

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery
clause with generating performance incentive
factor.

DOCKET NO. 160001-EI
ORDER NO. PSC-16-0504-PHO-EI
ISSUED: October 31, 2016

Pursuant to Notice and in accordance with Rule 28-106.209, Florida Administrative Code (F.A.C.), a Prehearing Conference was held on October 11, 2016, in Tallahassee, Florida, before Commissioner Art Graham, as Prehearing Officer.

APPEARANCES:

MATTHEW BERNIER, ESQUIRE, 106 East College Avenue, Tallahassee, Florida 32301-7740; and JOHN T. BURNETT and DIANNE M. TRIPLETT, ESQUIRES, 299 First Avenue North, St. Petersburg, Florida 33701
On behalf of Duke Energy Florida, LLC (DEF)

R. WADE LITCHFIELD, JOHN T. BUTLER, MARIA J. MONCADA, ESQUIRES, Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408-0420
On behalf of Florida Power & Light Company (FPL)

BETH KEATING, ESQUIRE, Gunster, Yoakley & Stewart, P.A., 215 South Monroe St., Suite 601, Tallahassee, Florida 32301
On behalf of Florida Public Utilities Company (FPUC)

JEFFREY A. STONE, RUSSELL A. BADDERS, and STEVEN R. GRIFFIN, ESQUIRES, Beggs & Lane, Post Office Box 12950, Pensacola, Florida 32591-2950
On behalf of Gulf Power Company (GULF)

JAMES D. BEASLEY, J. JEFFRY WAHLEN, and ASHLEY M. DANIELS, ESQUIRES, Ausley McMullen, Post Office Box 391, Tallahassee, Florida 32302
On behalf of Tampa Electric Company (TECO)

J.R. KELLY, PUBLIC COUNSEL, CHARLES REHWINKEL, PATRICIA A. CHRISTENSEN, ERIK SAYLER, and STEPHANIE MORRIS, ESQUIRES, Office of 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)

JON C. MOYLE, JR. and KAREN PUTNAL, ESQUIRES, Moyle Law Firm, PA, The Perkins House, 118 North Gadsden Street, Tallahassee, Florida 32301
On behalf of the Florida Industrial Power Users Group (FIPUG)

ROBERT SCHEFFEL WRIGHT and JOHN T. LAVIA, III, ESQUIRES,
Gardner, Bist, Bowden, Bush, Dee, LaVia & Wright, P.A., 1300 Thomaswood
Drive, Tallahassee, Florida 32308

On behalf of the Florida Retail Federation (FRF)

JAMES W. BREW, and LAURA A. WYNN, ESQUIRES, Stone Mattheis
Xenopoulos & Brew, PC, 1025 Thomas Jefferson St., NW, Eighth Floor, West
Tower, Washington, DC 20007

On behalf of White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate –
White Springs (PCS Phosphate)

DANIJELA JANJIC, and SUZANNE BROWNLESS, 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, ESQUIRE, Deputy General Counsel, Florida Public
Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-
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Advisor to the Florida Public Service Commission

KEITH HETRICK, ESQUIRE, General Counsel, Florida Public Service
Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850

Florida Public Service Commission General Counsel.

PREHEARING ORDER

I. CASE BACKGROUND

As part of the continuing fuel and purchased power adjustment and generating performance incentive clause proceedings, an administrative hearing will be held by the Florida Public Service Commission (Commission) on November 2-4, 2016. The Commission will address those issues listed in this prehearing order. The Commission has the option to render a bench decision with agreement of the parties on any or all of the issues listed below.

II. CONDUCT OF PROCEEDINGS

Pursuant to Rule 28-106.211, F.A.C., this Prehearing Order is issued to prevent delay and to promote the just, speedy, and inexpensive determination of all aspects of this case.

III. JURISDICTION

This Commission is vested with jurisdiction over the subject matter by the provisions of Chapter 366, Florida Statutes (F.S.). This hearing will be governed by said Chapter and Chapters 25-6, 25-22, and 28-106, F.A.C., as well as any other applicable provisions of law.

IV. PROCEDURE FOR HANDLING CONFIDENTIAL INFORMATION

Information for which proprietary confidential business information status is requested pursuant to Section 366.093, F.S., and Rule 25-22.006, F.A.C., shall be treated by the Commission as confidential. The information shall be exempt from Section 119.07(1), F.S., pending a formal ruling on such request by the Commission or pending return of the information to the person providing the information. If no determination of confidentiality has been made and the information has not been made a part of the evidentiary record in this proceeding, it shall be returned to the person providing the information. If a determination of confidentiality has been made and the information was not entered into the record of this proceeding, it shall be returned to the person providing the information within the time period set forth in Section 366.093, F.S. The Commission may determine that continued possession of the information is necessary for the Commission to conduct its business.

It is the policy of this Commission that all Commission hearings be open to the public at all times. The Commission also recognizes its obligation pursuant to Section 366.093, F.S., to protect proprietary confidential business information from disclosure outside the proceeding. Therefore, any party wishing to use any proprietary confidential business information, as that term is defined in Section 366.093, F.S., at the hearing shall adhere to the following:

- (1) When confidential information is used in the hearing that has not been filed as prefiled testimony or prefiled exhibits, parties must have copies for the Commissioners, necessary staff, and the court reporter, in red envelopes clearly marked with the nature of the contents and with the confidential information highlighted. Any party wishing to examine the confidential material that is not subject to an order granting confidentiality shall be provided a copy in the same fashion as provided to the Commissioners, subject to execution of any appropriate protective agreement with the owner of the material.
- (2) Counsel and witnesses are cautioned to avoid verbalizing confidential information in such a way that would compromise confidentiality. Therefore, confidential information should be presented by written exhibit when reasonably possible.

At the conclusion of that portion of the hearing that involves confidential information, all copies of confidential exhibits shall be returned to the proffering party. If a confidential exhibit has been admitted into evidence, the copy provided to the court reporter shall be retained in the Office of Commission Clerk's confidential files. If such material is admitted into the evidentiary record at hearing and is not otherwise subject to a request for confidential classification filed with the Commission, the source of the information must file a request for confidential

classification of the information within 21 days of the conclusion of the hearing, as set forth in Rule 25-22.006(8)(b), F.A.C., if continued confidentiality of the information is to be maintained.

V. PREFILED TESTIMONY AND EXHIBITS; WITNESSES

Testimony of all witnesses to be sponsored by the parties and Staff has been prefiled and will be inserted into the record as though read after the witness has taken the stand and affirmed the correctness of the testimony and associated exhibits. All testimony remains subject to timely and appropriate objections. Upon insertion of a witness' testimony, exhibits appended thereto may be marked for identification. Each witness will have the opportunity to orally summarize his or her testimony at the time he or she takes the stand. Summaries of testimony shall be limited to five minutes.

Witnesses are reminded that, on cross-examination, responses to questions calling for a simple yes or no answer shall be so answered first, after which the witness may explain his or her answer. After all parties and Staff have had the opportunity to cross-examine the witness, the exhibit may be moved into the record. All other exhibits may be similarly identified and entered into the record at the appropriate time during the hearing.

The Commission frequently administers the testimonial oath to more than one witness at a time. Therefore, when a witness takes the stand to testify, the attorney calling the witness is directed to ask the witness to affirm whether he or she has been sworn.

The parties shall avoid duplicative or repetitious cross-examination. Further, friendly cross-examination will not be allowed. Cross-examination shall be limited to witnesses whose testimony is adverse to the party desiring to cross-examine. Any party conducting what appears to be a friendly cross-examination of a witness should be prepared to indicate why that witness's direct testimony is adverse to its interests.

VI. ORDER OF WITNESSES

All witnesses are excused from the hearing.

<u>Witness</u>	<u>Proffered By</u>	<u>Issues #</u>
<u>Direct</u>		
Christopher A. Menendez	DEF	2C, 7-12, 19-23, 24A, 28-37
Joseph McCallister	DEF	1A, 1B, 2A, 2B
Matthew J. Jones	DEF	17, 18
Marcia Olivier	DEF	24B, 32

<u>Witness</u>	<u>Proffered By</u>	<u>Issues #</u>
G. J. Yupp	FPL	1A, 1B, 3A-3I, 3K, 9-12, 19
R. B. Deaton (adopting Terry J. Keith)	FPL	3J, 7-12, 19-23, 25, 28-37
C. R. Rote	FPL	17-18
M. Kiley	FPL	9-12, 19
Curtis D. Young	FPUC	9
Michael Cassel	FPUC	10-12, 19-23, 35
P. Mark Cutshaw	FPUC	11-12
Drane Shelley	FPUC	12
H. R. Ball	Gulf	1A, 5A, 5B, 7, 8, 28, 31, 32
C. S. Boyett	Gulf	7, 8, 9, 10, 11, 12, 19, 20, 21, 22, 23, 28, 29, 30, 31, 32, 33, 34, 35, 36
C. L. Nicholson	Gulf	17-18
Penelope A. Rusk	TECO	7,8,9,10,11,12,19,20,21,22,23,28, 29,30,31,32,33,34,35,36,37
Brian S. Buckley	TECO	17,18,19
Benjamin F. Smith	TECO	19, 32
Brent C. Caldwell	TECO	1A, 1B, 6A, 6B, 19
Simon O. Ojada	Staff	Staff Audit Report For Hedging Activities – Duke Energy Florida Inc.
Intesar Terkawi	Staff	Staff Audit Report For Hedging Activities – Tampa Electric Company

<u>Witness</u>	<u>Proffered By</u>	<u>Issues #</u>
Marissa N. Glover	Staff	Staff Audit Report For Hedging Activities – Florida Power & Light Company
Donna D. Brown	Staff	Staff Audit Report For Hedging Activities – Gulf Power Company
Michael A. Gettings	Staff	Expert Witness – Natural Gas Hedging Activities
Mark Anthony Cicchetti	Staff	Expert Witness – Natural Gas Hedging Activities
Tarik Noriega	OPC	1A, 1B
Daniel J. Lawton	OPC	1A, 1B
<u>Rebuttal</u>		
Joseph McCallister	DEF	1A, 1B, 2B
G. J. Yupp	FPL	1A, 1B, 3B
H. R. Ball	Gulf	1A, 1B, 5B
J. Brent Caldwell	TECO	1A, 1B, 6B

VII. BASIC POSITIONS

DEF: Not applicable. DEF’s positions to specific issues are listed below.

FPL: FPL’s 2017 Fuel and Purchased Power Cost Recovery factors and Capacity Cost Recovery factors, including its prior period true-ups, are reasonable and should be approved. As a result of the Florida Supreme Court’s decision on the Woodford Gas Reserves Project, FPL has included a refund to customers in the Fuel Clause of \$24,532,560. FPL’s asset optimization activities in 2015 delivered total gains of \$46,884,377. Of these total gains, FPL is allowed to retain \$530,626. FPL’s Incremental Optimization Costs are reasonable and should be approved for recovery. FPL’s hedging activities, as reported in the April 2016 and August 2016 hedging reports should be approved as compliant with its Commission-approved 2016 Risk Management Plan.

FPL supports and adopts the Joint Stipulation and Agreement for Interim Resolution of Hedging Issues that was filed in this docket on October 24, 2016

(the “Joint Stipulation”). The Commission should approve FPL’s Alternative 2017 Risk Management Plan filed on October 19, 2016, which provides for FPL to financially hedge zero percent of its 2018 projected natural gas requirements. FPL filed the Alternative 2017 Risk Management Plan in implementation of Paragraph 16 of the proposed stipulation and settlement of FPL’s rate case in Docket No. 160021-EI and consolidated dockets that was filed on October 6, 2016 (the “Proposed Settlement Agreement”). In the event that the Proposed Settlement Agreement were not approved, then the Alternative 2017 Risk Management Plan would implement the terms of the Joint Stipulation.

FPUC: The Commission should approve Florida Public Utilities Company’s final net true-up for the period January through December 2015, the estimated true-up for the period January through December, 2016, and the purchase power cost recovery factor for the period January through December, 2017.

GULF: It is the basic position of Gulf Power Company that the fuel and capacity cost recovery factors proposed by the Company present the best estimate of Gulf’s fuel and capacity expense for the period January 2017 through December 2017 including the true-up calculations, GPIF and other adjustments allowed by the Commission.

TECO: The Commission should approve Tampa Electric's calculation of its fuel adjustment, capacity cost recovery and GPIF true-up and projection calculations, including the proposed fuel adjustment factor of 2.951 cents per kWh before any application of time of use multipliers for on-peak or off-peak usage; the company's proposed capacity factor for the period January through December 2017; a GPIF reward of \$969,593 for performance during 2015; and approval of the company’s proposed GPIF targets and ranges for 2017. Tampa Electric also requests approval of its calculated wholesale incentive benchmark of \$1,337,579 for calendar year 2017.

OPC: *Hedging Issues 1A and 1B*

The Commission should re-examine and, based on the evidence submitted by the OPC, discontinue natural gas financial hedging practices by Florida investor-owned utilities. The testimony of Tarik Noriega and Dan Lawton provides compelling evidence that natural gas financial hedging is not in the best interests of Florida’s electric utility customers. The costs of hedging paid by customers has exceeded \$6.5 billion. These customer costs greatly outweigh any customer or shareholder benefits (e.g., reduced fuel price volatility experienced by customers, and reduced shareholder liquidity risks) received from hedging.

OPC witness Noriega reviewed the hedging gains (savings) and costs (losses) incurred since 2002 by the four Companies which financially hedge natural gas – Florida Power & Light Company (FPL), Duke Energy Florida (DEF or Duke), Gulf Power Company (Gulf), and Tampa Electric Company (TECO)

(collectively, Companies). From 2002 to 2015, the cumulative natural gas hedging losses for these Companies are approximately \$6.2 billion dollars. For 2016, the actual and estimate hedging losses exceed \$443 million, bringing the combined hedging losses paid by customers to over \$6.5 billion dollars. If the natural gas financial hedging programs are allowed to continue, OPC believes these losses are likely to continue detrimentally impacting the Companies' customers.

The stated purpose of natural gas financial hedging is to protect customers from fuel price volatility. However, the Commission's *annual* fuel adjustment clause proceeding and mid-course correction rule already effectively, efficiently, and economically mitigate against and reduce fuel price volatility experienced by the customers on their monthly bills. Unlike financial hedging, the annual fuel adjustment clause and mid-course correction rule do not result in lost cost opportunities for customers, while still mitigating the impacts of fuel price volatility.

While customers pay all the hedging costs, OPC witness Lawton describes how the shareholders reap the benefit of reduced shareholder liquidity risk. Shareholders' liquidity risks are reduced because the Companies are able to recover all their hedged fuel costs on a current basis, which is not the case if there is a significant under-recovery. Thus, Companies have an incentive to continue hedging in the face of financial losses.

It is the utilities' burden of proof to demonstrate that the customer benefits of continuing natural gas financial hedging to decrease fuel price volatility, as well as the shareholder benefits of reduced liquidity risk outweigh the costs of hedging as evidenced by the over \$6.5 billion in customer costs paid since 2002 (\$2.4 billion since 2011). If financial hedging is an insurance policy against fuel price volatility, then \$6.5 billion is an unacceptable premium paid by the customers to protect them from something that is already sufficiently mitigated by the annual fuel adjustment clause mechanism and mid-course correction rule.

OPC submits the natural gas financial hedging programs should be reevaluated and terminated based upon the current condition of the natural gas markets and projections. The Commission should deny the Company's Risk Management Plans as they relate to natural gas financial hedging activities, and should suspend and end the practice of natural gas financial hedging. The hedging transactions currently in place pursuant to Commission approved Risk Management Plans should be allowed to settle; however, the Commission should direct the Companies not to enter into any additional financial hedging transactions until such time as the Companies prove that financial hedging would provide a net benefit to the customers without the enormous downside costs cumulatively experienced by the customers since 2002.

OPC takes no position on other hedging activities described in the Companies' proposed 2016 Risk Management Plans. However, to the extent these other activities would authorize the hedging of natural gas, the plans should be rejected.

Other Issues

The utilities have the burden of proof to justify and support the recovery of costs and their proposal(s) seeking the Commission's adoption of policy statements (whether new or changed) or other affirmative relief sought, regardless of whether the Interveners provide evidence to the contrary. Regardless of whether the Commission has previously approved a program as meeting the Commission's requirements, the utilities must still meet their burden of demonstrating that the costs submitted for final recovery meet the statutory test(s) and are reasonable in amount and prudently incurred.

FIPUG:

Utility hedging should be discontinued immediately. During last year's fuel clause hearing, intervenor parties presented evidence that losses associated with utility hedging practices continue to mount. Total hedging losses suffered by customers is now approximately \$6.5 billion dollars. Those losses continue unabated, as customers are being asked to pay for the following hedging losses for 2015 and 2016 as of July 31, 2016 in this year's proceeding.

2015

FPL: \$504,393,229 dollar loss
Duke: \$225,543,645 dollar loss
TECO: \$39,842,325 dollar loss
Gulf: \$50,572,362 dollar loss

2016 (January 1 through July 31)

FPL: \$190,763,980 dollar loss
Duke: \$114,900,000 dollar loss
TECO: \$17,877,735 dollar loss
Gulf: \$37,505,696 dollar loss

Additionally, FIPUG adopts the position of the Office of Public Counsel on all hedging issues in this case. Finally, only costs legally authorized should be recovered through the fuel clause. FIPUG maintains that the respective utilities must satisfy their burden of proof for any and all monies or other relief sought in this proceeding.

FRF: **Fuel Cost Hedging Issues**

Based on the evidence presented by the Citizens' witnesses, the Commission should order Florida's investor-owned utilities ("IOUs") to discontinue their financial hedging practices. The testimony of the Citizens' witnesses provides compelling evidence that hedging is not in the best interests of electric utility customers in Florida. Accordingly, the Commission should also reject the IOUs' Risk Management Plans

Other Issues

All of the investor-owned electric utilities bear the burden of proving the reasonableness and prudence of their expenditures for which they seek recovery through their Fuel and Purchased Power Cost Recovery Charges.

PCS

PHOSPHATE: The principal issue affecting the Florida utility fuel factors in this docket concerns the hedging losses that have been realized by virtue of the volume-targeted hedging practices being employed today. Concerns regarding the losses have been building for some time while the Florida electric utilities have continued to incur substantial additional losses as they have hedged in declining cost natural gas markets. These losses have not been the result of poor market timing or an inaccurate assessment of market dynamics, but are instead the product of a hedging approach that is largely indifferent to market pricing trends, risk factors and related considerations.

Last year, the Public Counsel and other consumer parties urged the Commission to direct the utilities to discontinue hedging on the grounds that the current hedging practice does not serve the public interest, and OPC continues to advocate for suspension of hedging activities. In a proposal submitted earlier this year, the utilities collectively proposed to lower their hedging targets but not to alter the manner in which they conduct hedging. In PCS's view, the utility proposal was responsive to OPC's objections without being helpful and should not be adopted.

Notably, the Commission staff has submitted testimony that thoughtfully addresses the core concerns that are at stake. In short, Staff witnesses correctly explain that the existing volume-targeted fuel hedging approach aims to mitigate fuel cost volatility without creating a prudence (cost recovery) issue tied to utility fuel purchasing actions that are based on an actual appraisal of going forward fuel price trends. This existing approach hedges fuel prices badly and tends to induce actions designed more to avoid regulatory "second-guessing" than to benefit consumers.

As the generation fleets of Florida's utilities, and Duke Energy Florida's in particular, are becoming much more natural gas reliant, sound gas-purchasing strategies are essential to ensuring electric service at just and reasonable rates. PCS supports the Staff recommendations to abandon the current volume-targeted hedging approach and to require a more nuanced approach to fuel price risk assessment and purchasing that systematically evaluates pricing trends and risks.

Moreover, the heightened reliance on natural gas produces broader fuel and rate issues that the Commission should address. Specifically, as gas-fired units operate as both base-load and peaking units, the differential between on and off peak fuel prices continues to shrink as marginal generation costs during both periods increasingly are tied to gas costs. This reduces the price signals that apply to peak period usage and is inconsistent with the Commission's obligations under FEECA, which stresses the importance of reducing and controlling growth in weather sensitive peak load. Sec. 366.81, F.S. PCS asks that the Commission direct DEF to set a minimum differential between on and off peak fuel prices and to address the issue further in the next fuel proceeding..

STAFF: Staff's positions are preliminary and based on materials filed by the parties and on discovery. The preliminary positions are offered to assist the parties in preparing for the hearing. Staff's final positions will be based upon all the evidence in the record and may differ from the preliminary positions.

VIII. ISSUES AND POSITIONS

I. FUEL ISSUES

HEDGING ISSUES

ISSUE 1A: Is it in the consumers' best interest for the utilities to continue natural gas financial hedging activities?

** Proposed Type 2 Stipulation (Joint Stipulation as to DEF, FPL, Gulf, TECO, OPC, FIPUG and FRF). See Section X.*

FPUC: No position.

PCS

PHOSPHATE: PCS Phosphate Response to the Joint Stipulation:

PCS supports deferring Commission action on this issue at this time and establishing an open stakeholder process, including the workshops suggested in the Joint Stipulation, to discuss and assess hedging alternatives that would better serve Florida electric consumers. These are complex issues that will require time to evaluate as well as to attempt to reconcile competing methods and

perspectives. Simply deferring needed Commission action on utility hedging practices, however, does not benefit consumers if it merely postpones litigation of positions and testimony that have been filed and are pending in this docket. Accordingly, the workshops and other actions contemplated for a generic hedging docket must be initiated on an expedited basis to provide the greatest possible opportunity for development of a policy consensus in 2017.

STAFF: No objection to the Joint Stipulation.

ISSUE 1B: **What changes, if any, should be made to the manner in which electric utilities conduct their natural gas financial hedging activities?**

** Proposed Stipulation as to DEF, FPL, Gulf, TECO, OPC, FIPUG and FRF. See Section X.*

FPUC: No position.

PCS

PHOSPHATE: **PCS Phosphate Response to the Joint Stipulation:**

Based on current market conditions and DEF discovery responses, PCS does not support a hedging moratorium from the time of Commission approval of the proposed Joint Stipulation to the end of calendar year 2017 for Duke Energy Florida. Although DEF's 2017 Risk Management Plans has been withdrawn, planned hedging actions, primarily affecting 2018, will be affected by the proposed moratorium. The Commission should direct DEF to continue its hedging plan as filed and approved by the Commission in 150001-EI.

STAFF: No objection to the Joint Stipulation.

COMPANY-SPECIFIC FUEL ADJUSTMENT ISSUES

Duke Energy Florida, LLC

ISSUE 2A: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 2B: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 2C: *Proposed Type 2 Stipulation, See Section X.*

Florida Power & Light Company

ISSUE 3A: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 3B: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 3C: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 3D: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 3E: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 3F: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 3G: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 3H: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 3I: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 3J: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 3K: *Proposed Type 2 Stipulation, See Section X.*

Florida Public Utilities Company

No company-specific issues for Florida Public Utilities Company have been identified.

Gulf Power Company

ISSUE 5A: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 5B: *Proposed Type 2 Stipulation, See Section X.*

Tampa Electric Company

ISSUE 6A: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 6B: *Proposed Type 2 Stipulation, See Section X.*

GENERIC FUEL ADJUSTMENT ISSUES

ISSUE 7: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 8: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 9: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 10: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 11: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 12: *Proposed Type 2 Stipulation, See Section X.*

COMPANY-SPECIFIC GENERATING PERFORMANCE INCENTIVE FACTOR ISSUES

No company-specific issues for DEF, FPL, Gulf and TECO have been identified.

GENERIC GENERATING PERFORMANCE INCENTIVE FACTOR ISSUES

ISSUE 17: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 18: *Proposed Type 2 Stipulation, See Section X.*

FUEL FACTOR CALCULATION ISSUES

ISSUE 19: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 20: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 21: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 22: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 23: *Proposed Type 2 Stipulation, See Section X.*

II. CAPACITY ISSUES

COMPANY-SPECIFIC CAPACITY COST RECOVERY FACTOR ISSUES

Duke Energy Florida, LLC

ISSUE 24A: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 24B: *Proposed Type 2 Stipulation, See Section X.*

Florida Power & Light Company

ISSUE 25: *Proposed Type 2 Stipulation, See Section X.*

Gulf Power Company

No company-specific issues for Gulf have been identified.

Tampa Electric Company

No company-specific issues for TECO have been identified.

GENERIC CAPACITY COST RECOVERY FACTOR ISSUES

ISSUE 28: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 29: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 30: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 31: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 32: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 33: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 34: *Proposed Type 2 Stipulation, See Section X.*

III. EFFECTIVE DATE

ISSUE 35: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 36: *Proposed Type 2 Stipulation, See Section X.*

ISSUE 37: *Proposed Type 2 Stipulation, See Section X.*

IX. EXHIBIT LIST

<u>Witness</u>	<u>Proffered By</u>		<u>Description</u>
			<u>Direct</u>
Menendez	DEF	CAM-1T	Fuel Cost Recovery True-Up (Jan – Dec. 2015)
		CAM-2T	Capacity Cost Recovery True-Up (Jan – Dec. 2015)
		CAM-3T	Schedules A1 through A3, A6 and A12 for Dec 2015

<u>Witness</u>	<u>Proffered By</u>	<u>Description</u>
		CAM-4T 2015 Capital Structure and Cost Rates Applied to Capital Projects
		CAM-2 Actual/Estimated true-up Schedules for period January – December 2016 (Confidential)
		CAM-3 Projection factors for January to December 2017 (Confidential)
McCallister	DEF	JM-1T Hedging True-Up August through December 2015 (Confidential)
		JM-2T Hedging Monthly Projected light oil burns (Confidential)
		JM-1P 2017 Risk Management Plan (Confidential)
		JM-2P Hedging Report (January – July 2016) (Confidential)
Jones	DEF	MJJ-1T GPIF Reward/Penalty Schedules for 2015
		MJJ-1P GPIF Targets/Ranges Schedules (for Jan – Dec. 2017)
Olivier	DEF	MO-1 Projection factors for January to December 2017-ISFSI
		MO-2 Projection factors for January to December 2017-Batch 19 Fuel Sale- (Confidential)
		MO-3 Projection factors for January to December 2017-RRSSA Second Amendment- (Confidential)

<u>Witness</u>	<u>Proffered By</u>	<u>Description</u>
		CAM-3 Co-sponsoring Schedule E12-A, Page 1 of 2: Lines 26, 27, and 38 - (Confidential)
Deaton (adopting Terry J. Keith)	FPL	TJK-1 Fuel Cost Recovery 2015 Final True Up Calculation
		TJK-2 Capacity Cost Recovery 2015 Final True Up Calculation (Confidential)
		TJK-3 FCR 2016 Actual/Estimated True Up Calculation
		TJK-4 CCR 2016 Actual/Estimated True Up Calculation
		TJK-5 FCR 2017 E-Schedules Jan through Dec 2017
		TJK-6 CCR 2017 E-Schedules Jan through Dec 2017 Proposed Cost Allocation Methodology 12 CP and 25% (Confidential)
		TJK-7 CCR 2017 E-Schedules Jan through Dec 2017 Current Cost Allocation Methodology 12 CP and 1/13 th
		TJK-8 2017 Revenue Requirement Calculation for West County Energy Center Unit 3
Yupp	FPL	GJY-1 2015 Incentive Mechanism Results (Confidential)
		GJY-2 August 2015 through December 2015 Hedging Activity True-up Report (Confidential)
		GJY-3 Woodford Refund Calculation
		GJY-4 VOM Correction Refund

<u>Witness</u>	<u>Proffered By</u>	<u>Description</u>
		GJY-5 FCR 2017 Risk Management Plan (Confidential)
		GJY-6 Hedging Activity Report (Confidential)
		GJY-7 Fuel Cost Recovery Forecast Assumptions
		GJY-8 FCR Alternative 2017 Risk Management Plan
Rote	FPL	CRR-1 Generating Performance Incentive Factor Performance Results for January 2015 through December 2015
		CRR-2 Generating Performance Incentive Factor Performance Targets for January 2017 through December 2017
Young	FPUC	CDY-1 Final True Up Schedules (Schedules A, C1 and E1-B for FPUC's Divisions)
Cassel	FPUC	MC-1 Estimated/Actual (Schedules EI-A, EI-B, and EI-B1)
		MC-2 Schedules E1, E1A, E2, E7, E8, E10 and Schedule A Schedule A- (Confidential)
Ball	Gulf	HRB-1 Coal Suppliers, Natural Gas Price Variance, Hedging Effectiveness
		HRB-2 Projected vs. Actual Fuel Cost of System Generation Comparison 2006 - 2017
		HRB-3 Hedging Information Report August – December 2015 (Confidential)

<u>Witness</u>	<u>Proffered By</u>	<u>Description</u>
		HRB-4 Hedging Information Report January – July 2016 (Confidential)
		HRB-5 Risk Management Plan for Fuel Procurement for 2017 (Confidential)
Boyett	Gulf	CSB-1 Calculation of Final True-Up and A-Schedules January 2015 – December 2015 (Confidential)
		CSB-2 Estimated True-Up January 2016 – December 2016 (Confidential)
		CSB-3 Projection January 2017 – December 2017 (Confidential)
Nicholson	Gulf	CLN-1 Gulf Power Company GPIF Results January 2015 – December 2015
		CLN-2 Gulf Power Company GPIF Targets and Ranges January 2017 – December 2017
Rusk	TECO	PAR-1 Final True-up Capacity Cost Recovery January 2015 - December 2015
		PAR-1 Final True-up Fuel Cost Recovery January 2015 – December 2015
		PAR-1 Actual Fuel True-up Compared to Original Estimates January 2015 – December 2015
		PAR-1 Schedules A-1, A-2 and A-6 through A-9 and A-12 January 2015 – December 2015 (Confidential)

<u>Witness</u>	<u>Proffered By</u>	<u>Description</u>
		PAR-1 Capital Projects approved for Fuel Clause Recovery January 2015 – December 2015
		PAR-2 Actual/Estimated True-Up Fuel Cost Recovery January 2016 – December 2016
		PAR-2 Actual/Estimated True-Up Capacity Cost Recovery January 2016– December 2016 (Confidential)
		PAR-2 Capital Projects Approved for Fuel Clause Recovery January 2016 – December 2016
		PAR-3 Projected Capacity Cost Recovery January 2017 – December 2017 (Confidential)
		PAR-3 Projected Fuel Cost Recovery January 2017 – December 2017
		PAR-3 Levelized and Tiered Fuel Rate January 2017– December 2017
		PAR-3 Capital Projects Approved for Fuel Clause Recovery January 2017 – December 2017
Buckley	TECO	BSB-1 Final True-Up Generating Performance Incentive Factor January 2015 – December 2015
		BSB-1 Actual Unit Performance Data January 2015 – December 2015
		BSB-2 Generating Performance Incentive Factor January 2017 – December 2017

<u>Witness</u>	<u>Proffered By</u>	<u>Description</u>
		BSB-2 Summary of Generating Performance Incentive Factor Targets January 2017 – December 2017
Caldwell	TECO	JBC-1 Final True-Up Hedging Activity Report January 2015 – December 2015 (Confidential)
		JBC-2 Risk Management Plan January 2017 – December 2017 (Confidential)
		JBC-3 Natural Gas Hedging Report January 2016 – July 2016 (Confidential)
Noriega	OPC	TN-1 Résumé of Tarik Noriega
		TN-2 IOU Natural Gas Hedging Gains/(Losses) From 2002-2015
		TN-3 IOU Discovery Responses
Lawton	OPC	DJL-1 Resume of Daniel J. Lawton
		DJL-2 Testimony & Exhibits of Daniel J. Lawton filed in Docket No. 150001-EI
		DJL-3 Monthly Henry Hub Spot Prices \$/MMBTU
		DJL-4 Hedging Gains & Losses Summary (2002-2016)
		DJL-5 Excerpt From Dewhurst Deposition
		DJL-6 FPL Witness Yupp's 2015 Analysis of Hedging Volatility Reduction Benefits

		DJL-7	Alternative Non-Hedging Fuel Factor
Ojada	Staff	SOO-1	Staff Audit Report For Hedging Activities – DEF
Terkawi	Staff	IT-1	Staff Audit Report For Hedging Activities – TEC
Glover	Staff	MNG-1	Staff Audit Report For Hedging Activities - FPL
Brown	Staff	DDB-1	Staff Audit Report For Hedging Activities – GPC
Gettings	Staff	MAG-1	Curriculum Vitae of Michael A. Gettings
	Staff	MAG-2	Sample Quarterly Risk Report
	Staff	MAG-3	Glossary of Terms
Cicchetti	Staff	MAC-1	Curriculum Vitae of Mark Anthony Chicchetti
	Staff	MAC-2	Henry Hub Spot Price (January, 1997 through August, 2016)
	Staff	MAC-3	Proposed Resolution of Issues (from Order No. PSC-02-1484-FOF-EI)
	Staff	MAC-4	Utility Hedging Practices summary
	Staff	MAC-5	Hedging Under Scrutiny article

Parties and Staff reserve the right to identify additional exhibits for the purpose of cross-examination.

X. PROPOSED STIPULATIONS

As referenced in Section VIII, above, the parties have reached Type 2 stipulations on the issues described below. *Type 2 Stipulations* reflect stipulations upon which certain parties agree and the remaining parties take no position.

I. FUEL ISSUES

HEDGING ISSUES

ISSUE 1A: Is it in the consumers' best interest for the utilities to continue natural gas financial hedging activities?

**** Proposed Stipulation as to DEF, FPL, Gulf, TECO, OPC, FIPUG and FRF.***

STIPULATION: Consistent with the Joint Stipulation and Agreement for Interim Resolution of Hedging issues, dated October 24, 2016 (the "Joint Stipulation"), this issue should be deferred to the 2017 docket and the Joint Stipulation accepted as the replacement for the signatory companies' respective Risk Management Plans for 2017, rendering moot the company specific issues regarding their request for approval of their respective Risk Management Plans as filed for 2017. The parties to the Joint Stipulation request that the Commission direct staff to open a generic docket as soon as possible to allow all interested parties to engage in a workshop or workshops to consider all alternatives to prospectively resolving the hedging issues, including but not limited to the Gettings/Cicchetti approach, a reduction in the current levels of hedging and hedging durations, use of different financial products, or the termination of financial hedging altogether, with the goal of providing guidelines for risk management plans for 2018 and beyond that all stakeholders can either agree upon or not object to.

ISSUE 1B: What changes, if any, should be made to the manner in which electric utilities conduct their natural gas financial hedging activities?

**** Proposed Stipulation as to DEF, FPL, Gulf, TECO, OPC, FIPUG and FRF.***

STIPULATION: Consistent with the Joint Stipulation and Agreement for Interim Resolution of Hedging issues, dated October 24, 2016 (the "Joint Stipulation"), the parties have agreed to a moratorium on any new hedges effective immediately upon the Commission's approval of the stipulated positions offered on the hedging issues in this docket, with that moratorium extending through calendar year 2017 and therefore this issue should be deferred to the 2017 docket and the Joint Stipulation accepted as the replacement for the signatory companies' respective Risk Management Plans for 2017, rendering moot the company specific issues regarding their request for approval of their respective Risk Management Plans as filed for 2017. The parties to the Joint Stipulation request that the Commission direct staff to open a generic docket as soon as possible to allow all interested parties to engage in a workshop or workshops to consider all alternatives to prospectively resolving the hedging issues, including but not limited to the Gettings/Cicchetti approach, a reduction in the current levels of hedging and hedging durations, use of different financial products, or the termination of financial hedging altogether, with the goal of providing guidelines for risk

management plans for 2018 and beyond that all stakeholders can either agree upon or not object to.

COMPANY-SPECIFIC FUEL ADJUSTMENT ISSUES

Duke Energy Florida, LLC

ISSUE 2A: Should the Commission approve as prudent DEF's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in DEF's April 2016 and August 2016 hedging reports?

**Type 2 Stipulation*

STIPULATION: Yes, the Commission should approve as prudent DEF's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in DEF's April 2016 and August 2016 hedging reports.

ISSUE 2B: What action should the Commission take regarding DEF's 2017 Risk Management Plan?

**Type 2 Stipulation*

STIPULATION: Consistent with the Joint Stipulation and Agreement for Interim Resolution of Hedging issues, dated October 24, 2016 (the "Joint Stipulation"), this issue is rendered moot upon the Commission's acceptance and approval of the proposed stipulations on Issues 1A and 1B.

ISSUE 2C: Has DEF made appropriate adjustments, if any are needed, to account for replacement costs associated with the May 2016 forced outage at the Hines plant? If appropriate adjustments are needed and have not been made, what adjustment(s) should be made?

**Type 2 Stipulation*

STIPULATION: This issue is not ripe for resolution at this time. As of the date DEF filed its fuel cost recovery projections for 2017, the root cause analysis report for the May 2016 forced outage at Hines Unit 4 had not been completed, and decisions on appropriate adjustments, if any are needed, to account for replacement costs are premature. DEF has not included any replacement power costs to-date, and any necessary adjustments will be addressed in DEF's 2016 Final True-up filing.

Florida Power & Light Company

ISSUE 3A: Should the Commission approve as prudent FPL's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in FPL's April 2016 and August 2016 hedging reports?

**Type 2 Stipulation*

STIPULATION: Yes. FPL's risk management plan currently involves only natural gas hedging. FPL's actions to mitigate the price volatility of natural gas, as reported in FPL's April 2016 and August 2016 hedging reports, are reasonable and prudent.

ISSUE 3B: What action should the Commission take regarding FPL's 2017 Risk Management Plan?

**Type 2 Stipulation*

STIPULATION: The Commission should approve FPL's Alternative 2017 Risk Management Plan filed on October 19, 2016, which provides for FPL to financially hedge zero percent of its 2018 projected natural gas requirements. FPL filed the Alternative 2017 Risk Management Plan in implementation of Paragraph 16 of the proposed stipulation and settlement of FPL's rate case in Docket No. 160021-EI and consolidated dockets that was filed on October 6, 2016 (the "Proposed Settlement Agreement"). In the event that the Proposed Settlement Agreement were not approved, then the Alternative 2017 Risk Management Plan would implement the terms of the Joint Stipulation, which FPL supports.

ISSUE 3C: What is the total gain in 2015 under the Incentive Mechanism approved in Order No. PSC-13-0023-S-EI, and how is that gain to be shared between FPL and customers?

**Type 2 Stipulation*

STIPULATION: The total gain in 2015 under the Incentive Mechanism approved in Order No. PSC-13-0023-S-EI, was \$46,884,377. This amount should be shared between FPL and customers, with FPL retaining \$530,626.

ISSUE 3D: What is the appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for Personnel, Software, and Hardware costs for the period January 2015 through December 2015?

**Type 2 Stipulation*

STIPULATION: The appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for Personnel, Software, and Hardware costs for the period January 2015 through December 2015 is \$473,550.

ISSUE 3E: What is the appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for variable power plant O&M costs incurred to generate output for wholesale sales in excess of 514,000 megawatt-hours for the period January 2015 through December 2015?

**Type 2 Stipulation*

STIPULATION: The appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for variable power plant O&M costs incurred to generate output for wholesale sales in excess of 514,000 megawatt-hours for the period January 2015 through December 2015 is \$2,563,924.

ISSUE 3F: What is the appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for Personnel, Software, and Hardware costs for the period January 2016 through December 2016?

**Type 2 Stipulation*

STIPULATION: The appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for Personnel, Software, and Hardware costs for the period January 2016 through December 2016 is \$476,389.

ISSUE 3G: What is the appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for variable power plant O&M costs incurred to generate output for wholesale sales in excess of 514,000 megawatt-hours for the period January 2016 through December 2016?

**Type 2 Stipulation*

STIPULATION: The appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for variable power plant O&M costs incurred to generate output for wholesale sales in excess of 514,000 megawatt-hours for the period January 2016 through December 2016 is \$2,277,340.

ISSUE 3H: If the Commission approves FPL's petition to continue the Incentive Mechanism with modifications in Docket No. 160088-EI, what is the appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for Personnel, Software, and Hardware costs for the period January 2017 through December 2017?

**Type 2 Stipulation*

STIPULATION: On October 6, 2016, FPL, the Office of Public Counsel, the South Florida Hospital and Healthcare Association and the Florida Retail Federation jointly moved for approval of a proposed stipulation and settlement of FPL's rate case in Docket No. 160021-EI and consolidated dockets (the "Proposed Settlement Agreement"). The Proposed Settlement Agreement states that the Incentive Mechanism should continue, subject to certain modifications.

The appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for Personnel, Software, and Hardware costs for the period January 2017 through December 2017 is \$476,708.

If the Commission does not approve the Proposed Settlement Agreement or otherwise decides the Incentive Mechanism should not be continued, then the appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for Personnel, Software, and Hardware costs for the period January 2017 through December 2017 is \$0.

ISSUE 3I: If the Commission approves FPL's petition to continue the Incentive Mechanism with modifications in Docket No. 160088-EI, what is the appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for variable power plant O&M costs associated with wholesale economy sales and purchases for the period January 2017 through December 2017?

**Type 2 Stipulation*

STIPULATION: On October 6, 2016, FPL, the Office of Public Counsel, the South Florida Hospital and Healthcare Association and the Florida Retail Federation jointly moved for approval of a proposed stipulation and settlement of FPL's rate case in Docket No. 160021-EI and consolidated dockets (the "Proposed Settlement Agreement"). The Proposed Settlement Agreement states that the Incentive Mechanism should continue, subject to certain modifications.

The appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for variable power plant O&M costs associated with wholesale economy sales and purchases for the period January 2017 through December 2017 is \$496,340.

If the Commission does not approve the Proposed Settlement Agreement or otherwise decides the Incentive Mechanism should not be continued, then the appropriate amount of Incremental Optimization Costs under the Incentive Mechanism that FPL should be allowed to recover through the fuel clause for variable power plant O&M costs associated with wholesale economy sales and purchases for the period January 2017 through December 2017 is \$0.

ISSUE 3J: Is \$1,890,528 the appropriate refund amount associated with the Cape Canaveral Energy Center (CCEC) GBRA true-up?

**Type 2 Stipulation*

STIPULATION: Yes. The appropriate refund amount associated with the Cape Canaveral Energy Center (CCEC) GBRA true-up is \$1,890,528. This refund is reflected as a credit to FPL's projected capacity costs for 2017.

ISSUE 3K: What amount should be refunded to customers in the Fuel Clause as a result of the Florida Supreme Court's decision on the Woodford gas reserves project?

**Type 2 Stipulation*

STIPULATION: The amount that should be refunded to customers in the Fuel Clause as a result of the Florida Supreme Court's decision on the Woodford Gas Reserves Project is \$24,532,560, which includes interest of \$38,999 calculated from March 2015 through June 2016. This \$24,532,560 consists of \$21,294,315 credited to customers in June 2016 plus \$3,238,245 that is reflected in the 2016 monthly true-up amounts.

Florida Public Utilities Company

No company-specific issues for FPUC have been identified.

Gulf Power Company

ISSUE 5A: Should the Commission approve as prudent Gulf's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in Gulf's April 2016 and August 2016 hedging reports?

**Type 2 Stipulation*

STIPULATION: Yes, the Commission should approve as prudent Gulf's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in Gulf's April 2016 and August 2016 hedging reports.

ISSUE 5B: What action should the Commission take regarding Gulf's 2017 Risk Management Plan?

**Type 2 Stipulation*

STIPULATION: Consistent with the Joint Stipulation and Agreement for Interim Resolution of Hedging issues, dated October 24, 2016 (the "Joint Stipulation"), this issue is rendered moot upon the Commission's acceptance and approval of the proposed stipulations on Issues 1A and 1B.

Tampa Electric Company

ISSUE 6A: Should the Commission approve as prudent TECO's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in TECO's April 2016 and August 2016 hedging reports?

**Type 2 Stipulation*

STIPULATION: Yes, the Commission should approve as prudent TECO's actions to mitigate the volatility of natural gas, residual oil, and purchased power prices, as reported in TECO's April 2016 and August 2016 hedging reports.

ISSUE 6B: What action should the Commission take regarding TECO's 2017 Risk Management Plan?

**Type 2 Stipulation*

STIPULATION: Consistent with the Joint Stipulation and Agreement for Interim Resolution of Hedging issues, dated October 24, 2016 (the "Joint Stipulation"), this issue is rendered moot upon the Commission's acceptance and approval of the proposed stipulations on Issues 1A and 1B.

GENERIC FUEL ADJUSTMENT ISSUES

ISSUE 7: What are the appropriate actual benchmark levels for calendar year 2016 for gains on non-separated wholesale energy sales eligible for a shareholder incentive?

** Type 2 Stipulation*

STIPULATION: The appropriate actual benchmark levels for calendar year 2016 for gains on non-separated wholesale energy sales eligible for a shareholder incentive are as follows:

DEF: \$2,880,457.

FPL: Pursuant to the Stipulation and Settlement that was approved by the Commission in Order No. PSC-13-0023-S-EI, FPL implemented an Incentive Mechanism program which does not rely upon the three-year average Shareholder Incentive Benchmark specified in Order No. PSC-00-1744-PAA-EI. Setting the appropriate actual benchmark levels for calendar year 2016 for gains on non-separated wholesale energy sales eligible for a shareholder incentive is not applicable to FPL for calendar year 2016.

GULF: \$703,718.

TECO: \$1,563,273.

ISSUE 8: **What are the appropriate estimated benchmark levels for calendar year 2017 for gains on non-separated wholesale energy sales eligible for a shareholder incentive?**

**** Type 2 Stipulation***

STIPULATION: The appropriate estimated benchmark levels for calendar year 2017 for gains on non-separated wholesale energy sales eligible for a shareholder incentive are as follows:

DEF: \$2,933,170.

FPL: Pursuant to the Stipulation and Settlement that was approved by the Commission in Order No. PSC-13-0023-S-EI (the "2012 Settlement Agreement") , FPL implemented an Incentive Mechanism program which does not rely upon the three-year average Shareholder Incentive Benchmark specified in Order No. PSC-00-1744-PAA-EI. Setting the appropriate estimated benchmark levels for gains on non-separated wholesale energy sales eligible for a shareholder incentive is not applicable to FPL as part of its Incentive Mechanism.

The 2012 Settlement Agreement will expire at the end of 2016. However, on October 6, 2016, FPL, the Office of Public Counsel, the South Florida Hospital and Healthcare Association and the Florida Retail Federation jointly moved for approval of a proposed stipulation and settlement of FPL's rate case in Docket No. 160021-EI and consolidated dockets (the "Proposed Settlement Agreement"). The Proposed Settlement Agreement states that the Incentive Mechanism should continue, subject to certain modifications. In the event that the

Commission does not approve continuation of the modified Incentive Mechanism, FPL will file with the 2016 final true-up filing in March 2017 its actual benchmark levels for calendar year 2017 for gains on non-separated wholesale energy sales eligible for a shareholder incentive.

GULF: \$802,125.

TECO: \$1,337,579.

ISSUE 9: **What are the appropriate final fuel adjustment true-up amounts for the period January 2015 through December 2015?**

** Type 2 Stipulation*

STIPULATION: The appropriate fuel adjustment actual/estimated true-up amounts for the period January 2015 through December 2015 are as follows:

DEF: \$25,816, under-recovery.

FPL: The final fuel adjustment true-up amount of \$29,767,250, over-recovery was addressed by the mid-course correction approved by Order No. PSC 16-0120-PCO-EI.

FPUC: \$28,109, under-recovery.

GULF: \$1,324,066, under-recovery.

TECO: \$18,058,299, over-recovery.

ISSUE 10: **What are the appropriate fuel adjustment actual/estimated true-up amounts for the period January 2016 through December 2016?**

** Type 2 Stipulation*

STIPULATION: The appropriate fuel adjustment actual/estimated true-up amounts for the period January 2016 through December 2016 are as follows:

DEF: \$26,191,847, under-recovery.

FPL: \$26,483,684, under-recovery.

FPUC: \$1,261,783, under-recovery.

GULF: \$27,383,731, over-recovery.

TECO: \$104,581,497, over-recovery.

ISSUE 11: What are the appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2017 to December 2017?

** Type 2 Stipulation*

STIPULATION: The appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2017 through December 2017 are as follows:

DEF: \$26,217,663, to be collected (under-recovery).

FPL: \$26,483,684, to be collected (under-recovery).

FPUC: \$1,289,892, to be collected (under-recovery).

GULF: \$26,059,665, to be refunded (over-recovery).

TECO: \$122,639,796, to be refunded (over-recovery).

ISSUE 12: What are the appropriate projected total fuel and purchased power cost recovery amounts for the period January 2017 through December 2017?

**Type 2 Stipulation*

STIPULATION: The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2017 through December 2017 are as follows:

DEF: \$1,406,748,451.

FPL: \$2,966,325,004, which excludes prior period true up amounts, revenue taxes, the GPIF reward, the Vendor Settlement Refund, and FPL's portion of gains from its Incentive Mechanism.

FPUC: \$64,925,483.

GULF: \$346,008,822, including prior period true up amounts and revenue taxes.

TECO: \$562,715,593, which is adjusted by the jurisdictional separation factor, excluding the GPIF reward and the revenue tax factor, but including the prior period true up amounts.

COMPANY-SPECIFIC GENERATING PERFORMANCE INCENTIVE FACTOR ISSUES

No company-specific issues for DEF, FPL, Gulf and TECO have been identified

GENERIC GENERATING PERFORMANCE INCENTIVE FACTOR ISSUES

ISSUE 17: What is the appropriate generation performance incentive factor (GPIF) reward or penalty for performance achieved during the period January 2015 through December 2015 for each investor-owned electric utility subject to the GPIF?

**Type 2 Stipulation*

STIPULATION: The appropriate generation performance incentive factor (GPIF) rewards or penalty for performance achieved during the period January 2015 through December 2015 for each investor-owned electric utility subject to the GPIF are:

DEF: \$2,255,421 reward.

FPL: \$31,658,059 reward.

GULF: \$45,708 penalty.

TECO: \$969,593 reward.

ISSUE 18: What should the GPIF targets/ranges be for the period January 2017 through December 2017 for each investor-owned electric utility subject to the GPIF?

**Type 2 Stipulation*

STIPULATION: The GPIF targets/ranges for the period January 2017 through December 2017 for each investor-owned electric utility subject to the GPIF are:

Company	Plant/Unit	EAF			ANOHR		
		Target	Maximum		Target	Maximum	
		EAF (%)	EAF (%)	Savings (\$000's)	ANOHR BTU/KWH	ANOHR BTU/KWH	Savings (\$000's)
<u>DEF:</u>	Bartow 4	90.2	92.6	1,643	7,324	6,968	9,342
	Crystal River 4	88.2	92.4	2,398	10,255	9,814	6,784
	Crystal River 5	88.6	90.2	1,002	9,848	9,392	7,001
	Hines 1	91.5	92.3	178	7,515	7,043	4,412
	Hines 2	68.0	80.6	2,788	7,287	6,956	2,411

	Hines 3	87.3	89.0	413	7,171	6,676	5,232
	Hines 4	89.4	91.7	117	7,018	6,716	3,895
	Total			8,538			39,077
<u>FPL:</u>	Cape Canaveral 3	79.4	82.4	1,168	6,663	6,582	2,633
	Manatee 3	70.9	72.9	486	6,968	6,788	3,912
	Ft. Myers 2	92.4	94.9	1,011	7,301	7,090	8,454
	Martin 8	72.9	75.4	645	6,977	6,864	2,577
	St. Lucie 1	93.6	96.6	5,588	10,401	10,293	576
	St. Lucie 2	83.7	86.7	4,137	10,278	10,184	427
	Turkey Point 3	85.1	88.1	4,156	11,106	10,926	730
	Turkey Point 4	85.4	88.4	4,351	11,019	10,870	590
	Turkey Point 5	78.3	80.3	608	7,134	7,052	1,639
	West County 1	89.5	92.0	891	6,989	6,803	5,952
	West County 2	93.0	95.5	938	6,941	6,803	4,684
	West County 3	76.1	78.6	905	6,975	6,834	4,063
	Total			24,884			36,237
<u>GULF:</u>	Scherer 3*	79.0	79.9	22	10,878	10,552	1,750
	Crist 7	96.0	97.2	10	10,470	10,156	1,655
	Daniel 1	90.5	91.9	1	10,539	10,223	467
	Daniel 2	75.7	76.6	5	10,468	10,154	386
	Smith 3	93.1	93.7	50	6,920	6,712	2,326
	Total			88			6,584
<u>TECO:</u>	Big Bend 1	80.5	83.4	1,203	10,698	10,409	1,678
	Big Bend 2	69.6	74.7	1,583	10,545	10,098	2,294
	Big Bend 3	61.4	65.8	1,009	10,588	10,324	1,136
	Big Bend 4	79.1	82.3	1,423	10,447	10,243	1,309
	Polk 1	82.1	84.6	780	10,048	9,528	1,276
	Bayside 1	75.3	77.5	499	7,517	7,382	1,697
	Bayside 2	76.1	78.0	114	7,683	7,504	2,188
	Total			6,610			11,578

*The inclusion in the 2017 GPIF true-up is pending Commission's determination of the retail status of Scherer 3 in a separate proceeding.

FUEL FACTOR CALCULATION ISSUES

ISSUE 19: What are the appropriate projected net fuel and purchased power cost recovery and Generating Performance Incentive amounts to be included in the recovery factor for the period January 2017 through December 2017?

**Type 2 Stipulation*

STIPULATION: The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2017 through December 2017 are as follows:

DEF: \$1,436,253,271.

FPL: \$3,019,548,507, including prior period true-ups, revenue taxes, FPL's portion of Incentive Mechanism gains, the GPIF reward and Vendor Settlement Refund.

FPUC: \$66,215,375, which includes prior period true up amounts.

GULF: \$345,963,114, including prior period true up amounts and revenue taxes.

TECO: \$685,342,648, which is adjusted by the jurisdictional separation factor. The amount is \$564,090,341 when the GPIF reward or penalty, the revenue tax factor, and the prior period true up amounts are applied.

ISSUE 20: **What is the appropriate revenue tax factor to be applied in calculating each investor-owned electric utility's levelized fuel factor for the projection period January 2017 through December 2017?**

****Type 2 Stipulation***

STIPULATION: The appropriate revenue tax factor to be applied in calculating each investor-owned electric utility's levelized fuel factor for the projection period January 2017 through December 2017 is 1.00072.

ISSUE 21: **What are the appropriate levelized fuel cost recovery factors for the period January 2017 through December 2017?**

****Type 2 Stipulation***

STIPULATION: The appropriate levelized fuel cost recovery factors for the period January 2017 through December 2017 are as follows:

DEF: 3.663 cents per kWh (adjusted for jurisdictional losses).

FPL: 2.813 cents/kWh

FPUC: The appropriate factor is 6.593¢ per kWh.

GULF: 3.139 cents/kWh.

TECO: The appropriate factor is 2.951 cents per kWh before any application of time of use multipliers for on-peak or off-peak usage.

ISSUE 22: What are the appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class?

**Type 2 Stipulation*

STIPULATION: The appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class are shown below:

DEF: See Table 22-1 below:

Fuel Recovery Line Loss Multipliers		
Group	Delivery Voltage Level	Line Loss Multiplier
A	Transmission	0.9800
B	Distribution Primary	0.9900
C	Distribution Secondary	1.0000
D	Lighting Service	1.0000

Table 22-1

FPL: See Table 22-2 below:

Fuel Recovery Loss Multipliers		
Group	Rate Schedule	Loss Multiplier
A	RS-1 first 1,000 kWh	1.00252
A	RS-1, all addl. kWh	1.00252
A	GS-1, SL-2, GSCU-1, WIES-1, SL-2M	1.00252
A-1	SL-1, OL-1, PL-1, SL-1M ¹	1.00252
B	GSD-1	1.00246
C	GSLD-1, CS-1	1.00171
D	GSLD-2, CS-2, OS-2, MET	0.99482
E	GSLD-3, CS-3	0.97229
A	GST-1 On-Peak	1.00252
A	GST-1 Off Peak	1.00252
A	RTR-1 On-Peak	-
A	RTR-1 Off-Peak	-
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On Peak	1.00246
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off Peak	1.00246
C	GSDLT-1, CST-1, HLFT-2 (500-1,9999 kW) On Peak	1.00171
C	GSDLT-1, CST-1, HLFT-2 (500-1,9999 kW) Off Peak	1.00171
D	GSDLT-2, CST-2, HLFT-3 (2,000+ kW) On Peak	0.99535

¹Weighted Average 16% On-Peak and 84% Off-Peak

D	GSDLT-2, CST-2, HLFT-3 (2,000+ kW) On Peak	0.99535
E	GSDLT-3, CST-3, CILC-1(T), ISST-1(T) On Peak	0.97229
E	GSDLT-3, CST-3, CILC-1(T), ISST-1(T) Off Peak	0.97229
F	CILC-1(D), ISST-1(D) On Peak	0.99450
F	CILC-1(D), ISST-1(D) Off Peak	0.99450
B	GSD(T)-1 On-Peak	1.00246
	Seasonal Demand Time of Use Rider (SDTR) Loss Multipliers	
B	GSD(T)-1 Off-Peak	1.00246
C	GSLD(T)-1 On-Peak	1.00171
C	GSLD(T)-1 Off-Peak	1.00171
D	GSLD(T)-2 On-Peak	0.99535
D	GSLD(T)-2 Off-Peak	0.99535

Table 22-2

FPUC: The appropriate line loss multiplier is 1.0000.

GULF: See Table 22-3 below:

Fuel Recovery Line Loss Multipliers		
Group	Rate Schedules	Line Loss Multipliers
A	RS, RSVP, RSTOU, GS, GSD, GSdT, GSTOU, OSIII, SBS(1)	1.00773
B	LP, LPT, SBS(2)	0.98353
C	PX, PXT, RTP, SBS(3)	0.96591
D	OSI/II	1.00777
(1) Includes SBS customers with a contract demand in the range of 100 to 499 kW		
(2) Includes SBS customers with a contract demand in the range of 500 to 7,499 kW		
(3) Includes SBS customers with a contract demand over 7,499 kW		

Table 22-3

TECO: See Table 22-4 below:

Fuel Recovery Line Loss Multipliers	
Metering Voltage Schedule	Line Loss Multiplier
Distribution Secondary	1.0000
Distribution Primary	0.9900
Transmission	0.9800
Lighting Service	1.0000

Table 22-4

ISSUE 23: What are the appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses?

***Type 2 Stipulation**

STIPULATION: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses is shown in Tables 23-1 through 23-6 below:

DEF: See Table 23-1 below:

Fuel Cost Factors (cents/kWh)						
Group	Delivery Voltage Level	First Tier Factor	Second Tier Factors	Levelized Factors	Time of Use	
					On-Peak	Off-Peak
A	Transmission	--	--	3.594	4.482	3.181
B	Distribution Primary	--	--	3.630	4.527	3.213
C	Distribution Secondary	3.377	4.377	3.667	4.573	3.245
D	Lighting Secondary	--	--	3.494	--	--

Table 23-1

DEF and PCS Phosphate stipulate that the voltage level recovery factors shown on Table 23-1 are the appropriate factors for 2017. DEF and PCS Phosphate further agree that DEF's increasing reliance on natural gas-fired generation is one factor leading to a decrease in the differential between peak and off-peak fuel rates associated with the time of energy usage. DEF and PCS Phosphate agree to meet and discuss appropriate approaches for addressing this issue, including, but not limited to, the PCS Phosphate proposal to establish a minimum on-peak/off-peak differential for the applicable service classifications.

FPL: See Table 23-2 below:

Fuel Recovery Factors – By Rate Group (Adjusted for Line Losses)				
Group	Rate Schedule	Avg. Factor	Loss Multiplier	Fuel Recovery Factor
A	RS-1 first 1,000 kWh	2.813	1.00252	2.491
A	RS-1, all addl. kWh	2.813	1.00252	3.491
A	GS-1, SL-2, GSCU-1, WIES-1, SL-2M	2.813	1.00252	2.820
A-1	SL-1, OL-1, PL-1, SL-1M ²	2.739	1.00252	2.745
B	GSD-1	2.813	1.00246	2.820
C	GSLD-1, CS-1	2.813	1.00171	2.818
D	GSLD-2, CS-2, OS-2, MET	2.813	0.99482	2.798
E	GSLD-3, CS-3	2.813	0.97229	2.735

²Weighted Average 16% On-Peak and 84% Off-Peak

A	GST-1 On-Peak	3.204	1.00252	3.212
A	GST-1 Off Peak	2.650	1.00252	2.657
A	RTR-1 On-Peak	-	-	0.392
A	RTR-1 Off-Peak	-	-	(0.163)
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) On Peak	3.204	1.00246	3.212
B	GSDT-1, CILC-1(G), HLFT-1 (21-499 kW) Off Peak	2.650	1.00246	2.657
C	GSDLT-1, CST-1, HLFT-2 (500-1,9999 kW) On Peak	3.204	1.00171	3.209
C	GSDLT-1, CST-1, HLFT-2 (500-1,9999 kW) Off Peak	2.650	1.00171	2.655
D	GSDLT-2, CST-2, HLFT-3 (2,000+ kW) On Peak	3.204	0.99535	3.189
D	GSDLT-2, CST-2, HLFT-3 (2,000+ kW) Off Peak	2.650	0.99535	2.638
E	GSDLT-3, CST-3, CILC-1(T), ISST-1(T) On Peak	3.204	0.97229	3.115
E	GSDLT-3, CST-3, CILC-1(T), ISST-1(T) Off Peak	2.650	0.97229	2.577
F	CILC-1(D), ISST-1(D) On Peak	3.204	0.99450	3.186
F	CILC-1(D), ISST-1(D) Off Peak	2.650	0.99450	2.635
	Seasonal Demand Time of Use Rider (SDTR) Fuel Recovery Factors			
B	GSD(T)-1 On-Peak	4.017	1.00246	4.027
B	GSD(T)-1 Off-Peak	2.655	1.00246	2.662
C	GSLD(T)-1 On-Peak	4.017	1.00171	4.024
C	GSLD(T)-1 Off-Peak	2.655	1.00171	2.660
D	GSLD(T)-2 On-Peak	4.017	0.99535	3.998
D	GSLD(T)-2 Off-Peak	2.655	0.99535	2.643

Table 23-2

FPUC: The appropriate levelized fuel adjustment and purchased power cost recovery factors for the period January 2016 through December 2016 for the Consolidated Electric Division, adjusted for line loss multipliers and including taxes, are shown in Tables 23-3 and 23-4 below:

Rate Schedule	Adjustment (cents/kWh)
RS	10.417
GS	9.975
GSD	9.530
GSLD	9.238
LS	7.088
Step Rate for RS	--
RS Sales	10.417
RS with less than 1,000 kWh/month	10.055
RS with more than 1,000 kWh/month	11.305

Table 23-3

Consistent with the fuel projections for the 2017 period, the appropriate adjusted Time of Use (TOU) and Interruptible rates for the Northwest Division for 2016 period are shown in Table 23-4 below.

Rate Schedule	Adjustment On Peak (cents/kWh)	Adjustment Off Peak (cents/kWh)
RS	18.455	6.155
GS	13.975	4.975
GSD	13.530	6.280
GSLD	15.238	6.238
Interruptible	7.738	9.238

Table 23-4

GULF: See Table 23-5 below:

Group	Rate Schedules*	Line Loss Multipliers	Fuel Cost Factors ¢/KWH		
			Standard	Time of Use	
				On-Peak	Off-Peak
A	RS, RSVP, RSTOU, GS, GSD, GSDT, GSTOU, OSIII, SBS(1)	1.00773	3.163	3.806	2.897
B	LP, LPT, SBS(2)	0.98353	3.087	3.715	2.828
C	PX, PXT, RTP, SBS(3)	0.96591	3.032	3.648	2.777
D	OSI/II	1.00777	3.125	N/A	N/A

*The recovery factor applicable to customers taking service under Rate Schedule SBS is determined as follows: (1) customers with a contract demand in the range of 100 to 499 kW will use the recovery factor applicable to Rate Schedule GSD; (2) customers with a contract demand in the range of 500 to 7,499 kW will use the recovery factor applicable to Rate Schedule LP; and (3) customers with a contract demand over 7,499 kW will use the recovery factor applicable to Rate Schedule PX.

Table 23-5

TECO: See Table 23-6 below:

<u>Metering Voltage Level</u>	<u>Fuel Charge Factor (cents per kWh)</u>
Secondary	2.956
RS Tier I (Up to 1,000 kWh)	2.642
RS Tier II (Over 1,000 kWh)	3.642
Distribution Primary	2.926
Transmission	2.897
Lighting Service	2.916
Distribution Secondary	3.166 (on-peak)
	2.865 (off-peak)
Distribution Primary	3.134 (on-peak)
	2.836 (off-peak)
Transmission	3.103 (on-peak)
	2.808 (off-peak)

Table 23-6

II. CAPACITY ISSUES

COMPANY-SPECIFIC CAPACITY COST RECOVERY FACTOR ISSUES

Duke Energy Florida, LLC

ISSUE 24A: Has DEF included in the capacity cost recovery clause the nuclear cost recovery amount ordered by the Commission in Docket No. 160009-EI?

****Type 2 Stipulation***

STIPULATION: Yes, DEF included \$51,737,557 for the Crystal River 3 Uprate project, as authorized by Order No. PSC-16-0447-FOF-EI, issued October 10, 2016. Per the stipulation approved in Docket No. 150009-EI, the Levy portion of the NCRC charge has been set at \$0 for 2017.

ISSUE 24B: What is the appropriate amount of costs for the Dry Cask Storage Facility that DEF should be allowed to recover through the Capacity Cost Recovery Clause pursuant to the 3rd Amendment to the RRSSA?

****Type 2 Stipulation***

STIPULATION: The appropriate amount of costs for the Dry Cask Storage Facility that DEF should be allowed to recover through the Capacity Cost Recovery Clause pursuant to the 3rd Amendment to the RRSSA is \$5,287,371.

Florida Power & Light Company

ISSUE 25: If the Commission does not approve recovery of the WCEC-3 revenue requirement through base rates in Docket No. 160021-EI, what are the appropriate 2017 projected non-fuel revenue requirements for West County Energy Center Unit 3 (WCEC-3) to be recovered through the Capacity Clause?

****Type 2 Stipulation***

STIPULATION: On October 6, 2016, FPL, the Office of Public Counsel, the South Florida Hospital and Healthcare Association and the Florida Retail Federation jointly moved for approval of a proposed stipulation and settlement of FPL's rate case in Docket No. 160021-EI and consolidated dockets (the "Proposed Settlement Agreement"). The Proposed Settlement Agreement states that the revenue requirement associated with the West County Energy Center Unit 3 (WCEC3) currently collected in capacity clause factors would be moved to base rates on a revenue neutral basis.

If the Commission does not approve recovery of the WCEC-3 revenue requirement through base rates in Docket No. 160021-EI, the appropriate 2017 projected non-fuel revenue requirements for WCEC-3 to be recovered through the Capacity Clause is \$140,795,481.

Gulf Power Company

No company-specific issues for Gulf Power Company have been identified.

Tampa Electric Company

No company-specific issues for Tampa Electric Company have been identified.

GENERIC CAPACITY COST RECOVERY FACTOR ISSUES

ISSUE 28: What are the appropriate final capacity cost recovery true-up amounts for the period January 2015 through December 2015?

****Type 2 Stipulation***

STIPULATION: The appropriate final capacity cost recovery true-up amounts for the period January 2015 through December 2015 are as follows:

DEF: \$35,762,070 under-recovery, which is being recovered as part of a Mid-course Correction approved by Order No. PSC-16-0120-PCO-EI.

FPL: \$5,938,824 over-recovery.

GULF: \$965,767 under-recovery.

TECO: \$2,449,694, under-recovery.

ISSUE 29: What are the appropriate capacity cost recovery actual/estimated true-up amounts for the period January 2016 through December 2016?

**Type 2 Stipulation*

STIPULATION: The appropriate final capacity cost recovery true-up amounts for the period January 2016 through December 2016 are as follows:

DEF: \$14,665,234 over-recovery.

FPL: \$9,639,909 over-recovery.

GULF: \$149,231 over-recovery.

TECO: \$536,366, under-recovery.

ISSUE 30: What are the appropriate total capacity cost recovery true-up amounts to be collected/refunded during the period January 2017 through December 2017?

**Type 2 Stipulation*

STIPULATION: The appropriate final capacity cost recovery true-up amounts to be collected/refunded during the period January 2017 through December 2017 are as follows:

DEF: \$14,665,234, to be refunded (over-recovery).

FPL: \$15,578,733, to be refunded (over-recovery).

GULF: \$816,536, to be collected (under-recovery).

TECO: \$2,986,060, to be collected (under-recovery).

ISSUE 31: What are the appropriate projected total capacity cost recovery amounts for the period January 2017 through December 2017?

**Type 2 Stipulation*

STIPULATION: The appropriate projected total capacity cost recovery amounts for the period January 2017 through December 2017 are as follows:

DEF: \$386,010,796.

FPL: On October 6, 2016, FPL, the Office of Public Counsel, the South Florida Hospital and Healthcare Association and the Florida Retail Federation jointly moved for approval of a proposed stipulation and settlement of FPL's rate case in Docket No. 160021-EI and consolidated dockets (the "Proposed Settlement Agreement"). The Proposed Settlement Agreement states that the revenue requirement associated with the West County Energy Center Unit 3 (WCEC3) currently collected in capacity clause factors would be moved to base rates on a revenue neutral basis.

The appropriate projected total capacity cost recovery amount for the period January 2017 through December 2017 is Jurisdictionalized, \$313,376,833, excluding prior period true-ups, revenue taxes, and CCEC-3 Generating Base Rate Adjustment true up.

If the Commission does not approve the Proposed Settlement Agreement or otherwise decides to not move the revenue requirement associated with WCEC3 to base rates on a revenue neutral basis, then the appropriate projected total capacity cost recovery amount for the period January 2017 through December 2017 is Jurisdictionalized, \$454,172,314 (\$313,376,833 plus \$140,795,481), excluding prior period true-ups, revenue taxes, and CCEC-3 Generating Base Rate Adjustment true up.

GULF: \$83,530,252.

TECO: \$11,049,153.

ISSUE 32: **What are the appropriate projected net purchased power capacity cost recovery amounts to be included in the recovery factor for the period January 2017 through December 2017?**

****Type 2 Stipulation***

STIPULATION: The appropriate projected net purchased power capacity cost recovery amounts to be included in the recovery factor for the period January 2017 through December 2017 are as follows:

DEF: The appropriate projected net purchased power capacity cost recovery amount is \$428,637,858, which includes prior period true-up amounts, revenue taxes, and the appropriate amounts for nuclear cost recovery and for the Dry Cask Storage Facility.

FPL: On October 6, 2016, FPL, the Office of Public Counsel, the South Florida Hospital and Healthcare Association and the Florida Retail Federation jointly moved for approval of a proposed stipulation and settlement of FPL's rate case in Docket No. 160021-EI and consolidated dockets (the "Proposed Settlement Agreement"). The Proposed Settlement Agreement states that the revenue requirement associated with the West County Energy Center Unit 3 (WCEC3) currently collected in capacity clause factors would be moved to base rates on a revenue neutral basis.

The appropriate projected net purchased power capacity cost recovery amount to be included in the recovery factor for the period January 2017 through December 2017 is \$296,120,626, including prior period true-ups, revenue taxes, and CCEC Generating Base Rate Adjustment true up.

If the Commission does not approve the Proposed Settlement Agreement or otherwise decides to not move the revenue requirement associated with WCEC3 to base rates on a revenue neutral basis, then the appropriate projected total capacity cost recovery amount for the period January 2017 through December 2017 is Jurisdictionalized, \$436,916,107 (\$296,120,626 plus \$140,795,481), excluding prior period true-ups, revenue taxes, and CCEC-3 Generating Base Rate Adjustment true up.

GULF: \$84,407,518 including prior period true-up amounts and revenue taxes.

TECO: The total recoverable capacity cost recovery amount to be collected, including the true-up amount and adjusted for the revenue tax factor, is \$14,045,318.

ISSUE 33: **What are the appropriate jurisdictional separation factors for capacity revenues and costs to be included in the recovery factor for the period January 2017 through December 2017?**

****Type 2 Stipulation***

STIPULATION: The appropriate jurisdictional separation factors for capacity revenues and costs to be included in the recovery factor for the period January 2017 through December 2017 are as follows:

DEF: Base – 92.885%, Intermediate – 72.703%, Peaking – 95.924%, consistent with the Revised and Restated Stipulation and Settlement Agreement approved in Order No. PSC-13-0598-FOF-EI.

FPL: The appropriate jurisdictional separation factors are:
 FPSC 95.04658%
 FERC 4.95342%

GULF: 97.21125%.

TECO: The appropriate jurisdictional separation factor is 0.9958992.

ISSUE 34: What are the appropriate capacity cost recovery factors for the period January 2017 through December 2017?

**Type 2 Stipulation*

STIPULATION: The appropriate capacity cost recovery factors for the period January 2017 through December 2017 are shown in Tables 34-1, 34-2a through 34-2d, 34-3, and 34-4 below:

DEF: The appropriate capacity cost recovery factors for the period January 2017 through December 2017 are shown in Table 34-1 below:

Rate Class	Capacity Cost Recovery Factor	
	Cents / kWh	Dollars / kW-month
Residential	1.294	
General Service Non-Demand	1.006	
At Primary Voltage	0.996	
At Transmission Voltage	0.986	
General Service 100% Load Factor	0.708	
General Service Demand		3.67
At Primary Voltage		3.63
At Transmission Voltage		3.60
Curtable		2.89
At Primary Voltage		2.86
At Transmission Voltage		2.83
Interruptible		2.83
At Primary Voltage		2.80
At Transmission Voltage		2.77
Standby Monthly		0.356
At Primary Voltage		0.352
At Transmission Voltage		0.349
Standby Daily		0.170
At Primary Voltage		0.168
At Transmission Voltage		0.167
Lighting	0.203 (cents/kWh)	

Table 34-1

FPL: On October 6, 2016, FPL, the Office of Public Counsel, the South Florida Hospital and Healthcare Association and the Florida Retail Federation jointly moved for approval of a proposed stipulation and settlement of FPL's rate case in Docket No. 160021-EI and consolidated dockets (the "Proposed Settlement Agreement"). The Proposed Settlement Agreement would provide for FPL to continue using the 12 CP and 1/13th production cost methodology, and the revenue requirement associated with the West County Energy Center Unit 3 (WCEC3) currently collected in capacity clause factors would be moved to base rates on a revenue neutral basis. Upon approval of this stipulation by the Commission, FPL should file and serve two sets of tariff sheets that reflect the decision rendered on the allocation methodology and on WCEC3 in Docket No. 160021-EI and consolidated dockets.

The appropriate capacity cost recovery factors for the period January 2017 through December 2017 are in Tables 34-2a, 34-2b, 34-3, or 34-2c. Table 34-2a contains the Capacity Cost Recovery Factors based on a 12 CP and 1/13th Cost Of Service Allocation, excluding WCEC-3 cost recovery factors. Table 34-2b contains Capacity Cost Recovery Factors based on a 12 CP and 25% Production Plant Cost Of Service Allocation, excluding WCEC-3 cost recovery factors. Table 34-2c contains the Capacity Cost Recovery Factors based on a 12 CP and 1/13th Cost Of Service Allocation, including WCEC-3 cost recovery factors. Table 34-2d contains Capacity Cost Recovery Factors based on a 12 CP and 25% Production Plant Cost Of Service Allocation, including WCEC-3 cost recovery factors:

Rate Schedule	Total Capacity Cost Recovery Factors			
	\$/kW	\$/kWh	RDC \$/kW ³	SDD \$/kW ⁴
RS1/RTR1	-	0.00303	-	-
GS1/GST1	-	0.00278	-	-
GSD1/GSDT1/HLFT1	0.92	-	-	-
OS2	-	0.00201	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	1.03	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	1.01	-	-	-
GSLD3/GSLDT3/CS3/CST3	1.04	-	-	-
SST1T	-	-	\$0.13	\$0.06
SST1D1/SST1D2/SST1D3	-	-	\$0.13	\$0.06
CILC D/CILC G	1.14	-	-	-
CILC T	1.09	-	-	-
MET	1.17	-	-	-
OL1/SL1/PL1	-	0.00050	-	-
SL2, GSCU1	-	0.00197	-	-
Table 34-2a, Capacity Cost Recovery Factors based on a 12 CP and 1/13 th Cost Of Service Allocation, excluding WCEC-3 cost recovery factors.				

³RDC=((Total Capacity Costs)/(Projected Avg 12CP @gen)(.10)(demand loss expansion factor)/12 months

⁴SDD=((Total Capacity Costs)/(Projected Avg 12CP @gen)(21 onpeak days)(demand loss expn. factor)/12 months

Rate Schedule	Total Capacity Cost Recovery Factors			
	\$/kW	\$/kWh	RDC \$/kW ⁵	SDD \$/kW ⁶
RS1/RTR1	-	0.00298	-	-
GS1/GST1	-	0.00278	-	-
GSD1/GSDT1/HLFT1	0.94	-	-	-
OS2	-	0.00214	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	1.05	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	1.07	-	-	-
GSLD3/GSLDT3/CS3/CST3	1.09	-	-	-
SST1T	-	-	\$0.13	\$0.06
SST1D1/SST1D2/SST1D3	-	-	\$0.13	\$0.06
CILC D/CILC G	1.20	-	-	-
CILC T	1.17	-	-	-
MET	1.19	-	-	-
OL1/SL1/PL1	-	0.00092	-	-
SL2, GSCU1	-	0.00212	-	-

Table 34-2b, Capacity Cost Recovery Factors based on a 12 CP and 25% Cost Of Service Allocation, excluding WCEC-3 cost recovery factors.

Rate Schedule	Total Capacity Cost Recovery Factors			
	\$/kW	\$/kWh	RDC \$/kW ⁷	SDD \$/kW ⁸
RS1/RTR1	-	0.00446	-	-
GS1/GST1	-	0.00410	-	-
GSD1/GSDT1/HLFT1	1.36	-	-	-
OS2	-	0.00297	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	1.52	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	1.50	-	-	-
GSLD3/GSLDT3/CS3/CST3	1.54	-	-	-
SST1T	-	-	\$0.19	\$0.09
SST1D1/SST1D2/SST1D3	-	-	\$0.19	\$0.09
CILC D/CILC G	1.69	-	-	-
CILC T	1.62	-	-	-
MET	1.73	-	-	-
OL1/SL1/PL1	-	0.00081	-	-
SL2, GSCU1	-	0.00293	-	-

Table 34-2c, Capacity Cost Recovery Factors based on a 12 CP and 1/13th Cost Of Service Allocation, including WCEC-3 cost recovery factors (TIK-7, Pg. 7)

⁵RDC=((Total Capacity Costs)/(Projected Avg 12CP @gen)(.10)(demand loss expansion factor)/12 months

⁶SDD=((Total Capacity Costs)/(Projected Avg 12CP @gen)(21 onpeak days)(demand loss expn. factor)/12 months

⁷RDC=((Total Capacity Costs)/(Projected Avg 12CP @gen)(.10)(demand loss expansion factor)/12 months

⁸SDD=((Total Capacity Costs)/(Projected Avg 12CP @gen)(21 onpeak days)(demand loss expn. factor)/12 months

Rate Schedule	Total Capacity Cost Recovery Factors			
	\$/kW	\$/kWh	RDC \$/kW ⁹	SDD \$/kW ¹⁰
RS1/RTR1	-	0.00439	-	-
GS1/GST1	-	0.00410	-	-
GSD1/GSDT1/HLFT1	1.39	-	-	-
OS2	-	0.00315	-	-
GSLD1/GSLDT1/CS1/CST1/HLFT2	1.55	-	-	-
GSLD2/GSLDT2/CS2/CST2/HLFT3	1.58	-	-	-
GSLD3/GSLDT3/CS3/CST3	1.62	-	-	-
SST1T	-	-	\$0.19	\$0.09
SST1D1/SST1D2/SST1D3	-	-	\$0.19	\$0.09
CILC D/CILC G	1.78	-	-	-
CILC T	1.73	-	-	-
MET	1.76	-	-	-
OL1/SL1/PL1	-	0.00141	-	-
SL2, GSCU1	-	0.00314	-	-

Table 34-2d, Capacity Cost Recovery Factors based on a 12 CP and 25% Production Plant Cost Of Service Allocation, including WCEC-3 cost recovery factors (TJK-6, pg. 23).

GULE: The appropriate capacity cost recovery factors for the period January 2017 through December 2017 are shown in Table 34-3 below:

Rate Class	Capacity Cost Recovery Factor	
	Cents / kWh	Dollars / kW-month
RS, RSVP, RSTOU	0.888	-
GS	0.811	
GSD, GSDT, GSTOU	0.708	
LP, LPT	-	2.97
PX, PXT, RTP, SBS	0.585	-
OS-I/II	0.174	
OSIII	0.537	

Table 34-3

⁹RDC=((Total Capacity Costs)/(Projected Avg 12CP @gen)(.10)(demand loss expansion factor)/12 months

¹⁰SDD=((Total Capacity Costs)/(Projected Avg 12CP @gen)(21 onpeak days)(demand loss expn. factor)/12 months

TECO: The appropriate capacity cost recovery factors for the period January 2017 through December 2017 are shown in Table 34-4 below:

Rate Class and Metering Voltage	Capacity Cost Recovery Factor	
	Cents / kWh	Dollars / kW
RS Secondary	0.088	-
GS and CS Secondary	0.076	
GSD, SBF Standard		
Secondary	-	0.27
Primary		0.27
Transmission		0.26
GSD Optional		
Secondary	0.063	-
Primary	0.062	
IS, SBI		
Primary	-	0.14
Transmission		0.14
LS1 Secondary	0.017	-

Table 34-4

III. EFFECTIVE DATE

ISSUE 35: What should be the effective date of the fuel adjustment factors and capacity cost recovery factors for billing purposes?

**Type 2 Stipulation*

STIPULATION: The new factors should be effective beginning with the first billing cycle for January 2017 through the last billing cycle for December 2017. The first billing cycle may start before January 1, 2017, and the last cycle may be read after December 31, 2017, so that each customer is billed for twelve months regardless of when the recovery factors became effective. The new factors shall continue in effect until modified by this Commission.

ISSUE 36: Should the Commission approve revised tariffs reflecting the fuel adjustment factors and capacity cost recovery factors determined to be appropriate in this proceeding?

**Type 2 Stipulation*

STIPULATION: Yes. The Commission should approve revised tariffs reflecting the fuel adjustment factors and capacity cost recovery factors determined to be appropriate in this proceeding. The Commission should direct staff to verify that the revised tariffs are consistent with the Commission's decision.

ISSUE 37: Should this docket be closed?

****Type 2 Stipulation***

STIPULATION: This docket is an on-going docket and should remain open.

XI. PENDING MOTIONS

There are no pending motions at this time.

XII. PENDING CONFIDENTIALITY MATTERS

DEF:

1. April 6, 2016 – Portions of the direct testimony of Joseph McCallister and Exhibit Nos. JM-1T AND JM-2T [DN 01837-16].
2. September 29, 2016-Information provided in response to Staff's Sixth Set of Interrogatories (24-30), specifically 24, 25 & 27 [DN 07860-16].
3. October 6, 2016-Hedging Audit Workpapers-16-068-2-1 [DN 08045-16].

FPL:

1. Florida Power & Light Company's request for confidential classification of certain information contained in hedging activity report, Exh GJY-2 to testimony of Gerard J. Yupp, dated April 6, 2016. [DN 01842-16]
2. Florida Power & Light Company's request for confidential classification of Weaver and Tidwell LLP's joint interest billing audit plan (JIB audit plan), dated April 6, 2016. [DN 01849-16]
3. Florida Power & Light Company's request for confidential classification of materials provided pursuant to Audit No. 16-020-4-1., dated June 29, 2016. [DN 04091-16]
4. Florida Power & Light Company's request for confidential classification of certain information on 2017 risk management plan, which is Appendix V (Exh GJY-5) to the 2016 actual/estimated true-up petition, dated August 4, 2016. [DN 05880-16]
5. Florida Power & Light Company's request for confidential classification of materials provided pursuant to Audit No. 16-068-4-1 , dated September 14, 2016. [DN 07525-16]

FPUC:

1. None

GULF:

1. Request for confidentiality filed on April 6, 2016, relating to hedging information report [DN 01826-16].
2. Request for confidentiality filed on August 4, 2016, relating to portions of 2017 Risk Management Plan for fuel procurement [DN 05871-16].
3. Request for confidentiality filed on August 18, 2016, relating to portions of hedging information report for 1/16 through 7/16 [DN 06820-16].
4. Request for confidentiality filed on September 1, 2016, relating to schedule CCE-4 of exhibit CSB-3 to direct testimony of C. Shane Boyett [DN 07228-16].
5. Request for confidentiality filed on September 26, 2016, relating to certain documents produced in connection with a review of 2016 hedging transactions (Audit Control No. 16-068-1-1) (x-ref DN 07535-16) [DN 07793-16].
6. Request for extended confidential classification (of DN 02411-14) [(Audit Control No. 14-027-1-1)] [DN 01310-16].
7. Request for extended confidential classification (of DN 02415-14) [(Audit Control No. 14-027-1-2)] [DN 01311-16].

TECO:

1. Request for confidentiality filed on April 6, 2016, Pages 11, 12 & 13 of Exhibit JBC-1 of witness J. Brent Caldwell [DN 01830-16].
2. Request for confidentiality filed on August 22, 2016, Answer to Citizens' 2nd Set of Interrogatories Nos. 12, 13 and 17 [DN 06934-16].
3. Request for confidentiality filed on October 4, 2016, Information contained in audit workpapers pursuant to Audit Control No. 16-068-2-2 [DN 08010-16].
4. Request for confidentiality filed on October 5, 2016, Answer to Staff's 7th Set of Interrogatories No. 35 [DN 08025-16].

XIII. POST-HEARING PROCEDURES

If no bench decision is made, each party shall file a post-hearing statement of issues and positions. A summary of each position of no more than 100 words, set off with asterisks, shall be included in that statement. If a party's position has not changed since the issuance of this Prehearing Order, the post-hearing statement may simply restate the prehearing position; however, if the prehearing position is longer than 100 words, it must be reduced to no more than 50 words. If a party fails to file a post-hearing statement, that party shall have waived all issues and may be dismissed from the proceeding.

Pursuant to Rule 28-106.215, F.A.C., a party's proposed findings of fact and conclusions of law, if any, statement of issues and positions, and brief, shall together total no more than 40 pages and shall be filed at the same time.

XIV. RULINGS

Opening statements, if any, shall not exceed three minutes per party.

It is therefore,

ORDERED by Commissioner Art Graham, as Prehearing Officer, that this Prehearing Order shall govern the conduct of these proceedings as set forth above unless modified by the Commission.

By ORDER of Commissioner Art Graham, as Prehearing Officer, this 31st day of October, 2016.



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.

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.