$24,082	$14,599	$9,483	
7	Revenue Deficiency with No Surplus Depreciation Amortization Impact						$338,986	
8	Remaining Surplus Depreciation Owed to Ratepayers, per FPL filing						-$190,918	
9	Revenue Deficiency with Remaining Surplus Depreciation being Amortized						$148,068	
10	Adjust to reflect the amortization of surplus depreciation credit in the 2010 final order						$223,695	
11							$371,763	
12	Settlement Base Revenue Increase						$378,000	

Source: Excel worksheet provided by email dated 11/7/12 in response to OPC's 1st POD to FIPUG Exhibit JP-7 Settlement.xls

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 725
PARTY Florida Power & Light (FPL)
DESCRIPTION ~~Michael~~ Barrett (REB-17)
Robert E. (RUN 2.15.13)

EXHIBIT NO. 726

DOCKET NO: 120015-EI

WITNESS: Terry Deason

PARTY: Signatories

DESCRIPTION: March 13, 2012 E-Mail

DOCUMENTS:

PROFFERED BY: **OFFICE OF PUBLIC COUNSEL**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 120015-EI EXHIBIT 726
PARTY Office of Public Counsel
DESCRIPTION Terry Deason
3/12/12 Email

Rehwinkel, Charles

From: Hoffman, Kenneth [KENNETH.HOFFMAN@fpl.com]
Sent: Tuesday, March 13, 2012 9:21 AM
To: Rehwinkel, Charles
Cc: Litchfield, Wade
Subject: RE: Confidentiality Agreements

Charles– the Confidentiality Agreement form you have provided is acceptable to FPL. Please have your outside consultant(s) execute the form and provide to me. I will then have FPL execute the form and provide a fully executed copy to you and [redacted](as well as a copy of the fully executed Confidentiality Agreement) to the outside consultant(s) who execute the Confidentiality Agreement. If you have a suggestion for a different approach, please let me know.

Thank you,

Ken

Kenneth A. Hoffman
Vice President, Regulatory Affairs
Florida Power & Light Company
215 S. Monroe Street, Suite 810
Tallahassee, FL 32301
office: 850-521-3919
fax: 850-521-3939

From: Rehwinkel, Charles [mailto:REHWINKEL.CHARLES@leg.state.fl.us]
Sent: Thursday, March 01, 2012 4:13 PM
To: Hoffman, Kenneth
Subject: FW: Confidentiality Agreements

Ken:

Attached is an example of the standard agreement that the parties used in the PEF matter. Please advise if you have any questions.

Charles