BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 160021-EI

PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY.
_______________________________/

DOCKET NO. 160061-EI

PETITION FOR APPROVAL OF 2016-2018 STORM HARDENING PLAN BY FLORIDA POWER & LIGHT COMPANY.
_____________________________/

DOCKET NO. 160062-EI

2016 DEPRECIATION AND DISMANTLEMENT STUDY BY, FLORIDA POWER & LIGHT COMPANY.
_____________________________/

DOCKET NO. 160088-EI

PETITION FOR LIMITED PROCEEDING TO MODIFY AND CONTINUE INCENTIVE MECHANISM, BY FLORIDA POWER & LIGHT COMPANY.
_____________________________/

VOLUME 29

(Pages 4165 through 4365)

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING:
CHAIRMAN JULIE I. BROWN
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER ART GRAHAM
COMMISSIONER RONALD A. BRISÉ
COMMISSIONER JIMMY PATRONIS

DATE: Tuesday, August 30, 2016

TIME: Commenced at 10:54 a.m.
Concluded at 12:09 p.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: LINDA BOLES, CRR, RPR
Official FPSC Reporter
(850) 413-6734

APPEARANCES: (As heretofore noted.)

# I N D E X

## WITNESSES

EXHIBITS

| NUMBER: | | ID. | ADMTD. |
|---|---|---|---|
| 265 through 281 | | | 4272 |
| 723 | FPSC Order No. PSC-09-0283-FOF-EI Dated 4/30/09 in Docket No. 080317-EI | 4253 | 4273 |
| 724 | FPSC Staff Recommendation Dated 11/30/09 in Docket No. 090079-EI | 4254 | 4276 |

P R O C E E D I N G S

**CHAIRMAN BROWN:** Good morning, Mr. Wiseman.

**MR. WISEMAN:** Good morning, Madam Chair.

**CHAIRMAN BROWN:** How are you doing?

**MR. WISEMAN:** I'm doing great. How are you doing?

**CHAIRMAN BROWN:** Good. Are you ready to proceed?

**MR. WISEMAN:** I am.

**CHAIRMAN BROWN:** Okay. Welcome.

**MR. WISEMAN:** Thank you.

Whereupon,

**STEPHEN J. BARON**

was called as a witness on behalf of South Florida Hospital and Healthcare Association and, having first been duly sworn, testified as follows:

**EXAMINATION**

**BY MR. WISEMAN:**

**Q** Could you please state your name and business address for the record.

**A** My name is Stephen Baron, and my business address is J. Kennedy and Associates, Inc., 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30076.

**Q** And on whose behalf are you testifying in this proceeding?

**A** The South Florida Hospital and Healthcare Association.

**Q** And have you caused to be filed testimony consisting of 69 pages on July 7, 2016, in this case?

**A** Yes.

**Q** And did you also cause to be filed an errata on August 29, 2016?

**A** Yes.

**Q** And if I were to ask you the same questions that were posed in the prepared testimony as modified by the errata, would your answers be the same?

**A** Yes, they would. To the best of my knowledge, they'd be the same and that's true and correct.

**MR. WISEMAN:** Okay. Madam Chair, I would ask that Mr. Baron's testimony be entered the record as if read.

**CHAIRMAN BROWN:** We will enter Mr. Baron's direct prefiled testimony into the record as though read.

# ERRATA SHEET

WITNESS: STEPHEN BARON - DIRECT TESTIMONY

**Testimony Errata**

| **PAGE #** | **LINE#** | **CHANGE** |
|---|---|---|
| 26 | 5 | Delete “kW” and replace with kWh” |
| 26 | 6 | Delete “conventional” and replace with “advanced” |
| 51 | 11 | Delete “$13.52” and replace with “$13.42” |
| 51 | 12 | Delete “$8.26” and replace with “$8.20” |
| 51 | n.9 | Delete “$13.52” and replace with “$13.42” and delete “$8.26” and replace with “$8.20” |
| 56 | 3 | Delete “MFR E-14” and replace with “MFR E-13c” |
| 57 | 6 | Delete “MFR E-14” and replace with “MFR E-13c” |
| 57 | 18 | Delete “MFR E-14” and replace with “MFR E-13c” |
| 57 | n.11 | Delete “MFR E-14” and replace with “MFR E-13c” |
| 59 | Table 12 | Delete “MFR E-14” and replace with “MFR E-13c” |

**BEFORE THE**

**FLORIDA PUBLIC SERVICE COMMISSION**

| | | |
|---|---|---|
| **IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER AND LIGHT COMPANY AND SUBSIDIARIES** | ) ) ) | **DOCKET NO. 160021-EI** |

**DIRECT TESTIMONY OF STEPHEN J. BARON**

## I. INTRODUCTION

**Q. Please state your name and business address.**

A. My name is Stephen J. Baron. 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 the President and a Principal of Kennedy and Associates, a firm of utility rate, planning, and economic consultants in Atlanta, Georgia.

**Q. Please describe briefly the nature of the consulting services provided by Kennedy and Associates.**

A. Kennedy and Associates provides consulting services in the electric and gas utility industries. Our clients include state agencies, large consumers of electricity and other market participants. The firm provides expertise in system planning, load forecasting, financial analysis, cost-of-service, and rate design. Current clients include the Georgia and Louisiana Public Service Commissions, and consumer groups throughout the United States.

**Q. Please state your educational background.**

A. I graduated from the University of Florida in l972 with a B.A. degree with high honors in Political Science and significant coursework in Mathematics and Computer Science. In 1974, I received a Master of Arts Degree in Economics, also from the University of Florida. My areas of specialization were econometrics, statistics, and public utility economics. My thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which I received a grant from the Public Utility Research Center of the University of Florida. In addition, I have advanced study and coursework in time series analysis and dynamic model building.

**Q. Please describe your professional experience.**

A. I have more than thirty years of experience in the electric utility industry in the areas of cost and rate analysis, forecasting, planning, and economic analysis.

Following the completion of my graduate work in economics, I joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. My responsibilities included the analysis of rate cases for electric, telephone, and gas utilities, as well as the preparation of cross-examination material and the preparation of staff recommendations.

In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services, Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. My responsibilities included the management of a staff of consultants engaged in providing services in the areas of econometric modeling, load and energy forecasting, production cost modeling, planning, cost-of-service analysis, cogeneration, and load management.

I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this capacity I was responsible for the operation and management of the Atlanta office. My duties included the technical and administrative supervision of the staff, budgeting, recruiting, and marketing as well as project management on client engagements. At Coopers & Lybrand, I specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice President and Principal. I became President of the firm in January 1991.

During the course of my career, I have provided consulting services to numerous industrial, commercial, Public Service Commission and utility clients, including international utility clients.

I have presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." My article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, I completed a detailed analysis entitled

"Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

I have presented testimony as an expert witness in Arizona, Arkansas, Colorado, Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan, Minnesota, Maryland, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, South Dakota, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, Wyoming, before the Federal Energy Regulatory Commission ("FERC"), and in United States Bankruptcy Court. A list of my specific regulatory appearances can be found in Exhibit No. ___ (SJB-1).

**Q. Do you have previous experience in Florida Power and Light Co. ("FPL" or the "Company") regulatory proceedings?**

A. Yes. I have been involved in a number of FPL rate proceedings during my career. This includes participation as a Florida Public Service Commission ("Commission") Staff member in a 1975 FPL rate case, a generic DSM proceeding in 1993 and FPL rate cases in 2002, 2005, 2009 and 2012. I have also testified before the Commission in other proceedings on a number of occasions.

**Q. On whose behalf are you testifying in this proceeding?**

A. I am testifying on behalf of the South Florida Hospital and Healthcare Association, Inc. ("SFHHA" or the "hospitals"). SFHHA members take service on FPL General Service, High load factor-Time of Use and CILC rate schedules throughout the Company's service area.

**Q. What is the purpose of your testimony?**

A. I will address issues associated with FPL's class cost of service study and its proposed revenue allocation to rate classes of its requested Step 1 (January 2017) base rate revenue increase of $866 million, its requested Step 2 (January 2018) increase of $262 million and its Step 3 (June 2019) increase of $209 million. Departing from its past history of many years, FPL is proposing to replace its traditional 12 CP and 1/13th class cost of service study with a 12 CP and 25% energy methodology. This change unreasonably shifts costs to high load factor general service rate classes such as CILC-1D, GSLD(T)-1 and other commercial and industrial rates. As I will discuss, there is no basis for this dramatic change, which affects not only base rates but also clauses that incorporate a demand allocator. The Company has not presented any substantive evidence that justifies the change, which essentially is nothing more than a cost shift to large customer classes. I will explain in my testimony why the Commission should reject FPL's proposal and continue using the 12 CP and 1/13th methodology to allocate production and transmission demand costs to rate classes.

I will also discuss the Company's methodology to classify and allocate distribution related costs in its cost study. The Company proposes to classify most of its distribution costs on a 100% demand basis, while ignoring any customer related cost components. FPL classifies all distribution plant in FERC accounts 364 (poles), 365 (overhead conductors), 366 (underground conduit), 367 (underground conductors) and 368 (line transformers) as 100% demand related. FPL's methodology, which is inconsistent with the distribution cost allocation methodologies discussed in the NARUC Electric Utility

Cost Allocation Manual (the "NARUC Manual"), ignores the cause of <u>any</u> of the unavoidable cost consequences of simply connecting a customer to the Company's distribution system, regardless of the level of demand the customer imposes on the system or whether the customer premises are even occupied. Two major electric utilities in Florida (Tampa Electric Company ("TECO") and Gulf Power Company ("GPC")) have now adopted a minimum distribution system ("MDS") methodology. The MDS method more accurately recognizes that the installation of minimum size poles, conductors and transformers is required to serve customers, irrespective of their level of demand, that the costs of those installations are easily tracked, and are appropriately recovered through a customer component since the amount of the costs does not vary based on differences in the level of peak demand. The Commission has approved rates based on these MDS cost of service analyses. I will present an alternative 12 CP and 1/13$^{th}$ class cost of service study that incorporates a MDS methodology.[1]

I will also address FPL's proposal to terminate the CDR and CILC curtailment credits that were approved by the Commission in the prior base rate case (Docket No. 120015-EI) and to "Reset" these credits back to the pre-2012 rate case settlement levels. This proposal, which imposes an additional $23 million increase on CILC and general service customers that utilize the CDR program, is unjustified and unreasonable. As I will discuss, the current level of the CDR credit is fully justified by FPL's economic analyses, as filed in its DSM proceedings.

[1] I also will present an alternative 12 CP and 25% cost study that uses an MDS methodology, in the event that the Commission entertains FPL's proposal in this case.

I will also discuss the Company's proposed methodology to allocate revenue increases to each rate class. FPL has proposed three separate increases in this case, with the first two (January 2017 and January 2018) based on FPL's representation of class cost of service study results. The third increase (June 2019) is related to a single issue, the recovery of costs associated with the Okeechobee Clean Energy Center plant. FPL allocates the 2017 revenue increase based on its computation of revenue requirements for each rate class at its calculation of an equal rate of return (parity of 1.0), subject to a maximum increase of 1.5 times the average percentage increase in base plus clause revenues and a minimum increase of 0.5%. I will discuss a number of concerns that I have identified with the Company's methodology. First, consistent with my recommendation to use the 12 CP and 1/13$^{th}$ cost allocation method, including an MDS methodology, I will use these cost of service results to allocate the revenue increase to rate classes. In addition, the Company has treated the $23 million CDR/CILC increase as outside the "1.5 times" mitigation constraint, resulting in Rate CILC-1D customers receiving extreme increases in this case. While I strongly oppose FPL's CDR Reset proposal (the $23 million increase), if it is approved, then this increase should be included in the mitigation protection provided by the 1.5 times retail average limitation. I will present an alternative revenue allocation that properly reflects the total increases (including any CDR changes approved in this base rate proceeding) in the calculation of rate class increases. Finally, consistent with my position in FPL's prior base rate cases, I will recommend an alternative mitigation approach that applies the "1.5 times" increase limit to individual rate class base revenue increases, rather than total revenues including clause revenues. FPL's increases to a number of Commercial and Industrial ("C&I") rate classes are substantial and the application of the "1.5 times" limitation does not adequately mitigate those increases.

**Q. Would you summarize your conclusions and recommendations?**

A. Yes. FPL's proposal to reject the 12 CP and 1/13th average demand cost of service methodology, which the Company has been using consistently since 1983, is unreasonable and not supported by any substantive evidence. The Company has not provided a reasonable basis for its recommendation to use a 12 CP and 25% average demand methodology ("12 and 25% average demand") which produces a significant change in rate class cost responsibility. This methodology simply shifts approximately $25 million of costs to large C&I rate classes. The Commission should reject FPL's proposal to initiate such a cost shift in this case.

- **FPL has used cost of service methodologies in this case that unreasonably attribute cost responsibility to large general service rate classes due to the failure to use a Minimum Distribution System cost classification methodology to assign cost responsibility for FPL's primary and secondary distribution system.**

- **FPL is proposing to terminate the current level of CDR/CILC credits that were approved in the prior 2012 base rate case and increase rates to CILC and general service customers that have been provided CDR credits by an additional $23 million, which is over and above the large base rate increases**

**FPL is requesting in this case. FPL's proposal results in a base rate increase for Rate CILC-1D of 57%, due in large part to the Company's "Reset" of the CILC/CDR incentive credits. This proposal should be rejected as it is not justified by FPL's own economic analysis. That economic result should be applied to other dockets involving FPL as well.**

- **FPL has based its proposed rate class increases on the results of its flawed 12 CP and 25% average demand cost of service study and a goal to bring each rate class to within parity of the system average rate of return as determined using FPL's class cost of service methodology. FPL's proposed revenue allocation is unreasonable and should be rejected. Rather, the revenue allocation should be based on the results of the Company's 12 CP and 1/13$^{th}$ cost study and also should incorporate a Minimum Distribution System approach to the classification of distribution facilities. FPL's failure at the outset to reasonably allocate costs in this case has resulted in an over-allocation of cost of service to large customers, which FPL then relies on to support significantly above average increases to these rate classes.**

- **FPL has proposed increases to some rate classes that are substantially in excess of 1.5 times the average retail base rate increase FPL is requesting. Some rate classes, such as CILC-1D, GSLDT-1, GSLDT-2, and GSLDT-3 will receive base rate increases of more than 2 times the retail average base**

**revenue increase of 15%. Putting aside for the moment the issue of whether FPL's cost responsibility calculations are correct, in consideration of the impact and the potential for "rate shock" with such large increases, no rate class should receive an increase greater than 150% of the system average base rate increase.**

## II. COST ALLOCATION ISSUES

**Q. Have you reviewed the class cost of service study filed by FPL in this case?**

A. Yes. For the first time in decades, FPL is now opposing use of the 12 CP and 1/13th average demand class cost of service methodology. Instead it is proposing a 12 CP and 25% average demand methodology for production demand (generation) fixed costs. The Company is also proposing to use a 12 CP method to allocate transmission costs. This change increases the amount of fixed, demand related costs that are allocated to rate classes on the basis of energy usage, including off-peak energy usage, from 7.7% to 25%. Rate classes that use the FPL system on a more consistent and level basis are penalized by this change because customers in these rate classes have a higher utilization rate (load factor) of their respective demand. As a result, if a customer increases its off-peak energy (kWh) usage, it is deemed under FPL's new cost allocation method to have contributed more to the need for additional generating capacity and therefore is assigned increased cost responsibility for fixed, demand-related generation, notwithstanding that most of those costs are actually incurred to meet customer peaks in the summer, and perhaps in the winter months, but *not* in off-peak periods because FPL does not add generating capacity to meet increased off-peak energy usage, especially in non-summer and non-winter months. Yet FPL's new methodology assigns more costs to a customer based on increased off-peak usage, thus discouraging such a customer from utilizing the fixed generation resources of the Company to a greater extent. The effect of this change is to shift costs from lower load factor users to large C&I rate classes. The proposed methodology is neither appropriate nor justified and should be rejected by the Commission. I will discuss the Company's proposed study and explain why it is not a reasonable cost allocation method for FPL. Rather, it unfairly shifts costs to larger, high load factor customers.

Another important feature of the Company's cost study (beyond the allocation method for production demand costs) is the Company's classification of all distribution costs (except meters and services) as demand related. As I will discuss, the Company's methodology ignores any "customer related" cost responsibility for hundreds of millions of dollars of distribution plant and expenses, contrary to the approaches used by many other utilities throughout the country (including two major Florida electric utilities, TECO and GPC) and the NARUC Manual, which recognizes a "customer component" of distribution cost based on a minimum distribution system concept.

Given the significance placed on the rate of return parities produced by the Company's class cost of service study, the reasonableness of the Company's study is a significant issue. The reasonableness of FPL's class cost of service study is critically important if it is to be used to alleviate any rate of return disparities (at present rates) through the allocation of the overall revenue increase to rate classes.

**Q. Do you support the class cost of service study proposed by FPL in this case?**

A. No. I do not support the Company's study for a number of reasons, most importantly because it allocates production demand related costs on a 12 CP and 25% average demand allocation methodology.

In addition to my objection to FPL's use of a 12 CP and 25% average demand cost of service methodology, I do not agree with the Company's methodology used to classify distribution plant and expenses. FPL has not considered any minimum distribution system costs in its cost classification analysis, which unreasonably overstates the cost responsibility for large general service rate classes.

**Q. Would you address the Company's proposal to use a 12 CP and 25% average demand methodology to allocate production demand costs to rate classes?**

A. Despite the fact that FPL has been using the 12 CP and 1/13$^{th}$ method for over 32 years, the Company has offered little in the way of justification to warrant this significant change.[2] FPL cites to TECO's use in 2008 of 12 CP and 25% but fails to note that since that time TECO has implemented 12 CP and 1/13$^{th}$. FPL Witness Deaton cites the fact that FPL has added base load and intermediate load units that provide fuel savings as the sole support for her recommendation. However, neither she nor the Company presented any economic analyses to justify the allocation of 25% of fixed, demand related production costs on the basis of rate class energy use; FPL provided no explanation as to how the 25% factor is appropriate or its relationship to the asserted fuel savings that are cited.

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[2] According to witness Joseph Ender's 2012 base rate case testimony, FPL begin using the 12 CP and 1/13$^{th}$ methodology in 1983 (Docket No. 820097-EU). The Company has continued to use this method until the current case.

**Q. Did FPL provide any further support for its proposed class cost of service methodology change in response to discovery in this case?**

A. No. In response to FIPUG Interrogatory 1-10, the Company justified its change simply by reference to Ms. Deaton's testimony on pages 21 and 22 and because FPL is installing combined cycle generation instead of peaking generation. Exhibit No. ___ (SJB-2) contains a copy of this interrogatory response. FPL provided a similar response to SFHHA discovery on this issue. While the Company cites fuel savings that have been achieved over time, FPL has not presented a comprehensive analysis or study to support its decision to make such a significant change in its cost allocation methodology based on fuel cost savings or on other objective criteria. Exhibit No. ___ (SJB-3) contains the Company's responses to SFHHA Interrogatories 6-145 and 6-146.

**Q. What do you conclude from the supporting evidence provided by FPL for its decision to use the 12 CP and 25% average demand methodology?**

A. It appears that the change in methodology is primarily a cost shift from lower load factor customers to high load factor C&I rate classes. It is not based on a substantive analysis and is not based on cost causation.

**Q. What is the cost shift that results from FPL's proposal to use the 12 CP and 25% average demand method?**

A. Table 1, below, shows the effect of the Company's cost shift from other classes to large C&I rate classes, based on proposed revenue requirements at full cost of service (*i.e.*, a Parity of 1.0) for the 2017 test year. The change to the 12 CP and 25% average demand methodology has resulted in a cost shift of over $20 million annually to large C&I rate classes.

**Table 1**
**Cost Shifts Produced by "12 CP + 25%" Methodology ($1,000)**

**Proposed 2017 Target Revenue Requirments***

| | 12 CP + 25% | 12 CP + 1/13th | Difference |
|---|---|---|---|
| CILC-1D | 116,594 | 113,883 | 2,711 |
| CILC-1G | 4,661 | 4,566 | 95 |
| CILC-1T | 48,120 | 46,416 | 1,704 |
| GS(T)-1 | 401,378 | 401,551 | -173 |
| GSCU-1 | 3,975 | 3,887 | 88 |
| GSD(T)-1 | 1,364,534 | 1,354,147 | 10,388 |
| GSLD(T)-1 | 543,015 | 538,525 | 4,490 |
| GSLD(T)-2 | 110,321 | 107,765 | 2,556 |
| GSLD(T)-3 | 5,842 | 5,675 | 167 |
| MET | 4,693 | 4,659 | 33 |
| OL-1 | 13,630 | 13,279 | 351 |
| OS-2 | 1,478 | 1,465 | 13 |
| RS(T)-1 | 4,065,423 | 4,090,038 | -24,615 |
| SL-1 | 99,448 | 97,443 | 2,004 |
| SL-2 | 1,425 | 1,384 | 41 |
| SST-DST | 951 | 943 | 8 |
| SST-TST | 3,073 | 2,934 | 139 |
| TOTAL RETAIL | 6,788,559 | 6,788,559 | 0 |

* MFR E-1, Attachment 2 (2017)

**Q. In her Direct Testimony on page 22, witness Deaton cites TECO as a utility that uses the 12 CP and 25% average demand allocation method. Is this correct?**

A. No. TECO previously used this methodology. However, pursuant to a settlement in TECO's most recent base rate case (Docket No. 130040-EL), TECO now uses the 12 CP and 1/13$^{th}$ average demand method to allocate production demand fixed costs. The

Stipulation and Settlement Agreement that was approved by the Commission on September 30, 2013 (Order No. PSC-13-0443-FOF-EI) states as follows: "(ii) The rates will reflect the use of a 12 Coincident Peak and 1/13th Average Demand methodology for allocating production plant costs."

**Q. Is there any basis, as witness Deaton suggests, to support the shift to a 12 CP and 25% average demand method because FPL is now adding different types of generation resources?**

A. No. Table 2 below shows all of the generating units added by FPL in the past 12 years.

**Table 2**
**FPL Generating Unit Installations**
**(2006 - 2016)**

| | | |
|---|---|---|
| Cape Canaveral | Combined Cycle | 2013 |
| Cape Canaveral | Combined Cycle | 2013 |
| Cape Canaveral | Combined Cycle | 2013 |
| Cape Canaveral | Combined Cycle | 2013 |
| Riviera | Combined Cycle | 2014 |
| Riviera | Combined Cycle | 2014 |
| Riviera | Combined Cycle | 2014 |
| Riviera | Combined Cycle | 2014 |
| Turkey Point | Combined Cycle | 2007 |
| Turkey Point | Combined Cycle | 2007 |
| Turkey Point | Combined Cycle | 2007 |
| Turkey Point | Combined Cycle | 2007 |
| Turkey Point | Combined Cycle | 2007 |
| West County Energy Center | Combined Cycle | 2009 |
| West County Energy Center | Combined Cycle | 2009 |
| West County Energy Center | Combined Cycle | 2009 |
| West County Energy Center | Combined Cycle | 2009 |
| West County Energy Center | Combined Cycle | 2009 |
| West County Energy Center | Combined Cycle | 2009 |
| West County Energy Center | Combined Cycle | 2009 |
| West County Energy Center | Combined Cycle | 2009 |
| West County Energy Center | Combined Cycle | 2011 |
| West County Energy Center | Combined Cycle | 2011 |
| West County Energy Center | Combined Cycle | 2011 |
| West County Energy Center | Combined Cycle | 2011 |
| DeSoto Next Generation Solar Energy | Solar Photovoltaic | 2009 |
| Space Coast Next Gen Solar Energy | Solar Photovoltaic | 2010 |

Source: FPL_DATA_EIA860_3_Generator_Y2014

As can be seen, except for two very small solar projects (35 mW), all the generating resources that have been added to FPL's system in the last 12 years have been combined cycle units. Clearly, nothing has changed in 2016 to justify a change in FPL's cost of service methodology; FPL's arguments suggest that despite its two prior base rate cases during this period, it only has apparently concluded in 2016 that because it had added combined cycle capacity, its cost allocation methodology should be changed. If anything, the dramatic collapse in the price of natural gas since 2005 should suggest the amount of savings achieved by greater use of more efficient gas-fired generation has diminished, and thus the percent cost shift that could be justified based on that theory also should be diminished compared to prior circumstances.

**Q. Does FPL witness Deaton provide any evidence supporting her assertion that fuel savings justify the change to a 12 CP and 25% average demand method?**

A. No. She provides no reasonable basis to adopt this method beyond a general observation that energy usage is a factor in determining what type of generation to install (*i.e.*, combined cycle vs. peaking). While it is correct that a combined cycle unit involves more capital investment per generating capacity than a combustion turbine (peaking unit), and has a lower heat rate, FPL has presented no evidence to justify assigning 25% of fixed production demand related costs on the basis of rate class energy use, including energy use during off-peak periods, as opposed to any other percentage. Nor has FPL demonstrated that assignment of 25% of fixed production costs on the basis of energy use is more appropriate than an assignment of 8% as would occur under the 12 CP and 1/13$^{th}$ class cost of service methodology that FPL has previously used and which the Commission has required other utilities to present in their MFRs.

FPL's proposed production cost allocation methodology unreasonably assigns fixed generation costs to higher load factor general service demand class customers who efficiently use the Company's generating capacity at relatively consistent levels throughout the day and throughout the year, therefore helping to defray the cost of such capacity. The price signals that would be sent to those customers, if the Company's recommended methodology were adopted, would discourage off-peak use of the Company's costly generating unit resources. It links off-peak energy usage to generation resource additions. That link, of course, is contrary to logic and erroneous. Off peak use of the utility's generation resources helps defray the fixed costs of those assets that otherwise would have to be recovered from peak period use.

**Q. Would you discuss the problems that you have identified with FPL's proposed 12 CP and 25% average demand allocation method?**

A. The 12 CP and 25% average demand method is essentially a 75%/25% demand/energy weighted allocation method. While witness Deaton does not provide this level of analysis to support the method in her testimony, she implies that energy use or system load factor impacts the economic tradeoffs among the types of generation resources selected to meet customer demands. Intuitively, it would follow under her theory that the higher cost of base load capacity is only incurred because of the fuel savings that are provided by a base load (or intermediate load) resource relative to a simple cycle combustion turbine. The 12 CP and 25% average demand method therefore is often claimed to be justified as a substitution of capital investment in lieu of incurring higher fuel costs for peaking units. The "capital substitution" methodology is a production cost allocation method that attempts to capture the economic trade-offs between high capital cost base load (or, perhaps intermediate load) generating resources that have lower operating costs (*i.e.*, lower fuel costs/mWh due to fuel type or lower heat rates), versus lower capital cost resources (such as simple cycle combustion turbines) that have higher operating costs (*i.e.*, higher fuel costs due to use of oil or natural gas, or higher heat rates). The concept underlying the "capital substitution" theory is that higher energy use of "peakers" creates incentives to invest in lower capital cost resources – thus, creating a linkage between energy use and capital costs.

**Q. Has Ms. Deaton provided a study showing linkage between energy use and capital costs that supports the use of a 12 CP and 25% average demand methodology?**

A. No. At most, she implies that the relationship exists but does not present a study which analyzes the relationship let alone a study that actually confirms the relationship she implies exists.

**Q. Have you undertaken a study to examine the relationship between energy use and the capital costs of generating capacity available to FPL?**

A. Yes.

**Q. What does your cost causation analysis show?**

A. It shows that if the 12 CP and 25% average demand method is to be used, the cause of the costs FPL would shift to high load factor customers is consumption in peak summer demand periods, which should be the basis for allocation of such costs.

**Q. Will you describe your study?**

A. It is important to recognize that the principle of "cost causation" is used to develop a class cost of service analysis. As described on page 38 of the NARUC Electric Utility Cost Allocation Manual, "Cost causation is a phrase referring to an attempt to determine what, or who, is causing the costs to be incurred by the utility." In order to assess each rate class' share of total jurisdictional costs, all of the Company's costs are sorted into the various major functions provided by the utility: production, transmission, distribution and customer related costs (such as customer accounting). For example, the production function is assigned production costs, which would include generation plant in service, as well as depreciation reserves and other rate base related costs, depreciation expense, O&M expenses, fuel and purchased power. Once functionalized, these costs are then classified as either demand related, energy related or customer related. Finally, the functionalized and classified costs are then allocated to rate classes based on allocation factors reflecting cost causation. Fixed demand related costs are generally caused by the need for generation resources to meet peak demands; energy related costs, such as fuel expenses, are caused by the total amount of energy use of each rate class.

**Q. Why is it important to perform a reasonable allocation of costs to rate classes?**

A. There are a number of reasons to do so. First, economic efficiency requires that rates reflect underlying costs. For example, while one could just divide FPL's total fuel costs by the number of customers on the system and send each customer a uniform bill, that approach would clearly be unfair and result in a substantial misallocation of resources by overpricing energy related fuel costs to most customers and underpricing it to higher load factor customers. Cost causation dictates that these energy related costs be assigned on the basis of the energy (kWh) use of each rate class. Similarly, fixed demand related costs, such as the return on generation plant investment and fixed production O&M, are incurred by the utility to meet the peak demand of its customers.

Once these plants are constructed, these demand related costs are fixed and do not vary with the amount of energy used by customers. As a result, economic efficiency is best achieved by allocating fixed demand related costs on the basis of class peak demand.

In addition to economic efficiency, a related reason for allocating costs on the basis of cost causation is to prevent cross-subsidization of one rate class by another. Cross-subsidization occurs when one set of customers pays in excess of cost and another pays less than the cost of serving that set of customers.

FPL is proposing that this Commission adopt a methodology that classifies 75% of all of the Company's fixed production costs as demand related, compared to the current FPL method that classifies 92% of fixed production costs as demand related, which is already 8% less than strict cost causation would dictate. Strict cost causation, absent any other evidence to the contrary, would argue for a coincident peak allocator to assign cost responsibility for fixed, demand related costs. In the case of FPL, such an allocator would be a summer CP allocator. At a minimum, production demand related fixed costs should be allocated on the basis of 12 CP. The Commission has adopted a 12 CP and 1/13$^{th}$ allocator in many prior electric utility rate cases, including all FPL cases since 1983. While this allocator does include a small energy component, the practical effect of the 12 CP and 1/13$^{th}$ allocator is it more closely tracks cost causation for fixed production costs.

**Q. Have you developed any analysis that would test the reasonableness of FPL's decision to now classify 25% of production fixed costs as energy related?**

A. Yes. To test the reasonableness of FPL's recommended 12 CP and 25% average demand method, I developed a set of screening curves that evaluate the relative economics of a higher cost combined cycle unit ("CCGT") compared to a combustion turbine peaking unit ("CT").

**Q. Would you describe the specific analysis that you developed?**

A. Table 3 below summarizes CCGT and CT costs based on the U.S. Department of Energy, Energy Information Administration ("EIA") Annual Energy Outlook forecast for 2015 ("AEO 2015"). This forecast, which is prepared annually by EIA, provides projections of a significant number of energy industry metrics, including the U.S. electric utility industry. As part of its forecast, EIA prepares a set of assumptions that are incorporated into its models. Among these assumptions are a set of capital and operating costs for CCGT and CT generation resources. The data summarized in Table 1 are contained in EIA's June 2015 report entitled "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015." Exhibit No. ___ (SJB-4) contains an excerpt from this report.

**Table 3**
**U.S. Average Levelized Costs for Plants Entering Service in 2020**

| Levelized (2013 $/MWh)<br>C/O Date 2020 | Advanced<br>Combined Cycle | Advanced<br>Combustion<br>Turbine |
|---|---|---|
| Capacity Factor | 87% | 30% |
| Capital | 15.9 | 27.8 |
| Fixed O&M | 2 | 2.7 |
| Var O&M + Fuel | 53.6 | 79.6 |
| Transmission | 1.2 | 3.5 |
| Total | 72.6 | 113.6 |
| Total less Transmission | 71.4 | 110.1 |
| | | |
| Total Capital Cost/mW | $ 121,177 | $ 73,058 |
| Fixed O&M/mW | $ 15,242 | $ 7,096 |
| Total Fixed Cost/mW | $ 136,419 | $ 80,154 |
| | | |
| Total Variable Cost/mWh | $ 53.60 | $ 79.60 |

*Source: Energy Information Administration Annual Energy Outlook 2015, "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015" Table 1

The cost data presented in Table 3, as noted in the table, are levelized $2013 costs for an Advanced CCGT and an Advanced CT, both with commercial operation dates of 2020. This comparison provides a reasonable estimate of the economic trade-offs between lower and higher capital cost generation resources. As shown in the table, based upon the relative capacity factors of the two types of units, the annual levelized fixed cost of the CCGT is $136/kW, while the annual levelized fixed cost for the CT is $80/kW. The variable operating costs of the two resources are $53.6/mWh and $79.6/mWh respectively. Using this information, a screening curve comparison can be developed to identify the breakeven capacity factor or "hours use" of a kW of capacity between the two resources. A screening curve is a cost curve for the resource, reflecting both fixed costs (capital, O&M expense) and variable costs (fuel, variable O&M expense) at various capacity factor (hours of use) levels. It is designed to compare the cost of alternative resources at different usage levels. Table 3 shows the resulting all-in levelized costs at various capacity factors.[3]

[3] The EIA data are presented in terms of constant dollar ($2013) levelized costs for ease of comparison.

**Table 4**
**Screening Curve Analysis: CCGT vs. CT**

| | Total Busbar Cost | |
|---|---|---|
| mWh | CCGT | CT |
| 350 | $ 442.93 | $ 308.35 |
| 438 | $ 365.06 | $ 262.60 |
| 613 | $ 276.07 | $ 210.31 |
| 876 | $ 209.33 | $ 171.10 |
| 1,314 | $ 157.42 | $ 140.60 |
| 1,752 | $ 131.47 | $ 125.35 |
| 2,190 | $ 115.89 | $ 116.20 |
| 2,628 | $ 105.51 | $ 110.10 |
| 3,066 | $ 98.09 | $ 105.74 |
| 3,504 | $ 92.53 | $ 102.48 |
| 3,942 | $ 88.21 | $ 99.93 |
| 4,380 | $ 84.75 | $ 97.90 |
| 4,818 | $ 81.91 | $ 96.24 |
| 5,256 | $ 79.56 | $ 94.85 |
| 5,694 | $ 77.56 | $ 93.68 |
| 6,132 | $ 75.85 | $ 92.67 |
| 6,570 | $ 74.36 | $ 91.80 |
| 7,008 | $ 73.07 | $ 91.04 |
| 7,446 | $ 71.92 | $ 90.36 |
| 7,884 | $ 70.90 | $ 89.77 |
| 8,322 | $ 69.99 | $ 89.23 |

For example, the CCGT resource has a $2013 levelized total cost of $84.75 if it were operated for 4,380 hours (or one half of the time) per year. The CT cost, at the same 4,380 hour of operation, would cost $97.90 per kW.

As shown in Table 4, the breakeven hours-use of the conventional CCGT and the advanced CT occurs at about 2,190 hours of usage during the year. For operation at

2,190 hours or below, the CT is less costly, while for operation above 2,190 hours, the CCGT is less costly on a unit of production basis due to its lower heat rate (btu/kWh).

**Q. What are the cost of service implications of this screening curve analysis with regard to the 12 CP and 25% average demand methodology?**

A. The screening curve economic comparison shows that beyond 2,190 hours of annual operation (a quarter of the hours in a year), the CCGT is less expensive and would be selected as the least cost resource. As long as the system's energy needs required the generation resource to operate at least 2,190 hours during the year, the least cost resource is the CCGT. Energy usage beyond 2,190 mWh per mW has no impact on the economic decision to select the higher capital cost CCGT resource (over the lower capital cost CT). Thus, from a cost of service/cost responsibility standpoint, any energy usage in hours greater than the top 2,190 peak hours during the year do not "cause" the higher capital costs of the CCGT resource (compared to the CT) because the CCGT would be used. Translating this into a class cost responsibility framework, energy usage in the remaining 6,570 hours during the year does not impose any additional capital costs on the system. This result is particularly important in assessing the reasonableness of the Company's proposed 12 CP and 25% average demand method, which assigns fixed generation resource costs to rate classes on the basis of the classes' average demand during all 8,760 hours of the year. The screening curve economic analysis shows that energy usage in the 6,570 hours beyond the breakeven hour (approximately 2,190) is not responsible for any additional CCGT capacity costs (*i.e.*, those CCGT capital costs in excess of CT capital costs). Assigning 25% of all FPL fixed generation costs on the basis of class average demand, based on a theory that customers with higher load factors are causing these higher CCGT costs to be incurred, therefore is contrary to the economic evidence of cost responsibility that shows that kWh energy usage in excess of a system-wide 2190 hour level does not influence the decision concerning what type of generating unit to install. Perhaps that is why the Company does not base its request for use of the 12 CP and 25% average demand methodology on a cost causation analysis.

**Q. How does this CCGT vs. CT economic analysis support your position that the Company's proposed 12 CP and 25% average demand method is incorrect and not based on cost causation?**

A. The analysis shows that energy usage during the top 2,190 hours during the year is the only energy usage that impacts the trade-off between these two types of resources, not the annual energy usage presumed by the Company's proposal. Figure 1 below shows FPL's annual load duration curve based on 2014 hourly FERC Form 714 data, with a demarcation for 2,190 hours use. These top 2,190 hours of energy use occur primarily during the peak months of May through September as can be seen in Table 5. Moreover, the top 2,190 hours constitute a very high percentage of on-peak hours during these 5 months and a relatively low percentage of off-peak hours as compared to the on-peak hours in those months. This means that if 25% of rate class energy use is to be used in the production demand allocation factor, then the energy use should be a weighted energy use for each rate class, with most of the weight given to rate class energy use during the 5 peak months of May through September, with primary weight being given to on-peak energy use, not off-peak. Table 5 summarizes the distribution of the top 2,190 hours by month and then as a percentage of on-peak and off-peak hours during each month.

Figure 1
2014 FPL Load Duration Curve (FERC Form 714 Data)

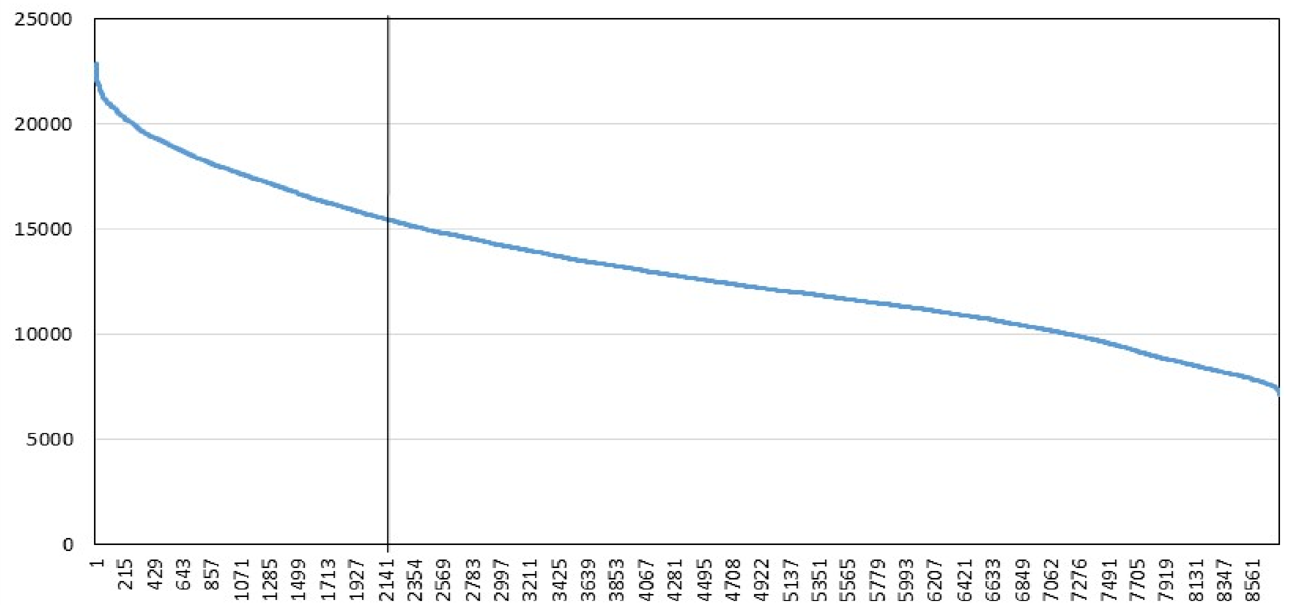


**Table 5**
**Distribution of Top 2,190 Hourly Loads By Month - 2014**

| | Hours | Monthly Distribution | % of Peak Hours in Month | % of Off-Peak Hours in Month |
|---|---|---|---|---|
| January | 10 | 0.5% | 5.1% | 0.2% |
| February | 39 | 1.8% | 5.0% | 6.1% |
| March | 15 | 0.7% | 1.2% | 2.3% |
| April | 149 | 6.8% | 47.5% | 10.5% |
| May | 280 | 12.8% | 89.4% | 20.0% |
| June | 314 | 14.3% | 86.2% | 28.4% |
| July | 378 | 17.3% | 96.5% | 34.2% |
| August | 419 | 19.1% | 95.2% | 43.1% |
| September | 322 | 14.7% | 91.5% | 28.1% |
| October | 225 | 10.3% | 72.9% | 13.8% |
| November | 31 | 1.4% | 4.6% | 4.2% |
| December | 8 | 0.4% | 0.6% | 1.2% |
| Total | 2,190 | 100.0% | 52.4% | 15.9% |

During the peak summer months, about 90% of the on-peak hours fall into the highest 2,190 load hours in the year, but only about 30% of the off-peak hours fall into this category.[4]

**Q. Does the Company's use of annual kWh energy (average demand) provide a reasonable measure of cost responsibility?**

A. No. Table 5 shows that energy use during the top 2,190 hours of the year is the determining factor in an economic analysis of the trade-offs between a CCGT and a peaking CT, not annual energy use as implied by FPL's 12 CP and 25% average demand method. Table 6 provides a comparison, for major rate classes, of the percent of annual energy use in the May through September period, when the top 2,190 hours occur vs. the October through April period. As can be seen, the lower load factor consumers contribute a larger percentage of FPL's annual kWh energy demand during the peak months of May through September as compared to the large C&I rate classes. Moreover, given the fact that the large C&I rate classes have a higher than average load factor, while other classes have a lower than average load factor, the energy usage of the latter group during these peak months (May through September) is more likely to be concentrated during the on-peak period of each of these months, thus further shifting responsibility to the residential class.[5]

[4] The analysis presented in Table 5 is based on the FERC Form 714 data for FPL using FPL's tariff criteria for on-peak and off-peak hours.

[5] As shown on MFR E-17, the Residential class 12 CP load factor is 60%, while the 12 CP load factor for GSLD(T)-1 is 79%; for GSD(T)-1 it is 75%; and for CILC-1D it is 92%.

**Table 6**
**Distribution of kWh Sales by Major Rate Class**
(Percent of Annual kWh Sales in Each Period)

| | May-Sept. | Oct-Apr |
|---|---|---|
| CILC-1D | 43.0% | 57.0% |
| CILC-1T | 42.2% | 57.8% |
| GSD(T)-1 | 44.9% | 55.1% |
| GSLD(T)-1 | 44.1% | 55.9% |
| GSLD(T)-2 | 43.9% | 56.1% |
| GSLD(T)-3 | 42.2% | 57.8% |
| | | |
| RS(T)-1 | 47.9% | 52.1% |
| GS(T)-1 | 46.0% | 54.0% |

**Q. Do these results demonstrate that using annual energy (average demand) in the Company's 12 CP and 25% average demand method improperly allocates cost?**

A. Yes. Because only energy usage during the highest 2,190 load hours of the year is relevant to generation resource trade-offs between high capital cost/low operating cost units and low capital cost/high operating cost units, allocating 25% of fixed production cost on average demand (which is the same as annual energy usage) is not based on cost causation. At most, if the 25% energy component is to be used, it should only be based on each class's share of energy during the top 2,190 hours of the year. In addition, if such a method were to be adopted, the "demand" portion of the allocator should only be the peak month CP or perhaps the summer and winter peak month CPs, not CP demands in all 12 months.

Because the use of the 12 CP method captures rate class usage during the 12 monthly peaks, plus the additional 1/13 energy (average demand) component reflecting annual energy usage, this methodology does a better job of reflecting each rate class's cost responsibility for FPL's fixed production costs than the Company's proposed 12 CP and 25% methodology.

**Q. Based on your analysis, should the Commission adopt FPL's proposal to use a 12 CP and 25% average demand method?**

A. No. There is no basis for the Company's proposal. It simply results in a substantial cost shift from lower load factor customers to the larger general service rate classes in contradiction of cost causation principles.

**Q. Should the Commission adopt FPL's current 12 CP and 1/13$^{th}$ method in this case?**

A. Yes. While I have supported a 100% demand based allocation method in prior FPL cases (for example, a 1 CP method) and continue to believe it most appropriately would allocate FPL's production costs, I believe that using the FPL 12 CP and 1/13$^{th}$ method in this case to allocate production and transmission demand related costs would more closely track cost causation than a 12 CP and 25% average demand method. In addition, the Company's cost study also should be modified to incorporate an MDS distribution cost classification and allocation method.

**Q. Would you please discuss the methodology used by FPL to allocate distribution plant investment and expenses to retail rate classes?**

A. Yes. As discussed in FPL witness Deaton's testimony, the Company has classified all distribution plant as demand related except account 369 Services and account 370 meters, which are classified as customer related.[6] The Company's approach does not give any recognition to a customer component of any primary or secondary line, pole or transformer. All of these costs are assigned on the basis of kW demand.

**Q. Do you agree with the Company's classification of these distribution costs?**

A. No. FPL places significant weight on the "parity" results from its cost of service study when assigning increases to rate classes. As a result of FPL's flawed parity study, the proposed increases to its general service rate classes are substantially higher than the system average increase. These parity results are driven to a large extent by the methodology used by FPL to classify and allocate costs to rate classes. This is not purely an argument of academic interest. If the cost of service study is used to allocate rate increases, the underlying methodology used in the study will materially increase rates to a number of rate classes. Therefore, given the significant reliance that the Company has placed on the results of its cost of service study in assigning its requested revenue increase to rate classes in this case, it is important to understand the drivers of cost incurrence and to assess alternative methods of classifying distribution costs to properly reflect cost causation.

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[6] Primary pull-offs are also specifically assigned to rate classes.

**Q. What is the central argument underlying a classification of some portion of distribution costs (other than services, meters and "primary pull-offs") as customer related?**

A. As described in the NARUC Electric Utility Cost Allocation Manual, the underlying argument in support of a customer component is that there is a minimal level of distribution investment necessary to connect a customer to the distribution system (lines, poles, transformers) that is independent of the level of demand of the customer.[7] The amount of distribution cost that is a function of the requirement to interconnect a customer, regardless of the customer's size, is appropriately assigned to rate classes on the basis of the number of customers, rather than on the kW demand of the class. As stated on page 90 of the NARUC cost allocation manual:

> When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs.

**Q. Has FPL offered evidence disputing that conclusion?**

A. No.

**Q. Would you briefly explain the conceptual basis for a minimum distribution cost methodology?**

A. As discussed in the NARUC cost allocation manual, the "minimum size" methodology attempts to measure the customer component of various distribution plant accounts (*e.g.*, poles, primary lines, secondary lines, line transformers, etc.). It is designed to estimate the component of distribution plant cost that is incurred by a utility to effectively interconnect a customer to the system, as opposed to providing a specific level of power (kW demand) to the customer. It is this cost, which is not related to customer usage levels, which should be allocated to rate classes based on the number of primary and secondary distribution customers taking service in the class.

Conceptually, this analysis is designed to estimate the behavior of costs statistically, as the Company meets growth in both the number of distribution customers and the loads of these customers. For example, new distribution investment in poles, or underground conductors, for a new subdivision may be associated with unsold, or unoccupied homes that have "0" kW demand – yet the cost for these facilities is still incurred. Similarly, distribution facilities must be installed to meet the needs of part time residents that may have little or no demand during a portion of the year – yet the cost of such distribution facilities still must be incurred and does not vary as a result of the fact that such facilities serve part-time residents. The MDS methodology gives recognition to this circumstance by assigning a portion of the cost of these facilities based on the existence of a "customer," and not just the level of the customer's kW demand. This is in contrast to FPL's analysis that assumes that all distribution costs (except services and meters) vary directly with kW demand, without any fixed component that should be allocated on the basis of the number of customers in each class.

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[7] An excerpt from the NARUC Manual that discusses the classification of distribution costs is contained in Exhibit No. ___ (SJB-5).

**Q. Do you have a specific example that illustrates this point?**

A. Yes. In FPL's last two base rate cases (Docket Nos. 080677-EI and 120015-EI), I analyzed the Company's allocation of account No. 364 secondary poles using its "100% demand" methodology. Those analyses clearly demonstrated that the Company's refusal to acknowledge <u>any</u> customer component of distribution cost (other than for services and meters) is not justified. For example, I showed in FPL's 2008 rate case that FPL's cost of service study assumed that 30 residential customers were served by a single pole while it took 19 poles to serve a single GSLDT-2 customer. My testimony in FPL's 2012 rate case showed that FPL's cost of service study assumed that 35 residential customers were served by a single pole while it took approximately 14 poles to serve a single GSLDT-2 customer. FPL's past studies simply did not produce realistic results.

**Q. Have you performed a similar analysis of account No. 364 data in this case?**

A. Yes. FPL has classified all costs in account No. 364, poles, towers and fixtures, as demand related and allocated these costs to rate classes on the basis of rate class NCP demand. This account mainly consists of primary and secondary poles. Based on the response to FIPUG 1-13, as of December 31, 2015 the Company had 1,168,532 poles in Account No. 364. *See* Exhibit No. ___ (SJB-8) at p. 3. Based on the primary/secondary split of Account No. 364, 4.93% of the costs in this account are classified as secondary, the remainder as primary. The Company considers smaller wooden poles to serve secondary customers. There were 174,085 poles in this smaller, wooden category at December 31, 2015. These secondary poles have been allocated to rate classes using rate class NCP demand (allocator FPL 105). Table 7 summarizes FPL's implicit allocation of these secondary poles to several rate classes on the basis of demand. As can be seen in the table, FPL's current cost of service study assumes that on average more than 35 residential customers are served from a single pole, while it takes about <u>13 poles to serve a single GSLDT-2 customer</u>. As with its past studies, FPL's current study does not reflect a realistic result; yet, this is the cost allocation underlying FPL's proposed rate class increases in this case.

**Table 7**
**FPL's Assignment of Secondary Poles Per Customer**

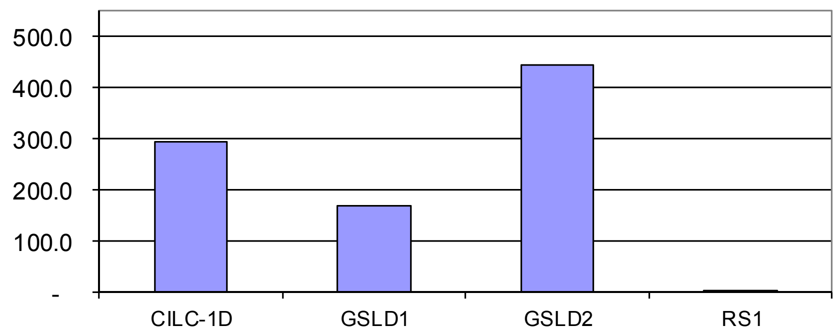
**Total Secondary Poles** **174,085**

| Rate Class | Allocation Factor* | Poles Allocated to Rate | Poles Per Customer | Poles Per Every 35 Customers |
|---|---|---|---|---|
| CILC-1D | 1.052% | 1,831 | 8.40 | 294.0 |
| GSLD1 | 8.529% | 14,848 | 4.80 | 168.0 |
| GSLD2 | 1.147% | 1,997 | 12.64 | 442.4 |
| RS1 | 60.754% | 105,764 | 0.02 | 0.9 |

* FPL105

Figure 2 below illustrates this in graphic form. This result suggests that the Company's study, which ignores any measure of a customer component for distribution facilities (other than meters and services), overstates cost responsibility for large general service rate classes. In sum, 13 distribution poles under FPL's study are necessary to serve the average single GLDT-2 customer, but those same poles would serve 455 residential accounts. FPL's current study reflects that FPL has not provided the Commission and parties with a cost allocation methodology that improves on the clearly erroneous methodology FPL has used in the past.

**Figure 2**
**FPL Cost of Service Study**
**Secondary Poles Per Every 35 Customers**




**Q.** **In FPL's 2012 rate case (Docket No. 120015-EI) FPL witness Ender addressed your MDS proposal in his Rebuttal Testimony. Did he respond to your analysis of FPL's allocation of poles in Account 364 and offer any explanation for what appears to be a misallocation in the Company's cost of service study?**

A. No. While Mr. Ender opposed the use of an MDS method for FPL, he never addressed the obvious flaw in the Company's cost allocation method discussed above. The results summarized in Figure 2 clearly demonstrate the flaw in the Company's methodology.

**Q.** **Do other major electric utility operations in Florida incorporate minimum distribution system classifications in class cost of service studies?**

A. Yes, both TECO and GPC utilize a minimum distribution system methodology to classify and allocate distribution costs. In its most recent base rate case (Docket No.

130040-EI), TECO filed and recommended a class cost of service study that uses the MDS methodology. Although it was in the context of a settlement, the Commission approved MDS for use in determining the allocation of distribution costs for TECO's system.

**Q. What was TECO's justification for the Company's change to an MDS methodology?**

A. In his Direct Testimony in Docket No. 1300040-EI, TECO's witness, Mr. Ashburn, stated as follows:

> Q. Why does the company believe the MDS method is a more appropriate classification of these distribution costs than previously recognized?
>
> A. Previously, the costs of distribution facilities (*i.e.* transformers, poles, conductors, and cables, etc.) were classified as capacity-related and allocated to rate classes based on the maximum load imposition on the distribution system. The company now recognizes certain deficiencies in this classification and rate design treatment for distribution costs and seeks to remedy them in this proceeding. First, the company seeks to recognize in its costing treatment the obligation it fulfills to electrically connect any customer desiring to energize their premise, no matter how much load the customer may impose or energy the customer may use. This requires the company to incur the cost to install transformers, poles and conductors in place to simply connect the customer to its power grid. The previous treatment of classifying these costs as only capacity-related ignored an important cost-causative responsibility to be energized and ready to serve. [Ashburn Direct Testimony at pages 26-27].

**Q. Do you agree with TECO witness Ashburn's statement in support of an MDS method?**

A. Yes.

**Q. Are GPC's base rates also based upon the MDS method to classify and allocate distribution costs?**

A. Yes. Again, the Commission approved the use of MDS for GPC as a result of a settlement, but as in the case of TECO, GPC supported the use of the MDS methodology in its direct case.

In GPC's 2011 rate case (Docket No. 110138-EI), GPC presented and strongly supported the use of an MDS methodology to develop its class cost of service study. GPC's cost of service witness in that case, Michael O'Sheasy, testified in support of an MDS methodology as follows:

> Q. Please explain why the Minimum Distribution System methodology is important to Gulf and its customers?
>
> A. As I discuss in more detail later, some costs of the distribution system beyond the customer meter and service drop do not vary with customers' use of electricity. The Minimum Distribution System (MDS) methodology is necessary to accurately determine and allocate these customer-related distribution costs. The misclassification of costs that results from not using the MDS methodology sends misleading price signals to customers. This misclassification also results in different customer rate classes bearing more or less costs than their cost-causative share of distribution costs. It is therefore important to examine these customer-related costs and classify them appropriately, which the MDS methodology enables us to do. [O'Sheasy Direct Testimony at pages 16-17, Gulf Power Company Docket No. 110138-EI].

**Q. Do you agree with Mr. O'Sheasy's quoted testimony on the MDS issue?**

A. Yes. There is no question that items in each of FPL's distribution accounts 364 to 368 are customer related. FPL nonetheless assumes that each of these accounts is 100% demand related. As a result, from cost incurrence and cost recovery perspectives it would be as if, in a day, week or month in which a customer were to decrease its usage to 0 kW, all of the facilities, such as poles, overhead conductors, underground conductors and transformers, or portions thereof, that had served that customer would somehow disappear. This is obviously not the case. It is simply not credible to argue, as FPL does, that 100% of its primary and secondary distribution system (other than services and meters), is cost-causally related to kW demand and none is related to the number of customers served on the distribution system.

**Q. What were the results of TECO's and GPC's MDS classification analyses?**

A. Exhibit Nos. ___ (SJB-6) and (SJB-7) contain copies of TECO witness Ashburn's MDS analysis and GPC witness O'Sheasy's MDS results. Table 8 summarizes these results.

**Table 8**
**Gulf Power Company/Tampa Electric Company MDS**
**Cost Causation Study Results**

| | TECO 2013[1] 130040-EI | | Gulf Power 2013[2] 130140-EI | | Averaged | |
|---|---|---|---|---|---|---|
| | % Cust | % Dem | % Cust | % Dem | % Cust | % Dem |
| **Poles** | | | | | | |
| 364 | 64% | 36% | 65% | 35% | 65% | 36% |
| **Conductors** | | | | | | |
| 365 | 9% | 91% | 13% | 87% | 11.1% | 88.9% |
| 366 | 9% | 91% | 3.9% | 96.1% | 6.5% | 93.6% |
| 367 | 9% | 91% | 4.8% | 95.2% | 6.9% | 93.1% |
| Total (365, 366, 367) | 9% | 91% | 7.3% | 92.7% | 8.2% | 91.8% [3] |
| **Transformers** | | | | | | |
| 368 | 24% | 76% | 25% | 75% | 25% | 75% |

[1] Ashburn Testimony page 28, lines 6-9.
[2] O'Sheasy Testimony pg 25-26 refers to Exhibit MTO-2 pgs 52-60.
[3] Weighted GPC by FPL test year account balances.

**Q. Do you believe that use of a minimum distribution system methodology is appropriate for FPL?**

A. Yes. Given the importance of the cost of service results (parities) in this case, it is appropriate for the Commission to adopt a class cost of service study that uses the MDS methodology. There is no plausible rationale that would somehow distinguish cost causation related to the installation of poles, overhead conductors, underground conductors and transformers on FPL's distribution system from that of TECO and GPC in the state, or the many other utilities that rely on the MDS method that is supported in the NARUC Manual. The conceptual basis for the MDS method is that it reflects a classification of the distribution facilities that would be required to simply interconnect a customer to the system, irrespective of the kW load of the customer. From a cost causation standpoint, the argument supporting this approach is that these are the minimum facilities investment needed to interconnect a customer to the FPL system, including meeting minimum safety standards set forth in the National Electric Safety Code, which the Commission requires be adhered to for all Florida electric utilities.

**Q. Have you performed any analysis to evaluate the reasonableness of using the GPC and TECO MDS results as a measure of minimum distribution costs on the FPL system?**

A. Yes. As described by GPC witness O'Sheasy in Docket No. 110138-EI on page 25 at line 24 of his Direct Testimony in GPC's direct case, GPC used a minimum size methodology for Account 364 data based on the "the average of the smallest, most frequently used poles since the unit cost of different sized poles did not lend itself to regression analysis."[8] In the GPC analysis, the Company used the cost of wooden poles that were 35 feet and smaller. Using FPL Account No. 364 data provided by the Company in response to OPC Interrogatory 7-192, Attachment No 1, I performed a similar analysis of the cost of smaller wooden poles on the FPL system, which is shown in Exhibit No. ___ (SJB-8), pages 1 through 3. The minimum size pole analysis is

[8] For all other distribution plan accounts, GPC used a zero intercept, regression methodology.

shown on page 1, while pages 2 and 3 contain supporting information from various FPL data responses and workpapers.

The Company's response to OPC 7-192, which is on page 2 of (SJB-8), provides Account No. 364 cost data at December 31, 2015, by size of pole. Based on the Company's own data, there were 174,085 wooden poles on the FPL system in the smallest categories used by FPL (23/30 FT and 35/40/45 FT). As shown on page 1 of (SJB-8), the average cost of these smaller wooden poles is $786.87 per pole. The entire inventory of FPL poles (1,168,532, as shown on page 3 of (SJB-8)) is then re-priced in my analysis at this minimum unit cost. Based on this analysis, using the GPC methodology, 69.7% of FPL's Account No. 364 costs are customer related. This compares to GPC's Account No. 364 classification that assigns 65% of these costs as customer related and TECO's study that assigns 64% as customer related. The higher FPL customer classification appears to be consistent with the fact that FPL's 35 foot category also included slightly longer 40 foot and 45 foot poles. Nonetheless, my conclusion from this analysis is that the GPC and TECO classification results are reasonably representative for the FPL system.

**Q. Have you developed an alternative class cost of service study reflecting a minimum distribution system methodology?**

A. Yes. In order to provide indicative rate of return parity impacts from the use of an MDS methodology, I have rerun FPL's 12 CP and 1/13$^{th}$ class cost of service study for 2017 and 2018 using the customer/demand classifications for FERC Account Nos. 364

through 368 developed by TECO and GPC. For purposes of my analyses, I have used an average of the TECO and GPC results for each major distribution plant type, which I presented in Table 8. These results illustrate the bias in the Company's study as a result of the classification of 100% of distribution plant accounts 364 through 368 as demand related and 0% as customer related. Exhibit Nos. ___ (SJB-9) and (SJB-10) present the results for the 2017 and 2018 test years.

**Q. How do the rate of return parities in your MDS cost of service study compare to the Company's filed 12 CP and 1/13th cost study?**

A. Table 9 shows the comparisons for 2017. I have highlighted the large general service rate classes in Table 9 to show the impact of these changes to the Company's cost of service study. As can be seen from the table, there are significant differences in the rate of return parities for most large general service rate classes once MDS cost responsibility is properly recognized.

**Table 9**
**2017 Class Cost of Service Study**
**12 CP and 1/13th with MDS**

| | 12CP+1/13 As-Filed | | 12CP+1/13 w/MDS | |
|---|---|---|---|---|
| | ROR | Parity | ROR | Parity |
| CILC-1D | 3.89% | 0.78 | 4.25% | 0.854 |
| CILC-1G | 5.53% | 1.11 | 5.97% | 1.201 |
| CILC-1T | 3.80% | 0.76 | 3.80% | 0.764 |
| GS(T)-1 | 5.96% | 1.20 | 5.70% | 1.145 |
| GSCU-1 | 8.08% | 1.62 | 6.24% | 1.255 |
| GSD(T)-1 | 4.82% | 0.97 | 5.23% | 1.051 |
| GSLD(T)-1 | 3.15% | 0.63 | 3.52% | 0.709 |
| GSLD(T)-2 | 3.36% | 0.68 | 3.71% | 0.747 |
| GSLD(T)-3 | 4.27% | 0.86 | 4.27% | 0.858 |
| MET | 5.26% | 1.06 | 5.65% | 1.137 |
| OL-1 | 7.99% | 1.61 | 8.33% | 1.675 |
| OS-2 | 2.88% | 0.58 | 3.65% | 0.735 |
| RS(T)-1 | 5.23% | 1.05 | 5.03% | 1.011 |
| SL-1 | 5.89% | 1.18 | 6.14% | 1.235 |
| SL-2 | 7.98% | 1.60 | 8.51% | 1.710 |
| SST-DST | 5.04% | 1.01 | 5.99% | 1.203 |
| SST-TST | 13.00% | 2.61 | 13.00% | 2.615 |
| Total Retail | 4.97% | 1.00 | 4.97% | 1.000 |

**Q. What is the implication of these results from properly recognizing responsibility for MDS costs?**

A. More carefully attributing responsibility for a minimum level of distribution cost associated with connecting customers to the system produces a more accurate measure of rate class revenue increases. I believe that the Commission should rely on a class cost of service study that incorporates an MDS methodology. FPL should file an MDS cost of service study using the methodology employed by TECO and GPC in a compliance filing in this case and use these results to allocate the revenue requirement the Commission approves in this case. The compliance filing should use MDS. In the alternative, I recommend that the Commission use the MDS cost of service study that I have developed above. Further, I recommend that the Commission require FPL to perform and file an MDS cost of service study with the appropriate supporting data in its next base rate case.

**Q. Did you also develop an MDS cost of service studies for 2017 and 2018 using FPL's proposed 12 CP and 25% average demand method?**

A. Yes. Though I do not support the use of the 12 CP and 25% average demand method in this case, as I previously discussed, I have developed an MDS version of the Company's study for both 2017 and 2018 in the event that the Commission relies on this production cost allocation method in this case. These studies are presented in Exhibit Nos. ___ (SJB-11) and (SJB-12). Table 10 below shows the results for 2017.

**Table 10**
**2017 Class Cost of Service Study**
**12 CP and 25% with MDS**

| | 12CP+25 As-Filed | | 12CP+25 w/MDS | |
|---|---|---|---|---|
| | ROR | Parity | ROR | Parity |
| CILC-1D | 3.68% | 0.74 | 4.01% | 0.807 |
| CILC-1G | 5.30% | 1.06 | 5.72% | 1.150 |
| CILC-1T | 3.47% | 0.70 | 3.47% | 0.697 |
| GS(T)-1 | 5.96% | 1.20 | 5.70% | 1.146 |
| GSCU-1 | 7.73% | 1.55 | 5.99% | 1.204 |
| GSD(T)-1 | 4.74% | 0.95 | 5.14% | 1.033 |
| GSLD(T)-1 | 3.08% | 0.62 | 3.45% | 0.693 |
| GSLD(T)-2 | 3.16% | 0.64 | 3.49% | 0.702 |
| GSLD(T)-3 | 3.99% | 0.80 | 3.99% | 0.802 |
| MET | 5.18% | 1.04 | 5.57% | 1.120 |
| OL-1 | 7.62% | 1.53 | 7.94% | 1.597 |
| OS-2 | 2.82% | 0.57 | 3.57% | 0.718 |
| RS(T)-1 | 5.30% | 1.06 | 5.09% | 1.024 |
| SL-1 | 5.62% | 1.13 | 5.86% | 1.178 |
| SL-2 | 7.55% | 1.52 | 8.05% | 1.618 |
| SST-DST | 4.96% | 1.00 | 5.88% | 1.182 |
| SST-TST | 12.11% | 2.43 | 12.11% | 2.434 |
| Total Retail | 4.97% | 1.00 | 4.97% | 1.000 |

## III. FPL's PROPOSAL TO DECREASE THE CDR AND CILC CREDITS

**Q. What does this CDR/CILC credit decrease issue involve?**

A. FPL is proposing to decrease the current level of CDR credits and CILC incentives that were established by the Commission, pursuant to the Order in the Company's 2012 base rate case (Docket No. 1200015-EI). This decrease, which FPL characterizes in its testimony as a "Reset," results in an increase in base rates of $23 million, over and above the $866 million 2017 increase requested by the Company. As shown in MFR E-

5, page 1 of 2 at line 31 ("Decrease in CILC/CDR Credit Offsets"), this $23 million adjustment reduces present base revenues for Rate CILC-1D by $9.943 million in the test year. All else being equal, this produces a very significant increase to customers taking service on CILC rates and general service rates that use CDR credits as part of FPL's DSM program.

**Q. What is FPL's explanation for its proposal to impose these additional increases on CILC and CDR customers through a so-called "Reset?"**

A. FPL witness Cohen addresses this issue in her testimony at pages 18 and 19. The entire testimony explaining this $23 million CILC/CDR credit offset decrease is as follows: "Also, credits provided under the 2012 Rate Settlement for Commercial Industrial Load Control ("CILC") and Commercial Demand Rider ("CDR") customers are reset to pre-settlement levels (adjusted for Generation Base Rate Adjustments) as shown in MFR E-14, Attachment 5."

**Q. What is the impact of FPL's proposal to decrease the CILC/CDR credit offsets?**

A. Rate CILC-1D customers will see a <u>57% increase in base rates</u> when coupled with the other increases proposed for CILC-1D customers in this case. This can be seen in the proof of revenue calculation for CILC-1D shown in MFR E-13c, page 2 of 45 (attached as Exhibit No. ___ (SJB-13)). Under any reasonable standard, this proposal is not consistent with gradualism.

**Q. Is the current level of the CILC and CDR credits cost effective from a DSM perspective?**

A. Yes. Exhibit No. ___ (SJB-14) contains FPL's response to Staff's First Data Request, Request No. 22 in Docket No. 150085-EG that addresses the cost effectiveness of the current level of CDR credits (these are the credits used to develop the CILC rates). As discussed in FPL's response, all of the demand response programs are <u>very cost-effective</u> under the Rate Impact Measure (RIM) test. This includes the CILC and CDR credits approved by the Commission in the 2012 Rate Settlement that FPL now wants to reduce in this 2016 base rate case. In fact, based on FPL's own economic analysis provided to the Staff in response to Staff's First Data Request, No. 21 (attached as Exhibit No. ___ (SJB-15)), a CDR credit of $13.52/kW month would be cost effective under the RIM test.[9] This compares to the current level of CDR credit of $8.26/kW month that FPL now wants to reduce in this base rate case. Given the cost effectiveness of the current level of credits, there is no basis for FPL's proposed $23 million reduction in this base rate case. The Company's proposal is particularly unreasonable given the extreme increase that it produces for CILC customers.

**Q. Are there any additional reasons to reject FPL's proposal?**

A. Yes. In FPL's 2012 base rate case (Docket No. 120015-EI), witness Deaton testified that it was inappropriate to consider a change in the CDR credit in a base rate case. In

[9] From Exhibit No. ___ (SJB-15), the net benefits of the CDR program shown in column 13 on an NPV basis are $20.279 million. The CILC/CDR incentives shown in column 4 are $31.835 million (NPV). If the incentives, which are the CDR credits, are increased by 63.7%, the net benefits would be $0. Thus, the current CDR credit of $8.26/kW month could be increased by 63.7% to $13.52/kW month and the CDR program would still be cost effective.

FPL's Rebuttal Testimony to FIPUG witness Pollock in that case, witness Deaton addressed Mr. Pollock's proposal to increase the CDR and CILC curtailment credits (Deaton Rebuttal at pages 12 and 13, Docket No. 1200015-EI). In her testimony, witness Deaton testified that it would be inappropriate and contrary to Commission Orders to increase the CDR and CILC credits in a base rate case. Witness Deaton testified as follows:

> **Q. Do you agree with FIPUG witness Pollock's assertions beginning on page 40 of his testimony that the CILC Rate Schedule should be reopened and the credits for CILC and the CDR Rider should be increased in this docket?**
>
> A. No. The CILC and CDR rates are conservation programs initiated as part of FPL's DSM plan. The proper venue for addressing conservation programs is in the DSM plan docket. FPL's DSM plan was recently assessed by the Commission in Docket No. 100155-EG. The Commission concluded in that docket that FPL's current programs should continue without modification. In Order No. PSC-11-0346-PAA-EG, the Commission stated, "We find that the programs currently in effect, contained in FPL's existing plan, are cost effective and accomplish the intent of the statute. Therefore, exercising the specific authority granted us by Section 366.82(7), F.S., we hereby modify FPL's 2010 Demand-Side Management Plan, such that the DSM Plan shall consist of those programs that are currently in effect today." (p. 5) Since the CILC program was frozen and closed to new customers in Order No. PSC-99-0505-PCO-EG issued on March 10, 1999, in Docket No. 990002-EG, re-opening the program would be contrary to the Commission's Order to continue the current programs without modification. **Likewise, increasing the credits for either CILC or CDR would be contrary to the Commission's Order.** Any request to reopen the CILC rate classes and increase the CILC and CDR rider credits should be addressed in a DSM docket and not a base rate docket. [Emphasis added].

Given FPL's prior position, it is disingenuous for the Company to now propose a $23 million CDR and CILC credit reduction in this base rate case. If it is contrary to

Commission Orders to increase these credits in a base rate case, it clearly would be contrary to Commission Orders to decrease them in a base rate case. Such a decrease is all the more inappropriate given that FPL's own analysis shows that the credits are cost effective, as I previously discussed.

## IV. ALLOCATION OF THE AUTHORIZED REVENUE INCREASE

**Q. What does this issue involve?**

A. FPL is seeking to increase *base rates* by a series of revenue increases that will be effective on January 1, 2017 ($866 million), January 1, 2018 ($262 million), and June 1, 2019 ($209 million). Based on these revenue increases, average FPL base rates will increase by an average of 14.60% in 2017, an additional 3.90% in 2018 and another 2.99% in 2019. The base rate increases proposed for Rate Schedules CILC and other general service commercial and industrial rate schedules are much higher than the average FPL proposed increases. Also, as I discussed in the previous section of my testimony, FPL is proposing additional increases on CILC rates and general service customers, such as GSLD(T)-1, -2 and -3, that participate in the CDR program by reducing the CILC/CDR credits (the so-called "Reset" proposal). This section of my testimony concerns how increases in base rates should be spread across customer classes.

**Q. What is the single most important goal in this exercise in your opinion?**

A. I believe it is critically important to use revenue related to base rates -- not other revenues (*e.g.*, fuel or other costs subject to trackers that are triggered in ways independent of base rate cost responsibility) -- to allocate these step increases. Also, as stated previously, FPL's unreasonable reduction in the CILC and CDR credits should be rejected.

**Q. Would you please briefly describe the methodology that FPL is proposing to use to allocate its requested base rate increase of $866 million (in 2017) to rate classes?**

A. Based on the testimony of FPL witness Tiffany Cohen and an analysis of FPL's workpapers in this case, the Company has used a two-step approach to develop the initial "target revenue increases" for base rates in each rate class. The first component of the target revenue increase for base rates is FPL's calculation of proposed revenue requirements at an equal rate of return (Parity = 1.0), based on the Company's 12 CP and 25% average demand cost of service study. Second, the Company computes an adjustment so that the final base revenue increase (including increases in unbilled revenues and miscellaneous charges) for each rate schedule is no greater than 1.5 times the average retail percentage increase, measured on a "base revenue plus clause revenue" basis.[10] However, the final base revenue increase that is tested to determine whether or not it meets the 1.5 times the average increase test <u>is first adjusted by FPL by offsetting a portion of the base rate increase to CILC and CDR customers by subtracting the decrease in the CILC/CDR credit offset (the so-called "Reset," which produces a base revenue increase to CILC/CDR customers).</u> As I discuss next, this "decrease" in

[10] The method also sets a minimum increase floor of 0.5% applied to a rate schedule's present base revenue plus clause revenue.

the credit results in a substantial increase in charges to CILC and CDR customers. As a result of this adjustment FPL has systematically isolated a significant part of the increases that it is actually proposing in this case from the Commission's mitigation protection method (the "1.5 times" limit).

**Q. What is the implication of the Company's adjustment to remove the effect of the $23 million increase associated with the so-called "Reset" of CILC and CDR credit offsets?**

A. This $23 million increase is excluded from FPL's application of the mitigation test (*i.e.*, that no rate schedule receives an increase greater than 1.5 times the average increase). As a result, Rate CILC-1D, for example, is receiving a base revenue increase (without clauses) of 38.7% and an increase calculated on base revenues plus clauses of 17.32%, <u>which is more than 2.0 times the average increase.</u> Table 11 shows that actual percentage increases being proposed by FPL in 2017, together with FPL's presentation of the same increases.

**Table 11**
**FPL Proposed 2017 Rate Schedule Increases**
**Including the CILC/CDR Incentive Credit Reductions**

| | **Increases as Presented by FPL** | | **Increases Including CDR "Reset"** | | |
|---|---|---|---|---|---|
| Rate | "Base +Clause" | "Base" | "Base +Clause" | | "Base" |
| CILC-1D | 12.34% | 27.5% | 17.32% | * | 38.7% |
| CILC-1G | 6.23% | 12.5% | 10.67% | | 21.3% |
| CILC-1T | 12.33% | 32.9% | 17.73% | * | 47.4% |
| GS(T)-1 | 3.51% | 5.9% | 3.51% | | 5.9% |
| GSCU-1 | 0.53% | 0.9% | 0.53% | | 0.9% |
| GSD(T)-1 | 9.84% | 19.1% | 9.94% | | 19.3% |
| GSLD(T)-1 | 12.34% | 26.3% | 12.84% | * | 27.4% |
| GSLD(T)-2 | 12.34% | 28.3% | 12.93% | * | 29.6% |
| GSLD(T)-3 | 11.24% | 28.3% | 11.24% | | 28.3% |
| MET | 7.23% | 13.9% | 7.23% | | 13.9% |
| OL-1 | 0.58% | 0.8% | 0.58% | | 0.8% |
| OS-2 | 12.34% | 18.3% | 12.34% | | 18.3% |
| RS(T)-1 | 7.33% | 12.3% | 7.33% | | 12.3% |
| SL-1 | 6.34% | 8.1% | 6.34% | | 8.1% |
| SL-2 | 0.50% | 0.9% | 0.50% | | 0.9% |
| SST-DST | 8.21% | 16.9% | 8.21% | | 16.9% |
| SST-TST | 0.47% | 0.8% | 0.47% | | 0.8% |
| Total Retail | 8.23% | 14.6% | 8.45% | | 15.0% |
| "1.5 X Limit" | 12.34% | | 12.67% | | |

* Violates 1.5X average increase limitation

**Q. In the Company's proof of revenue (MFR E-14) for Rate CILC-1D, the base revenue increase is shown to be 57%, not the 38.7% shown in your Table 11. Can you explain the difference?**

A. Yes. My Table 11 follows FPL's standard presentation approach that calculates revenue increases for CILC and general service rate classes receiving CDR credits by computing the percentage changes in base revenues and "base revenues plus clauses" by first adding back the incentive credits ("credit offset") to present base revenues. However, I also recognize the effect of the reduction in current CDR credits that FPL is proposing in this base rate case. I followed FPL's general approach by including the current level of CDR credits as revenues which effectively fully offset the credits (the "credit offset"), but I also included the reduction in the credit as part of the revenue increase, which FPL did not reflect in its presentation of the increase. However, in MFR E-14, the Company shows the actual increase in base revenues that will be paid by CILC-1D customers, which includes the CDR credits at present base rates and the reduced ("Reset") CDR credits at proposed rates. For CILC-1D customers, this is the change in base rates.

When both the present and proposed level of CILC/CDR credits are included in the calculation of base rates for CILC-1D, the increase produced by FPL's current filing is actually 57%.[11] Again, in my Table 11, following FPL's revenue distribution methodology, I have added back the current level of the CDR credits in my percentage increase calculation (*i.e.*, included the current level of the credit offset). This increases the dollar base on which the percentage increase is calculated. With a larger total amount of base revenues (due to including the credit offset, and only including the effect of the reduced credit (the "Reset") at proposed revenues), the percentage increase is lower (a 38.7% increase) than the calculation in MFR E-14 (a 57% increase). Keep in mind that the dollar amount of the increase is identical in both calculations (the sum of the base revenue increase plus the increase from the CDR credit Reset). Customers

[11] Also, unbilled and miscellaneous revenues are not reflected in the MFR E-14 calculation.

taking service on Rate CILC-1D will actually see an increase in their base rate bill of 57%, if FPL's proposal is approved as-filed. This is obviously a very large increase in a customer's total bill, and this is just the 2017 increase. Table 12 below provides a detailed comparison of the alternative calculations of FPL's proposed increase for CILC-1D.

**Table 12**
**Calculation of Percentage Increases for Rate Schedule CILC-1D**

| | MFR E-14 - Base Rate | MFR E-8 As-Filed - w/o Clauses | MFR E-8 As-Filed - with Clauses | Baron Table 11 w/o Clauses | Baron Table 11 with Clauses |
|---|---|---|---|---|---|
| **Present Revenues** | | | | | |
| Rate Sched Revenue (before CDR credit) | 87,717,549 | 87,717,549 | 87,717,549 | 87,717,549 | 87,717,549 |
| CDR Credit | (27,075,627) | (27,075,627) | (27,075,627) | (27,075,627) | (27,075,627) |
| Net Base Rate Sched Revenue | 60,641,923 | 60,641,923 | 60,641,923 | 60,641,923 | 60,641,923 |
| CILC Credit Offset (add-back CDR credit) | | 27,075,627 | 27,075,627 | 27,075,627 | 27,075,627 |
| | | 87,717,549 | 87,717,549 | 87,717,549 | 87,717,549 |
| Unbilled and Other Revenues | | 1,708,169 | 1,708,169 | 1,708,169 | 1,708,169 |
| Total Operating Revenues | | 89,425,718 | 89,425,718 | 89,425,718 | 89,425,718 |
| Clauses | | - | 110,216,026 | - | 110,216,026 |
| Total Revenue with Clauses | | 89,425,718 | 199,641,744 | 89,425,718 | 199,641,744 |
| | | | | | |
| **Proposed Revenues** | | | | | |
| Rate Sched Revenue (before CDR credit) | 112,346,055 | 112,346,055 | 112,346,055 | 112,346,055 | 112,346,055 |
| CDR Credit | (27,075,627) | (27,075,627) | (27,075,627) | (27,075,627) | (27,075,627) |
| **CDR Credit Reduction ("Reset" Increase)** | **9,943,455** | **9,943,455** | **9,943,455** | **9,943,455** | **9,943,455** |
| Net Base Rate Sched Revenue | 95,213,883 | 95,213,883 | 95,213,883 | 95,213,883 | 95,213,883 |
| CILC Credit Offset | | 27,075,627 | 27,075,627 | 27,075,627 | 27,075,627 |
| **Remove Effect of Credit Reduction** | | **(9,943,455)** | **(9,943,455)** | | |
| Unbilled and Other Revenues | | 1,713,077 | 1,713,077 | 1,713,077 | 1,713,077 |
| Total Operating Revenues | | 114,059,132 | 114,059,132 | 124,002,587 | 124,002,587 |
| Clauses | | - | 110,216,026 | - | 110,216,026 |
| Total with Clauses | | 114,059,132 | 224,275,157 | 124,002,587 | 234,218,613 |
| **Increase** | **34,571,961** | **24,633,413** | **24,633,413** | **34,576,869** | **34,576,869** |
| **% Increase** | **57.01%** | **27.55%** | **12.34%** | **38.67%** | **17.32%** |

**Q. Would you explain the alternative calculations of the CILC-1D increase shown in Table 12?**

A. The first column shows the derivation of the CILC-1D increase presented in MFR E-14. This is the actual base rate increase that customers would see on their FPL bills. It shows the basis for the 57% increase in CILC-1D base revenues, including the impact of the reduction in the CDR credit. The next two columns show FPL's calculation of the increase, which is the method used by the Company to determine the amount of mitigation required to meet the "1.5 times" average increase criterion. This calculation includes the CDR credit offset, which adds-back the CDR credits paid to CILC-1D customers before computing the percentage increase. This calculation also includes miscellaneous and unbilled revenues in the percentage calculation, in contrast to the MFR E-14 calculation that only reflects base rate impacts. The Company's calculation also includes an adjustment that removes the CDR credit "Reset" from the amount of the increase. This is shown on the highlighted row ("Remove Effect of Credit Reduction"). Despite the fact that Rate Schedule CILC-1D and all other customers receiving CDR credits will pay this additional charge in their bills, FPL has not included this amount ($23 million for all rate schedules, $9.94 million for CILC-1D) in its calculation of its proposed rate increase and corresponding percentage increase. FPL's calculation shows the CILC-1D increase to be 12.34% (with clause revenues included).

In the last two columns of Table 12, I show the derivation of the percentage increases for CILC-1D that I presented in Table 11. These increases, which correct FPL's calculation, do include the additional base revenue increase associated with the CDR reduction ("Reset").

**Q. What would the rate schedule increases be if FPL had included the impact of its CILC/CDR incentive offset "Reset" in the application of the "1.5 X average" limitation?**

A. Table 13, below, shows these increases. These increases are based entirely on FPL's cost of service study and methodology; the only change is the inclusion of the increases that CILC and CDR customers will face if the CILC/CDR incentive "Reset" is reflected in the revenue allocation calculation. While I am not recommending these increases because they are not based on my recommended class cost of service study, if FPL's general methodology is accepted, these increases reflect a correct application of "1.5 times" mitigation. In this corrected analysis, all rate schedules meet the mitigation limit. The impact of this adjustment on the residential class is minimal (0.20%), while the impact on Rate CILC-1D and other large C&I rate classes is very significant.[12]

[12]Per MFR E-8, FPL is proposing a 7.3% increase in Residential rates (base plus clause revenues), versus the 7.5% increase shown in Table 13.

**Table 13**
**Corrected FPL Proposed 2017 Rate Schedule Increases**
**Including the CILC/CDR Incentive Credit Reductions**

| Rate | "Base + Clause" Increase Including CDR "Reset" | "Base" Increase Including CDR "Reset" |
|---|---|---|
| CILC-1D | 12.67% | 28.3% |
| CILC-1G | 10.91% | 21.8% |
| CILC-1T | 12.67% | 33.8% |
| GS(T)-1 | 3.47% | 5.8% |
| GSCU-1 | 0.53% | 0.9% |
| GSD(T)-1 | 10.18% | 19.7% |
| GSLD(T)-1 | 12.67% | 27.1% |
| GSLD(T)-2 | 12.67% | 29.0% |
| GSLD(T)-3 | 11.72% | 29.5% |
| MET | 7.40% | 14.2% |
| OL-1 | 0.58% | 0.8% |
| OS-2 | 12.67% | 18.8% |
| RS(T)-1 | 7.50% | 12.6% |
| SL-1 | 6.49% | 8.3% |
| SL-2 | 0.50% | 0.9% |
| SST-DST | 8.43% | 17.3% |
| SST-TST | 0.50% | 0.9% |
| Total Retail | 8.45% | 15.0% |
| "1.5 X Limit" | 12.67% | 22.53% |

**Q. Do you agree with FPL's revenue allocation methodology for its January 1, 2017 $866 million revenue increase?**

A. No. As I have discussed, I have a number of concerns with the Company's proposed revenue allocation. A reasonable, cost based revenue allocation of the Commission approved increase should be based on the following factors:

- The increases should be based on a 12 CP and 1/13$^{th}$ average demand method that incorporates an MDS methodology to classify and allocate distribution costs.

- FPL's proposal to reduce the current CILC and CDR credit offsets by $23 million should be rejected.

- The 1.5 times average retail increase mitigation limitation should be applied to present base revenues and not to present revenues including clause revenues.

**Q. What is the basis for your recommendation to apply the 1.5 times average increase mitigation factor to only present base revenues without clause revenues?**

A. While it is true that the Commission required FPL to include all clause revenues in the application of the "1.5 times" adjustment in the 2009 FPL rate case, I recommend in this case that this mitigation adjustment apply only to the present base revenues as shown on MFR Schedule E-5, that excludes clause revenues. I will refer to this as total "present base revenues." While the Commission has included "clause revenues" in the calculation of the "1.5 times" maximum increase limitation in prior cases, I am recommending that the Commission consider modifying this mitigation protocol to exclude clause revenues in the determination of whether the increase to any rate schedule is excessive and would constitute rate shock. As is shown in MFR E-14, the base rate increase for CILC-1D customers is 57%. If the calculation is performed using the current level of the credit offsets and the reduced amount of the credit (the Reset) is included as part of the increase, the increase is 38.7%. The 38.7% increase reflects FPL's proposed base revenue increase for CILC-1D, but also includes the reduced

CILC/CDR credit as part of the increase in base revenue. The average retail base revenue increase calculated on the same basis is 15% (*see* Table 11).

**Q. Is FPL's use of base revenues plus clause revenues in the application of the "1.5 times" maximum rate class increase rule reasonable?**

A. No. Given the circumstances of this case, I do believe that it is reasonable to include clause revenues to calculate the percentage increase in the application of the "1.5 times" maximum increase rule. The "1.5 times" maximum increase rule should only apply to present base revenues because of the significant increases being proposed by the Company for some large general service rate classes. As I showed in Table 11, the increases proposed for some rate classes are very substantial – clearly the mitigation adjustment that FPL has made is not sufficient to reasonably protect customers on some of these rate schedules, consistent with the regulatory concept of "gradualism."

The inclusion of clause revenues in the mitigation testing reduces its effectiveness to actually mitigate rate shock. Most of the clause revenues reflect the recovery of fuel charges. Because higher load factor rate classes have a higher proportion of fuel charges (which they already have paid for in their fuel clause charges), such rate classes effectively receive a smaller amount of mitigation protection using FPL's method.

**Q. Is there another reason that clause revenues should not be used to veil the impact of FPL's proposed rate increase?**

A. Yes. The clause revenues are reviewed and adjusted in other proceedings. Moreover, clause costs and rates can fluctuate due to factors that are independent of base rates.

**Q. What would the rate class revenue increases be using FPL's class cost of service study results, but applying the 1.5 times average increase cap to base revenues only (*i.e.*, not base plus clause revenues)?**

A. Table 14 shows these results. It assumes FPL's class cost of service results and includes the Company's proposed CILC/CDR Incentive Reset, with two changes to FPL's As-Filed methodology. These changes are: 1) to include the revenue impact of the CILC/CDR Incentive Reset in the determination of the percentage increases, and 2) then apply the 1.5 times average increase cap to base revenues only. As can be seen, the increases to the large C&I rate schedules are much more reasonable than FPL's proposal, and the residential class continues to receive a lower than average increase.

**Table 14**
**Corrected FPL Proposed 2017 Rate Schedule Increases**
**Including the CILC/CDR Incentive Credit Reductions**
**With 1.5 Times CAP Applied Only to Base Revenues**

| Rate | "Base +Clause" Increase Including CDR "Reset" | "Base" Increase Including CDR "Reset" |
|---|---|---|
| CILC-1D | 10.09% | 22.5% |
| CILC-1G | 11.20% | 22.4% |
| CILC-1T | 8.43% | 22.5% |
| GS(T)-1 | 3.62% | 6.1% |
| GSCU-1 | 0.33% | 0.6% |
| GSD(T)-1 | 10.63% | 20.6% |
| GSLD(T)-1 | 10.55% | 22.5% |
| GSLD(T)-2 | 9.84% | 22.5% |
| GSLD(T)-3 | 8.96% | 22.5% |
| MET | 7.74% | 14.9% |
| OL-1 | 0.46% | 0.6% |
| OS-2 | 15.21% | 22.5% |
| RS(T)-1 | 7.84% | 13.2% |
| SL-1 | 6.78% | 8.7% |
| SL-2 | 0.27% | 0.5% |
| SST-DST | 8.81% | 18.1% |
| SST-TST | 0.29% | 0.5% |
| Total Retail | 8.45% | 15.0% |
| "1.5 X Limit" | 12.67% | 22.53% |

**Q. Have you developed rate class revenue allocations for the January 1, 2017 increase using your modified cost of service methodology, the elimination of FPL's CILC/CDR Incentive "Reset" and the application of the 1.5 times average increase cap to base rate revenues only?**

A. Yes. I have developed a number of alternative sets of rate class increases in order to show the impacts of the various issues that I have addressed. Exhibit No. ___ (SJB-16) presents my recommended revenue allocation using a 12 CP and $1/13^{th}$ average demand method, including an MDS methodology. This analysis also follows my recommendation to reflect FPL's proposal to reset the CILC and CDR incentives. Finally, the 1.5 times average increase mitigation is applied to only present base revenues and does not include clause revenues in the calculation. Table 15 summarizes my recommendations for 2017 based on the Company's full proposed revenue requirement.[13]

[13]These increases are based on the Company's full revenue increase requested in this case for illustration purposes and do not reflect likely Commission adjustments to FPL's overall revenue increase request. They are made without prejudice to revenue requirement adjustments supported by SFHHA.

**Table 15**
**Alternative 2017 Rate Schedule Increases**
**(12 CP + 1/13 MDS Cost Study w/o CILC/CDR Reset)**
**With 1.5 Times CAP Applied Only to Base Revenues**

| Rate | Base Increase | "Base +Clause" Percentage Increase | Base Percentage Increase |
|---|---|---|---|
| CILC-1D | 19,545 | 9.81% | 21.95% |
| CILC-1G | 234 | 2.81% | 5.63% |
| CILC-1T | 7,968 | 8.22% | 21.95% |
| GS(T)-1 | 30,732 | 4.81% | 8.04% |
| GSCU-1 | 127 | 1.77% | 2.93% |
| GSD(T)-1 | 152,180 | 6.78% | 13.16% |
| GSLD(T)-1 | 85,020 | 10.25% | 21.95% |
| GSLD(T)-2 | 17,479 | 9.56% | 21.95% |
| GSLD(T)-3 | 1,014 | 8.73% | 21.95% |
| MET | 362 | 4.53% | 8.72% |
| OL-1 | 112 | 0.58% | 0.76% |
| OS-2 | 223 | 14.76% | 21.95% |
| RS(T)-1 | 547,939 | 8.91% | 14.98% |
| SL-1 | 3,319 | 2.80% | 3.59% |
| SL-2 | 14 | 0.50% | 0.95% |
| SST-DST | 46 | 2.74% | 5.67% |
| SST-TST | 38 | 0.50% | 0.87% |
| Total Retail | 866,354 | 8.23% | 14.6% |
| "1.5 X Limit" | | 12.34% | 21.94% |

**Q. Would you describe the additional revenue allocation analyses that you have developed?**

A. Yes. Notwithstanding my recommendation to reject the Company's 12 CP and 25% average demand methodology, I have also developed a revenue allocation based on the results of my 2017 12 CP and 25% average demand, MDS cost of service study that I developed (*see* Exhibit No. ___ (SJB-11)). The 2017 revenue allocation reflecting this

12 CP and 25% average demand, MDS cost of service study is presented in Exhibit No. ___ (SJB-17).

**Q. If the Commission determines that it is appropriate to approve a subsequent year adjustment, what are your recommended rate schedule increases for January 1, 2018?**

A. My recommendation is to use the results of the 2018 12 CP and 1/13$^{th}$ average demand, with MDS cost of service study that I presented in Exhibit No. ___ (SJB-10). The rate schedule increases should be based on the results of my 2018 12 CP and 1/13$^{th}$ MDS class cost of service study using the same revenue distribution methodology that I used to develop my recommended 2017 increases. Exhibit No. ___ (SJB-16).

**Q. Does that complete your prepared direct testimony?**

A. Yes.

**BY MR. WISEMAN:**

**Q** And Mr. Baron, did you also have attached to your testimony Exhibits SJB-1 through SJB-17, which have been marked for identification as Exhibits 265 through 281?

**A** Yes.

**Q** Okay. And were those exhibits prepared by you or under your supervision?

**A** Yes.

**MR. WISEMAN:** Okay. And I believe staff has a number of exhibits that it would like to identify.

**CHAIRMAN BROWN:** Yes. Thank you.

Ms. Brownless.

**MS. BROWNLESS:** Thank you.

**EXAMINATION**

**BY MS. BROWNLESS:**

**Q** Good morning, Mr. Baron?

**A** Good morning.

**Q** Did you -- have you had an opportunity to look at what's been identified on the Comprehensive Exhibit List as 544, 545, 548, and 549?

**A** Yes.

**Q** Okay. And did you prepare these exhibits or were they prepared under your direction and supervision?

**A** Yes, except I need to clarify that with respect to Exhibit, I guess, 545, the interrogatory No. 26, I prepared and sponsored the response to part A, and the response to part B was prepared by counsel.

**Q** Thank you. But do you adopt 26, part B?

**A** I'm sorry. Could you repeat that?

**Q** Do you adopt the response in 26, part B?

**A** I -- I have -- I don't adopt it or reject it. It was prepared by counsel. I did not provide the evidentiary support for the response, so I'm not supporting it per se in terms of any independent analyses that I've done. It was done by counsel.

**Q** Thank you. Are these responses that you prepared true and correct to the best of your knowledge and belief?

**A** Yes, they are.

**Q** And if -- would your answers be the same today if I asked the same questions?

**A** Yes, to the best of my knowledge.

**Q** Okay. Are any portions of your listed exhibits confidential, sir?

**A** Not that I'm aware of.

**MS. BROWNLESS:** Thank you.

**CHAIRMAN BROWN:** Mr. Wiseman.

**MR. WISEMAN:** Madam Chair, if Mr. Baron could provide his summary now.

**CHAIRMAN BROWN:** Yes, good morning.

**THE WITNESS:** Good morning.

**CHAIRMAN BROWN:** You may go.

**THE WITNESS:** Thank you. My testimony addresses issues associated with FP&L's class cost of service study and the proposed revenue allocation of its requested January 2017 and 2018 increases. Departing from its past history of many years, FP&L is now proposing to replace its traditional 12 and 1/13th class cost of service study method with a 12 and 25 percent average demand method. The company has not provided a cost-based analysis to attempt to support its proposal, which produces a significant change in rate class responsibility, cost responsibility. FP&L's proposed method shifts approximately $25 million of cost to large C&I rate classes. My testimony explains why the Commission should reject FP&L's proposal to initiate such a cost shift and, rather, the Commission you should continue using the 12 and 1/13th method.

I also discuss FP&L's methodology to classify and allocate distribution-related costs. FP&L classifies most of its distribution costs on a 100 percent demand basis, while ignoring any customer-related components. FP&L's method is inconsistent with the distribution cost allocation methods discussed in the NARUC Electric Utility Cost Allocation Manual, and it ignores the costs FP&L incurs to connect the customer to the company's distribution system.

As a result of Commission-approved settlements for both Tampa Electric and Gulf Power, these utilities have now adopted a minimum distribution system methodology. The MDS method accurately recognizes that the installation of minimum size poles, conductors, and transformers is required to connect customers to the system regardless of the customer's level of demand. The Commission should require FP&L to allocate distribution costs based on an MDS method because it properly assigns costs.

I also address FP&L's proposal to terminate the increased CDR and CILC curtailment credits approved by the Commission in FP&L's 2012 base rate case. And FP&L is proposing to substantially reduce these credits back to reflect pre-2012 rate case settlement levels. This proposal, which FP&L calls a reset, imposes an additional $23 million of increase on rates, CILC, and other large C&I customers that use the CDR program. The current level of the CDR credit is fully justified by FP&L's own economic analyses as demonstrated in its DSM filings before this Commission. FP&L's proposal is unreasonable and should be rejected.

I also address the company's proposed methodology to allocate revenue increases to rate classes. FP&L proposes to allocate its increases to move classes towards a 1.0 parity subject to the 1.5 times approach. My recommendation is to use a 12 and 1/13th method with an MDS methodology and to apply the 1.5 times mitigation proposal to base rates as opposed to base rates plus clause as the company has used in this case. In particular, the company has ignored the increase in the CDR charges or the reduction in the CDR credit, this $23 million, when it calculates its mitigation, and, therefore, the increases to many rate classes like CILC-1D are very substantial, approaching 57 percent on base rates. And these proposals should be modified and rejected too, as I discuss in my testimony.

In summary, the Commission should use a 12 and 1/13th method with an MDS approach. It should reject the company's proposal to reduce the CDR credits. And, finally, the Commission should adopt and modify its mitigation proposal to a 1.5 times base rate approach and include any adjustment to the CDR credit in that calculation. That completes my summary.

**MR. WISEMAN:** Thank you. Madam Chair, Mr. Baron is available for cross-examination.

**CHAIRMAN BROWN:** Thank you. And, again, welcome. It's always nice to have a double 'Gator as a witness in front of us, so from Tallahassee Florida.

**THE WITNESS:** Thank you, Madam Chair. And an alumnus of the staff here at the FPC -- Florida Commission.

**CHAIRMAN BROWN:** Thank you.

Mr. Rehwinkel.

**MR. REHWINKEL:** I have no friendly questions to ask my fellow double 'Gator.

**CHAIRMAN BROWN:** And here comes another one. FIPUG.

**MR. MOYLE:** I do just have a couple of questions. Thank you.

**CHAIRMAN BROWN:** Reminder, reminder, no friendly cross.

**MR. MOYLE:** Okay. I'll let you be the judge, obviously, of this.

**CHAIRMAN BROWN:** Thank you. Thanks for that.

**MR. MOYLE:** It's kind -- beauty is in the eye of the beholder on some of these things. But staff had asked the question previously with another witness with respect to the rate classes they're in, and I wanted to ask this witness if he knew who was in the CILC rate class. He talked about it. So that's my question. I'll preview it with you. Is it good to go?

**CHAIRMAN BROWN:** So far.

**MR. MOYLE:** Okay. All right.

**EXAMINATION**

**BY MR. MOYLE:**

**Q** So do you know who is in the CILC rate class generally maybe based on who's sitting at this table who would be adversely affected if the changes to the CILC credit and other things took place? Could you tell the Commission that, please?

**A** I'm not familiar, obviously, with the entirety of customers who are in the class. It's a class that -- each of the customers that are in the class agrees to be subject to curtailment or interruption, and in exchange receives implicitly a CDR credit. That's part of the CILC rate.

With respect to members of the South Florida Hospital and Healthcare Association, there are a substantial number of very large and small hospitals that utilize the CILC-1D rate. They have designed their operations around that rate. They've made investments to partake in that rate based on their ability to withstand those curtailments, and they have basically evaluated the economics of losing power under a curtailment to the tradeoff of receiving a credit.

**Q** Were you here last night when staff asked a question of one of the FEA's witnesses whether FEA's customers, including military bases, use the CILC credit?

**A** I was not present, no.

**MR. MOYLE:** Okay. Thank you. That's all I have.

**CHAIRMAN BROWN:** Thank you, Mr. Moyle.

Retail Federation.

**MR. WRIGHT:** Other than offering my fellow 'Gator a Triscuit, I have no questions. Thank you.

**CHAIRMAN BROWN:** I noticed that box. Where is it?

**MR. WRIGHT:** Right here.

**CHAIRMAN BROWN:** Very nice.

**MR. WRIGHT:** Would you like a Triscuit, Mr. Baron?

**THE WITNESS:** No, thank you.

**MR. WRIGHT:** Good to see you.

**CHAIRMAN BROWN:** FEA.

**MR. JERNIGAN:** Ma'am, I actually do have a couple of questions. They should not be friendly, but just to give you an idea, FEA has put forth a discussion with regards to gradualism and applying it to a few of the clauses where this witness has said it should only be in base rates. And that's where I'm going to be limiting my discussion, and that's where we do not believe it is friendly.

**CHAIRMAN BROWN:** Okay. I'm just going to do a reminder to speak clearly into the mike, too, and a little bit louder for me.

**MR. JERNIGAN:** Okay.

**CHAIRMAN BROWN:** Thank you.

**MR. JERNIGAN:** All right. Thank you.

**EXAMINATION**

**BY MR. JERNIGAN:**

**Q** Mr. Baron, I believe in your summary you spoke about gradualism and how it should only be applied to base rates; is that correct?

**A** Yes, that's my recommendation in this case, that it should be.

**Q** Okay. Did you have an opportunity to read Ms. Alderson's testimony with regards to how gradualism should be applied?

**A** I did read her testimony at one point. It was pretty much after it was filed, so I don't have a strong recollection of that specific issue.

**Q** If I were to represent to you that her method of gradualism applied it to all revenues except for the fuel base revenue, would that generally coincide with what you remember?

**A** I generally recall that that was an issue, yes, that she had recommended that.

**Q** And that is not your recommendation here.

**A** That is not my recommendation. It's certainly -- given that fuel revenues are a substantial part of the clause revenues, it probably would be similar in terms of its quantitative result.

**Q** Are you aware of any other commissions that have followed a recommendation similar to your own?

**A** I'm trying to think. Commissions use a variety of methodologies to implement gradualism, the concept. I think most commissions that I'm aware of do follow a methodology or a policy of gradualism. I'm trying -- I can't recall at this time which cases, which commissions use -- I've been in -- as my resumé shows, I've been in many case. In many -- there have been jurisdictions that I generally recall where the commissions have used a measure of the -- not to -- that the increase should not be more than some percentage times the average base rate increase, but I can't cite to specifics at this point.

**Q** Okay. I guess I wasn't clear with my question. I was asking if you are familiar with any commissions that have applied it only to base rates and excluded the riders that you're discussing.

**A** I believe so, yes, and that's what I'm -- I was answering that question. I just can't recall specifically which commissions. So many commissions -- for example, a lot of commissions that I'm familiar with, regulatory jurisdictions, instead of applying a specific mitigation measure in terms of the max -- the maximum percentage increase relative to the average, those commissions use the parity analysis to determine mitigation. For example, in the Florida commission the approach is to -- and Florida Power & Light's approach is to bring every class to a parity of 1.0 and then back off of that if it exceeds or violates the mitigation standard.

Other commissions that I'm familiar with in past cases use measures such that will bring a particular class towards, maybe 80 percent towards parity one way or the other but not full parity as a method of mitigation. Other approaches that I've recommended in many other cases is to reduce the subsidies, which is the same -- which is similar or analogous to a parity method. In other words, if you calculate that at present rates a particular rate class is being subsidized by $20 million, I've recommended methodologies where that subsidy is reduced at proposed rates but not fully eliminated, in recognition that you have to have some measure of gradualism in mitigation, not to do it in one fell swoop so that a class is -- receives excessive increases.

**MR. JERNIGAN:** Okay. Thank you. I have no further questions.

**CHAIRMAN BROWN:** Thank you.

Sierra Club is not here.

AARP.

**MR. COFFMAN:** No questions.

**CHAIRMAN BROWN:** Thank you.

Florida Power & Light.

**MS. CLARK:** Thank you, Madam Chairman, and good morning. Yes, we have questions. We have some things to pass out as well.

**CHAIRMAN BROWN:** Okay. Staff will help you.

(Pause.)

Sir, are you Wal -- representing Wal-Mart?

**MR. WILLIAMSON:** Yes, ma'am.

**CHAIRMAN BROWN:** My apologies.

**MR. WILLIAMSON:** That's okay.

**CHAIRMAN BROWN:** I have you crossed off. While FPL is passing these out, do you have any cross?

**MR. WILLIAMSON:** I have no cross-examination for this witness, ma'am.

**CHAIRMAN BROWN:** Thank you. Thank you. Please feel free to, you know, speak up. My apologies. And your name, sir?

**MR. WILLIAMSON:** Derrick Williamson.

**CHAIRMAN BROWN:** Welcome.

**MR. WILLIAMSON:** Thank you.

**CHAIRMAN BROWN:** Ms. Clark, we are going to be starting, if you'd like them identified or marked, at seven --

**MS. CLARK:** Madam Chairman, I heeded your subtle hint yesterday that we do not have to mark orders as exhibits.

**CHAIRMAN BROWN:** Oh, I see that. Great.

**MS. CLARK:** But I left the exhibit.

**CHAIRMAN BROWN:** It's at your preference, but we'll be at 723, if you'd like to.

**MS. CLARK:** All right. We'll make it 723 for the order.

**CHAIRMAN BROWN:** Okay. 723 for the Public Service Commission order.

(Exhibit 723 marked for identification.)

**MS. CLARK:** Yes. And then there is an excerpt from a staff recommendation in Docket No. 090079-EI.

**CHAIRMAN BROWN:** We're going to mark that as

724, and I hope the court reporter got that clearly.

(Exhibit 724 marked for identification.)

And so, Mr. Baron, you have two exhibits in front of you, the Public Service Commission Order PSC-09-0283-FOF-EI. That should be -- and that should be marked as 723.

**THE WITNESS:** Yes. Yes, Madam Chair.

**CHAIRMAN BROWN:** And the other one is the Public Service Commission staff recommendation, which should be marked as 724. And you have them both?

**THE WITNESS:** Yes, I do.

**CHAIRMAN BROWN:** Ms. Clark, please proceed.

**MS. CLARK:** Thank you.

**EXAMINATION**

**BY MS. CLARK:**

**Q** And good morning, Mr. Baron.

**A** Good morning. And if you could speak up, my hearing is a little weak.

**Q** I will. I'd like to ask you for my first questions, on page 11, lines 2 and 3, of your direct testimony, you indicate you have reviewed FPL's cost of service study; is that correct?

**A** Yes.

**Q** And based on your analysis, you are recommending alternative methods for both production plant and distribution plant. Am I correct?

**A** Yes, the alternative method being the company's 12CP and 1/13th study for production and transmission.

**Q** And Exhibit 10 to your testimony provides the results of your alternative methods based on FPL data and your analysis of that data; is that correct?

**A** If you'll just give me a moment. Did you say Exhibit 10?

**Q** I did.

**A** Exhibit 10 is -- that is -- those are the results of my 12CP and 1/13th method for 2018, but it also includes the MDS methodology for distribution. So with respect to production and transmission, it is the 12 and 1/13th method. For distribution, it's the MDS method.

**Q** Okay. But the 12CP and 1/13th is not what FPL is proposing in this case; correct?

**A** That's correct.

**Q** Okay. And do you think this is a competent analysis that the Commission could rely on for allocating plant?

**A** Yes.

**Q** So you had enough data to do what you consider a competent analysis; is that correct?

**A** I -- I'm -- I've done an analysis. I've described -- I've fully described it using the 12 and 1/13th method and an MDS methodology that relies on the Tampa Electric and Gulf Power customer demand or MDS allocations. And I believe it is a reasonable method to use in this case to allocate costs, if that's what your question is.

**Q** So the answer is yes.

**A** Yes. Yes.

**Q** Thank you. Turning briefly to something you said in your summary, and then I think it was followed up on by Mr. Jenkins (sic), you are recommending a modification in the Commission's gradualism calculation; is that correct?

**A** Yes, I am.

**Q** And you would agree with me that one of the objectives of rate design is to move more rate classes to parity.

**A** I agree that that's an objective, subject to gradualism, which the Commission recognizes.

**Q** Mr. Baron, starting on page 27 of your testimony, you advance an argument against FPL's 12CP and 25 percent allocation method based on what you call a screening curve analysis; is that correct?

**A** Yes.

**Q** And your point is that energy usage beyond a break-even hour is not responsible for any additional combined cycle capacity cost; is that correct?

**A** Yes. Under the framework that I've used for the screening curve analysis, that's what it shows. It's essentially that the economic cost drivers are determined in the first, in this case, 2,100 hours of usage. So from a cost causation standpoint, those are the relevant considerations.

**Q** Mr. Baron, are you aware that this break-even analysis has been considered and rejected by this Commission in previous cases?

**MR. WISEMAN:** Objection. Assumes a matter not in evidence.

**MS. CLARK:** Well, Mr. --

**COMMISSIONER EDGAR:** I'm sorry. Mr. Wiseman, I could not completely hear you. The objection is?

**MR. WISEMAN:** Sorry. My objection is that the question assumed a matter not in evidence.

**BY MS. CLARK:**

**Q** Okay. If we could turn to what's been marked as Exhibit 23 -- 723. Excuse me. And as I said previously, this is PSC Order PSC-09-0283-FOF.

Mr. Baron, could you turn to page 83 of that order, which is part of that exhibit, and read the highlighted text in the top paragraph and then the second to the last paragraph, please, and would you read it out loud.

**A** You want me to read it out loud?

**Q** Yes, please.

**A** The highlighted sentence beginning with, "Witness Ashburn"?

**Q** Yes. No. At the top, "Witness Pollock."

**A** Okay. "Witness Pollock's main criticism of TECO's proposal was that it allocates costs based -- costs beyond the economic breakpoint between baseload and peaking capacity, and thus crosses the line between cost causation and cost shifting."

**Q** And then would you just read the next para -- the next highlighted portion?

**A** "Witness Ashburn, in his rebuttal testimony, stated that the example Mr. Pollock used to support his position is mathematically correct, but it is inconsistent with equitable principals that are generally employed in average cost ratemaking. It is Witness Ashburn maintained, closer to marginal cost pricing concept in that it assumes usage beyond the break-even point does not benefit from the higher investment cost. Under the average cost pricing, which has traditionally been used to set utility rates, both the first and last kilowatt hour benefit equally from the lower operating costs of the base and intermediate plant."

**Q** And then finally, would you read the highlighted text on page 85?

**A** "Based on the record, we find that TECO's proposal for a 12CP and 25 percent average demand allocation is reasonable and, therefore, it shall be approved."

**Q** So in that case, the Commission did reject the analysis of the break-even?

**A** They -- the Commission -- what I can say, I am not familiar with that, this case, and I'm not familiar with Mr. Pollock's analysis that is being referred to here. What I can surmise from this is that the Commission rejected an argument being made and adopted TECO's 12 and 25 percent method. Again, I don't know whether this analysis that is being described here is the same analysis that I did, whether it's making the same points, but it is what it says.

**Q** Okay. And in that case, the order did approve the 12CP and 25 percent; correct?

**A** That's what the Commission order says.

**Q** Would you turn to the next exhibit, Exhibit 724. And you have page -- I think you have the title page, and then you also have page 297. Would also read the highlighted text into the record?

**A** Yes. And I should also point out that I was not in this case either.

"However, as discussed during the hearing in Docket No. 080317-EI for TECO, both the first and the last kilowatt hour -- kWh benefit equally from the lower operating costs of the base and intermediate plant according to average cost pricing, which has traditionally been used to set utility rates. Staff found the intervenors' argument against consideration of benefits accrued beyond the break-even point to be unpersuasive in both the TECO docket and the current PEF proceeding."

**Q** So, again, the staff in this case was not accepting of your break-even analysis; is that correct?

**MR. WISEMAN:** I'm going to object to the question. This is an excerpt out of what, at least from what we can see, is a minimum of a 297-page document. That is a recommendation by staff. The witness has no way of looking at this single page and making any conclusion with respect to what the analysis was.

**MS. CLARK:** Madam Chairman, I have provided counsel with the whole staff recommendation, and it certainly was available to them in their research regarding allocating production plant.

**CHAIRMAN BROWN:** I will allow the question. And if the witness is able to answer it, then he can answer it. If he cannot answer it, then that's fine.

**MS. CLARK:** I believe he answered the question.

**THE WITNESS:** I answered it that I read the recommendation and that I wasn't familiar with the case or the underlying foundation for this issue. I would point out that that's not the -- the issue of benefits is not the basis for my recommendation in this case.

**BY MS. CLARK:**

**Q** Okay. Thank you.

Isn't it true, Mr. Baron, that regardless of the number of customers in a rate class, each customer in a rate class benefits from fuel efficiencies and lower O&M costs?

**A** Regardless of the number of customers?

**Q** Yes.

**A** Yes. I would say that. There's basically, all else being equal, if kilowatt hour -- the cost of a kilowatt hour is reduced from some other level, higher level, then every usage of a kilowatt hour would be -- provide a benefit. That's, of course, not the basis for cost allocation, which is cost causation.

**Q** And you would also agree that customers who have a higher portion of their bill made up of fuel costs paid through the fuel clause benefit the most from fuel efficiencies and lower O&M costs; correct?

**A** Are you asking that just for clarification, all else being equal --

**Q** Yes.

**A** -- in other words, assuming that those same customers aren't charged for some other compensating, offsetting cost? But just as a matter of straightforward arithmetic, if you use more kilowatt hours, you -- and those kilowatt hours are less expensive, then you're going to achieve the savings. It's self-evident.

**MS. CLARK:** Thank you, Mr. Baron. That's all we have.

Oh, just a minute, Madam Chairman.

(Pause.)

Thank you, Madam Chairman. That's all we have.

**CHAIRMAN BROWN:** Thank you.

Staff.

**EXAMINATION**

**BY MS. BROWNLESS:**

**Q** Good afternoon or morning, whatever.

**A** Good morning.

**Q** I'm always confused today.

**A** Good morning.

**Q** Were you provided the responses to staff interrogatories and PODs and requests associated with your subject areas as they became available?

**A** My firm received copies, to the best of my knowledge, of the interrogatory responses from counsel from all the parties. So the firm received it. We developed a centralized database. There were a number of people in my firm that were utilizing that information.

**Q** Okay. And during the course of your engagement in this proceeding, did you prepare discovery questions for other parties in the case?

**A** I did some, yes.

**Q** Okay. And did you receive and review the responses to the discovery that you asked for?

**A** Yes, to the responses to the SFHHA interrogatories and PODs --

**Q** Okay. Thank you so much.

**A** -- that were in my subject area, I should say.

**MS. BROWNLESS:** Yes, sir. Thank you so much.

**EXAMINATION**

**BY MS. LEATHERS:**

**Q** Good morning, Mr. Baron. I'm Margo Leathers with Commission staff as well.

Could you please turn to page 39 of your testimony and refer to lines 13 to 14.

**CHAIRMAN BROWN:** That's page 39, lines 13 and 14.

**A** Yes. I have page 39 and line 13.

**Q** In there you stated that both Tampa Electric Company and Gulf Power Company utilized a minimum distribution system methodology to classify and allocate distribution costs. To the best of your knowledge, has this Commission ever approved the use of a minimum distribution system methodology outside the context of a settlement agreement?

**A** I have a recollection that there was some very old case. I may have it some -- in one of my documents. But it was -- I can't even remember. It wasn't a major utility, but it was a quite old case.

**Q** Okay. And now could you please refer to page 13, lines 3 through 5?

**CHAIRMAN BROWN:** Page 13, lines 3 through 5.

**A** Okay. I've turned to that page, yes.

**Q** And in there you state that "FPL has not considered any minimum distribution costs in its cost classification analysis, which unreasonably overstates the cost responsibility for large general service classes." Would you agree, however, that a change from FPL's proposed method of cost classification to the use of a minimum distribution system would allocate more cost to the residential and small commercial rate classes?

**A** I would agree that it would allocate some additional costs to the residential class. It's -- it -- my estimate was it probably would be in the neighborhood of 2 percent in terms of the increase.

**Q** And would you also agree that a cost shift away from large general service classes to the residential and small commercial classes would result in higher base rates for the residential and small commercial classes?

**A** If the -- is your question if the MDS cost allocation method were adopted, that it -- I just want to make sure I understand your question.

**Q** Yes. Yes.

**A** Yes, I think I agreed that to properly -- to recognize the fact that there is a customer component of cost means that the number of customers in the class determines to some degree the amount of distribution costs that would be assigned to that class and, therefore, that class's cost responsibility. So to the extent that that is used to allocate and classify costs, it produces results that -- in the case of the residential class, there are many, many residential customers, and if you want to recognize that there is a minimum cost to connect each of those customers to the system, then it will raise costs from what they otherwise would be if you just used FP&L's approach that it's based on demand only and zero customer component.

**MS. LEATHERS:** Okay. Thank you, Mr. Baron. We have nothing further.

**CHAIRMAN BROWN:** Thank you.

Commissioners?

Redirect.

**MR. WISEMAN:** Thank you, Madam Chair.

**EXAMINATION**

**BY MR. WISEMAN:**

**Q** Mr. Baron, do you recall you were asked a question of whether your proposal was a modification to the Commission's policy on gradualism?

**A** Yes.

**Q** Okay. Can you explain why you were recommending a modification to that policy?

**A** Yes. As -- and I discuss to some extent in my testimony that given the results in this class -- in this case, and particularly the impact on the GSLD

T1 and -2 classes and the CILC-1D, the very substantial increases that the company's gradualism method, which is, I acknowledge is the Commission's policy, that approach results in very substantial increases. As I said, CILC-1D on a base rate basis is getting -- those customers will receive a 57 percent increase. Even with clause revenues, it results in a 17 percent increase. And the -- of course, that is due to two things, but it -- those are very substantial increases, and I believe the mitigation policy should be modified.

**Q** How, if at all, is your proposal to modify the gradualism policy impacted by the CDR/CILC credit issue in this case?

**A** The -- my -- well, let me try to explain it in this matter.

**CHAIRMAN BROWN:** Mr. Baron, just a reminder to try to be as succinct as possible. Thank you.

**A** Yes. I appreciate it. The CDR increases are going to -- would increase rates by $23 million. 9 million of that goes on CILC-1D. The company just ignored that in its gradualism calculation. It pretended that that doesn't even exist. And so even if you accept the 1.5 times with clause revenues that is the traditional Commission policy, at the minimum the CDR-related increases should be included. And that's something the company did not do.

**Q** All right. Now you also testified that an objective is to move classes either to or toward parity. Do you recall that?

**A** Yes.

**Q** Okay. How, if at all, does your proposal or do your proposals move classes toward parity in this case?

**A** My recommendation is to follow the company's basic methodology and the Commission's precedent to move classes towards 1.0 parity. That's the starting point of my recommendation. And as in the case of the company, I then propose a mitigation adjustment to -- that would move that off the 1.0 mark, which is exactly the Commission's policy. I'm recommending a different mitigation adjustment.

The other difference that I'm recommending from what the company filed is that the CDR-related increases should be included in that mitigation calculation. It makes no sense to ignore it. The CDR increases don't affect parity at all in this case, and it's just -- the company is basically changing the DSM-related costs. In the case of CILC-1D, that increases their overall rate increase by 9 million, and it's ignored in the mitigation.

**Q** Do you have an exhibit that sets forth your parity calculations?

**A** Yes, I do. Probably the easiest way to look at it would be the -- one of my tables, which is a summary -- well, my Table 10 on page 49 shows the parity results using the cost of service study that I am recommending in this case, and it compares those to the company's filed studies. So now you have an apples-to-apples comparison. And as I indicated in my response to your previous question, my methodology for applying the increases to each rate class starts with moving each rate class to a parity of 1.0 using these cost of service results.

And, excuse me, the parity -- Table 10 is at a 12 and 25. I should have referred you to Table 9, which is the 12 and 1/13th method. I apologize.

**Q** And what page is Table 9 on?

**A** That's on page 47.

**Q** All right. Now do you recall also staff asked you some questions about the MDS methodology?

**A** Yes.

**Q** And do you recall that one question, in response to that question you indicated that additional costs would be allocated to the residential and small commercial customer classes?

**A** Yes.

**Q** Okay. Can you -- how, if at all, is your recommendation consistent with cost causation principles?

**A** The recommendation that I'm making to incorporate an MDS method recognizes, in my view, in my opinion, and the opinion of many other regulatory bodies and parties, that a customer component is a cost to connect a customer to the system. And if you ignore that cost, you are not properly allocating costs. And to the extent that an MDS method separates distribution costs into a customer component and a demand component, and the customer component is allocated to classes based on the number of customers in the class, the number of individual entities that have to be connected to the system, it allocates costs associated with that. So it's based on cost causation. It's not designed to shift costs to residential customers or to punish anyone.

**Q** Do you recall you were asked the question whether this Commission has authorized MDS in the con -- in a context other than a settlement previously?

**A** Yes.

**Q** Okay. Are you aware of any other commissions that have authorized MDS in litigated proceedings?

**A** Yes. Many other regulatory commissions use the MDS method, and I just -- I cited some of the cases that I'm familiar with. The Georgia commission uses it, the Virginia commission uses the method, the West Virginia commission uses it, the Kentucky commission uses it. And just recently, in the last couple of days I found out that the New York Public Service Commission uses it for Consolidated Edison, a very urban-oriented utility, probably the most urban, densely populated city in the United States, and they use an MDS method that has a customer component.

**Q** And just so the record is clear, when you refer to Consolidated Edison and a city, you're referring to New York City; correct?

**A** I'm sorry.

**Q** When you refer to Consolidated Edison and you referred to a city, some people call it "the city," you're referring to New York City?

**A** New York City, yes.

**MR. WISEMAN:** Thank you. I have no further questions.

**CHAIRMAN BROWN:** Thank you, Mr. Wiseman.

All right. This witness has Exhibits 265 through 281.

**MR. WISEMAN:** We would move the admission of those exhibits.

**CHAIRMAN BROWN:** Any objection to moving those in? Ms. Clark?

**MS. CLARK:** I'm sorry. We would move --

**CHAIRMAN BROWN:** No, no. Any objections?

**MS. CLARK:** Oh, no, no objection.

**CHAIRMAN BROWN:** All right. Seeing no objection, we will move in 265 through 281 into the record.

(Exhibits 265 through 281 admitted into the record.)

And then we do have two exhibits that have been marked for identification purposes from FPL. That would be 723 and 724.

**MS. CLARK:** FPL would move those into the record.

**MR. WISEMAN:** Madam Chair, I have, well, both a comment and an objection, I think.

**CHAIRMAN BROWN:** And that would be for 724, the full -- is FPL going to be moving the full recommendation into the record?

**MR. WISEMAN:** Well, on seven -- if we go to 723 first, it's the Commission order. I think, consistent with your ruling, we don't actually -- at the beginning of the hearing -- we don't need to put orders in the case as exhibits. If FPL wants to put this order in as is or this single or couple of pages from the order, I really don't have an objection to that so long as I'm not limited in any way in referring to the entirety of the decision in our brief, should we so wish, and just would like that clarification.

**CHAIRMAN BROWN:** And I've been advised by our legal staff that if a party wishes to -- although we do take official recognition of Commission orders, if a party wishes to enter it into the record, that it is within -- a judgment call, and so --

**MS. CLARK:** Madam Chairman, I would recommend that we do enter it into the record. But I believe Mr. Wiseman could refer to the entire order that the Commission can take judicial notice of.

**CHAIRMAN BROWN:** Okay.

**MS. CLARK:** He would not be limited.

**MR. WISEMAN:** Okay. That's fine on 723.

**CHAIRMAN BROWN:** Okay. We're going to go ahead and move 723 into the record.

(Exhibit 723 admitted into the record.)

And then 724, your objection?

**MR. WISEMAN:** 724, I do have an objection, at least subject to optional completeness. Again, this is a staff recommendation. It's at least 300 pages long, and I don't know what else is in this recommendation. And so if it's going to be moved into the record, I would like the option to put the entire document in.

**MR. MOYLE:** And FIPUG would join in the objection. Also state as an additional grounds authentication. I don't think this witness authenticated the staff recommendation. Somebody from staff arguably would need to authenticate a staff recommendation. I don't think it's the practice typically of introducing staff recommendations into the record as well.

**CHAIRMAN BROWN:** Ms. Clark.

**MS. CLARK:** Well, Madam Chairman, we would move it into the record subject to it being the entire recommendation.

**CHAIRMAN BROWN:** Okay. Legal.

**MS. BROWNLESS:** I think it should get in as a business record. If they're worried about hearsay or authentication, it's a business record routinely prepared by the Commission. It's available to all, it's on the website, and so I think the full document should come in, of course.

**CHAIRMAN BROWN:** Okay. Ms. Helton.

**MS. HELTON:** I agree that it can come in, and it's also a public record as well available on our website.

**CHAIRMAN BROWN:** Okay. We're going to --

**MR. MOYLE:** Can I just be heard briefly?

**CHAIRMAN BROWN:** Briefly.

**MR. MOYLE:** Because I think we may be getting into briefly how the business record and public record exception applies.

**CHAIRMAN BROWN:** We're not getting into that right now. We're not getting into that right now, Mr. Moyle.

**MR. MOYLE:** Well, it's not appropriate as a business record or a public record because that measures things like weather and what time did the sun rise? It doesn't have subjective opinions. All this -- this is 300 pages or whatever, has all this opinion and other stuff. It's not appropriate to go in under either of those exceptions.

**MS. HELTON:** Madam Chairman, may I also say that it is a staff recommendation. It's what your staff said. It's not what the Commission said. What the Commission said would be the order that would signify or codify your vote from that staff recommendation.

**CHAIRMAN BROWN:** Thank you. I'm aware of that.

Ms. Clark.

**MS. CLARK:** Well, I would just comment that I think Mr. Moyle has misstated what the law is on a business and public record, and I think that staff is right on this one. As a matter of business record, it can come in.

**CHAIRMAN BROWN:** Okay. I'm going to defer to staff on this, and I'm going to enter the 724 in its completion, though. So we'll have the full -- FPL, make sure that the court reporter and the parties have a full and complete copy of that staff recommendation for 724.

(Exhibit 724 admitted into the record.)

**MS. CLARK:** I did give Mr. Wiseman a full copy. I will make sure the court reporter has one.

**CHAIRMAN BROWN:** Okay. Excellent.

Would you like your witness excused, Mr. Wiseman, now?

**MR. WISEMAN:** Yes, please.

**CHAIRMAN BROWN:** All right. Mr. Baron, safe travels back to Atlanta.

**THE WITNESS:** Thank you.

**CHAIRMAN BROWN:** Thank you. We'll take about a five-minute break before we get into Mr. Pollock, who's up next.

(Recess taken.)

**CHAIRMAN BROWN:** All right. It's been about five minutes. If you could kindly take your seats.

**MR. BUTLER:** Madam Chair, as we are reassembling, all of this optional completeness has inspired me. We went back and looked at -- Exhibit 698 was an excerpt from FPL's 2015 Form 10-K, and we would like an opportunity to submit a complete copy of that as the exhibit for -- hearing exhibit for 698.

**CHAIRMAN BROWN:** And I think the topic of completeness is important, and I'd like to remind the parties that if they want excerpts, to insert excerpts into the record, they need to have available the full and complete copy. So I don't see any objection with entering -- having FPL provide the full and complete copy of 698, which was the NextEra 2015 SEC Form 10-K. Are there any objections to that?

**MR. MOYLE:** Can I ask Mr. Butler a question of it? Because I think there's two things: One, if you use an exhibit for impeachment purposes and show them a line, that shouldn't then be the basis for a big, old document coming in.

**CHAIRMAN BROWN:** That was Dewhurst. Okay? And it was 698 was actually entered into or requested by -- it was used by Hospitals. It was not used by FPL. It was actually used by the Hospitals for this line of questioning on Dewhurst. It's already in the record.

**MR. MOYLE:** As an excerpt?

**MR. BUTLER:** Yeah. And I would suggest that it's actually that very reason why you typically will want the completeness is that, you know, a particular narrow part of something gets referred to in examination but there's other materials in it that give context, and that just -- that's the circumstance in which we would like to request completeness.

**CHAIRMAN BROWN:** Okay. Well, I favor completeness, so, and it is already in the record. I don't see any prejudice of putting the complete copy in at this time since it's already in the record, and with the -- in the spirit of having a complete record, we're going to go ahead and do that. So, FPL, please provide the court reporter with the full and complete copy.

**MR. BUTLER:** We will do it today. Thank you.

**CHAIRMAN BROWN:** Thank you. All right.

Mr. Moyle, your man is on. Mr. Pollock.

**MR. MOYLE:** Thank you. Yes. This if FIPUG's witness to present to you. It's Mr. Jeff Pollock from Missouri, and he has been sworn.

**CHAIRMAN BROWN:** Mr. Pollock, it's nice to see you.

**THE WITNESS:** Likewise.

**CHAIRMAN BROWN:** Thanks for coming down here.

**THE WITNESS:** Thanks for having me.

**CHAIRMAN BROWN:** All right. You may proceed.

**MR. MOYLE:** Thank you.

Whereupon,

**JEFFRY POLLOCK**

was called as a witness on behalf of the Florida Industrial Power Users Group and, having first been duly sworn, testified as follows:

**EXAMINATION**

**BY MR. MOYLE:**

**Q** Sir, would you please confirm you've been sworn, and then state your name and address for the record.

**A** I have been sworn. My name is Jeffry Pollock. My address is 12647 Olive Boulevard, St. Louis, Missouri.

**Q** And did you cause to be prepared and filed 75 pages of testimony in this proceeding on or about July 7th?

**A** Yes.

**Q** And did you also cause or prepare exhibits that were filed with your testimony and marked JP-1 to JP-16?

**A** Yes.

**Q** Okay. And you're aware that staff has prepared an exhibit that has renumbered your JP-1 through JP-16 as Exhibits 236 to 251?

**A** Yes.

**Q** And do you have any changes to your prefiled testimony?

**A** I have just one minor change in my prefiled testimony and it's on page 42.

**CHAIRMAN BROWN:** Page 42?

**THE WITNESS:** Yes, ma'am.

**CHAIRMAN BROWN:** Okay.

**THE WITNESS:** And the question that is on line 4, I need to insert the word "more" after the word "applying." So it should read "applying more reasonable gradualism principles."

**BY MR. MOYLE:**

**Q** Other than that change, if I were to ask you the questions set forth in your prefiled direct testimony, would your answers today be the same as if were you giving live testimony?

**A** Yes, they would.

**MR. MOYLE:** Okay. I believe staff may have questions.

**CHAIRMAN BROWN:** Ms. Brownless. Or would you like to insert his prefiled testimony into the record as though read at this time?

**MR. MOYLE:** I'll go ahead and insert -- move to insert that, please. Thank you.

**CHAIRMAN BROWN:** We will go ahead and insert Mr. Pollock's prefiled direct testimony into the record as though read.

**MR. MOYLE:** Thank you.

# Direct Testimony of Jeffry Pollock

## 1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. Jeffry Pollock; 12647 Olive Blvd., Suite 585, St. Louis, MO 63141.

**Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?**

A. I am an energy advisor and President of J. Pollock, Incorporated.

**Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A. I have a Bachelor of Science Degree in Electrical Engineering and a Master's Degree in Business Administration from Washington University. Since graduation in 1975, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in both the United States and several Canadian provinces. My qualifications are documented in **Appendix A.** A partial list of my appearances is provided in **Appendix B** to this testimony.

**Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

A. I am testifying on behalf of the Florida Industrial Power Users Group (FIPUG). FIPUG members purchase electricity from Florida Power & Light Company (FPL). They consume significant quantities of electricity, often around-the-clock, and require a reliable affordably-priced supply of electricity to power their operations. Therefore, FIPUG members have a direct and significant interest in the outcome of this proceeding.

**Q. WHAT ISSUES DO YOU ADDRESS?**

A. I am addressing the following issues:

- FPL's multi-year rate plan;
- Performance incentive;
- Construction work in progress;
- Cost of capital (long-term debt, cost of equity and capital structure);
- Class revenue allocation;
- Class cost-of-service study; and
- GSLD/CILC rate design.

**Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?**

A. Yes. I am sponsoring **Exhibits ___(JP-1) through ___(JP-16).**

**Q. THROUGHOUT YOUR TESTIMONY AND EXHIBITS YOU REFER TO FPL'S PROPOSED REVENUE REQUIREMENTS, CLASS COST-OF-SERVICE STUDY AND OTHER PROPOSALS. SHOULD THIS BE INTERPRETED AS AN ENDORSEMENT OF FPL'S PROPOSALS?**

A. No. Any reference to FPL's proposals is strictly for illustrative purposes. It should not be interpreted as endorsing FPL's proposals both on the issues addressed as well as the issues not addressed in my testimony.

## Summary

**Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.**

A. My findings and recommendations are as follows:

### *Multi-Year Rate Plan*

- The proposal would raise base revenues by approximately $1.31 billion over four years, including a 2017 increase effective on January 1, 2017, a subsequent year adjustment effective on January 1, 2018 and a limited scope increase to recognize the Okeechobee Clean Energy Center shortly after its commercial in-service date, which is projected to occur in June 2019.

- From a factual perspective, the request for a subsequent year adjustment is an objectionable pancaking of two separate rate cases in a single proceeding. Pancaked rate increases are bad policy because they fail to properly balance the utility's needs with the needs of its customers, they rely on speculation rather than known and reasonably predictable revenues and costs to set base rates, and they would unnecessarily bind a future commission by prematurely setting rates now for 2018.
- Multi-year rate plans are not a common practice, and they are unnecessary in jurisdictions like Florida where 45% of a utility's costs are separately recovered outside of a rate case in various cost recovery clauses.
- The 2017 test year and subsequent year adjustment revenue requirements are based on budgets that were developed and approved in October 2015, which is 14 to 26 months prior to the effective dates of the proposed 2017 and 2018 rates. Though sales, revenues and costs are likely to change between October 2015 and the time the Board approves FPL's official corporate budgets for 2017 and 2018, FPL is not proposing to adjust the assumptions underlying the subsequent year adjustment in this proceeding.
- FPL's sales assumptions, which are a key component in determining its revenue needs and rate design, show negative growth in 2017 and only 0.3% per growth over the period 2016-2018. These are in stark contrast to the 1% per year growth that FPL has experienced since 2011 and the much higher growth rates in prior years. Accordingly, the Commission should be highly skeptical of such modest and self-serving growth projections.
- Further, given that many of the 2017 assumptions also carry-over to 2018, there may not be any need for a subsequent year adjustment even if the projections could be relied upon to set rates.
- The subsequent year adjustment should be rejected because it is speculative, inappropriate and unnecessary.

***Performance Incentive***

- FPL's proposed 50 basis point return on equity performance incentive alone would account for about $120 million of the proposed $829.7 million 2017 base revenue increase.

- A performance incentive should only be necessary for service provided above and beyond reasonable expectations. FPL's many cost-savings investments, which retail customers have paid and are paying for, are neither above nor beyond its obligation to provide reliable service at the lowest reasonable cost. Customers should not be forced to pay for these investments twice in the form of higher rates. Further, it is improper to ignore the $3.2 billion of hedging losses that FPL has incurred from 2002-2014, for which customers have paid higher fuel charges.

- FPL has consistently earned the maximum allowed return on equity without the addition of a performance adder due to its very liberal use of surplus depreciation and fossil fuel dismantlement balances. This practice has more than adequately rewarded executives and shareholders while leaving retail customers saddled with a $99 million depreciation deficiency.

- FPL is already subject to a Generation Performance Incentive Factor that encourages the investment in improvements as well as operational efficiency in each base load unit that results in net savings to customers.

- Accordingly, no further performance incentive is either necessary or deserved.

***Construction Work in Progress***

- FPL is seeking recovery of $748 million of construction work in progress (CWIP) in rate base consisting of projects on which FPL says it cannot capitalize allowance for funds used during construction. This accounts for only 2% of FPL's proposed 2017 test-year rate base.

- CWIP is plant that is not used and useful in providing electricity service.

- FPL has not demonstrated that current recovery of the financing costs on CWIP is either extraordinary or necessary to maintain its financial integrity and its current credit ratings.

- Pursuant to Rule 25-6.0141 F.A.C., the Commission *may* include non-interest bearing CWIP, but it also can remove CWIP from rate base to mitigate the impact on rates. Given that FPL's proposed four-year multi-year rate plan would cause rate shock, CWIP should be removed from rate base to help mitigate the impact on rates.

***Cost of Capital***

- FPL's projected cost of long-term debt is overstated because it fails to recognize that interest rates are less likely to increase due to recent changes in global economic and financial markets in part due to Brexit.

- The Commission should find that FPL's cost of long-term debt in 2017 is not greater than 4.5489%.

- FPL's proposed 11% cost of equity (before any performance incentive) is excessive relative to the returns authorized by this Commission as well as by other state regulatory commissions nationwide in rate case decisions since 2012 for vertically integrated electric investor-owned utilities. Authorized returns have averaged below 10% since 2013.

- An 11% cost of equity is especially inappropriate given that equity would comprise nearly 60% of FPL's "financial" capital structure. Accordingly, FPL's return on equity should be set below the electric utility average.

- A 60% financial equity ratio is clearly excessive in this case because FPL's proposed 11% cost of equity is 645 basis points more expensive than long-term debt. This excessive equity ratio results in a higher cost of capital and higher rates than a utility with a more leveraged capital structure.

- On average, other vertically integrated electric investor-owned utilities collectively have an average 51.1% financial equity ratio, which is 890 basis points lower than FPL is proposing in this case.

- For ratemaking purposes, FPL's capital structure should be more in line with the average of other vertically integrated electric investor-owned utilities.

***<u>Class Revenue Allocation</u>***

- Base revenues should reflect the actual cost of providing service to each customer class, as closely as practicable, using a class cost-of-service study that appropriately reflects cost causation. Cost-based rates are equitable, send proper price signals, encourage cost-effective conservation and provide more stability.

- Cost-based rates are also consistent with this Commission's long-standing practice.

- The only exceptions to setting rates to cost are rate administration and gradualism.

- FPL's proposed class revenue allocation ignores the impact of reducing the CILC/CDR credits by $23 million or 37%. A 37% reduction would result in CILD and CDR customers experiencing substantial rate shock. It is also not consistent with the proper application of gradualism, which limits the increase to 1.5 times the system average increase, irrespective of whether gradualism is measured relative to revenues including or excluding the cost recovery clauses.

- FPL's proposed class revenue allocation should be rejected because it would result in increases that exceed 1.5 times the system average increase for the CILC/CDR customers.

- Because the cost recovery clauses are not being changed for ratemaking purposes in this case, it is proper to measure gradualism relative to base revenues (*i.e.,* excluding the clauses).

***Class Cost-of-Service Study***

- FPL's class cost-of-service study fails to reflect cost causation for three reasons.

- First, FPL is proposing to change the way it allocates production plant-related costs by increasing the energy weighting from 7.6% (*i.e.,* 1/13$^{th}$ average demand) to 25% without providing any study or analysis supporting said change. In fact, FPL has not changed the way it either plans or operates its system since its last rate case, when it supported the 12CP+1/13$^{th}$ AD method.

- FPL would be the only major electric utility in Florida not using 12CP+1/13th AD. Duke Energy Florida, Gulf Power Company and Tampa Electric Company all use 12CP+1/13$^{th}$ AD.

- The capacity additions that are purportedly a major cost driver of the proposed base revenue increases were justified on the basis of meeting FPL's capacity needs based on its projections of firm peak demand.

- Further, FPL has chosen to install capacity that is highly flexible; that is, it can be cycled more cost-efficiently than FPL's older steam turbines to meet changes in system loads and integrate increasing amounts of renewable generation. This enhanced load following capability provides a significant reliability benefit, which supports a heavier demand weighting.

- Accordingly, 12CP+1/13th AD should be retained.

- Second, FPL failed to classify any of its distribution "network" as a customer-related cost. As with production plant, FPL is clearly an outlier. Both Gulf and TECO classify about 26% of their distribution network costs as customer-related. Further, many other utilities also follow this practice.

- The distribution network provides a connection to the grid, and it includes facilities that also provide the voltage support needed before any power or energy can be delivered to and consumed by the customer. These prerequisites (*i.e.*, a grid connection and voltage support) are clearly related to the existence of the customer.

- Classifying these costs entirely to demand would have the practical effect of allocating less than 1 pole, less than 20 feet of overhead conductors and less than 5 feet of underground conductors to serve each Residential and General Service Non-Demand customer, which is clearly contrary to reality.

- FPL's investments to "harden" the distribution system are driven by the need to maintain a connection and the voltage support during major storm events. Based on its projections, FPL will have invested over $2 billion in distribution storm hardening for the period 2014 through 2018. Thus, distribution storm hardening costs are a major driver of FPL's proposed rate increase and further support a significant customer component.

- Approximately 26% of FPL's distribution network costs should be classified as a customer-related cost.

- Third, FPL fails to recognize that it provides distribution service to customers that take service directly at an FPL-owned distribution substation. Distribution Substation service is less costly to provide than Primary Distribution service because the customer, not FPL, provides the necessary equipment to distribute electricity to and within the customer's facilities. The only difference between Transmission and Distribution Substation services is that FPL must provide the step-down transformer and related equipment to serve the latter.

- Accordingly, FPL should be ordered to file a cost-based tariff for Distribution Substation service within 90 days after a final order is issued in this proceeding.

***GSLD/CILC Rate Design***

- FPL's proposed GSLD/CILC rate design features Energy charges that would recover substantially more than energy-related costs, thereby resulting in intra-class subsidies. Accordingly, consistent with cost-based ratemaking (*i.e.,* setting rates that reflect cost subject to gradualism concerns), the Energy charges should not be increased by more than 50% of the corresponding increase in the Demand charges.

- FPL is proposing to reduce the incentive payments to CILC/CDR customers by $23 million or 37%. Notwithstanding the obvious impact on CILC/CDR customers, which FPL ignored in applying gradualism, the CILC/CDR credits cannot and should not be "reset" as FPL is proposing.

- FPL has provided no explanation and no study supporting a 37% reduction in the CILC/CDR incentive payments.

- The Commission has previously determined in FPL's 2015 Demand Side Management case that CILC/CDR were cost-effective at the *current* level of incentive payments. Accordingly, by FPL's own admission, no further change can be made in this case.

- Prior to the 2012 FPL rate case, the CDR credits had not been changed since 2004. The CILC incentive payments had not been revised prior to FPL's 2008 rate case. The increase in the incentive payments in the 2012 rate case, thus, reflected inflationary factors, coupled with strong load growth that has prompted FPL to add new capacity to maintain reliability.

- Further, the CILC/CDR credits should not be changed because FPL can use CILC/CDR load to defer or avoid installing new generation capacity, such as peaking units. Thus, FPL is able to maintain reliable service to its firm customers with less installed capacity while incurring less costs because non-firm load is not included in FPL's peak demand projections that are used to assess resource adequacy when planning to meet its firm load.

- Accordingly, the Commission should reject FPL's proposal to reduce the CILC/CDR credits.

## 2. MULTI-YEAR RATE PLAN

**Q. WHAT BASE RATE INCREASES IS FPL SEEKING IN THIS PROCEEDING?**

A. In its Application, FPL was seeking to increase base revenues by approximately $1.34 billion. It has since identified adjustments that would reduce the proposed increase to about $1.31 billion.[1]

**Q. HOW IS FPL PROPOSING TO IMPLEMENT ITS PROPOSED $1.31 BILLION BASE REVENUE INCREASE IN THIS PROCEEDING?**

A. FPL is proposing a forward-looking multi-year rate plan (MYRP). Each step increase was derived using fully projected periods. Under the proposed MYRP, the base revenue increases would be implemented as follows:

**FPL's Proposed MYRP ($ in Millions)[2]**

| Description | Effective Date | Projection Period | Amount |
|---|---|---|---|
| **Test Year** | 1/1/2017 | CY 2017 | $829.7 |
| **Subsequent Year Adjustment (SYA)** | 1/1/2018 | CY 2018 | $266.8 |
| **Okeechobee Clean Energy Center Limited Scope Adjustment** | 6/1/2019 | 6/19 - 5/20 | $209.2 |
| **Cumulative Increases** | | | $1,305.7 |

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[1] FPL's Notice of Identified Adjustments filed on May 3, June 16, and June 30.

[2] Initial proposal adjusted as follows:

- Test Year: $866.4 Million per MFR Schedule A-1 less $36.6 Million of identified adjustments;
- SYA: $262.3 Million per MFR Schedule A-1 2018 Subsequent Year Adjustment less $32.3 Million plus $36.8 Million ($36.6 Million growth adjusted) of identified adjustments;
- OCEC: MFR Schedule A-1 OCEC Limited Scope 2019 plus $0.2 Million. The OCEC increase would be implemented after the plant is placed in commercial operation.

Further, FPL asserts that it would not adjust base rates in 2020. Thus, its proposed MYRP would be a four-year commitment.

**Q. IS FPL SEEKING COMMISSION APPROVAL OF MULTIPLE BASE RATE INCREASES AT THIS TIME?**

A. Yes. In addition to implementing an increase in 2017, FPL is also seeking Commission approval of what it has characterized as a "subsequent year adjustment" (SYA) to raise base rates in 2018. In addition, FPL is proposing an Okeechobee Clean Energy Center (OCEC) Limited Scope increase. However, the amount and impact of the OCEC increase would not be finalized until the plant is placed in commercial operation, which is expected to occur on June 1, 2019.

**Q. SHOULD THE COMMISSION GRANT A SUBSEQUENT YEAR ADJUSTMENT RATE INCREASE?**

A. No. As a preliminary matter, please note that I do not address the Commission's authority to grant a SYA rate increase. This is a legal issue.

From a factual perspective, the request for an additional increase in 2018 is an objectionable pancaking of two separate rate cases in a single proceeding. The reasons for not allowing pancaked rate increases are discussed below.

More importantly, the requested SYA is especially objectionable because the 2018 revenue requirements FPL attempts to rely upon are based on projections that were approved in October 2015.[3] These projections will be 26 months old when the

[3] FPL's Response to FIPUG's Interrogatory No. 1. Energy sales were derived from an updated forecast that was prepared in early 2016.

proposed SYA rates would become effective. Also, FPL is not proposing to update any of the SYA assumptions.[4] Further, the SYA sales, revenues and costs do not reflect FPLs "official" 2018 corporate budget. In fact, FPL's official 2017 corporate budget will not be approved by the Board of Directors until December 2016.[5] This is after the record in this case will be closed. Thus, the official 2018 corporate budget will not be known until 30-days prior to the effective date of the proposed SYA rates.

Finally, considering the various cost recovery clauses, the ability to implement a limited scope proceeding for a major new investment, and adjustments to FPL's projected sales, revenues, rate base, cost of capital and expenses that various parties are likely to propose, a SYA may simply be unnecessary.

**Q. HOW WOULD YOU CHARACTERIZE THE SUBSEQUENT YEAR ADJUSTMENT PROPOSAL?**

A. The phrase "subsequent year adjustment" is really a misnomer and a thinly-disguised attempt to package a second proposed base rate increase filed at the same time as the first base rate increase as something other than what it is — a full scale 2018 base rate case and attendant rate increase. This takes the concept of pancaking rate increases – filing increases one after another in close order — to the ultimate extreme, in my view.

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[4] FPL's Response to FIPUG's Interrogatory No. 89.

[5] FPL's Response to FIPUG's Interrogatory No. 4.

**Q. WHY DO YOU CONCLUDE THAT THE SUBSEQUENT YEAR ADJUSTMENT IS AN ATTEMPT TO PROSECUTE TWO RATE CASES AT ONCE?**

A. The SYA is a filing that looks, feels and smells like a full rate case. First, the SYA is not a proposal to adjust rates based on a specific occurrence or event, such as what might be addressed in a limited scope proceeding. Rather, it is a second rate filing in which FPL seeks to have increased rates put into effect to cover all manner of cost increases ranging from an increase in the overall cost of capital from 6.6% to 6.7%, operation and maintenance (O&M), depreciation, tax expenses, adjustments to billing determinants, capital additions and even inflation-related adjustments, all based on speculative costs projected for 2018. These are not specific SYAs, but rather the full set of pro-forma adjustments that are seen as part of a full rate increase filing. Second, FPL has filed a full set of minimum filing requirements (MFRs) for the SYA. These are the same MFRs that were filed with its 2017 test year request.

**Q. IS IT A REASONABLE REGULATORY POLICY TO ALLOW ELECTRIC UTILITIES TO PROSECUTE TWO BACK-TO-BACK RATE INCREASES IN THE SAME PROCEEDING, AS FPL PROPOSES?**

A. No. Such back-to-back rate increases fail to properly balance the utility's needs with the needs of its customers. Assuming its 2018 assumptions are accurate (which FIPUG disputes), FPL is really asking the Commission to guarantee that it will achieve the authorized return. Providing such a guarantee is contrary to accepted regulatory practice, which is to provide an *opportunity* to earn the authorized return.

Further, as previously discussed, the 2018 test year is based on a budget that was approved in October 2015. FPL will not formally approve its "official" 2018 budget until December 2017, which is well after this rate case will be decided. Thus, setting rates for 2018 is highly speculative. Rates should not be set based on speculation about the future. Additionally, this Commission should not bind a future Commission by setting rates now for 2018.

And finally, the proposed 2018 increase may be unnecessary depending on the Commission's findings on FPL's 2017 revenue requirements. The need for further relief can only be evaluated in the context of the rates that this Commission determines to be appropriate for the 2017 test year.

**Q. IS IT A COMMON PRACTICE TO ALLOW UTILITIES TO PROPOSE MULTI-YEAR RATE PLANS?**

A. No. This practice is not widely used. The only exceptions are in states, like Minnesota and Mississippi, which have statutes specifically authorizing Commission approval of a MYRP.

**Q ARE THERE OTHER TOOLS THAT ALLOW FPL TO REMAIN WHOLE BETWEEN RATE CASES?**

A Yes. This Commission has authorized limited scope increases to recognize major asset additions, such as OCEC, or to implement special riders to recover restoration costs following a major storm event. FPL also has many separate cost recovery clauses, such as Fuel and Purchased Power (Fuel), Capacity Payment Recovery (Capacity), Environmental Cost Recovery (Environmental), and Energy Conservation

Cost Recovery (Conservation). Together, these clauses recover 45% of FPL's revenue requirement. Finally, if FPL's earnings fall below the low end of the authorized range, or are unacceptably low, FPL always reserves the right to file a rate case.

**Q. WHAT IS SIGNIFICANT ABOUT THE USE OF PROJECTED REVENUES AND COSTS CALCULATED IN THE FALL OF 2015 TO SET RATES FOR 2018?**

A. The use of projections calculated more than two years prior to when the 2018 rate would be implemented will result in rates that are based on highly speculative information that could change significantly in the future. The farther out in time projections are, the less likely they are to be accurate.

In Florida, no doubt due in part to the numerous recovery clauses, many years can elapse between rate cases. If the Commission were to base 2018 rates on speculative data from 2015 – which will undoubtedly change as 2018 gets closer – these inaccurate rates may be in effect for a long time and ratepayers may be paying more than necessary. This is a risk to which ratepayers should not be exposed.

If FPL can support a case for rate relief in 2018, it can file a rate case when projections and budgets will be more accurate.

**Q. IS THERE A BASIS TO ASSUME THAT ANY OF FPL'S 2018 PROJECTIONS MAY BE QUESTIONABLE?**

A. Yes. **Exhibit ___ (JP-1)** provides an analysis of FPL's historical and projected weather-normalized retail sales and average customer forecasts. Specifically, FPL's historical 2011-2015 sales and customers are shown on lines 1-5, while the corresponding 2016-2018 projections are shown on lines 7-9. Historically, FPL has experienced 1% per year average weather-normalized sales growth and 1.2% average customer growth (line 6). These are in stark contrast to FPL's projections, which reveal a rather anemic sales growth rate of only 0.3% per year for the period 2016 through 2018 despite projected customer growth of 1.5% per year for the same period (line 10).

**Q. WHAT DO THESE CHANGES SUGGEST WITH REGARD TO THE 2018 SUBSEQUENT YEAR ADJUSTMENT?**

A. Sales and customer projections are key to quantifying FPL's annual revenue needs and essential to accurately designing future rates. If projected sales are understated, FPL's revenue needs and the resulting rates would be overstated. Using questionable assumptions to set rates would give FPL the opportunity to earn more than its authorized midpoint return if FPL were to experience sales growth that is more consistent with past experience.

The substantial changes highlighted above raise serious questions as to whether the 2018 SYA sales and revenues are sufficiently known and measurable so as to form an appropriate and sufficient basis for determining the SYA base rate increases and rate designs. In effect, FPL is asking the Commission to accept that a sales forecast produced in early 2016 is sufficiently accurate to measure FPL's net income at current rates and to design rates. This is simply a forecast, a look beyond the horizon, and not an official budget. At best, FPL's 2018 revenue needs are a preliminary estimate. Thus, although my analysis demonstrates that FPL's 2017 sales and revenue projections should be thoroughly reviewed, it would clearly be premature to use its 2018 forecast to set 2018 rates at this time.

**Q. WILL CHANGES MADE TO FPL'S 2017 REVENUE REQUIREMENTS OBVIATE THE NEED FOR A SECOND RATE CASE?**

A. Yes. FPL's originally proposed second rate increase is $262.3 million. It is based on the same assumptions (*e.g.,* cost of capital, depreciation rates) as the first rate increase scheduled to take effect in 2017. For example, if the Commission reduces FPL's 2017 cost of capital, FPL's 2018 revenue needs may be minimal or non-existent. Similarly, if 2017 sales grow at a rate more consistent with recent experience, FPL may earn in excess of the Commission-authorized mid-point return. This outcome would not be in the public interest.

**Q. SHOULD THE COMMISSION CONSIDER THE AVAILABILITY OF THE VARIOUS COST RECOVERY CLAUSES AND FPL'S ABILITY TO SEEK A LIMITED PROCEEDING, IF CIRCUMSTANCES SUPPORT IT, WHEN CONSIDERING THE SUBSEQUENT YEAR ADJUSTMENT FPL SEEKS?**

A. Yes. Taken as a whole, the Florida regulatory scheme provides utilities with more than ample opportunity to timely recover legitimate costs and expenses. The overall effect of the cost recovery clauses (which currently account for 45% of FPL's total revenues) is to limit substantially the need for full rate cases. The annual clauses also serve to substantially reduce the risk of under-recovery. When reaching a decision regarding the "subsequent year" concept – pancaked rate increases in this case – the Commission must also be mindful of the existence of, use of, and benefits that already accrue to utilities in the state of Florida from the numerous cost recovery clauses.

**Q. WHY SHOULD PANCAKED RATE INCREASES BE AVOIDED?**

A. Pancaked rate increases are not consistent with good public policy. This is especially true under the current circumstances, where base rates are set using a completely forward-looking test year, regulatory lag is minimal, 45% of FPL's costs are recoverable outside of base rate cases through cost recovery clauses, and inflation is minimal. On average, rate case decisions in Florida occur within five months of the filing date. This is the second shortest regulatory lag of any state regulatory commission.

**Q. WHAT DO YOU RECOMMEND?**

A. The Commission should reject FPL's SYA because it is speculative, inappropriate and unnecessary.

## 3. PERFORMANCE INCENTIVE

**Q. WHAT IS THE PERFORMANCE INCENTIVE ADDER THAT FPL IS REQUESTING?**

A. FPL is requesting a 50 basis point adder to its requested cost on equity of 11.0% "to reflect what FPL has already accomplished in its efforts to deliver superior value to its customers and as an incentive to promote further efforts to improve the customer value proposition."[6] This would set its authorized return on equity (ROE) at 11.50%.

**Q. WHAT IS THE REVENUE IMPACT OF A 50 BASIS POINT PERFORMANCE INCENTIVE?**

A. The proposed 50 basis point performance incentive comprises about $120 million of the 2017 revenue requirement. Thus, it would account for about 14% of FPL's proposed 2017 base revenue increase.

**Q. SHOULD FPL BE REWARDED WITH A 50 BASIS POINT PERFORMANCE ADDER?**

A. No. FPL is requesting the adder to reward and incent the company for providing reliable service at the lowest reasonable cost, exactly what a regulated utility is expected to do, regardless of any incentives. It does not need any additional financial incentive to do this. As stated by FPL witness, Moray P. Dewhurst, customer bills are 30% below the national average and 20% below the state average.[7] This result is a combination of dramatically lower natural gas prices and

[6] Direct Testimony of Moray P. Dewhurst at 27.

[7] *Id*. at 11.

investments in more efficient generation capacity. It has been accomplished without any performance adder. A performance adder should not be the determining factor as to whether a utility will pursue superior customer value or whether it will be able to provide reliable and affordable electric service. FPL shouldn't be rewarded for providing the required service and the performance adder should be denied.

**Q. ARE FPL'S AVERAGE RATES LOWER THAN THOSE FOR OTHER UTILITIES ACROSS THE COUNTRY AND ACROSS FLORIDA?**

A. Yes, according to FPL. However, FPL has lower costs because it has invested in cost savings measures, such as installing lower heat rate generation capacity and smart grid meters. Retail customers are paying for these cost savings measures, and they are entitled to benefit from their investments, not pay a higher rate to reward FPL. FPL wants customers to pay for cost saving investments while it reaps the rewards of those cost saving investments.

**Q. WHAT COST SAVING MEASURES HAS FPL (AND ITS CUSTOMERS) INVESTED IN THAT HAVE RESULTED IN COST SAVINGS?**

A. FPL states that it has transformed its fossil generating fleet, which has resulted in cost reductions and performance improvements achieved by FPL's generating fleet that provide substantial benefits to its customers. These include reducing heat rate by 25%, reducing EFOR by 60%, reducing air emissions by 33% for $CO_2$, 94% for $NO_x$ and 99% for $SO_2$, and reducing total non-fuel O&M per kW by 39%. Combined these have resulted in $8 billion cumulatively in fuel cost avoidance for customers.[8]

[8] Direct Testimony of Roxane R. Kennedy at 6.

This $8 billion of savings required $7.1 billion of capital which will be recovered in rates.[9] Again, the customers have paid for these cost savings investments and should not be forced to pay for them twice in the form of higher rates.

**Q. MR. DEWHURST STATES THAT IT IS INCONSISTENT WITH SOUND REGULATORY POLICY FOR A COMPANY WITH A SUPERIOR RECORD OF DELIVERING VALUE TO ITS CUSTOMERS TO EMERGE FROM A KEY REGULATORY PROCEEDING WITHOUT ANY REFLECTION OF THAT PERFORMANCE IN ITS ALLOWED ROE[10]. DO YOU AGREE?**

A. No, I do not. To the contrary, it would be *inconsistent* with sound regulatory policy to impose an additional fee on customers for receiving the expected reliable and affordable service for which they have already paid.

**Q. WHY ELSE WOULD A PERFORMANCE INCENTIVE BE UNNECESSARY?**

A. For the past six years FPL has consistently earned high ROEs without the addition of a performance adder, as shown in the table below.

| Earned Return on Equity[11] | |
|---|---|
| **Year** | **Amount** |
| 2010 | 11.00% |
| 2011 | 11.00% |
| 2012 | 11.00% |
| 2013 | 10.96% |
| 2014 | 11.50% |
| 2015 | 11.50% |

[9] FPL's Response to SFHHA Interrogatory No. 151.

[10] Direct Testimony of Moray P. Dewhurst at 30.

[11] FPL's Response to AARP's Interrogatory No. 10.

As can be seen, over the last several years FPL has enjoyed generous ROEs at the top end rather than the mid-point of its authorized ROE range (9.50%-11.50%) *without* a performance adder.

**Q HOW WAS FPL ABLE TO EARN SUCH HIGH RETURNS ON EQUITY IN THE RECENT PAST?**

A FPL was able to maintain such high ROEs, in part, by amortizing a $894.6 billion depreciation reserve imbalance and a portion of its fossil fuel dismantlement surplus (*i.e.,* Reserve Amount). The amortization commenced in 2010 following FPL's 2009 rate case, and it was continued in 2013 following the Settlement Agreement in FPL's last rate case.[12]

**Q WILL FPL CONTINUE TO USE THE RESERVE AMORTIZATION TO EARN HIGHER RETURNS ON EQUITY?**

A Yes. FPL projects that by amortizing all of the remaining $263 million of the Reserve Amount it will earn an 11.5% ROE in 2016.[13] However, this will deplete the Reserve Amount, and FPL now asserts that it has a $99 million depreciation deficiency.[14]

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[12] *In Re: Petition for Increase in Rates by Florida Power & Light Company* and *In re: 2009 depreciation and dismantlement study by Florida Power & Light Company,* Docket Nos. 080677-EI and 090130-EI, Order No. PSC-IO-0153-FOF-EI at 81 (Mar. 17, 2010)*; In Re: Petition for Increase in Rates by Florida Power & Light Company*, Docket No. 120015-EI, Order Approving Revised Stipulation and Settlement at 4 (Jan. 14, 2013).

[13] FPL's Response to AARP's Interrogatory No. 54.

[14] Direct Testimony of Ned W. Allis at 53.

**Q. WAS FPL OBLIGATED TO AMORTIZE THE RESERVE AMOUNT TO EARN AT THE HIGH END OF ITS AUTHORIZED ROE RANGE?**

A. No. FPL was required to amortize an amount that would allow it to achieve a minimum 9.5% ROE (and not to exceed a maximum 11.5% ROE). FPL used its discretion to use the Reserve Amount to earn at the maximum 11.5% ROE, thereby handsomely rewarding its executives and benefiting shareholders.

**Q. HOW DOES FPL'S CHOICE TO DEPLETE THE RESERVE AMOUNT AUTHORIZED BY THE COMMISSION RELATE TO ITS REQUEST FOR A PERFORMANCE INCENTIVE?**

A. FPL has taken advantage of the 2010 Rate Case Order and the 2012 Settlement to earn the maximum possible returns for the benefit of its executives and shareholders. As a result, FPL's customers may now be saddled with a $99 million depreciation reserve deficiency. Accordingly, FPL has been more than compensated for its superior performance. No further incentive is necessary or appropriate.

**Q. DOES FPL ALREADY HAVE INCENTIVE MECHANISMS TO REWARD SUPERIOR PERFORMANCE?**

A. Yes. FPL is subject to a Generation Performance Incentive Factor (GPIF) that encourages the investment in improvements as well as operational efficiency in each base load unit that results in net savings to customers.[15] On several occasions, FPL has received GPIF rewards.

[15] Eduardo Balbis, P.E. (Commissioner Florida Public Service Commission), *Role of Incentives – A Florida Prospective*.

**Q. ARE THERE ANY ASPECTS OF FPL'S OPERATIONS THAT ARE NOT DESERVING OF A PERFORMANCE INCENTIVE?**

A. Yes. FPL has incurred $3.2 billion of hedging losses for the period 2002 through 2014.[16] These hedging losses have directly increased the fuel costs charged to FPL's customers. The magnitude of these losses is not consistent with rewarding a utility for superior performance.

**Q. WHAT DO YOU RECOMMEND?**

A. The Commission should reject FPL's proposed 50 basis point performance incentive because it is unnecessary and not deserved.

[16] *In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor,* Docket No. 150001-EI, Order No. PSC-15-0586-FOF-EI at 5 (Dec. 23, 2015).

## 4. CONSTRUCTION WORK IN PROGRESS

**Q. IS FPL SEEKING TO INCLUDE CONSTRUCTION WORK IN PROGRESS IN RATE BASE?**

A. Yes. For the 2017 test year, FPL is proposing to include $748 million of construction work in progress (CWIP) in rate base. The $748 million consists of projects on which FPL says it cannot capitalize allowance for funds used during construction (AFUDC).[17] Accordingly FPL is seeking a current cash return on this CWIP.

**Q. IS THE RECOVERY OF CWIP IN RATE BASE CONSISTENT WITH TRADITIONAL RATEMAKING?**

A. No. CWIP is the investment in facilities that are in construction and are not providing service. In other words, this investment is not "used and useful." Under traditional ratemaking, investment that is not used and useful is excluded from rate base.

**Q IS ALLOWING A CASH RETURN ON CONSTRUCTION WORK IN PROGRESS A NORMAL REGULATORY PRACTICE?**

A No. For example, the Public Utility Commission of Texas (PUCT) regards CWIP as an "exceptional form of rate relief." Under the PUCT's rules:

> Under ordinary circumstances the rate base shall consist only of those items which are used and useful in providing service to the public. Under exceptional circumstances, the commission will include construction work in progress in rate base to the extent that:
>
> (i.) the electric utility has proven that:

[17] FPL's Response to FIPUG No. 92.

(I.) the inclusion is necessary to the financial integrity of the electric utility; and

(II.) major projects under construction have been efficiently and prudently planned and managed. However, construction work in progress shall not be allowed for any portion of a major project which the electric utility has failed to prove was efficiently and prudently planned and managed; or

(ii.) for a project ordered by the Commission under §25.199 of this title (relating to Transmission Planning, Licensing and Costs-recovery for Utilities within the Electric Reliability Council of Texas), if the commission determines that conditions warrant the inclusion of CWIP in rate base, the project is being efficiently and prudently planned and managed, and there will be a significant delay between initial investment and the initial cost recovery for a transmission project.[18]

**Q UNDER WHAT CIRCUMSTANCES CAN UTILITIES BE ALLOWED TO BEGIN RECOVERING A CASH RETURN ON CONSTRUCTION COSTS?**

A Because of its extraordinary nature, the recovery of a cash return on CWIP from retail customers is generally limited to extraordinary circumstances. Such circumstances would occur when a utility is engaged in a very large construction program relative to its existing rate base and where the utility requires substantial external financing. Under these circumstances, a utility may experience lower earnings quality; that is, its cash earnings may not provide ample interest coverage, and its reported earnings would include a substantial amount of non-cash AFUDC earnings. These non-cash AFUDC earnings cannot be used to pay the interest and repay the principal on outstanding long-term debt.

[18] P.U.C. SUBST. R. 25.231(c)(2)(D).

The lower earnings quality could possibly trigger a reassessment of the utility's outstanding debt by the major credit rating agencies. Absent prospects for improvement over time, the credit rating agencies could consider whether to downgrade the utility's bonds. All other things equal, a lower bond rating would increase the cost of the debt issued to finance the utility's construction program. This could increase the utility's cost of capital and may result in higher rates.

**Q. IS THERE ANY CONCERN THAT FPL'S CREDIT RATINGS MAY DETERIORATE IF IT IS NOT ALLOWED TO HAVE CWIP IN RATE BASE?**

A. No. CWIP accounts for only 2% of FPL's proposed 2017 test-year rate base. This is not a sufficient amount to have any impact on FPL's cash earnings or the financial indicators used by the major credit rating agencies to evaluate FPL's bond ratings.

**Q. WHY ELSE SHOULD CWIP BE EXCLUDED FROM RATE BASE IN THIS CASE?**

A. FPL's proposed $1.31 billion of base revenue increases over the next four years is very substantial and, as discussed later, will result in rate shock for customers. Thus, the Commission should take all necessary steps to mitigate rate increases of this magnitude on FPL's retail customers consistent with the intent of Rule 25-6.0141 F.A.C., which states:

> (g) On a prospective basis, the Commission, upon its own motion, may determine that the potential impact on rates may require the exclusion of an amount of CWIP from a utility's rate base that does not qualify for AFUDC treatment per paragraph (1)(a) and to allow the utility to accrue AFUDC on that excluded amount.

**Q. WHAT DO YOU RECOMMEND?**

A. The Commission should reject FPL's proposal to include CWIP in rate base.

## 5. COST OF CAPITAL

**Q. HAS YOU REVIEWED FPL'S PROPOSED COST OF CAPITAL?**

A. Yes. FPL's proposed 2017 cost of capital is summarized in the table below.

| FPL's Proposed Cost of Capital<br>Test Year Ending December 31, 2017 | | | |
|---|---|---|---|
| **Description** | **Percent of Capital** | **Cost** | **Weighted Cost** |
| | (1) | (2) | (3) |
| **Long-Term Debt** | 28.763% | 4.617% | 1.328% |
| **Customer Deposits** | 1.252% | 2.045% | 0.026% |
| **Common Equity** | 45.127% | 11.500% | 5.190% |
| **Short-Term Debt** | 1.884% | 1.850% | 0.035% |
| **Deferred Income Tax** | 22.647% | 0.000% | 0.000% |
| **Investment Tax Credits** | 0.327% | 8.821% | 0.029% |
| **Total** | 100.000% | | 6.607% |

As the table demonstrates, FPL is seeking an 11.5% ROE including the proposed 50 basis point incentive. Ignoring customer deposits, deferred income taxes, and investment tax credits, FPL's "financial" capital structure would consist of approximately 40% (short and long-term) debt and 60% equity.

**Q. DO YOU HAVE ANY CONCERNS WITH FPL'S PROPOSED COST OF CAPITAL?**

A. Yes. My primary concerns are:

- The projected cost of long-term debt is overstated.
- Even without the 50 basis point performance incentive, the proposed ROE is excessive relative to the ROEs authorized by this Commission and by other state regulatory commissions for electric investor-owned electric utilities (IOUs) operating in the Southeast.
- FPL's equity ratio is excessive.

**Long-Term Debt**

**Q. WHAT LONG-TERM INTEREST RATE COST DID FPL ORIGINALLY PROJECT FOR 2017 AND 2018?**

A. For 2017, FPL projected a 6.16% cost for long-term debt issues in March and November 2017 and 6.50% for debt issues in February and November 2018.[19] These projections are based on the December 2014 Blue Chip Financial Forecast's interpolated data for Corporate Aaa and Baa rated debt.[20] Thus, this forecast was made 24 and 36 months prior to the beginning of 2017 and 2018.

**Q. ARE THESE RATES REASONABLE?**

A. No. The forecast used by FPL to project the interest rate for 2017 and 2018 debt issues is dated. Further, FPL could have used more current information because these forecasts are published monthly and long range consensus forecasts are provided semi-annually. FPL itself stated that the "Corporate Aaa & Baa bond yields that are used in FPL's forecasted assumptions have decreased 20 basis points and 10 basis points, respectively, based on a 5-year average, compared to December 2015."[21] This further demonstrates that FPL's forecast rates are too high.

Further, it is more difficult to forecast debt rates this far out, especially in times of uncertain market conditions when the Federal Reserve has indicated that it

[19] MFR Schedule D-8.

[20] FPL's Response to SFHHA No. 88.

[21] FPL's Response to AARP's Interrogatory No. 46.

will raise rates gradually and cautiously, without a set timetable.[22] The odds that the Federal Reserve will raise interest rates by the end of the year have dropped substantially, from 60% on June 22, 2016 to less than 5% on June 25th.[23] This is mainly due to the fall-out from the recent British vote to exit from the European Union. Due to the latest economic news, it makes it even more difficult to forecast long-term interest rates.

**Q HAS FPL UPDATED ITS FORECAST OF LONG-TERM DEBT COSTS?**

A Yes. It is now projecting long-term debt costs of 5.66% for debt issued in 2017 and 6.13% for debt issued in 2018.[24] These are based on the latest forecast information from the most recent issue of Blue Chip Financial Forecasts. As can be seen, there has been a drop of 50 basis points for 2017 long-term debt costs and 37 basis points for 2018 long-term costs.

**Q. WHAT DO YOU RECOMMEND?**

A. As a conservative estimate, using FPL's updated forecast, I believe that FPL has overstated the cost of long-term debt issues planned for 2017 and 2018 by *at least* 10 basis points. Lowering the debt costs by 10 basis points would reduce FPL's 2017 cost of long-term debt to 4.5489%. The calculation of FPL's 2017 cost of long-term debt is provided in **Exhibit ___ (JP-2)**.

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[22] Hilsenrath, Jon "Yellen: Recession Unlikely, but Long-Run Growth Could Be Slow" *The Wall Street Journal*, June 21, 2016.

[23] Lahart, Justin "What Brexit means for U.S. Investors" *The Wall Street Journal*, June 26, 2016.

[24] FPL's Response to Staff No. 254, Att. 1.

**<u>Cost of Equity</u>**

**Q. HOW DOES FPL'S REQUESTED RETURN ON EQUITY COMPARE WITH OTHER ELECTRIC INVESTOR-OWNED UTILITIES?**

A. FPL's proposed 11% ROE is clearly excessive. This is shown in **Exhibit __ (JP-3)**, which is a summary of the authorized ROEs by other state regulatory commissions for vertically integrated electric IOUs for the period 2012 through the first quarter of 2016. Page 1 summarizes the authorized ROEs by year. Pages 2-4 list the 111 rate case decisions referenced on page 1. As can be seen:

- For rate cases decided since FPL's last rate case, the average authorized ROEs have steadily declined.
- Beginning in 2014, the average authorized ROE is *below* 10%.

**Q. HOW DOES FPL'S REQUESTED RETURN ON EQUITY COMPARE WITH OTHER ELECTRIC INVESTOR-OWNED UTILITIES IN FLORIDA?**

A. The currently authorized ROEs for other Florida IOUs is shown in the table below.

**Authorized Returns on Equity by**
**The Florida Public Service Commission**

| Utility | Docket No. | Decision Date | ROE |
|---|---|---|---|
| **Duke Energy Florida** | 090079-EI | 3/5/10 | 10.50% |
| **Gulf Power Company** | 130140-EI | 12/3/13 | 10.25% |
| **Tampa Electric Company** | 130040-EI | 9/11/13 | 10.25% |

As the table demonstrates, FPL's requested ROE is 50 to 75 basis points higher than the ROEs authorized for Duke Energy Florida (Duke), Gulf Power Company (Gulf) and Tampa Electric Company (TECO). A 50 to 75 basis point change in FPL's authorized ROE would reduce FPL's requested 2017 base revenue increase by between $120 and $180 million, thereby resulting in considerable savings benefitting FPL's retail customers.

**Q. WHAT DO YOU RECOMMEND?**

A. I am not recommending a specific ROE at this time. FPL's proposed 11% ROE is excessive particularly with a 60% equity ratio. Accordingly, I recommend that the Commission set FPL's ROE below the average of the authorized ROEs by other state regulatory commissions. This would recognize the much lower risk associated with a 60% equity ratio.

## Capital Structure

**Q. WHAT IS THE BASIS FOR YOUR STATEMENT THAT FPL'S PROPOSED EQUITY RATIO IS EXCESSIVE?**

A. **Exhibit ___ (JP-4)** summarizes the average financial equity ratio of each vertically integrated electric IOU in the most recent rate case decided during the period 2012 through March 2016. A financial capital structure is comprised of debt and equity. This is in contrast to a "regulatory" capital structure, which may also include deferred taxes, customer deposits and deferred investment tax credits.

Page 1 shows the financial equity ratio. Page 2 plots both the authorized ROEs and financial equity ratios. Referring to page 1, the average electric IOU financial equity ratio has ranged from 45% to 53%. FPL's proposed ROE and financial equity ratio are specifically identified on page 2. As can be seen, relatively few electric IOUs have financial equity ratios comparable to FPL. However, even in these instances, the authorized ROE is well below FPL's proposed 11.5% (including the performance incentive).

**Exhibit ___ (JP-4)**, pages 3-4 list each of the 63 rate case decisions depicted on pages 1 and 2. The average financial common equity ratio is 51.10%. Thus, FPL's proposed financial common equity ratio is 890 basis points higher than the electric IOU average.

**Q ARE THERE ANY CONSEQUENCES OF USING MORE EQUITY AND LESS DEBT TO FINANCE THE UTILITY'S RATE BASE?**

A Yes. FPL's higher percentage of equity and lower percentage of debt in its capital structure lowers its financial risk. Furthermore, common equity is more expensive than debt. In this case, FPL is proposing an 11% cost of equity, but the proposed cost of debt would be only 4.6%, which is 640 basis points lower. A utility with 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 greater the benefits to FPL's shareholders and executives and the higher the rates all FPL retail customers will bear. FPL should not be rewarded for its overly conservative use of debt and high equity ratio.

**Q. WHAT DO YOU RECOMMEND?**

A. FPL can use whatever capital structure it chooses. However, for ratemaking purposes, FPL's capital structure should be more in line with the average of electric IOUs. Accordingly, I recommend that FPL's equity ratio not exceed 51.10%.

## 6. CLASS REVENUE ALLOCATION

**Q. WHAT IS CLASS REVENUE ALLOCATION?**

A. Class revenue allocation is the process of determining how any base revenue change the Commission approves should be apportioned to each customer class the utility serves.

**Q. HOW SHOULD ANY CHANGE IN BASE REVENUES APPROVED IN THIS DOCKET BE APPORTIONED AMONG THE VARIOUS CUSTOMER CLASSES FPL SERVES?**

A. Base revenues should reflect the actual cost of providing service to each customer class as closely as practicable. Regulators sometimes limit the immediate movement to cost based on principles of gradualism and rate administration.

**Q. WHAT IS THE PRINCIPLE OF GRADUALISM?**

A. Gradualism is a concept that is applied to prevent a class from receiving an overly-large rate increase. That is, the movement to cost should be made gradually rather than all at once because it would result in rate shock to the affected customers.

**Q. HOW IS RATE ADMINISTRATION RELATED TO CLASS REVENUE ALLOCATION?**

A. Rate administration is a concept that applies when the design of a rate may be tied to the design of other rates to minimize revenue losses when customers migrate from a more expensive to a less expensive rate. FPL applies this concept in designing the GSLD and derivative rates (*e.g.,* SDTR, HLFT).

**Q. SHOULD THE RESULTS OF THE COST-OF-SERVICE STUDY BE THE PRIMARY FACTOR IN DETERMINING HOW ANY BASE REVENUE CHANGE SHOULD BE ALLOCATED?**

A. Yes. Cost-based rates will send the proper price signals to customers. This will allow customers to make rational consumption decisions.

**Q. ARE THERE OTHER REASONS TO APPLY COST-OF-SERVICE PRINCIPLES WHEN CHANGING RATES?**

A. Yes. The other reasons to adhere to cost-of-service principles are equity, engineering efficiency (cost-minimization), stability and conservation.

**Q. WHY ARE COST-BASED RATES EQUITABLE?**

A. Rates which primarily reflect cost-of-service considerations are equitable because each customer pays what it actually costs the utility to serve the customer – no more and no less. If rates are not based on cost, then some customers must pay part of the cost of providing service to other customers, which is inequitable.

**Q. HOW DO COST-BASED RATES PROMOTE ENGINEERING EFFICIENCY?**

A. With respect to engineering efficiency, when rates are designed so that demand and energy charges are properly reflected in the rate structure, customers are provided with the proper incentive to minimize their costs, which will, in turn, minimize the costs to the utility.

**Q. HOW CAN COST-BASED RATES PROVIDE STABILITY?**

A. When rates are closely tied to cost, the utility's earnings are stabilized because changes in customer use patterns result in parallel changes in revenues and expenses.

**Q. HOW DO COST-BASED RATES ENCOURAGE CONSERVATION?**

A. By providing balanced price signals against which to make consumption decisions, cost-based rates encourage conservation (of both peak day and total usage), which is properly defined as the avoidance of wasteful or inefficient use (not just less use). If rates are not based on an appropriate class cost-of-service study, then consumption choices are distorted.

**Q. DOES COMMISSION POLICY SUPPORT THE MOVEMENT OF UTILITY RATES TOWARD ACTUAL COST?**

A. Yes. The Commission's support for cost-based rates is longstanding and unequivocal. The Commission reiterated this principle in the most recent fully litigated Tampa Electric Company rate case:

> It has been our long-standing practice in rate cases that ***the appropriate allocation of any change in revenue requirements, after recognizing any additional revenues realized in other operating revenues, should track, to the extent practical, each class's revenue deficiency as determined from the approved cost of service study, and move the classes as close to parity as practicable.*** The appropriate allocation compares present revenue for each class to the class cost of service requirement and then distributes the change in revenue requirements to the classes. No class should receive an increase greater than 1.5 times the system average percentage increase in total, and no class should receive a decrease.[25]

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[25] *In Re: Petition for Rate Increase by Tampa Electric Company*, Docket No. 080317-EI, Order No. PSC-09-0283-FOF-EI at 86-87 (Apr. 30, 2009). Footnote omitted and emphasis added.

Therefore, a more gradual movement of FPL's rates closer to cost would be consistent with Commission policy rather than what FPL has proposed.

**FPL's Proposal**

**Q. HOW IS FPL PROPOSING TO ALLOCATE THE PROPOSED BASE REVENUE INCREASE IN THIS PROCEEDING?**

A. FPL states that it set the target revenue by rate class to move all rates closer to cost to the greatest extent possible, while recognizing gradualism.[26] I will discuss FPL's application of gradualism later. FPL's proposed base revenue increase is shown in **Exhibit ___ (JP-5)**. Page 1 shows the allocation of the proposed 2017 increase, while page 2 shows the cumulative base revenue increases based on FPL's proposed SYA.

Referring to page 1, the 2017 increase would be a 15.8% base rate increase (line 21). The increases by class would range from 0.7% for OL-1 to 77.6% for CILC-1T. The other CILC rates would see similarly large increases (28.1% for CILC-1G and 57.0% for CILC-1D).

Referring to page 2, the cumulative 2017 and SYA base revenue increase would be 20.4% (line 21). The proposed cumulative increases would range from 0.7% for OL-1 to over 80% for CILC-1T. The corresponding cumulative base rate increases to the other CILC rates would be 33.7% for CILC-1G and 69.6% for CILC-1D.

[26] Direct Testimony of Tiffany C. Cohen at 14.

**Q. WOULD THE BASE RATE INCREASES PROPOSED BY FPL FOR CERTAIN CUSTOMER CLASSES CONSTITUTE RATE SHOCK?**

A. Yes. FPL's proposed 38% and 72% cumulative base rate increases for the GSLD and CILC rates, respectively, would constitute rate shock. A more in-depth analysis of how FPL's proposed class revenue allocation is inconsistent with accepted gradualism principles is provided later.

**Q. WHY IS FPL PROPOSING SUCH LARGE BASE RATE INCREASES IN THE CILC RATES?**

A. The very large CILC base rate increases can be attributed to two factors. First, FPL is proposing to "reset" the credits paid to CILC customers as well as the GSD and GSLD customers that take non-firm service under Rider CDR. This accounts for a significant portion of the proposed base rate increases to CILC and CDR customers, as shown in the table below.

**Impact of "Resetting" the CDR/CILC Credits[27]**

| Customer Class | Amount ($000) | Percent Of Total Increase |
|---|---|---|
| **CILC-1D** | $9,943 | 27% |
| **CILC-1D** | 370 | 24% |
| **CILC-1T** | 5,234 | 33% |
| **GSD-1** | 2,201 | 0% |
| **GSLD-1** | 4,152 | 3% |
| **GSLD-2** | 1,069 | 3% |
| **Total** | $22,969 | 1% |

[27] MFR No. E-14 Attachment 2 of 6 at 30.

Thus, resetting the CILC/CDR credits would result in a $23 million additional base revenue increase and would account for up to one-third of the proposed CILC-1T base revenue increase. As discussed later, this rate case is not an appropriate venue for changing the CILC/CDR credits.

Second, FPL's class cost-of-service study (CCOSS) purportedly shows that the CILC classes are paying rates well below their allocated costs. As discussed later, FPL's CCOSS is flawed and cannot be used to set rates in this proceeding.

**Q. WHAT DOES RESETTING THE CILC/CDR CREDITS MEAN?**

A. FPL is proposing to restate the CILC/CDR credits to the levels that existed prior to the Settlement in its 2012 rate case, adjusted for the subsequent generation base rate adjustments (GBRAs) that have been implemented since 2012.

**Q. IS FPL'S PROPOSED 2017 CLASS REVENUE ALLOCATION REASONABLE?**

A. No. FPL's proposed class revenue allocation would violate this Commission's long-standing principle of gradualism.

## Gradualism

**Q. HOW HAS FPL APPLIED GRADUALISM?**

A. FPL states that it followed the Commission practice of limiting the increase of each rate class to 1.5 times the system average increase in revenue, including adjustment clauses, and not allowing any class to receive a decrease.[28] FPL's application of gradualism is shown in **Exhibit ___ (JP-6)**.

[28] Direct Testimony of Tiffany C. Cohen at 14.

**Q. PLEASE EXPLAIN EXHIBIT ___ (JP-6).**

A. **Exhibit ___ (JP-6)** is a reproduction of a portion of MFR Schedule E-14 Attachment 2. Column 1 shows the present operating revenues including the clauses. Operating revenues include:

- Base rate revenues.
- Clause revenues (*i.e.,* Fuel, Conservation, Capacity, Environmental).
- Other revenues (*i.e.,* late payment charges, pole attachments, connect/reconnect charges, returned check charges).

Columns 2 and 3 show FPL's proposed base revenue increase (in dollars and expressed as a percent of operating revenues) as shown in MFR Schedule E-13a. Column 4 shows the impact of reversing the CILC/CDR credits.

In measuring the impact of gradualism, FPL removed the CILC/CDR credits from the proposed base revenue increases (column 4). The net revenue increase shown in column 5 matches the increases shown in MFR Schedule E-8. The percentage change in base revenues (column 6) measures the net revenue increase (ignoring the CILC/CDR credits) as a percent of present total operating revenues. When measured on this basis, the system average increase is 8.3%. Thus, applying a 150% gradualism constraint would result in a maximum increase of 12.4%. As can be seen, none of the proposed increases, including clauses, would exceed 12.4%.

**Q. IS THIS A PROPER APPLICATION OF GRADUALISM?**

A. No, for three reasons. First, FPL included other operating revenue in the calculation. Gradualism is typically measured on the revenues generated from electricity sales, not revenues from other sources, such as pole attachment and late payment charges. Second, FPL has ignored the impact of resetting the CILC/CDR credits in measuring the impact of its proposed base revenue increase. In other words, FPL has assumed that the CILC/CDR customers would not be affected by reducing their credits by $23 million. This is clearly wrong as resetting the credits clearly impacts the CILC/CDR customers. Third, gradualism should not be measured by including the clause revenues because the clauses are not at issue in a base rate case.

**Q. ARE THERE ANY POLICY REASONS WHY GRADUALISM SHOULD BE APPLIED TO ONLY BASE RATES?**

A. Yes. From a policy perspective, cost recovery clauses should not be included in this analysis because they change on an annual basis whereas base rates generally remain in place for a much longer period of time. And, as we have seen over the past eight years, fuel prices, for example, may experience great fluctuation in one year and then dramatically change again in the next year. Thus, it would be inappropriate to include and rely on projections of clause revenues for just one year (the test year) in setting base rates.

**Q. HOW SHOULD GRADUALISM BE APPLIED?**

A. FPL is seeking an increase in base rates. The cost recovery clauses are not at issue in this case. In other words, the increase FPL is now seeking has nothing to do with increases or decreases in fuel, energy conservation, environmental, or capacity costs. For this reason, gradualism should be applied to that portion of the rate that is subject to change in this proceeding—*the base rate*.

Further, gradualism is not a consideration in setting the cost recovery clauses. Thus, a sudden increase or decrease in natural gas prices will not affect how base rates are determined in this case.

The Commission should apply the principle of gradualism to any base revenue increase that may be approved in this case, notwithstanding any predictions about subsequent changes in cost recovery clauses.

Given that the cost recovery clauses are separate ratemaking mechanisms and can have positive or negative impacts on customers depending on the circumstances, any projected short-term clause changes should not be considered in setting base rates.

**Q. ASSUMING THAT GRADUALISM IS APPLIED TO OVERALL RATES AND NOT TO BASE RATES, WOULD FPL'S PROPOSED CLASS REVENUE ALLOCATION BE CONSISTENT?**

A. No. **Exhibit ___ (JP-7)** is the same as **Exhibit ___ (JP-6)** except that:

- Other revenues have been removed from column 1.
- The CILC/CDR reset was not removed from the proposed base revenue increase.

Focusing on the base revenue impact, base revenues would increase by $893.1 million or 8.7%, including clauses. Applying a 150% gradualism constraint, no customer class should receive an increase higher than 13%. However, FPL's proposal would result in increases higher than 13% for the GSLD-1, GSLD-2, CILC-1D and CILC-1T classes.

Thus, FPL's proposed class revenue allocation would clearly violate gradualism if it is applied on total revenues, including the clauses.

**Q. HAVE YOU DEVELOPED AN ALTERNATIVE CLASS REVENUE ALLOCATION APPLYING MORE JB REASONABLE GRADUALISM PRINCIPLES?**

A. Yes. **Exhibit ___ (JP-8)** is an alternative class revenue allocation that applies gradualism on a total revenue basis, including the clauses. Applying a 150% gradualism constraint, the maximum increase cannot exceed 12.7%. As can be seen, no class would receive an increase higher than 12.7% measured on total sales revenues, including the clauses. It also differs from FPL's proposal because:

- The CILC/CDR credits were retained.
- Any revenue shortfall was used to move the remaining classes (not affected by applying gradualism) equally closer to cost.

As can be seen in **Exhibit ___ (JP-9)**, applying this class revenue allocation to FPL's CCOSS study would move rates about 44% closer to cost for those classes not affected by gradualism.

**Q. PLEASE EXPLAIN HOW THE CLASS COST-OF-SERVICE STUDY RESULTS ARE MEASURED.**

A. The results presented in **Exhibit ___ (JP-9)** are measured in three ways: (1) rate of return; (2) parity index; and (3) interclass subsidies.

***Rate of return*** is the ratio of net operating income (revenues less allocated operating expenses) to the allocated rate base. Net operating income is the difference between operating revenues and allocated operating expenses. If a class is presently providing revenues sufficient to recover its cost of service (at the current system rate of return), it will have a rate of return equal to or greater than the Florida retail jurisdictional return of 4.97% at present rates.

The ***parity index*** is the ratio of each class's rate of return to the Florida retail average rate of return. A parity index above 100 means that a class is providing a rate of return higher than the system average, while a parity index below 100 indicates that a class is providing a below-system average rate of return.

The ***interclass subsidy*** measures the difference between the revenues required from each class to achieve the system rate of return and the revenues actually being recovered. A negative amount indicates that a class is being subsidized each year (*i.e.*, revenues are below cost at the system rate of return), while a positive amount indicates that a class is providing a subsidy each year (*i.e.*, revenues are above cost).

**Q. WHAT DO YOU RECOMMEND?**

A. First, the Commission should reject FPL's proposed class revenue allocation because it violates gradualism principles. Second, gradualism should be applied on a base revenue basis because the cost recovery clauses are not being changed in this case (except possibly the allocation factors if FPL's proposed CCOSS is adopted).

Finally, the Commission should use a more appropriate CCOSS to determine a class revenue allocation. Later in my testimony I discuss two adjustments to FPL's CCOSS that reflect cost causation. The results of this revised study should be used to determine the spread of any base revenue increase approved for 2017. Specifically, all customer classes should be moved equally closer to cost, provided that no class receives an increase exceeding 150% of the system average base rate increase. Finally, as discussed later, the CILC/CDR credits should be maintained and not reset.

**Q. IF THE COMMISSION APPROVES A LOWER REVENUE REQUIREMENT THAN FPL HAS PROPOSED, HOW SHOULD ANY CHANGE IN BASE REVENUES BE ALLOCATED?**

A. If the Commission approves more than 33% (but less than 100%) of FPL's proposed base revenue increase, I recommend reducing the amounts shown in **Exhibit ___ (JP-8)**, column 2, proportionally if FPL's CCOSS is adopted. Should the Commission adopt the changes to FPL's CCOSS as discussed later, the increase should be reduced in proportion to the amounts shown in **Exhibit ___ (JP-14)**, column 2.

If however, the Commission approves less than 33% of FPL's proposed base revenue increase or a decrease, it should be spread equally to all customer classes.

## 7. CLASS COST-OF-SERVICE STUDY

**Q. WHAT IS A CLASS COST-OF-SERVICE STUDY?**

A. A CCOSS is an analysis used to determine each class' responsibility for the utility's costs. Thus, it determines whether the revenues a class generates cover the class's cost of service. A CCOSS separates the utility's total costs into portions incurred on behalf of the various customer groups. Most of a utility's costs are incurred to jointly serve many customers. For purposes of rate design and revenue allocation, customers are grouped into homogeneous classes according to their usage patterns and service characteristics. The procedures used to conduct a CCOSS are described in **Appendix C**.

### FPL's Class Cost-of-Service Study

**Q. HAVE YOU REVIEWED THE CLASS COST-OF-SERVICE STUDY FPL FILED IN THIS PROCEEDING?**

A. Yes.

**Q. DOES FPL'S CLASS COST-OF-SERVICE STUDY COMPORT WITH ACCEPTED INDUSTRY PRACTICES?**

A. Yes, in many respects. FPL's CCOSS generally recognizes the different types of costs as well as the different ways electricity is used by various customers. However, there are several significant flaws that must be corrected before the study can be used to design rates in this proceeding. The flaws include:

- Use of the Twelve Coincident Peak and 25% Average Demand (12CP+25% AD) method to allocate production plant and related costs;

- The failure to recognize that a portion of the costs incurred to provide a distribution network (*i.e.,* investments booked to FERC Account Nos. 364 through 368) is customer-related; and
- Over-allocating distribution plant and related expenses due to the failure to recognize that some customers take service directly from an FPL-owned distribution substation.

Each of the above flaws is discussed below.

## Allocation of Production Plant-Related Costs

**Q. WHAT IS THE 12CP+25% AD METHOD?**

A. The 12CP+25% AD method allocates production plant costs using both 12CP (which is also used to allocation transmission plant related costs) and energy (or average demand). Specifically, the 12CP+25% AD allocation factors are derived as follows:

$$\mathbf{12}\boldsymbol{CP} + \mathbf{25}\%\boldsymbol{AD} = \mathbf{12}\boldsymbol{CP}\%\ \boldsymbol{X}\ \mathbf{75}\% + \boldsymbol{AD}\%\ \boldsymbol{X}\ \mathbf{25}\%$$

Where: 12CP = Twelve Coincident Peak Demand
AD = Average Demand

Average Demand is the same as energy. Thus, 12CP+25% AD weights energy by 25%,

**Q. HAS FPL EVER PROPOSED THE 12CP+25% AD METHOD?**

A. No.

**Q. WHAT METHODOLOGY IS FPL CURRENTLY USING?**

A. FPL is currently using the 12CP+1/13$^{th}$ AD method. In contrast to 12CP+25% AD, 12CP+1/13$^{th}$ AD weights energy by 7.6% This method has been used by FPL in rate cases filed since 1982.

**Q. WHY DID FPL SUPPORT THE 12CP+1/$13^{TH}$ AD METHOD IN PAST CASES?**

A In its last rate case, FPL supported 12CP+1/13th AD stating that:

> ***The 12 CP and 1/$13^{th}$ methodology recognizes that the decision to add generating capacity is driven primarily by peak demands on the system.*** This methodology classifies 12/$13^{ths,}$ or approximately 92% of costs on the basis of coincident peak demand and 1/$13^{th}$, or approximately 8%, of costs on the basis of energy. That portion classified to demand is allocated to the individual rate classes based on their 12 CP contributions, adjusted for losses, while the portion classified to energy is allocated based on their kWh sales, adjusted for losses. ***Under the 12 CP and 1/$13^{th}$ methodology, all generating units are treated consistently based on their function (i.e. production), their classification (12/$13^{th}$ demand and 1/$13^{th}$ energy), and their allocation (contribution to the system peak and kWh of energy).*** The 12 CP and 1/$13^{th}$ methodology has a significant history of regulatory acceptance in Florida. The 12 CP and 1/$13^{th}$ methodology was used in Docket No. 830465-EI and Docket No. 080677-EI. Furthermore, the FPSC has approved the 12 CP and 1/$13^{th}$ methodology in rate cases involving other investor-owned utilities.[29i] (Emphasis added)

**Q. WHAT METHODOLOGY IS CURRENTLY BEING USED BY OTHER FLORIDA INVESTOR-OWNED ELECTRIC UTILITIES?**

A. Like FPL, Duke, Gulf and TECO currently use 12CP+1/$13^{th}$ AD. Thus, FPL would be the only Florida IOU not to use the 12CP+1/$13^{th}$ AD method if its proposal is adopted.

**Q. WOULD FPL'S DECISION TO CHANGE THE ALLOCATION METHOD AFFECT ONLY THE BASE RATES DETERMINED IN THIS PROCEEDING?**

A. No. If the Commission approves FPL's proposal to increase the energy weighting from 7.6% to 25%, it will also change how costs are allocated to, and recovered from

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[29] *In Re: Petition for Rate Increase by Florida Power & Light Company*, Docket No. 120015- EI, Testimony and Exhibits of Joseph A. Ender at 21.

customer classes in the Capacity, Conservation and Environmental clauses. Thus, it would have a more significant impact beyond this base rate case. Not only would adopting 12CP+25% AD shift base rate costs, it will also shift Capacity, Conservation and Environmental costs from residential to non-residential customers.

**Q. WHY IS FPL PROPOSING TO CHANGE THE ALLOCATION METHODOLOGY?**

A. FPL asserts that 12CP+25% AD is more appropriate because it considers how FPL plans and operates its power plants in response to customer energy and demand needs. FPL also cites how it has installed a significant amount of generation capacity that costs more to construct but is less costly to operate over time than peaking generation. This type of generation improves system heat rate and lowers fuel costs.[30]

**Q. DO ANY OF THESE EXPLANATIONS SUPPORT CHANGING THE CURRENTLY USED 12CP+1/13$^{TH}$ AD METHOD?**

A. No. First, FPL has not changed the way it plans and operates its system since the last rate case, when it supported 12CP+1/13$^{th}$ AD.[31] Second, FPL does not plan or operate its system any differently than any other Florida utility. Duke, Gulf and TECO are among the other Florida utilities that plan and operate generating systems in Florida. Further, these utilities have had regulatory proceedings before the Commission in recent years. In these cases, Duke and TECO ultimately agreed to use the 12CP+1/13$^{th}$ AD method, and Gulf continued to support the 12CP+1/13$^{th}$ AD

[30] Direct Testimony of Renae B. Deaton at 21.

[31] FPL's Response to FIPUG's Interrogatory No.84.

method. The Commission approved these settlements finding that they were in the public interest. Finally, because FPL is a predominantly summer-peaking utility using 12CP as the demand allocator implicitly recognizes many of the factors cited by Ms. Deaton that purportedly support a higher energy weighting.

**Q. WHAT DOES MS. DEATON MEAN BY THE TERM INTERMEDIATE LOAD GENERATION?**

A. I presume Ms. Deaton is referring to the combined cycle power plants that FPL has been adding to its system. Specifically, FPL has added over 9,000 MW of combined cycle gas turbine (CCGT) plants over the past ten years.

**Q. WHAT IS A COMBINED CYCLE POWER PLANT?**

A. A combined-cycle power plant uses both a gas and a steam turbine together to produce up to 50% more electricity from the same fuel than a traditional simple-cycle plant. The waste heat from the gas turbine is routed to the nearby steam turbine, which generates extra power. They are comprised of an array of combustion turbine (CT) peaking units and steam turbines. In a combined-cycle power plant, the exhaust heat from the CTs is captured in a heat recovery steam generator (HRSG), which create steam and deliver that steam to a steam turbine generator, which produces additional electricity.[32]

**Q. WHY DO UTILITIES INSTALL COMBINED CYCLE POWER PLANTS?**

A. Combined-cycle power plants provide flexible operating capacity. They can be

[32] https://powergen.gepower.com/resources/knowledge-base/combined-cycle-power-plant-how-it-works.html.

started up more quickly than older steam units and have considerable load-following capability. Load following means that generator output can be automatically adjusted from moment-to-moment so that the available supply always matches the utility's loads in real time. Flexible capacity is especially important for systems having substantial amounts of intermittent resources (*i.e.,* solar, hydro, wind).

With more flexible capacity, CCGTs can also be used to supply Contingency Reserves, which consist of generation and interruptible loads available within 15 minutes. Contingency Reserves are necessary to assure that sufficient capability exists to meet the NERC Disturbance Control Standard and to reestablish resource and demand balance following a Reportable Disturbance.[33] These functions are clearly necessary to maintain system reliability.

Thus, it is a misnomer to characterize CCGTs as "intermediate" capacity. The reality is that CCGTs can provide both base load and load following (*i.e., peaking)* capacity.

**Q. ARE COMBINED-CYCLE POWER PLANTS INSTALLED SOLEY TO SAVE FUEL COSTS?**

A. No. Ms. Deaton's assertion that any *extra* investment that may be incurred to install CCGTs is driven by fuel savings is an oversimplification, and it confuses cost causation with benefits.

[33] Florida Reliability Coordinating Council, Inc. FRCC Handbook, FRCC Contingency (Operating Reserve) Policy (July 7, 2011) at 1.

**Q. PLEASE EXPLAIN.**

A. Every CCGT that FPL has installed has received a determination of need. A determination of need means that FPL has demonstrated that the capacity is needed in order to meet its planning reserve requirements. For example, in the OCEC Unit 1 Determination of Need case, FPL asserted that:

> ….the OCEC Unit 1 will enable the Company to meet a projected need for additional generation resources that begins in 2019, continues into 2020, and increases each year thereafter.[34]

The Commission agreed, stating:

> We find that FPL demonstrates a need for additional generation, beginning in 2019***, in order to maintain electric system reliability and integrity based on a reasonable load forecast and a 20% reserve margin criterion as discussed below***.[35]

Thus, the factor driving the need for new capacity is the growth in projected peak demand and the need to maintain an appropriate reserve margin. In other words, peak demand is the cost causer, while fuel savings is the outcome of installing more efficient generation capacity. Ms. Deaton would have us believe that the opposite is true (*i.e.* fuel savings drive plant investment) which is clearly contradicted by the facts.

Having determined that capacity is needed, FPL has chosen the generation technology that would result in the lowest overall cost. CCGTs are the most efficient generating technology and thus are also the lowest cost source of capacity.

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[34] *In re*: *Petition For Determination Of Need For Okeechobee Clean Energy Center Unit 1, by Florida Power & Light Company*, Docket No. 150196-EI, Order No. PSC-16-0032-FOF-EI at 2 (Jan. 19, 2016)

[35] *Id.* at 4.

**Q. ARE CCGTS THE ONLY TYPE OF CAPACITY THAT FPL HAS INVESTED IN OVER THE PAST TEN YEARS?**

A. No. First, FPL is upgrading the "Compressor" section and improving the "Combustor" section of 26 of its GE 7FA CTs. Second, FPL is also replacing approximately 1,700 MW of peaking capacity. These investments are projected to be completed by the end of 2017.[36] These investments demonstrate FPL's continuing need for peaking capacity to meet both system and local area needs.

**Q. ARE THERE OTHER FACTORS, BESIDES THE CAPITAL COST-FUEL COST TRADE-OFF, THAT CAN AFFECT UTILITY INVESTMENT DECISIONS?**

A. Yes. A generating unit represents a 30 to 60-year investment. The long life-cycle makes it difficult for a utility to anticipate every contingency, such as new regulations that require utilities to cease using certain types of fuels, limit operations or install costly equipment to meet prevailing emissions standards or changes in public policy. These contingencies could transform what is otherwise an economical resource under today's circumstances into an uneconomical resource under different circumstances. Thus, it behooves a utility to manage these risks by installing a diversified portfolio of generating resources.

**Q. HAS FPL ADEQUATELY SUPPORTED ITS PROPOSAL TO CHANGE THE COST ALLOCATION METHODOLOGY FROM 12CP+1/13TH AD TO 12CP+25% AD?**

A. No. FPL has provided no study to support changing the energy weighting from 7.6%

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[36] Direct Testimony of Roxane R. Kennedy at 16-17.

to 25%.[37] Further, FPL's decision to install CCGTs is no different from any other growing utility that requires new and more efficient capacity to meet the projected increase in peak demand, provide an appropriate reserve margin and replace older less efficient capacity. Finally, given that FPL's new CCGTs and new/modernized CTs enhance the utility's load following capabilities, which provide significant reliability benefits, it is particularly inappropriate to increase the energy weighting for the entirety of FPL's entire generation fleet.

**Q. WHAT DO YOU RECOMMEND?**

A. The Commission should reject FPL's proposal to use 12CP+25% AD and retain 12CP+1/13$^{th}$ AD.

## Distribution Cost Classification

**Q. HOW HAS FPL CLASSIFIED DISTRIBUTION INVESTMENT?**

A. FPL has classified all of its distribution network investment as demand-related costs.

**Q. WHAT DO YOU MEAN BY THE DISTRIBUTION NETWORK?**

A. The distribution "network" consists of FPL's investment in poles, towers, fixtures, overhead lines and line transformers. These investments are booked to FERC Account Nos. 364, 365, 366, 367, and 368.

**Q. IS FPL'S PROPOSAL CONSISTENT WITH COST CAUSATION?**

A. No. The purpose of the distribution network is to deliver power from the transmission grid to the customer, where it is eventually consumed. Certain investments (*e.g.,*

[37] FPL's Response to FIPUG's Production of Documents Request No. 33.

meters, service drops) must be made just to attach a customer to the system. These investments are clearly customer-related. However, each utility must also invest in a distribution network, which provides the necessary voltage support to allow power to flow to the customer. Thus, a portion of the distribution network should also be classified as a customer-related cost. Classifying these costs entirely to demand is unreasonable.

**Q HOW IS FPL'S PROPOSAL TO CLASSIFY ALL DISTRIBUTION NETWORK COSTS TO DEMAND UNREASONABLE?**

A FPL's proposal would result in allocating far too few poles, overhead conductors and underground conductors to Residential and General Service customers and far too many poles, overhead conductors and underground conductors to GSLD and CILC customers. This conclusion is demonstrated in the table below. To arrive at this conclusion, I allocated the number of poles, overhead conductors and underground conductors using FPL's distribution demand allocation factor. I then divided the results by the number of customers to derive the number of primary poles and the lengths of overhead and underground conductors per customer.

| **Effect of FPL's Proposal to Classify All Distribution Network Facilities As Demand-Related Costs** | | | |
|---|---|---|---|
| **Customer Class** | **Distribution Poles (No. Per Customer)** | **Overhead Conductors (1000 ft. Per Customer)** | **Underground Conductors (1000 ft. Per Customer)** |
| **Residential** | 0.2 | 0.02 | 0.00 |
| **General Service** | 0.2 | 0.02 | 0.00 |
| **GS Demand** | 2.3 | 0.45 | 0.10 |
| **GS LD** | 37.3 | 57.94 | 49.56 |
| **CILC** | 60.1 | 386.37 | 356.88 |
| **MET** | 32.7 | 557.29 | 522.31 |
| **Standby** | 0.7 | 0.26 | 0.16 |

As the table demonstrates, FPL's proposed 100% demand allocation results in over 37 poles, 58,000 feet of overhead conductors and 50,000 feet of underground conductors being allocated to each GSLD customer. Similarly, over 60 poles, 386,000 feet of overhead conductors and 357,000 feet of underground conductors are allocated to each CILC customer.

In stark contrast, less than 1 pole, less than 20 feet of overhead conductors and less than 5 feet of underground conductors are allocated to each Residential and GS customer and only 2.3 poles, 450 feet of overhead conductors and 100 feet of underground conductors per GSD customer.

These results are not only highly unlikely, it demonstrates how FPL's proposal is not consistent with either cost causation or the physical realities of the distribution system.

**Q. WHY ELSE IS IT APPROPRIATE TO CLASSIFY A PORTION OF THE DISTRIBUTION NETWORK INVESTMENTS AS A CUSTOMER-RELATED COST?**

A. Classifying a portion of the distribution network as a customer-related cost recognizes the reality that every utility must provide a path through which electricity can be delivered to each and every customer, regardless of the peak demand or energy consumed. Further, that path must be in place if the utility is to meet its obligation to provide service upon demand.

Absent a connection to the system, a customer cannot take power. Further, the connecting facilities must provide voltage support before any power or energy can be consumed. These prerequisites (*i.e.,* a grid connection with facilities sized to provide voltage support) are clearly related to the existence of the customer.

**Q. DO ANY OTHER FACTORS JUSTIFY CLASSIFYING A PORTION OF THE DISTRIBUTION NETWORK AS CUSTOMER-RELATED?**

A. Yes. The distribution network must comply with this Commission's standards of construction. Specifically, Rule 25-6.034 F.A.C. requires that:

> (1) The facilities of each utility shall be constructed, installed, maintained and operated in accordance with generally accepted engineering practices to assure, as far as is reasonably possible, continuity of service and uniformity in the quality of service furnished.
>
> (2) Each utility shall, at a minimum, comply with the National Electrical Safety Code [ANSI C-2) [NESC], incorporated by reference in Rule 25-6.0345, F.A.C.

Rule 25-6.0342 F.A.C. was more recently enacted. It requires utilities to cost-effectively strengthen critical electric infrastructure to increase the ability of transmission and distribution facilities to withstand extreme weather conditions and reduce restoration costs and outage times to end-use customers associated with extreme weather conditions.

**Q. IS DISTRIBUTION STORM HARDENING A SIGNIFICANT COST DRIVER IN THIS CASE?**

A. Yes. Based on its projections, FPL will have invested over $2 billion in distribution storm hardening for the period 2014 through 2018.[38] Thus, distribution storm hardening costs are a major driver of FPL's proposed rate increase.

**Q. ARE DISTRIBUTION STORM HARDENING INVESTMENTS NEEDED FOR FPL TO MEET PEAK DEMAND?**

A. No. Distribution storm hardening investments are not required because of the amount of electric power and energy demanded. They are required because of the existence of each customer and FPL's obligation to provide a reliable connection to the grid. Thus, there is no question that a significant portion of the distribution network is a customer-related cost.

**Q. IS IT A RECOGNIZED PRACTICE TO CLASSIFY A PORTION OF THE DISTRIBUTION NETWORK AS CUSTOMER-RELATED?**

A. Yes. For example, the NARUC Electric Utility Cost Allocation Manual states that:

> Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and

[38] FPL's Response to SFHHA's Interrogatory No. 99.

meters are directly related to the number of customers on the utility's system.[39]

An excerpt from the Manual pertaining to distribution cost classification is provided in **Exhibit ___ (JP-10)**.

**Q. IS THIS PRACTICE FOLLOWED BY OTHER ELECTRIC UTILITIES?**

A. Yes. **Exhibit ___ (JP-11)** is a partial list of the utilities that classify some portion of their distribution network investment as customer-related. As can be seen, the list includes both Gulf and TECO. Thus, this practice has been previously accepted by the Commission.

**Q. WHAT DO YOU RECOMMEND?**

A. I recommend that approximately 26% of FPL's distribution network costs should be classified as customer-related. As shown in **Exhibit ___ (JP-11)**, both Gulf and TECO classify approximately the same portion of their investments in FERC Account Nos. 364 through 368, respectively, as a customer-related cost. Since FPL has not conducted its own study, I recommend that the specific customer cost determinations by Gulf and TECO be applied to FPL.

## Distribution Substation Service

**Q. DOES FPL PROVIDE DISTRIBUTION SUBSTATION SERVICE?**

A. Yes.[40]

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[39] NARUC, *Electric Utility Cost Allocation Manual* at 90 (Jan. 1992).

[40] FPL's Response to FIPUG's Interrogatory No. 17.

**Q. WHAT IS DISTRIBUTION SUBSTATION SERVICE?**

A. Distribution substation service is provided when a customer takes service directly from a utility-owned distribution substation. Under these circumstances, the customer does not require the utility to install any other distribution facilities to provide service.

**Q. HOW IS DISTRIBUTION SUBSTATION SERVICE DIFFERENT FROM OTHER TYPES OF DELIVERY SERVICES?**

A. Examples of other types of electric delivery services are provided in **Exhibit ___ (JP-12)**

1. Transmission (page 1)
2. Distribution Primary (page 2)

A transmission-level customer takes service directly from the transmission system. This means that the customer owns all of the transformation equipment, as well as the lower voltage distribution facilities used to deliver electricity throughout the customer's grid.

In contrast to Transmission service, Distribution Primary service requires that the utility own not only the transformation equipment to step power down from transmission to distribution level, but also the wires to deliver electricity to the customer. Thus, Distribution Primary service requires the utility to invest in hundreds, or even thousands, of miles of distribution wires and related facilities. It also incurs more electrical losses as power and energy are delivered through the distribution system. Because of the necessity of providing additional wires, related facilities, and the incurrence of greater losses, Distribution Primary service is more costly to provide than either Transmission or Distribution Substation services.

**Q. IS DISTRIBUTION SUBSTATION SERVICE DIFFERENT FROM TRANSMISSION AND OTHER TYPES OF DISTRIBUTION DELIVERY SERVICES?**

A. Yes. Distribution Substation service is shown in **Exhibit ___ (JP-12)**, page 3. It is clearly distinguishable. Unlike transmission service, a Distribution Substation customer does not own the initial transformation equipment located at the substation where electricity is stepped down from transmission voltage to a distribution voltage. However, a Distribution Substation customer owns its own distribution facilities. The ownership of private distribution lines distinguishes a Distribution Substation customer from a Distribution Primary customer. The difference is that the former provides its own distribution wires service, not the utility. Thus, Distribution Substation service is distinct from both Transmission and Distribution Primary services.

**Q. DOES FPL'S COST-OF-SERVICE STUDY RECOGNIZE DISTRIBUTION SUBSTATION SERVICE?**

A. No. FPL's CCOSS treats the customers receiving Distribution Substation service the same as all other Primary Distribution customers. This is despite the fact that no primary distribution investment is required by FPL to service a Distribution Substation customer.

**Q. WHAT IS THE CONSEQUENCE OF THE FAILURE TO SEPARATELY RECOGNIZE DISTRIBUTION SUBSTATION SERVICE?**

A. FPL includes the loads of customers that take Distribution Substation service in allocating primary distribution costs.[41] Thus, in addition to allocating distribution substation costs, Distribution Substation customers were allocated costs associated with FERC Account Nos. 364, 365, 366, 367, and 368.

Thus, Distribution Substation customers are paying distribution costs that they do not impose on the system because they hook up to the distribution system at the substation. It also means that FPL has over-stated the allocation of distribution primary costs to those distribution level non-residential customer classes that have customers taking Distribution Substation service. Accordingly, the rates of return calculated for these classes in FPL's CCOSS are understated.

**Q. WHAT CUSTOMER CLASSES HAVE LOADS TAKING DISTRIBUTION SUBSTATION SERVICE?**

A. This is unknown because FPL does not track statistics on the customers that take Distribution Substation service.[42]

**Q. WHAT DO YOU RECOMMEND?**

A. FPL should be ordered to develop the information necessary to identify the customers that take Distribution Substation service. This includes the loads and number of accounts of these customers.

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[41] FPL's Response to FIPUG's Interrogatory No. 85.

[42] *Id.*

FPL should also be ordered to file a new Distribution Substation tariff that reflects the lower costs of providing this type of distribution service. The new tariff should be filed within 90 days after a final order is issued in this proceeding.

**Revised Class Cost-of-Service Study**

**Q. HAVE YOU CONDUCTED A CLASS COST-OF-SERVICE STUDY THAT INCORPORATES YOUR RECOMMENDED CHANGES TO FPL'S STUDY?**

A. Yes. The revised CCOSS at present rates is provided in **Exhibit ___ (JP-13)**. The revised CCOSS incorporates the following changes:

- Production plant and related costs were allocated to customers classes using the 12CP+1/13th AD method.
- Distribution network costs (*i.e.,* FERC Account Nos. 364-368) were partially classified as customer-related using the same percentages developed by Gulf and TECO in their most recent rate cases.

However, the revised CCOSS does not recognize Distribution Substation service because FPL could not provide the necessary information. Thus, the rates of return from the classes that most likely serve Distribution Substation customers (*i.e.,* GSLD, CILC-1-D) are understated.

**Q. HAVE YOU DEVELOPED A CLASS REVENUE ALLOCATION BASED ON THE REVISED CLASS COST-OF-SERVICE STUDY?**

A. Yes. **Exhibit ___ (JP-14)** is my recommended base revenue allocation using the CCOSS presented in **Exhibit ___ (JP-13)**. It is designed to move all rates approximately the same distance closer to cost except in limited circumstances when gradualism was applied. To give appropriate recognition to gradualism, I limited the base revenue increase to 150% of FPL's proposed 15.4% system average base rate increase, which is 23.1%, excluding the clauses. This proposal does not change the current CILC/CDR credits.

**Q. WOULD ALL RATES MOVE CLOSER TO COST UNDER YOUR PROPOSED CLASS REVENUE ALLOCATION?**

A. Yes. **Exhibit ___ (JP-15)** summarizes the revised CCOSS results at present and recommended rates. As can be seen, the major customer classes (and rates overall) would move approximately 23% closer to cost.

## 8. GSLD/CILC RATE DESIGN

**Q. WHAT RATE DESIGN ISSUES WILL YOU ADDRESS?**

A. Rate design is the continuation of the cost allocation process. Many of the same principles that drive the CCOSS and class revenue allocation also affect rate design. In this section, I will discuss:

- The Demand and Energy charges in the GSLD and CILC rates.
- Why the CILC/CDR credits cannot and should not be "reset" as FPL is proposing in this proceeding.

### Demand and Energy Charges

**Q. DESCRIBE THE DEMAND AND ENERGY CHARGES.**

A. These charges are designed to recover base rate (non-fuel) costs. Demand charges are billed relative to a customer's maximum metered (kW) demand in the billing month, while the Energy charges are billed on the amount of kWh purchased.

**Q. HOW IS FPL PROPOSING TO CHANGE THE DEMAND AND ENERGY CHARGES?**

A. FPL states that it increased the current Demand and Energy charges by the same rate class percentage maintaining demand and energy rate relationships established in previous rate proceedings. Further, the Energy charges were adjusted to achieve revenue neutrality.[43]

FPL's proposed GSLD and CILC rate designs are shown in **Exhibit ___ (JP-16)**. As can be seen, FPL's proposed rate design would essentially increase the Demand and Energy charges by approximately the same percentage.

[43] Direct Testimony of Tiffany C. Cohen, Exhibit TCC-6 at 7-8 and 16-17.

**Q. HOW SHOULD THE GSLD/CILC RATES BE DESIGNED?**

A. Consistent with cost causation, the Customer, Demand and Energy charges should closely reflect the customer-related, demand-related, and energy-related unit costs as derived in the CCOSS. Ironically, FPL followed this practice in designing the proposed Customer charges, but it ignored this practice in designing the proposed Demand and Energy charges.

**Q. WHAT ARE THE UNIT ENERGY COSTS DERIVED FROM THE CLASS COST-OF-SERVICE STUDY?**

A. The 2017 unit energy costs and the corresponding proposed charges for the GSLD and CILC classes are as follows:

| GSLD/CILC Energy Charges (¢/kWh) | | | |
|---|---|---|---|
| **Class** | **Unit Cost[44]** | **Present Charge** | **Proposed Charge** |
| **GSLD-1** | 0.7788 | 1.035 | 1.314 |
| **GSLD-2** | 0.7739 | 1.003 | 1.291 |
| **GSLD-3** | 0.7556 | 0.892 | 1.127 |
| **CILC-1D** | 0.7734 | 0.822 | 1.272 |
| **CILC-1T** | 0.7562 | 0.731 | 1.307 |

The unit costs are based on the 12CP+1/13th AD CCOSS at equalized rates of return. As can be seen, FPL's proposed Energy charges would be significantly (between 49% and 73%) higher than the corresponding energy costs. All of the current Energy charges (except CILC-1T) already exceed unit cost. The fact that the proposed standard Energy charges would exceed unit cost means that the

[44] MFR No. E-6b, Attachment No. 2 of 2 at 2 and 6.

corresponding Demand charges are understated, and a significant amount of demand-related costs would be collected in the Energy charge. The proposed time-of-use (TOU) rates, which are derived from the standard rates, were also designed to collect a significant amount of demand-related costs in the proposed On-Peak Energy charges.

**Q. HAS FPL ADEQUATELY EXPLAINED WHY THE ENERGY CHARGES ARE MUCH HIGHER THAN ACTUAL ENERGY COSTS?**

A. No. As previously stated, FPL proposed maintaining the existing relationships while adjusting the Energy charges to achieve the desired class revenue targets.

**Q. WHAT DO YOU RECOMMEND?**

A. The GSLD and CILC Energy charges should move closer to unit cost. However, my analysis reveals that the GSLD and CILC Energy charges are, for the most part, already above cost. Based on this fact, coupled with recognizing gradualism, I recommend that the increase in the current GSLD and CILC standard Energy charges should not exceed 50% of the increase in the corresponding Demand charges. Any revenue shortfall resulting from this change should be recovered in the corresponding GSLD and CILC Demand Charges.

## <u>CILC/CDR Credits</u>

**Q. IS FPL PROPOSING ANY CHANGE IN THE DESIGN OF ITS NON-FIRM RATES?**

A. Yes. FPL is proposing to “reset” the payments to customers taking non-firm service under Rate CILC and Rider CDR. The proposal would reduce the payments by about 37% as shown in the table below.

| FPL's Proposed Reset of the CILC/CDR Credits ($000) | | | | |
|---|---|---|---|---|
| **Customer Class** | **Present Rates[45]** | **Proposed Rates** | **Reduction[46]** | **Percent Reduction** |
| | (1) | (2) = (1) – (3) | (3) | (4) |
| **CILC-1D** | $27,076 | $17,132 | $9,943 | 37% |
| **CILC-1G** | 945 | 575 | 370 | 39% |
| **CILC-1T** | 13,667 | 8,433 | 5,234 | 38% |
| **GSD** | 6,139 | 3,938 | 2,201 | 36% |
| **GSLD-1** | 11,579 | 7,428 | 4,152 | 36% |
| **GSLD-2** | 2,982 | 1,913 | 1,069 | 36% |
| **Total** | $62,387 | $39,418 | $22,969 | 37% |

The impact of FPL's proposal would reduce the credits by $23 million or 37%. The reductions in the CDR and CILC credits would be 36% and 38% respectively.

**Q. HOW ARE THE CREDITS PAID TO THE CILC AND CDR CUSTOMERS RECOVERED?**

A. These payments are recovered in the Conservation clause, and they are paid by all customers, including the CILC and CDR customers.

**Q. PLEASE DESCRIBE THE CILC RATE.**

A. The CILC (Commercial and Industrial Load Control) rate is a tariff that allows FPL to control customer-established loads of 200 kW or greater during system emergencies. Load control equipment is installed at the customer's facility to allow FPL to control

45 FPL's Response to OPC Production of Documents Request No. 2, Deaton Workpaper Sheet E-5 Test.

46 MFR No. E-14 Attachment 2 of 6 at 30.

customer loads. In return for agreeing to allow FPL to control a portion or all of a customer's load, the customer receives a lower rate. The terms under which FPL can control a customer's load are as follows:

> The Customer's controllable load served under this Rate Schedule is subject to control when such control alleviates any emergency conditions or capacity shortages, either power supply or transmission, or whenever system load, actual or projected, would otherwise require the peaking operation of the Company's generators. Peaking operation entails taking base loaded units, cycling units or combustion turbines above the continuous rated output, which may overstress the generators.
>
> Frequency: The Control Conditions will typically result in less than fifteen (15) Load Control Periods per year and will not exceed twenty-five (25) Load Control Periods per year. Typically, the Company will not initiate a Load Control Period within six (6) hours of a previous Load Control Period.
>
> Notice: The Company will provide one (1) hour's advance notice or more to a Customer prior to controlling the Customer's controllable load. Typically, the Company will provide advance notice of four (4) hours or more prior to a Load Control Period.
>
> Duration: The duration of a single Load Control Period will typically be four (4) hours and will not exceed six (6) hours.
>
> In the event of an emergency, such as a Generating Capacity Emergency (see Definitions) or a major disturbance, greater frequency, less notice, or longer duration than listed above may occur. If such an emergency develops, the Customer will be given 15 minutes' notice. Less than 15 minutes' notice may only be given in the event that failure to do so would result in loss of power to firm service customers or the purchase of emergency power to serve firm service customers. The Customer agrees that the Company will not be liable for any damages or injuries that may occur as a result of providing no notice or less than one (1) hour's notice.[47]

[47] FPL Tariff, Fourth Revised Sheet No. 8.652.

**Q. PLEASE DESCRIBE RIDER CDR.**

A. Rider CDR (Commercial/Industrial Demand Reduction) is similar to CILC. This program allows FPL to control customer-established loads of 200 kW or greater during system emergencies. Load control equipment is installed at the customer's facility to allow FPL to control customer loads. The terms under which FPL can control a CDR customer's load are similar to CILC as follows:

> The Customer's controllable load served under this Rider is subject to control when such control alleviates any emergency conditions or capacity shortages, either power supply or transmission, or whenever system load, actual or projected, would otherwise require the peaking operation of the Company's generators. Peaking operation entails taking base loaded units, cycling units or combustion turbines above the continuous rated output, which may overstress the generators.
>
> <u>Frequency</u>: The Control Conditions will typically result in less than fifteen (15) Load Control Periods per year and will not exceed twenty-five (25) Load Control Periods per year. Typically, the Company will not initiate a Load Control Period within six (6) hours of a previous Load Control Period.
>
> <u>Notice</u>: The Company will provide one (1) hour's advance notice or more to a Customer prior to controlling the Customer's controllable load. Typically, the Company will provide advance notice of four (4) hours or more prior to a Load Control Period.
>
> <u>Duration</u>: The duration of a single Load Control Period will typically be three (3) hours and will not exceed six (6) hours.
>
> In the event of an emergency, such as a Generating Capacity Emergency (see Definitions) or a major disturbance, greater frequency, less notice, or longer duration than listed above may occur. If such an emergency develops, the Customer will be given 15 minutes' notice. Less than 15 minutes' notice may only be given in the event that failure to do so would result in loss of power to firm service customers or the purchase of emergency power to serve firm service customers. The Customer agrees that the Company will not be liable

for any damages or injuries that may occur as a result of providing no notice or less than one (1) hour's notice.[48]

**Q. DO THE CILC AND CDR TARIFFS PROVIDE BENEFITS TO FPL AND ITS FIRM CUSTOMERS?**

A. Yes. By agreeing to curtail load during system emergencies and other capacity-related events, FPL is able to maintain reliable service to its firm customers with less installed capacity, and thus, less costs. This is because under the Commission-approved statewide reserve margin requirement, non-firm load is not included in FPL's peak demand projections that are used to assess resource adequacy when planning to meet its firm load.

**Q. WHY IS FPL PROPOSING TO "RESET" THE CILC/CDR CREDITS?**

A. FPL has provided no real explanation other than a desire to maintain them at the levels that existed prior to the 2012 Settlement adjusted only for the commensurate base rate increases for the Canaveral, Riviera and Port Everglades modernizations.[49] Further, the proposed reset is not based on any updated cost-effectiveness studies.[50]

**Q. DOES THIS EXPLANATION JUSTIFY REDUCING THE CILC/CDR CREDITS BY OVER 30%, AS FPL IS PROPOSING IN THIS CASE?**

A. No. First, FPL believes that because the CILC/CDR credits are set in the Demand

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48 FPL Tariff, Second Revised Sheet No. 8.681.

49 FPL's Response to FIPUG's Interrogatory No. 31.

50 FPL's Response to FIPUG's Interrogatory No. 24.

Side Management Docket, they cannot be changed in a base rate case.[51] FPL's explanation assumes that the credits established in the last Demand Side Management Docket were based on the levels authorized prior to the settlement of its last rate case.

**Q. WHEN WERE THE CURRENT CILC/CDR CREDITS ESTABLISHED?**

A. They were established in FPL's last rate case, Docket No. 120015-EI. The rates approved in the last rate case became effective on January 2, 2013.

**Q. WHY WERE THE CREDITS INCREASED IN THE LAST RATE CASE?**

A. Prior to the last rate case, the CDR credits had not been increased since 2004, and I am unaware of any changes in the CILC incentive payments since prior to FPL's 2008 rate case. The increase in the credits in the 2012 rate case, thus, reflects inflationary factors, coupled with strong load growth that has prompted FPL to add new capacity to maintain reliability. FPL can use interruptible load to defer new generation capacity, such as peaking units. Hence, the higher CILC/CDR credits recognized the greater value of interruptible service in allowing FPL to maintain reliable service to its firm customers at a lower cost than building new capacity.

**Q. WHEN DID FPL'S MOST RECENT DEMAND SIDE MANAGEMENT DOCKET OCCUR?**

A. FPL's most recent Demand Side Management case was Docket No. 150085-EG. A final order in this case was issued on August 19, 2015. Thus, the evaluation of the

[51] Direct Testimony of Tiffany C. Cohen, Exhibit TCC-6 at 17.

CILC/CDR programs was based on the credits approved in the settlement of the last rate case, which the Commission accepted.[52]

**Q. DID THE FINAL ORDER IN THE DEMAND SIDE MANAGEMENT DOCKET APPROVE THE CONTINUATION OF THE CILC/CDR PROGRAMS?**

A. Yes. In approving the continuation of the CILC/CDR programs, the Order states:

> All of FPL's proposed programs with allocated demand and energy savings pass both the RIM and Participants tests, with the exception of one residential program. These tests consist of the benefits divided by the costs, as defined by Rule 25-17.008, F.A.C., so that programs are determined to be cost-effective if the result of the test is a ratio greater than 1.00.[53]

Further, the then effective Rider CDR was found to have a benefit-cost ratio of 1.6 times, meaning that it is still cost-effective.

**Q. SHOULD THE COMMISSION APPROVE FPL'S PROPOSED 37% REDUCTION IN THE CILC/CDR CREDITS?**

A. No. The Commission's Order in FPL's most recent Demand Side Management Docket approved the continuation of the CILC/CDR programs then in effect, which are the same credits that were implemented following the settlement of FPL's last rate case. Thus, FPL's point that the credits cannot be changed in this case is correct, which means that the credits cannot now be reset as FPL is proposing. Further, the credits should not be reset as they help FPL avoid or defer new

[52] FPL's Response to FIPUG's Interrogatory No. 31.

[53] *In Re: Petition for Approval of Florida Power & Light Company's Demand-Side Management Plan and Request to Cancel Closed on Call Tariff Sheets*, Docket No. 150085-EG, Order No. PSC-15-0331-PAA-EG at 6 (Aug. 19, 2015).

generation capacity and the corresponding associated capital expenditures and other fixed costs.

**Q, WHAT DO YOU RECOMMEND?**

A. The Commission should reject FPL's proposal to reset the CILC/CDR credits.

## 9. CONCLUSION

**Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.**

A. The Commission should accept the following recommendations:

- FPL's proposed SYA should be rejected because it is speculative, inappropriate and unnecessary.
- The proposed 50 basis point performance incentive should be rejected because it is unnecessary to reward FPL for providing the quality service that is expected and because it would force customers to pay twice (in the form of higher rates) for the many cost-reduction measures that have been implemented.
- CWIP should be removed from rate base because it is not needed to preserve FPL's financial integrity and because its four-year rate plan would result in rate shock.
- The 2017 cost of long-term debt should be reduced to 4.5489% to recognize the more recent lower interest rate projections and global and other economic events.
- FPL's proposed 11% ROE (excluding the performance incentive) is clearly excessive given that it would be coupled with a 60% financial equity ratio and because it would be significantly higher than has been previously authorized both by this Commission and state regulatory commissions in rate case decision since 2012. Assuming no change in the equity ratio, FPL's ROE should be set below the average of the ROEs authorized by state regulatory commissions.
- FPL's equity ratio is 890 basis points higher than other vertically integrated investor-owned electric utilities, which have average financial equity ratios of 51.1%. Accordingly, FPL's financial equity ratio should not exceed 51.1%.
- Base rates should move closer to cost using an appropriate CCOSS and properly recognizing gradualism.
- FPL's proposed application of gradualism is flawed and would not prevent the CILC/CDR customers from experiencing substantial rate shock. Further, gradualism should apply to changes in base rates because the clauses are not subject to change in this proceeding.
- FPL's CCOSS should be rejected because it does not reflect cost causation.
- There is no valid justification to change the production plant allocation method that is currently being used not only by FPL, but also by Duke, Gulf, and TECO. Similarly, approximately 26% of FPL's distribution

network costs should be classified as customer-related costs, which is also consistent with Gulf, TECO and many other electric utilities

- FPL should file a tariff to recognize the lower cost of serving customers directly at (or within two spans of) a distribution substation within 90 days after a final order is issued in this proceeding.
- The GSLD and CILC Energy charges are already above cost and should not be increased by more than 50% of the increase in the corresponding Demand charges.
- The CILC/CDR credits cannot and should not be reset in this proceeding because doing so would violate past practice and unnecessarily diminish the value of a system resource that helps FPL provide reliable service at the lowest reasonable cost.

**Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes.

**CHAIRMAN BROWN:** Staff.

**MS. BROWNLESS:** Yes, ma'am.

**EXAMINATION**

**BY MS. BROWNLESS:**

**Q** Good morning, sir. How are you?

**A** Good almost afternoon to you too.

**Q** I've got timing issues today. That's why I left that part off.

Have you had an opportunity to review what's been marked as staff Exhibit 541?

**A** I have, yes.

**Q** Okay. And did you prepare the responses to these interrogatories and discovery requests?

**A** It was a -- yes. It was also a joint work product between myself and counsel, but, yes, I prepared the responses.

**Q** Okay. And are they true and correct to the best of your knowledge and belief?

**A** Yes, with one addition.

**Q** Yes, sir.

**A** On the response to interrogatory 20 that references gradualism.

**Q** Yes, sir.

**A** Yes, I reviewed a prior order in the Tampa Electric case, Docket 080317-EI. It was issued in

April 2009. And in that case, Tampa Electric filed -- made a compliance filing where they showed the application of gradualism that was approved in that order. And based on that compliance filing, it appears that the 1.5 times constraint was actually applied to base revenues, that is, excluding clauses. So I would have listed that as well as the Gulf Power order that was listed in that response.

**Q** Thank you. With the exception of what you've just explained, if I asked you these same responses again, would your answers be the same?

**A** Yes.

**Q** Are there any portions of your testimony that have been considered or qualified as confidential?

**A** No.

**MS. BROWNLESS:** Thank you, sir.

**CHAIRMAN BROWN:** Mr. Moyle.

**MR. MOYLE:** Thank you.

**EXAMINATION**

**BY MR. MOYLE:**

**Q** Mr. Pollock, have you prepared a summary of your testimony?

**A** I have.

**Q** Would you please provide it to the Commission and the parties?

**A** Gladly. Good afternoon, Commissioners. As I address a wide range of issues, I'm going to, in the interest of brevity, highlight some of the key ones.

FPL's proposed $1.3 billion ask will be a substantial increase for all customers and all customer classes, but it will be a triple whammy to FPL's large commercial and industrial customers, the very ones that FPL says it values and who also provide good jobs.

Whammy number one. FPL wants to substantively devalue the CILC/CDR program that continue to provide a source of cost-effective capacity that benefits all customers -- not just FPL customers, but statewide. The resetting would reduce the credits by 37 percent. The capacity provided by CILC and CDR cut programs defers generation that FPL would otherwise have to install. FPL's load management programs, of which the two programs we talked about are a significant part, have saved the equivalent of 16 400-megawatt power plants. And given these benefits, I think it's appropriate to reject the company's proposal to devalue what is clearly a valuable proposition. Those credits are properly reviewed in the context of the goals docket, and nothing compels you to change them in this case. Resetting the credits now will also have a serious advantage -- disadvantage as far as the large industrial customers, who also provide the reliable demand-side management tool because it represents about a third of the increase that the company is asking for.

Whammy number two. For the first time in 20 years, the company is proposing to change its production cost allocation method and revise the Commission's long-standing method, the 12CP and 1/13th, and FPL fails to recognize that now other accepted practices are being used in this state and many other states to allocate and classify distribution network costs. Nothing has changed about how FPL plans or operates its generation system. FPL's change is not supported by any study. In essence, it's a guise to achieve a desired end result. So it would kind of replace the Commission standard, which is to set cost-based rates, with price-based rates. We recommend that you reject price-based costing, adopt the status quo on production allocation, and modify the distribution allocation consistent with the practice you accepted for TECO and Gulf Power Company, the minimum distribution system approach, that doesn't allocate large commercial and industrial customers unnecessary distribution assets.

Whammy number three. FPL's proposed application of gradualism is fundamentally flawed. In my 40-plus years of being an expert witness, I've never seen, except in FPL cases, an application of gradualism quite like this. As proof, the CILC customers, particularly the 1T customers, would see an increase of up to 80 percent, 80 percent, in their base rates. This is a 21 percent bill increase. That's more than twice the average increase of 8.7 percent. 21 percent is more than double 8.7 percent. Your gradualism constraint says you shouldn't go above 1.5 times.

Further, we recommend that the constraint applied to exclude the clauses because the clause determinations are separate from base rate cases. You don't take into account gradualism in the clause cases. This is the only forum in which gradualism and customer impact are considered and fairly considered.

Past practices and policies should not be applied in a vacuum, as FPL is insisting. As regulators, you strive to achieve a balance between the company and the customers. We hope that addressing the three issues that I've just addressed plus several others that are in my testimony, that you'll try to restore some semblance of balance that's going on. In particular, we want to make sure that the CILC/CDR credits are retained, that we retain the status quo and the cost of service study, but also use the minimum distribution system because that's a more appropriate cost causation methodology. We also recommend that you award an ROE that's more comparable to your -- what your colleagues have been recommending over the last years, similarly make adjustments to the capital structure that are consistent with what the FPL's peers are allowed to set rates on, eliminate the subsequent year adjustment, and substantially reduce the proposed $1.3 billion ask. Thank you.

**MR. MOYLE:** We would -- FIPUG would tender Mr. Pollock for cross-examination.

**CHAIRMAN BROWN:** Thank you.

And, again, welcome, Mr. Pollock.

**THE WITNESS:** Thank you.

**CHAIRMAN BROWN:** Mr. Sayler.

**MR. SAYLER:** Good morning -- or actually afternoon, Madam Chair. How are you doing?

**CHAIRMAN BROWN:** Good.

**MR. SAYLER:** We have no questions for this witness.

**CHAIRMAN BROWN:** Thank you, Mr. Sayler.

All right. Hospitals.

**MR. WISEMAN:** No questions, Madam Chair.

**CHAIRMAN BROWN:** Thank you, Mr. Wiseman.

Retail Federation.

**MR. WRIGHT:** No questions. Thank you, Madam

Chairman.

**CHAIRMAN BROWN:** Thank you. FEA.

**MR. JERNIGAN:** Yes, ma'am, similar to the questions I had before with a previous witness, I have a few today. I'll try to speak up.

**CHAIRMAN BROWN:** Thank you.

**EXAMINATION**

**BY MR. JERNIGAN:**

**Q** Good morning, Mr. Pollock. How are you today?

**A** Good afternoon.

**Q** It is afternoon. Thank you.

As you stated in your summary, you have taken a position that gradualism should only be applied to base rates; is that correct?

**A** Yes.

**Q** Okay. Are you familiar with the testimony provided by Ms. Alderson in this case?

**A** Yes.

**Q** Okay. In that testimony, she said that fuel revenue should be excluded but others -- other riders, et cetera, should be considered.

**A** I understand that's her proposal, yes.

**Q** Okay. All right. Are you aware of commissions that have adopted your recommendation in the past?

**A** Yes.

**Q** Would you like to expand upon that and explain who they are?

**A** Yeah. Most of the commissions that set delivery rates only look at the delivery cost. That's very similar to excluding fuel and clauses, because in addition to paying for delivery service, the customers that are in, I'll call it, retail access states also pay energy and generation transmission charges, which are totally excluded, you know, in setting rates for delivery service. So that's clearly an example. Even where utilities provide vertical -- still vertically integrated service, most of the -- some of the commissions that I work with regularly apply gradualism, but also remove fuel and purchased power costs because those are also subject to separate cost recovery treatment. Similarly with energy efficiency and other cost recovery riders.

Texas, New Mexico, and some others that I can't recall right now, but are certainly states that have always used base rates to measure how to measure gradualism in applying a rate increase to move everybody closer to parity.

(Transcript continues in sequence in Volume 30.)

STATE OF FLORIDA )
: CERTIFICATE OF REPORTER
COUNTY OF LEON )

I, LINDA BOLES, CRR, RPR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 31st day of August, 2016.

Linda Boles

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