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July 7, 2016

VIA E-FILING

Carlotta S. Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399

Re:

- *Docket No. 160021-EI, In re: Petition for Rate Increase by Florida Power & Light Company;* and
- *Docket No. 160062-EI, In re: 2016 Depreciation and dismantlement study by Florida Power & Light Company (consolidated)*

Dear Ms. Stauffer:

Please find enclosed for electronic filing in the above-referenced dockets the Direct Testimony and exhibits of witnesses Richard Baudino (Exhibits RAB-1 through RAB-13), Lane Kollen (Exhibits LK-6 through LK-36), and Stephen Baron (Exhibits SJB-1 through SJB-17), filed on behalf of intervenor South Florida Hospital & Healthcare Association.

If you have any questions, please do not hesitate to contact me at (202) 662-2715 or by e-mail at kwiseman@andrewskurth.com.

Very truly yours,

/s/ Kenneth L. Wiseman
Kenneth L. Wiseman

cc: All parties of record

CERTIFICATE OF SERVICE
DOCKET NO. 160021-EI

I HEREBY CERTIFY that a copy of the foregoing has been furnished by electronic mail and U.S. Mail to the following parties on this 7th day of July, 2016:

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/s/ Kevin C. Siqveland
Kevin C. Siqveland

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE
SOUTH FLORIDA HOSPITAL AND HEALTH CARE ASSOCIATION

July 2016

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

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

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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 any 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 1/13th 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 1/13th 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 1/13th 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 1/13th. 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.

[2] According to witness Joseph Ender's 2012 base rate case testimony, FPL begin using the 12 CP and 1/13th 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 1/13th 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 1/13th 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) C/O Date 2020	Advanced Combined Cycle	Advanced Combustion 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)

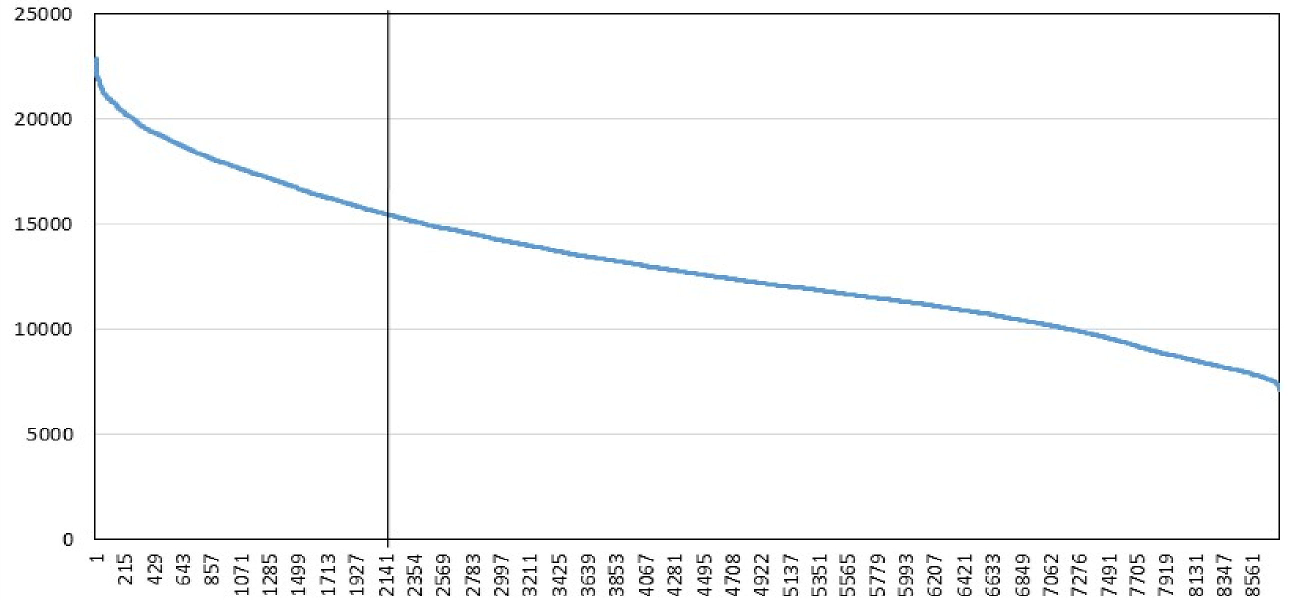

Table 5
Distribution of Top 2,190 Hourly Loads By Month - 2014

	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]

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[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 1/13th 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 1/13th 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.

[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 13 poles to serve a single GSLDT-2 customer. 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

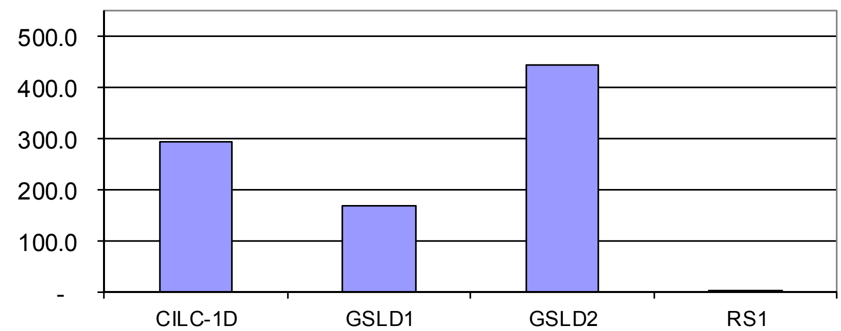
Total Secondary Poles **174,085**

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 1/13th 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 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). 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. <u>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.</u>[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 1/13th 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 1/13th 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 1/13th 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 1/13th 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.

AFFIDAVIT

STATE OF GEORGIA)
)
COUNTY OF FULTON)

STEPHEN J. BARON, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Stephen J. Baron

Sworn to and subscribed before me on this
6th day of July 2016.

Notary Public

JESSICA K INMAN
MY COMMISSION EXPIRES
NOTARY
PUBLIC
JULY 31, 2019
CHEROKEE COUNTY, GEORGIA

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

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

EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF THE

SOUTH FLORIDA HOSPITAL AND HEALTH CARE ASSOCIATION

July 2016

EXHIBIT NO. ___ (SJB-1)

Professional Qualifications

Of

Stephen J. Baron

Mr. Baron 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, he received a Master of Arts Degree in Economics, also from the University of Florida. His areas of specialization were econometrics, statistics, and public utility economics. His thesis concerned the development of an econometric model to forecast electricity sales in the State of Florida, for which he received a grant from the Public Utility Research Center of the University of Florida. In addition, he has advanced study and coursework in time series analysis and dynamic model building.

Mr. Baron has 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, he joined the staff of the Florida Public Service Commission in August of 1974 as a Rate Economist. His 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, he joined the Utility Rate Consulting Division of Ebasco Services, Inc.

as an Associate Consultant. In the seven years he worked for Ebasco, he received successive promotions, ultimately to the position of Vice President of Energy Management Services of Ebasco Business Consulting Company. His 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.

He 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 he was responsible for the operation and management of the Atlanta office. His 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, he specialized in utility cost analysis, forecasting, load analysis, economic analysis, and planning.

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

During the course of his career, he has provided consulting services to more than thirty utility, industrial, and Public Service Commission clients, including three international utility clients.

He has presented numerous papers and published an article entitled "How to Rate Load Management Programs" in the March 1979 edition of "Electrical World." His article on "Standby Electric Rates" was published in the November 8, 1984 issue of "Public Utilities Fortnightly." In February of 1984, he completed a detailed analysis entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research Institute, which published the study.

Mr. Baron has 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, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, Wyoming, the Federal Energy Regulatory Commission and in United States Bankruptcy Court. A list of his specific regulatory appearances follows.

**Expert Testimony Appearances
of
Stephen J. Baron
As of June 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	KY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of-service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisville Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa Clara	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2016

Date	Case	Jurisdict.	Party	Utility	Subject
6/85	84-768-E-42T	WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of-service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER-8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726-EL-AIR	OH	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081-E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2016

Date	Case	Jurisdict.	Party	Utility	Subject
3/87	EL-86-53-001 EL-86-57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023-E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072-E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of-service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.
10/87	E-015/	MN	Taconite	Minnesota Power	Excess capacity, power and

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2016

Date	Case	Jurisdict.	Party	Utility	Subject
	GR-87-223		Intervenors	& Light Co.	cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171-EL-AIR 88-170-EL-AIR Interim Rate Case	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171-EL-AIR 88-170-EL-AIR	OH	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.

**Expert Testimony Appearances
of
Stephen J. Baron
As of June 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load forecasting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off-system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of-service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	MI	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.
5/91	90-12-03 Phase II	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of-service, rate design, demand-side management.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2016

Date	Case	Jurisdict.	Party	Utility	Subject
8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand-side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372 EL-UNC	OH	Armco Steel Co., L.P.	Cincinnati Gas & Electric Co.	Economic analysis of cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
Note: No testimony was prefiled on this.					
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410- EL-AIR	OH	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	CT	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.

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Stephen J. Baron
As of June 2016**

Date	Case	Jurisdict.	Party	Utility	Subject
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO_2 allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design, gas rate design (flexible rates).
2/93	E002/GR-92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806-000 (Rebuttal)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114-E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.

Expert Testimony Appearances of Stephen J. Baron As of June 2016

Date	Case	Jurisdict.	Party	Utility	Subject
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035- E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-000	FERC	Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	CO	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2016

Date	Case	Jurisdict.	Party	Utility	Subject
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	I-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bank-ruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues

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7/97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98 (Allocated Stranded Cost Issues)	U-22092	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.
3/98	U-22092		Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735		Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.
12/98	8794	MD	Maryland Industrial Group and Millennium Inorganic Chemicals Inc.	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross- Answering Testimony)	EC-98-40-000	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.

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5/99 (Response Testimony)	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongahela Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	CT	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658-EL-ETP	OH	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.

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08/00	98-0452 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
10/00	SOAH 473-00-1020 PUC 2234	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66-000 & ER00-2854 EL95-33-002	LA	Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Addressing Contested Issues	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic .	Independent Transmission Company ("Transco"). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep. - Texas Restructuring Plan.

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08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and the Entergy Operating Companies	Modifications to the Inter-Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	CO	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	CO	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-000 ER03-583-001 ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001 ER03-682-002	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-Ing, L.P, and Entergy Power, Inc.	Evaluation of Wholesale Purchased Power Contracts.
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345-03-0437	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation rate design.
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.
03/04	03A-436E	CO	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.

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04/04	2003-00433 2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service Rate Design
0-6/04	03S-539E	CO	Cripple Creek, Victor Gold Mining Co., Goodrich Corp., Holcim (U.S.,), Inc., and The Trane Co.	Aquila, Inc.	Cost of Service, Rate Design Interruptible Rates
06/04	R-00049255	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
10/04	04S-164E	CO	CF&I Steel Company, Climax Mines	Public Service Company of Colorado	Cost of service, rate design, Interruptible Rates.
03/05	Case No. 2004-00426 Case No. 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
06/05	050045-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
07/05	U-28155	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Independent Coordinator of Transmission – Cost/Benefit
09/05	Case Nos. 05-0402-E-CN 05-0750-E-PC	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Environmental cost recovery, Securitization, Financing Order
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses. Congestion Cost Recovery Mechanism
03/06	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Transmission Prudence Investigation
06/06	R-00061346 C0001-0005	PA	Duquesne Industrial Intervenors & IECPA	Duquesne Light Co.	Cost of Service, Rate Design, Transmission Service Charge, Tariff Issues
06/06	R-00061366 R-00061367 P-00062213 P-00062214		Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Generation Rate Cap, Transmission Service Charge, Cost of Service, Rate Design, Tariff Issues
07/06	U-22092 Sub-J	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Separation of EGSI into Texas and Louisiana Companies.

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07/06	Case No. 2006-00130 Case No. 2006-00129	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Louisville Gas & Electric Co.	Environmental cost recovery.
08/06	Case No. PUE-2006-00065	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Incr, Off-System Sales margin rate treatment
09/06	E-01345A-05-0816	AZ	Kroger Company	Arizona Public Service Co.	Revenue alllocation, cost of service, rate design.
11/06	Doc. No. 97-01-15RE02	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power United Illuminating	Rate unbundling issues.
01/07	Case No. 06-0960-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Implementation of FERC Decision Jurisdictional & Rate Class Allocation
05/07	Case No. 07-63-EL-UNC	OH	Ohio Energy Group	Ohio Power, Columbus Southern Power	Environmental Surcharge Rate Design
05/07	R-00049255 Remand	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues and transmission service charge.
06/07	R-00072155	PA	PP&L Industrial Customer Alliance PPLICA	PPL Electric Utilities Corp.	Cost of service, rate design, tariff issues.
07/07	Doc. No. 07F-037E	CO	Gateway Canyons LLC	Grand Valley Power Coop.	Distribution Line Cost Allocation
09/07	Doc. No. 05-UR-103	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
11/07	ER07-682-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Schedule MSS-3. Cost functionalization issues.
1/08	Doc. No. 20000-277-ER-07	WY	Cimarex Energy Company	Rocky Mountain Power (PacifiCorp)	Vintage Pricing, Marginal Cost Pricing Projected Test Year
1/08	Case No. 07-551	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Class Cost of Service, Rate Restructuring, Apportionment of Revenue Increase to Rate Schedules
2/08	ER07-956	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
2/08	Doc No. P-00072342	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Default Service Plan issues.

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3/08	Doc No. E-01933A-05-0650	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
05/08	08-0278 E-GI	WV	West Virginia Energy Users Group	Appalachian Power Co. American Electric Power Co.	Expanded Net Energy Cost "ENEC" Analysis.
6/08	Case No. 08-124-EL-ATA	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Recovery of Deferred Fuel Cost
7/08	Docket No. 07-035-93	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Rate Design
08/08	Doc. No. 6680-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Doc. No. 6690-UR-119	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
09/08	Case No. 08-936-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Competitive Solicitation
09/08	Case No. 08-935-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
09/08	Case No. 08-917-EL-SSO 08-918-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Provider of Last Resort Rate Plan
10/08	2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
11/08	08-1511 E-GI	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
11/08	M-2008-2036188, M-2008-2036197	PA	Met-Ed Industrial Energy Users Group and Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Transmission Service Charge
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
01/09	E-01345A-08-0172	AZ	Kroger Company	Arizona Public Service Co.	Cost of Service, Rate Design
02/09	2008-00409	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Cost of Service, Rate Design

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Date	Case	Jurisdict.	Party	Utility	Subject
5/09	PUE-2009 -00018	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Transmission Cost Recovery Rider
5/09	09-0177-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost "ENEC" Analysis
6/09	PUE-2009 -00016	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Fuel Cost Recovery Rider
6/09	PUE-2009 -00038	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Fuel Cost Recovery Rider
7/09	080677-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
8/09	U-20925 (RRF 2004)	LA	Louisiana Public Service Commission Staff	Entergy Louisiana LLC	Interruptible Rate Refund Settlement
9/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Energy Cost Rate issues
9/09	Doc. No. 05-UR-104	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
9/09	Doc. No. 6680-UR-117	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Co.	Cost of Service, rate design, tariff Issues, Interruptible rates.
10/09	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Cost of Service, Allocation of Rev Increase
10/09	09AL-299E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Cost of Service, Rate Design
11/09	PUE-2009 -00019	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Cost of Service, Rate Design
11/09	09-1485 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost "ENEC" Analysis.
12/09	Case No. 09-906-EL-SSO	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Provider of Last Resort Rate Plan
12/09	ER09-1224	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Entergy's Compliance Filing System Agreement Bandwidth Calculations.
12/09	Case No. PUE-2009-00030	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Allocation of Rev Increase, Rate Design

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2/10	Docket No. 09-035-23	UT	Kroger Company	Rocky Mountain Power Co.	Rate Design
3/10	Case No. 09-1352-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Retail Cost of Service Revenue apportionment
3/10	E015/ GR-09-1151	MN	Large Power Intervenors	Minnesota Power Co.	Cost of Service, rate design
4/10	EL09-61	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to off-system sales
4/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses.
4/10	2009-00548 2009-00549	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
7/10	R-2010-2161575	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Company	Cost of Service, Rate Design
09/10	2010-00167	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Cost of Service, Rate Design
09/10	10M-245E	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Economic Impact of Clean Air Act
11/10	10-0699-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Cost of Service, Rate Design, Transmission Rider
11/10	Doc. No. 4220-UR-116	WI	Wisconsin Industrial Energy Group, Inc.	Northern States Power Co. Wisconsin	Cost of Service, rate design
12/10	10A-554EG	CO	CF&I Steel Company Climax Molybdenum	Public Service Company	Demand Side Management Issues
12/10	10-2586-EL-SSO	OH	Ohio Energy Group	Duke Energy Ohio	Provider of Last Resort Rate Plan Electric Security Plan
3/11	20000-384-ER-10	WY	Wyoming Industrial Energy Consumers	Rocky Mountain Power Wyoming	Electric Cost of Service, Revenue Apportionment, Rate Design
5/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Cost of Service, Rate Design
6/11	Docket No. 10-035-124	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
6/11	PUE-2011-00045	VA	VA Committee For Fair Utility Rates	Dominion Virginia Power Company	Fuel Cost Recovery Rider

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07/11	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	Entergy System Agreement - Successor Agreement, Revisions, RTO Day 2 Market Issues
07/11	Case Nos. 11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Electric Security Rate Plan, Provider of Last Resort Issues
08/11	PUE-2011-00034	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Co.	Cost Allocation, Rate Recovery of RPS Costs
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility	Louisville Gas & Electric Co. Kentucky Utilities Company	Environmental Cost Recovery
09/11	Case Nos. 11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	Ohio Power Company Columbus Southern Power Co.	Electric Security Rate Plan, Stipulation Support Testimony
10/11	11-0452 E-P-T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Energy Efficiency/Demand Reduction Cost Recovery
11/11	11-1272 E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost “ENEC” Analysis
11/11	E-01345A-11-0224	AZ	Kroger Company	Arizona Public Service Co.	Decoupling
12/11	E-01345A-11-0224	AZ	Kroger Company	Arizona Public Service Co.	Cost of Service, Rate Design
3/12	Case No. 2011-00401	KY	Kentucky Industrial Utility Consumers	Kentucky Power Company	Environmental Cost Recovery
4/12	2011-00036 Rehearing Case	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Cost of Service, Rate Design
5/12	2011-346 2011-348	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Interruptible Rate Issues
6/12	PUE-2012 -00051	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Fuel Cost Recovery Rider
6/12	12-00012 12-00026	TN	Eastman Chemical Co. Air Products and Chemicals, Inc.	Kingsport Power Company	Demand Response Programs
6/12	Docket No. 11-035-200	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
6/12	12-0275-E-GI-EE	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Rider

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6/12	12-0399-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
7/12	120015-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design
7/12	2011-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Environmental Cost Recovery
8/12	Case No. 2012-00226	KY	Kentucky Industrial Utility Consumers	Kentucky Power Company	Real Time Pricing Tariff
9/12	ER12-1384	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement, Cancelled Plant Cost Treatment
9/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
11/12	12-1238 E-GI	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost Recovery Issues
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana	Purchased Power Contracts
12/12	EL09-61	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to off-system sales Damages Phase
12/12	E-01933A-12-0291	AZ	Kroger Company	Tucson Electric Power Co.	Decoupling
1/13	12-1188 E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Securitization of ENEC Costs
1/13	E-01933A-12-0291	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
4/13	12-1571 E-PC	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Generation Resource Transition Plan Issues
4/13	PUE-2012 -00141	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Generation Asset Transfer Issues
6/13	12-1655 E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Generation Asset Transfer Issues
06/13	U-32675	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. Entergy Louisiana, LLC	MISO Joint Implementation Plan Issues

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7/13	130040-EI	FL	WCF Health Utility Alliance	Tampa Electric Company	Cost of Service, Rate Design
7/13	13-0467-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
7/13	13-0462-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Issues
8/13	13-0557-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Right-of-Way, Vegetation Control Cost Recovery Surcharge Issues
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Ratemaking Policy Associated with Rural Economic Reserve Funds
10/13	13-0764-E-CN	WV	West Virginia Energy Users Group	Appalachian Power Company	Rate Recovery Issues – Clinch River Gas Conversion Project
11/13	R-2013-2372129	PA	United States Steel Corporation	Duquesne Light Company	Cost of Service, Rate Design
11/13	13A-0686EG	CO	CF&I Steel Company Climax Molybdenum	Public Service Company of Colorado	Demand Side Management Issues
11/13	13-1064-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Right-of-Way, Vegetation Control Cost Recovery Surcharge Issues
4/14	ER-432-002	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Union Pacific Railroad Litigation Settlement
5/14	2013-2385 2013-2386	OH	Ohio Energy Group	Ohio Power Company	Electric Security Rate Plan Interruptible Rate Issues
5/14	14-0344-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
5/14	14-0345-E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Energy Efficiency Issues
5/14	Docket No. 13-035-184	UT	Kroger Company	Rocky Mountain Power Co.	Class Cost of Service
7/14	PUE-2014-00007	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Renewable Portfolio Standard Rider Issues
7/14	ER13-2483	FERC	Bear Island Paper WB LLC	Old Dominion Electric Cooperative	Cost of Service, Rate Design Issues
8/14	14-0546-E-PC	WV	West Virginia Energy Users Group	Appalachian Power Company	Rate Recovery Issues – Mitchell Asset Transfer
8/14	PUE-2014	VA	Old Dominion Committee	Appalachian Power	Biennial Review Case - Cost

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2016

Date	Case	Jurisdict.	Party	Utility	Subject
	-00026			Company	of Service Issues
9/14	14-841-EL-SSO	OH	Ohio Energy Group	Duke Energy Ohio	Electric Security Rate Plan Standard Service Offer
10/14	14-0702-E-42T	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Cost of Service, Rate Design
11/14	14-1550-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Expanded Net Energy Cost ("ENEC")
12/14	EL14-026	SD	Black Hills Power Industrial Intervenors	Black Hills Power, Inc.	Cost of Service Issues
12/14	14-1152-E-42T	WV	West Virginia Energy Users Group	Appalachian Power Company	Cost of Service, Rate Design transmission, lost revenues
2/15	14-1297 EI-SS0	OH	Ohio Energy Group	Ohio Edison, Toledo Edison Cleveland Electric Illuminating	Electric Security Rate Plan Standard Service Offer
3/15	2014-00396	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Cost of service, rate design, transmission expenses.
3/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. Kentucky Utilities Co.	Cost of Service, Rate Design
5/15	EL10-65	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Interruptible load
615	14-1580-EL-RDR	OH	Ohio Energy Group	Duke Energy Ohio	Energy Efficiency Rider Issues
5/15	15-0301-E-P	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
7/15	EL10-65	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Off-System Sales and Bandwidth Tariff
8/15	PUE-2015 -00034	VA	Old Dominion Committee For Fair Utility Rates	Appalachian Power Company	Renewable Portfolio Standard Rider Issues
8/15	87-0669-E-P	WV	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Cost of Service, Rate Design
11/15	D2015-6.51	MT	Montana Large Customer Group	Montana Dakota Utilities Co.	Class Cost of Service, Rate Design
3/16	EL01-88 Remand	FERC	Louisiana Public Service Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement Issues Related to Bandwidth Tariff

Expert Testimony Appearances
of
Stephen J. Baron
As of June 2016

Date	Case	Jurisdict.	Party	Utility	Subject
5/16	16-0239-E-ENEC	WV	West Virginia Energy Users Group	Appalachian Power Company	Expanded Net Energy Cost ("ENEC")
6/16	E-01933A-15-0322	AZ	Kroger Company	Tucson Electric Power Co.	Cost of Service, Rate Design
6/16	16-00001	TN	East Tennessee Energy Consumers	Kingsport Power Co.	Cost of Service, Rate Design

EXHIBIT NO. ___ (SJB-2)

QUESTION:
With respect to FPL's decision to utilize a 12CP and 25% methodology for production plant, rather than the 12CP and 1/13th method used in prior cases (Deaton testimony at 21):
a. Who made the decision to change the production plant allocation methodology?
b. What other methodologies (besides 12CP and 25%) did FPL consider and why were these rejected?
c. When was this decision made?
d. Identify all facts and circumstances supporting the change.
e. Identify any analysis or studies conducted by or for FPL supporting the change.
f. Identify any studies conducted either by or for FPL demonstrating how FPL determined that 25% of production plant (and not some other percentage) should be allocated on average demand.
g. Identify all documents reviewed in determining that allocating 25% of production plant on average demand better reflects cost causation.

RESPONSE:
a. A team led by FPL's Rates & Tariffs Department including Renae Deaton developed and recommended the proposed approach which was approved by FPL management.
b. FPL also considered and filed the 12CP & 1/13th methodology. The rationale for using the 12 CP and 25%, rather than the 12CP and 1/13th, is explained in Renae Deaton's direct testimony, at pages 21 and 22.
c. The decision was made as part of the above-referenced review and was conducted in 2015.
d. The facts and circumstances are as described in Renae Deaton's direct testimony at pages 21 and 22.
e.-f. As explained in response to subpart (d) above, the decision to propose the 12CP and 25% methodology was based on how FPL plans and operates its generating units. The 25% methodology is supported by the fact that FPL continues to install combined cycle generation rather than peaking generation on the basis of lower cumulative present value revenue requirements. The combined cycle generation involves a greater up-front cost but provides lower overall system fuel and operating costs, which contributes to FPL's low customer bills.
g. The documents reviewed included filings and orders from prior rate cases described in witness Deaton's testimony. See also response to subparts (d) through (e).

EXHIBIT NO. ___ (SJB-3)

QUESTION:
Regarding Deaton at 21:19: To the extent that FPL has added base load, intermediate and peaking units during the past 40 years, please provide a detailed explanation of what has occurred to justify switching FPL's class cost of service method to the 12 CP and 25% method in this base rate case.

RESPONSE:
See FPL's response to SFHHA's First Set of Interrogatories No 12. FPL's ten year site plan provides a list of all generation currently in service that has been installed in the last 40 years or more.

As explained on page 21 of witness Deaton's testimony, "FPL is proposing to utilize a 12 CP and 25% methodology for production plant, rather than the 12 CP and 1/13th method used in prior rate cases, to better reflect cost causation. The proposed methodology provides a more appropriate classification and allocation of production plant considering how power plants are planned and operated at FPL in response to customer energy and demand needs. FPL has installed a significant amount of base and intermediate load generation that costs more to construct but is less costly to operate over time than peaking generation. Investment in these generating units that improve system heat rates and lower fuel costs drives the need to use a greater energy allocation (e.g., 25%) for production plant. As discussed by FPL witness Kennedy, these investments have resulted in approximately $8 billion of fuel savings for customers since 2001." Also, page 22 of witness Deaton's testimony discusses the prior Commission orders approving varying levels of production plant to be classified and allocated based on energy, including approval of 12CP & 25% for TECO in Docket No. 080317-EI. In Duke Energy Florida's 2009 rate case, the staff also recommended approval of the 12CP & 25% allocation method for production plant.

Since 2006, the fuel savings associated with the new combined cycle generation has either fully or partially offset the increase in base rates required to recover the capital and O&M cost. Since the last rate case, FPL has installed three more combined cycle generation units, and continues to plan to install more combined cycle generation; has completed the uprates at the nuclear plants; and has begun construction of 3 solar plants that will provide net present value fuel savings benefits over and above the revenue requirements associated with the plants. Witness Kennedy's testimony on page 8, lines 12 – 21, states that FPL's system heat rate was 25% better in 2015 than 1990, resulting in more than half a billion in fuel savings in 2015 alone. As such, it is appropriate to re-evaluate the amount of generation plant that is allocated based on energy vs. demand. Moving to 12CP and 25% at this time is an appropriate step to better match allocation of the capital cost with the fuel savings these plants bring to the system.

QUESTION:
Regarding Deaton at 21:19: Please identify each and every reason for FPL's proposal to change its cost of service methodology from 12 CP and 1/13 to 12 CP and 25%, other than a change in FPL's generation planning protocols. If there are no other reasons for the change, then so state.

RESPONSE:
FPL has not referenced a change in generation planning protocols as a reason for FPL's proposal to use the 12 CP and 25% cost of service methodology.

See FPL's response to FIPUG's First Set of Interrogatories No. 10(d), SFHHA's First Set of Interrogatories No. 12, SFHHA's Sixth Set of Interrogatories No. 145, witness Deaton's testimony, pages 21 – 22, and witness Kennedy's testimony p. 8 lines 12-21.

EXHIBIT NO. ___ (SJB-4)

Independent Statistics & Analysis
U.S. Energy Information Administration

June 2015

Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015

This paper presents average values of levelized costs for generating technologies that are brought online in 2020[1] as represented in the National Energy Modeling System (NEMS) for the *Annual Energy Outlook 2015* (AEO2015) Reference case.[2] Both national values and the minimum and maximum values across the 22 U.S. regions of the NEMS electricity market module are presented.

Levelized cost of electricity (LCOE) is often cited as a convenient summary measure of the overall competiveness of different generating technologies. It represents the per-kilowatthour cost (in real dollars) of building and operating a generating plant over an assumed financial life and duty cycle. Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, and an assumed utilization rate for each plant type.[3] The importance of the factors varies among the technologies. For technologies such as solar and wind generation that have no fuel costs and relatively small variable O&M costs, LCOE changes in rough proportion to the estimated capital cost of generation capacity. For technologies with significant fuel cost, both fuel cost and overnight cost estimates significantly affect LCOE. The availability of various incentives, including state or federal tax credits, can also impact the calculation of LCOE. As with any projection, there is uncertainty about all of these factors and their values can vary regionally and across time as technologies evolve and fuel prices change.

It is important to note that, while LCOE is a convenient summary measure of the overall competiveness of different generating technologies, actual plant investment decisions are affected by the specific technological and regional characteristics of a project, which involve numerous other factors. The ***projected utilization rate***, which depends on the load shape and the existing resource mix in an area where additional capacity is needed, is one such factor. The ***existing resource mix*** in a region can directly impact the economic viability of a new investment through its effect on the economics surrounding the displacement of existing resources. For example, a wind resource that would primarily displace existing natural gas generation will usually have a different economic value than one that would displace existing coal generation.

A related factor is the ***capacity value**,* which depends on both the existing capacity mix and load characteristics in a region. Since load must be balanced on a continuous basis, units whose output can be varied to follow demand (dispatchable technologies) generally have more value to a system than less

[1] 2020 is shown for all technologies except for the advanced nuclear plant type. Because of additional licensing requirements for new, unplanned nuclear units, the AEO2015 assumes 2022 is the first year a new nuclear plant, not already under construction, could come online and the LCOE/LACE in tables 1-4 represent data consistent with the 2022 online date.
[2] The full report is available at http://www.eia.gov/forecasts/aeo/index.cfm.
[3] The specific assumptions for each of these factors are given in the *Assumptions to the Annual Energy Outlook*, available at http://www.eia.gov/forecasts/aeo/assumptions/.

flexible units (non-dispatchable technologies), or those whose operation is tied to the availability of an intermittent resource. The LCOE values for dispatchable and nondispatchable technologies are listed separately in the tables, because caution should be used when comparing them to one another.

Since projected utilization rates, the existing resource mix, and capacity values can all vary dramatically across regions where new generation capacity may be needed, the direct comparison of LCOE across technologies is often problematic and can be misleading as a method to assess the economic competitiveness of various generation alternatives. Conceptually, a better assessment of economic competitiveness can be gained through consideration of avoided cost, a measure of what it would cost the grid to generate the electricity that is otherwise displaced by a new generation project, as well as its levelized cost. Avoided cost, which provides a proxy measure for the annual economic value of a candidate project, may be summed over its financial life and converted to a stream of equal annual payments. The avoided cost is divided by average annual output of the project to develop the "levelized" avoided cost of electricity (LACE) for the project.[4] The LACE value may then be compared with the LCOE value for the candidate project to provide an indication of whether or not the project's value exceeds its cost. If multiple technologies are available to meet load, comparisons of each project's LACE to its LCOE may be used to determine which project provides the best net economic value. Estimating avoided costs is more complex than estimating levelized costs because it requires information about how the system would have operated without the option under evaluation. In this discussion, the calculation of avoided costs is based on the marginal value of energy and capacity that would result from adding a unit of a given technology and represents the potential revenue available to the project owner from the sale of energy and generating capacity. While the economic decisions for capacity additions in EIA's long-term projections use neither LACE nor LCOE concepts, the LACE and net value estimates presented in this report are generally more representative of the factors contributing to the projections than looking at LCOE alone. However, both the LACE and LCOE estimates are simplifications of modeled decisions, and may not fully capture all decision factors or match modeled results.

Policy-related factors, such as environmental regulations and investment or production tax credits for specified generation sources, can also impact investment decisions. Finally, although levelized cost calculations are generally made using an assumed set of capital and operating costs, the inherent uncertainty about future fuel prices and future policies may cause plant owners or investors who finance plants to place a value on ***portfolio diversification***. While EIA considers many of these factors in its analysis of technology choice in the electricity sector, these concepts are not included in LCOE or LACE calculations.

The LCOE values shown for each utility-scale generation technology in Table 1 and Table 2 in this discussion are calculated based on a 30-year cost recovery period, using a real after tax weighted average cost of capital (WACC) of 6.1%[5]. In reality, the cost recovery period and cost of capital can vary

[4] Further discussion of the levelized avoided cost concept and its use in assessing economic competitiveness can be found in this article: http://www.eia.gov/renewable/workshop/gencosts/.

[5]The real WACC for plants entering service in 2020 is 6.1%; nuclear plants are assumed to enter service in 2022 and have a real WACC of 6.2%. The real WACC corresponds to a nominal after tax rate of 8.1% for both plants entering service in 2020 and 2022. An overview of the WACC assumptions and methodology can be found in the *Electricity Market Module of the National*

by technology and project type. In the AEO2015 reference case, 3 percentage points are added to the cost of capital when evaluating investments in greenhouse gas (GHG) intensive technologies like coal-fired power and coal-to-liquids (CTL) plants without carbon control and sequestration (CCS). In LCOE terms, the impact of the cost of capital adder is similar to that of an emissions fee of $15 per metric ton of carbon dioxide (CO2) when investing in a new coal plant without CCS, which is representative of the costs used by utilities and regulators in their resource planning.[6] The adjustment should not be seen as an increase in the actual cost of financing, but rather as representing the implicit hurdle being added to GHG-intensive projects to account for the possibility that they may eventually have to purchase allowances or invest in other GHG-emission-reducing projects to offset their emissions. As a result, the LCOE values for coal-fired plants without CCS are higher than would otherwise be expected.

The levelized capital component reflects costs calculated using tax depreciation schedules consistent with permanent tax law, which vary by technology. Although the capital and operating components do not incorporate the production or investment tax credits available to some technologies, a subsidy column is included in Table 1 to reflect the estimated value of these tax credits, where available, in 2020. In the reference case, tax credits are assumed to expire based on current laws and regulations.

Some technologies, notably solar photovoltaic (PV), are used in both utility-scale generating plants and distributed end-use residential and commercial applications. As noted above, the LCOE (and also subsequent LACE) calculations presented in the tables apply only to the utility-scale use of those technologies.

In Table 1 and Table 2, the LCOE for each technology is evaluated based on the capacity factor indicated, which generally corresponds to the high end of its likely utilization range. Simple combustion turbines (conventional or advanced technology) that are typically used for peak load duty cycles are evaluated at a 30% capacity factor. The duty cycle for intermittent renewable resources, wind and solar, is not operator controlled, but dependent on the weather or solar cycle (that is, sunrise/sunset) and so will not necessarily correspond to operator dispatched duty cycles. As a result, their LCOE values are not directly comparable to those for other technologies (even where the average annual capacity factor may be similar) and therefore are shown in separate sections within each of the tables. The capacity factors shown for solar, wind, and hydroelectric resources in Table 1 are simple averages of the capacity factor for the marginal site in each region. These capacity factors can vary significantly by region and can represent resources that may or may not get built in EIA capacity projections. Projected capacity factors for these resources in the AEO 2015 or other EIA analyses will not necessarily correspond to these levels.

As mentioned above, the LCOE values shown in Table 1 are national averages. However, as shown in Table 2, there is significant regional variation in LCOE values based on local labor markets and the cost and availability of fuel or energy resources such as windy sites. For example, LCOE for incremental wind capacity coming online in 2020 ranges from $65.6/MWh in the region with the best available resources in 2020 to $81.6/MWh in regions where LCOE values are highest due to lower quality wind resources

Energy Modeling System: Model Documentation. This report can be found at http://www.eia.gov/forecasts/aeo/nems/documentation/electricity/pdf/m068%282014%29.pdf.
[6] Morgan Stanley, "Leading Wall Street Banks Establish The Carbon Principles" (Press Release, February 4, 2008), www.morganstanley.com/about/press/articles/6017.html.

and/or higher capital costs for the best sites that can accommodate additional wind capacity. Costs shown for wind may include additional costs associated with transmission upgrades needed to access remote resources, as well as other factors that markets may or may not internalize into the market price for wind power.

As previously indicated, LACE provides an estimate of the cost of generation and capacity resources displaced by a marginal unit of new capacity of a particular type, thus providing an estimate of the value of building such new capacity. This is especially important to consider for intermittent resources, such as wind or solar, that have substantially different duty cycles than the baseload, intermediate and peaking duty cycles of conventional generators. Table 3 provides the range of LACE estimates for different capacity types. The LACE estimates in this table have been calculated assuming the same maximum capacity factor as in the LCOE. A subset of the full list of technologies in Table 1 is shown because the LACE value for similar technologies with the same capacity factor would have the same value (for example, conventional and advanced combined cycle plants will have the same avoided cost of electricity). Values are not shown for combustion turbines, because turbines are more often built for their capacity value to meet a reserve margin rather than to meet generation requirements and avoid energy costs.

When the LACE of a particular technology exceeds its LCOE at a given time and place, that technology would generally be economically attractive to build. While the build decisions in the real world, and as modeled in the AEO, are somewhat more complex than a simple LACE to LCOE comparison, including such factors as policy and non-economic drivers, the net economic value (LACE minus LCOE, including subsidy, for a given technology, region and year) shown in Table 4 provides a reasonable point of comparison of first-order economic competitiveness among a wider variety of technologies than is possible using either the LCOE or LACE tables individually. In Table 4, a negative difference indicates that the cost of the marginal new unit of capacity exceeds its value to the system, as measured by LACE; a positive difference indicates that the marginal new unit brings in value in excess of its cost by displacing more expensive generation and capacity options. The range of differences columns represent the variation in the calculation of the difference for each region. For example, in the region where the advanced combined cycle appears most economic in 2020, the LCOE is $74.6/MWh and the LACE is $75.8/MWh, resulting in a net difference of $1.2/MWh. This range of differences is not based on the difference between the minimum values shown in Table 2 and Table 3, but represents the lower and upper bound resulting from the LACE minus LCOE calculations for each of the 22 regions.

The average net differences shown in Table 4 are for plants coming online in 2020, consistent with Tables 1-3, as well as for plants that could come online in 2040, to show how the relative competitiveness changes over the projection period. Additional tables showing the LCOE cost components and regional variation in LCOE and LACE for 2040 can be found in the Appendix. In 2020, the average net differences are negative for all technologies except geothermal, reflecting the fact that on average, new capacity is not needed in 2020. However, the upper value for the advanced combined cycle technology is above zero, indicating competiveness in a particular region. Geothermal cost data is site-specific, and the relatively large positive value for that technology results because there may be individual sites that are very cost competitive, leading to new builds, but there is a limited amount of capacity available at that cost. By 2040, the LCOE values for most technologies are lower, typically reflecting declining capital costs over time. All technologies receive cost reductions from learning over time, with newer, advanced technologies receiving larger cost reductions, while conventional technologies will see smaller learning effects. Capital costs are also adjusted over time based on commodity prices, through a factor based on the metals and metal products index, which declines in real terms over the projection. However, the LCOE for natural gas-fired technologies rises over time, because rising fuel costs more than offset any decline in capital costs. The LACE values for all technologies increase by 2040 relative to 2020, reflecting higher energy costs and a greater value for new capacity. As a result, the difference between LACE and LCOE for almost all technologies gets closer to a net positive value in 2040, and there are several technologies (advanced combined cycle, wind, solar PV, and geothermal) that have regions with positive net differences.

Table 1. Estimated levelized cost of electricity (LCOE) for new generation resources, 2020

		U.S. Average Levelized Costs (2013 $/MWh) for Plants Entering Service in 2020[1]						
Plant Type	Capacity Factor (%)	Levelized Capital Cost	Fixed O&M	Variable O&M (including fuel)	Transmission Investment	Total System LCOE	Subsidy[2]	Total LCOE including Subsidy
Dispatchable Technologies								
Conventional Coal	85	60.4	4.2	29.4	1.2	95.1		
Advanced Coal	85	76.9	6.9	30.7	1.2	115.7		
Advanced Coal with CCS	85	97.3	9.8	36.1	1.2	144.4		
Natural Gas-fired								
Conventional Combined Cycle	87	14.4	1.7	57.8	1.2	75.2		
Advanced Combined Cycle	87	15.9	2.0	53.6	1.2	72.6		
Advanced CC with CCS	87	30.1	4.2	64.7	1.2	100.2		
Conventional Combustion Turbine	30	40.7	2.8	94.6	3.5	141.5		
Advanced Combustion Turbine	30	27.8	2.7	79.6	3.5	113.5		
Advanced Nuclear	90	70.1	11.8	12.2	1.1	95.2		
Geothermal	92	34.1	12.3	0.0	1.4	47.8	-3.4	44.4
Biomass	83	47.1	14.5	37.6	1.2	100.5		
Non-Dispatchable Technologies								
Wind	36	57.7	12.8	0.0	3.1	73.6		
Wind – Offshore	38	168.6	22.5	0.0	5.8	196.9		
Solar PV[3]	25	109.8	11.4	0.0	4.1	125.3	-11.0	114.3
Solar Thermal	20	191.6	42.1	0.0	6.0	239.7	-19.2	220.6
Hydroelectric[4]	54	70.7	3.9	7.0	2.0	83.5		

[1]Costs for the advanced nuclear technology reflect an online date of 2022.
[2] The subsidy component is based on targeted tax credits such as the production or investment tax credit available for some technologies. It only reflects subsidies available in 2020, which include a permanent 10% investment tax credit for geothermal and solar technologies. EIA models tax credit expiration as follows: new solar thermal and PV plants are eligible to receive a 30% investment tax credit on capital expenditures if placed in service before the end of 2016, and 10% thereafter. New wind, geothermal, biomass, hydroelectric, and landfill gas plants are eligible to receive either: (1) a $23.0/MWh ($11.0/MWh for technologies other than wind, geothermal and closed-loop biomass) inflation-adjusted production tax credit over the plant's first ten years of service or (2) a 30% investment tax credit, if they are under construction before the end of 2013. Up to 6 GW of new nuclear plants are eligible to receive an $18/MWh production tax credit if in service by 2020; nuclear plants shown in this table have an in-service date of 2022.
[3] Costs are expressed in terms of net AC power available to the grid for the installed capacity.
[4]As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2015*, April 2015, DOE/EIA-0383(2015).

Table 2. Regional variation in levelized cost of electricity (LCOE) for new generation resources, 2020[1]

	Range for Total System LCOE (2013 $/MWh)			Range for Total LCOE with Subsidies[2] (2013 $/MWh)		
Plant Type	Minimum	Average	Maximum	Minimum	Average	Maximum
Dispatchable Technologies						
Conventional Coal	87.1	95.1	119.0			
Advanced Coal	106.1	115.7	136.1			
Advanced Coal with CCS	132.9	144.4	160.4			
Natural Gas-fired						
Conventional Combined Cycle	70.4	75.2	85.5			
Advanced Combined Cycle	68.6	72.6	81.7			
Advanced CC with CCS	93.3	100.2	110.8			
Conventional Combustion Turbine	107.3	141.5	156.4			
Advanced Combustion Turbine	94.6	113.5	126.8			
Advanced Nuclear	91.8	95.2	101.0			
Geothermal	43.8	47.8	52.1	41.0	44.4	48.0
Biomass	90.0	100.5	117.4			
Non-Dispatchable Technologies						
Wind	65.6	73.6	81.6			
Wind – Offshore	169.5	196.9	269.8			
Solar PV[3]	97.8	125.3	193.3	89.3	114.3	175.8
Solar Thermal	174.4	239.7	382.5	160.4	220.6	351.7
Hydroelectric[4]	69.3	83.5	107.2			

[1]Costs for the advanced nuclear technology reflect an online date of 2022.
[2]Levelized cost with subsidies reflects subsidies available in 2020, which include a permanent 10% investment tax credit for geothermal and solar technologies.
[3] Costs are expressed in terms of net AC power available to the grid for the installed capacity.
[4]As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.
Note: The levelized costs for non-dispatchable technologies are calculated based on the capacity factor for the marginal site modeled in each region, which can vary significantly by region. The capacity factor ranges for these technologies are as follows: Wind – 31% to 40%, Wind Offshore – 33% to 42%, Solar PV- 22% to 32%, Solar Thermal – 11% to 26%, and Hydroelectric – 35% to 65%. The levelized costs are also affected by regional variations in construction labor rates and capital costs as well as resource availability.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2015*, April 2015, DOE/EIA-0383(2015).

Table 3: Regional variation in levelized avoided costs of electricity (LACE) for new generation resources, 2020[1]

Plant Type	Range for LACE (2013$/MWh) Minimum	Average	Maximum
Dispatchable Technologies			
Coal without CCS	65.9	70.9	80.8
IGCC with CCS[2]	65.9	71.0	80.8
Natural Gas-fired Combined Cycle	65.8	71.4	80.7
Advanced Nuclear	68.4	72.1	82.0
Geothermal	70.7	70.9	71.0
Biomass	66.0	71.7	80.9
Non-Dispatchable Technologies			
Wind	60.6	64.6	69.0
Wind – Offshore	64.6	71.5	78.1
Solar PV	61.6	80.4	92.3
Solar Thermal	59.4	83.0	89.4
Hydroelectric	64.8	69.5	80.0

[1]Costs for the advanced nuclear technology reflect an online date of 2022.
[2]Coal without CCS cannot be built in California, therefore the average LACE for coal technologies without CCS is computed over fewer regions than the LACE for IGCC with CCS. Otherwise, the LACE for any given region is the same across coal technologies, with or without CCS.

Table 4: Difference between levelized avoided costs of electricity (LACE) and levelized costs of electricity (LCOE), 2020[1] and 2040

	Comparison of LCOE and LACE (2013 $/MWh)				
	Average LCOE	Average LACE	Average Difference	Range of Differences	
Plant Type				Minimum of Range	Maximum of Range
2020					
Dispatchable Technologies					
Conventional Coal	95.1	70.9	-24.1	-43.0	-15.5
Advanced Coal	115.7	70.9	-44.7	-60.0	-34.6
Advanced Coal with CCS	144.4	71.0	-73.4	-88.9	-61.4
Natural Gas-fired					
Conventional Combined Cycle	75.2	71.4	-3.8	-10.8	-1.8
Advanced Combined Cycle	72.6	71.4	-1.2	-7.6	1.2
Advanced CC with CCS	100.2	71.4	-28.8	-35.9	-22.5
Advanced Nuclear	95.2	72.1	-23.2	-31.4	-10.6
Geothermal	44.4	70.9	26.5	22.7	30.0
Biomass	100.5	71.7	-28.8	-44.4	-16.9
Non-Dispatchable Technologies					
Wind	73.6	64.6	-9.0	-19.6	0.1
Wind – Offshore	196.9	71.5	-125.5	-191.6	-98.3
Solar PV	114.3	80.4	-33.9	-83.5	-10.5
Solar Thermal	220.6	83.0	-137.5	-266.0	-74.3
Hydroelectric	83.5	69.5	-14.0	-33.9	-1.4
2040					
Dispatchable Technologies					
Conventional Coal	91.7	78.9	-12.8	-34.6	-3.5
Advanced Coal	105.5	78.9	-26.6	-43.3	-17.1
Advanced Coal with CCS	127.6	79.2	-48.4	-58.9	-38.7
Natural Gas-fired					
Conventional Combined Cycle	82.6	79.3	-3.3	-9.9	-1.2
Advanced Combined Cycle	79.3	79.3	-0.1	-5.6	2.1
Advanced CC with CCS	106.3	79.3	-27.0	-32.8	-21.9
Advanced Nuclear	88.9	78.7	-10.3	-19.3	-0.2
Geothermal	56.9	80.6	23.7	-2.8	50.2
Biomass	93.5	79.6	-13.9	-34.0	-1.6
Non-Dispatchable Technologies					
Wind	75.1	71.7	-3.4	-47.9	8.6
Wind – Offshore	175.6	79.3	-96.3	-155.6	-69.9
Solar PV	107.1	91.0	-16.1	-70.1	3.0
Solar Thermal	197.1	95.6	-101.5	-210.9	-49.1
Hydroelectric	89.9	77.7	-12.2	-30.4	-0.5

[1]Costs for the advanced nuclear technology reflect an online date of 2022.

Appendix: Tables for 2040

Table A5. Estimated levelized cost of electricity (LCOE) for new generation resources, 2040

	U.S. Average Levelized Costs (2013 $/MWh) for Plants Entering Service in 2020[1]							
Plant Type	**Capacity Factor (%)**	**Levelized Capital Cost**	**Fixed O&M**	**Variable O&M (including fuel)**	**Transmission Investment**	**Total System LCOE**	**Subsidy[2]**	**Total LCOE including Subsidy**
Dispatchable Technologies								
Conventional Coal	85	56.8	4.2	29.5	1.1	91.7		
Advanced Coal	85	69.1	6.9	28.4	1.1	105.5		
Advanced Coal with CCS	85	84.9	9.8	31.8	1.2	127.6		
Natural Gas-fired								
Conventional Combined Cycle	87	13.7	1.7	66.0	1.2	82.6		
Advanced Combined Cycle	87	14.3	2.0	61.9	1.2	79.3		
Advanced CC with CCS	87	25.8	4.2	75.2	1.2	106.3		
Conventional Combustion Turbine	30	38.4	2.8	110.3	3.4	154.9		
Advanced Combustion Turbine	30	24.1	2.7	88.4	3.4	118.6		
Advanced Nuclear	90	62.5	11.8	13.5	1.1	88.9		
Geothermal	94	38.2	21.2	0.0	1.4	60.8	-3.8	56.9
Biomass	83	43.0	14.5	34.8	1.2	93.5		
Non-Dispatchable Technologies								
Wind	35	58.9	13.0	0.0	3.1	75.1		
Wind – Offshore	38	147.4	22.5	0.0	5.7	175.6		
Solar PV[3]	25	101.8	11.4	0.0	4.1	117.3	-10.2	107.1
Solar Thermal	20	165.6	42.1	0.0	5.9	213.6	-16.6	197.1
Hydroelectric[4]	52	76.1	4.4	7.3	2.0	89.9		

[1]The subsidy component is based on targeted tax credits such as the production or investment tax credit available for some technologies. It only reflects subsidies available in 2020, which include a permanent 10% investment tax credit for geothermal and solar technologies. EIA models tax credit expiration as follows: new solar thermal and PV plants are eligible to receive a 30% investment tax credit on capital expenditures if placed in service before the end of 2016, and 10% thereafter. New wind, geothermal, biomass, hydroelectric, and landfill gas plants are eligible to receive either: (1) a $23.0/MWh ($11.0/MWh for technologies other than wind, geothermal and closed-loop biomass) inflation-adjusted production tax credit over the plant's first ten years of service or (2) a 30% investment tax credit, if they are under construction before the end of 2013. Up to 6 GW of new nuclear plants are eligible to receive an $18/MWh production tax credit if in service by 2020; nuclear plants shown in this table have an in-service date of 2022.

[2] Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[3]As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2015*, April 2015, DOE/EIA-0383(2015).

Table A6. Regional variation in levelized cost of electricity (LCOE) for new generation resources, 2040

	Range for Total System LCOE (2013 $/MWh)			Range for Total LCOE with Subsidies[1] (2013 $/MWh)		
Plant Type	Minimum	Average	Maximum	Minimum	Average	Maximum
Dispatchable Technologies						
Conventional Coal	83.2	91.7	114.8			
Advanced Coal	96.4	105.5	123.6			
Advanced Coal with CCS	117.1	127.6	141.6			
Natural Gas-fired						
Conventional Combined Cycle	76.8	82.6	93.2			
Advanced Combined Cycle	74.0	79.3	88.4			
Advanced CC with CCS	97.5	106.3	117.5			
Conventional Combustion Turbine	143.0	154.9	168.5			
Advanced Combustion Turbine	111.1	118.6	129.8			
Advanced Nuclear	85.9	88.9	94.1			
Geothermal	36.6	60.8	85.0	34.4	56.9	79.4
Biomass	82.9	93.5	116.2			
Non-Dispatchable Technologies						
Wind	61.1	75.1	122.8			
Wind – Offshore	151.1	175.6	239.5			
Solar PV[2]	91.5	117.3	180.5	83.7	107.1	164.2
Solar Thermal	155.4	213.6	340.6	143.3	197.1	314.0
Hydroelectric[3]	78.0	89.9	107.7			

[1]Levelized cost with subsidies reflects subsidies available in 2040, which includes a permanent 10% investment tax credit for geothermal and solar technologies, based on the Energy Policy Act of 1992.
[2] Costs are expressed in terms of net AC power available to the grid for the installed capacity.
[3]As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.
Note: The levelized costs for non-dispatchable technologies are calculated based on the capacity factor for the marginal site modeled in each region, which can vary significantly by region. The capacity factor ranges for these technologies are as follows: Wind – 32% to 41%, Wind Offshore – 33% to 42%, Solar PV- 22% to 32%, Solar Thermal – 11% to 26%, and Hydroelectric – 35% to 65%. The levelized costs are also affected by regional variations in construction labor rates and capital costs as well as resource availability.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2015*, April 2015, DOE/EIA-0383(2015).

Table A7: Regional variation in levelized avoided costs of electricity (LACE) for new generation resources, 2040

	Range for Levelized Avoided Costs (2013$/MWh)		
Plant Type	**Minimum**	**Average**	**Maximum**
Dispatchable Technologies			
Coal without CCS	72.8	78.9	86.4
IGCC with CCS[1]	72.8	79.2	86.4
Natural Gas-fired Combined Cycle	72.6	79.3	86.3
Advanced Nuclear	72.4	78.7	86.4
Geothermal	76.7	80.6	84.6
Biomass	72.9	79.6	86.4
Non-Dispatchable Technologies			
Wind	66.5	71.7	77.2
Wind – Offshore	71.1	79.3	85.2
Solar PV	70.4	91.0	99.4
Solar Thermal	66.3	95.6	114.7
Hydroelectric	71.5	77.7	85.5

[1]Coal without CCS cannot be built in California, therefore the average LACE for coal technologies without CCS is computed over fewer regions than the LACE for IGCC with CCS. Otherwise, the LACE for any given region is the same across coal technologies, with or without CCS.

EXHIBIT NO. ___ (SJB-5)

ELECTRIC UTILITY COST ALLOCATION MANUAL

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

January, 1992

PREFACE

This project was jointly assigned to the NARUC Staff Subcommittees on Electricity and Economics in February, 1985. Jack Doran, at the California PUC had led a task force in 1969 that wrote the original **Cost Allocation Manual**; the famous "Green Book". I was asked to put together a task force to revise it and include a Marginal Cost section.

I knew little about the subject and was not sure what I was getting into so I asked Jack how he had gone about drafting the first book. "Oh" he said, "There wasn't much to it. We each wrote a chapter and then exchanged them and rewrote them." What Jack did not tell me was that like most NARUC projects, the work was done after five o'clock and on weekends because the regular work always takes precedence. It is a good thing we did not realize how big a task we were tackling or we might never have started.

There was great interest in the project so when I asked for volunteers, I got plenty. We split into two working groups; embedded cost and marginal cost. Joe Jenkins from the Florida PSC headed up the Embedded Cost Working Group and Sarah Voll from the New Hampshire PUC took the Marginal Cost Working Group. We followed Jack's suggestions but, right from the beginning, we realized that once the chapters were technically correct, we would need a single editor to cast them all "into one hand" as Joe Jenkins put it. Steven Mintz from the Department of Energy volunteered for this task and has devoted tremendous effort to polishing the book into the final product you hold in your hands. Victoria Jow at the California PUC took Steven's final draft and desktop published the entire document using Ventura Publisher.

We set the following objectives for the manual:

- It should be simple enough to be used as a primer on the subject for new employees yet offer enough substance for experienced witnesses.
- It must be comprehensive yet fit in one volume.
- The writing style should be non-judgmental; not advocating any one particular method but trying to include all currently used methods with pros and cons.

It is with extreme gratitude that I acknowledge the energy and dedication contributed by the following task force members over the last five years.

Steven Mintz, Department of Energy, Editor; Joe Jenkins, Florida PSC, Leader, Embedded Cost Working Group; Sarah Voll, New Hampshire PUC, Leader, Marginal Cost Working Group; Victoria Jow, California PUC; John A. Anderson, ELCON; Jess Galura, Sacramento MUD; Chris Danforth, California PUC; Alfred Escamilla, Southern California Edison; Byron Harris, West Virginia CAD; Steve Houle, Texas Utility Electric Co.; Kevin Kelly, formally NRRI; Larry Klapow California PUC; Jim Ketter P.E., Missouri PSC; Ed Lucero, Price Waterhouse; J. Robert Malko, Utah State University; George McCluskey, New Hampshire PUC; Marge Meeter, Florida PSC; Gordon Murdock, The FERC; Dennis Nightingale, North Carolina UC; John Orecchio, The FERC; Carl Silsbee, Southern California Edison; Ben Turner, North Carolina UC; Dr. George Parkins, Colorado PUC; Warren Wendling, Colorado PUC; Schef Wright, formally Florida PSC; **IN MEMORIAL** Bob Kennedy Jr., Arkansas PSC.

Julian Ajello
California PUC

CHAPTER 6

CLASSIFICATION AND ALLOCATION OF DISTRIBUTION PLANT

Distribution plant equipment reduces high-voltage energy from the transmission system to lower voltages, delivers it to the customer and monitors the amounts of energy used by the customer.

Distribution facilities provide service at two voltage levels: primary and secondary. Primary voltages exist between the substation power transformer and smaller line transformers at the customer's points of service. These voltages vary from system to system and usually range between 480 volts to 35 KV. In the last few years, advances in equipment and cable technology have permitted the use of higher primary distribution voltages. Primary voltages are reduced to more usable secondary voltages by smaller line transformers installed at customer locations along the primary distribution circuit. However, some large industrial customers may choose to install their own line transformers and take service at primary voltages because of their large electrical requirements.

In some cases, the utility may choose to install a transformer for the exclusive use of a single commercial or industrial customer. On the other hand, in service areas with high customer density, such as housing tracts, a line transformer will be installed to serve many customers. In this case, secondary voltage lines run from pole-to-pole or from handhole-to-handhole, and each customer is served by a drop tapped off the secondary line leading directly to the customer's premise.

I. COST ACCOUNTING FOR DISTRIBUTION PLANT AND EXPENSES

The Federal Energy Regulatory Commission (FERC) Uniform System of Accounts requires separate accounts for distribution investment and expenses. Distribution plant accounts are summarized and classified in Table 6-1. Distribution expense accounts are summarized and classified in Table 6-2. Some utilities may choose to establish subaccounts for more detailed cost reporting.

TABLE 6-1

CLASSIFICATION OF DISTRIBUTION PLANT[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Distribution Plant [2]		
360	Land & Land Rights	X	X
361	Structures & Improvements	X	X
362	Station Equipment	X	-
363	Storage Battery Equipment	X	-
364	Poles, Towers, & Fixtures	X	X
365	Overhead Conductors & Devices	X	X
366	Underground Conduit	X	X
367	Underground Conductors & Devices	X	X
368	Line Transformers	X	X
369	Services	-	X
370	Meters	-	X
371	Installations on Customer Premises	-	X
372	Leased Property on Customer Premises	-	X
373	Street Lighting & Signal Systems [1]	-	-

[1]Assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classification may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

TABLE 6-2

CLASSIFICATION OF DISTRIBUTION EXPENSES[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Operation [2]		
580	Operation Supervision & Engineering	X	X
581	Load Dispatching	X	-
582	Station Expenses	X	-
583	Overhead Line Expenses	X	X
584	Underground Line Expenses	X	X
585	Street Lighting & Signal System Expenses [1]	-	-
586	Meter Expenses	-	X
587	Customer Installation Expenses	-	X
588	Miscellaneous Distribution Expenses	X	X
589	Rents	X	X
	Maintenance [2]		
590	Maintenance Supervision & Engineering	X	X
591	Maintenance of Structures	X	X
592	Maintenance of Station Equipment	X	-
593	Maintenance of Overhead Lines	X	X
594	Maintenance of Underground Lines	X	X
595	Maintenance of Line Transformers	X	X
596	Maint. of Street Lighting & Signal Systems [1]	-	-
597	Maintenance of Meters	-	X
598	Maint. of Miscellaneous Distribution Plants	X	X

[1]Direct assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classifications may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

To ensure that costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst's evaluation of how the costs in these accounts were incurred. In making this determination, supporting data may be more important than theoretical considerations.

Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses. This will ensure that costs are assigned to the correct functional groups for classification and allocation. As indicated in Chapter 4, all costs of service can be identified as energy-related, demand-related, or customer-related. Because there is no energy component of distribution-related costs, we need consider only the demand and customer components.

To recognize voltage level and use of facilities in the functionalization of distribution costs, distribution line costs must be separated into overhead and underground, and primary and secondary voltage classifications. A typical functionalization and classification of distribution plant would appear as follows:

Substations:	Demand
Distribution:	Overhead Primary
	Demand
	Customer
	Overhead Secondary
	Demand
	Customer
	Underground Primary
	Demand
	Customer
	Underground Secondary
	Demand
	Customer
	Line Transformers
	Demand
	Customer
Services:	Overhead
	Demand
	Customer
	Underground
	Demand
	Customer
Meters:	Customer
Street Lighting:	Customer
Customer Accounting:	Customer
Sales:	Customer

From this breakdown it can be seen that each distribution account must be analyzed before it can be assigned to the appropriate functional category. Also, these accounts must be classified as demand-related, customer-related, or both. Some utilities assign distribution to customer-related expenses. Variations in the demands of various customer groups are used to develop the weighting factors for allocating costs to the appropriate group.

II. DEMAND AND CUSTOMER CLASSIFICATIONS 0F DISTRIBUTION PLANT ACCOUNTS

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.

Classifying distribution plant as a demand cost assigns investment of that plant to a customer or group of customers based upon its contribution to some total peak load. The reason is that costs are incurred to serve area load, rather than a specific number of customers.

Distribution substations costs (which include Accounts 360 -Land and Land Rights, 361 - Structures and Improvements, and 362 -Station Equipment), are normally classified as demand-related. This classification is adopted because substations are normally built to serve a particular load and their size is not affected by the number of customers to be served.

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 meters are directly related to the number of customers on the utility's system. As shown in Table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.

A. <u>The Minimum-Size Method</u>

Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines the price of all installed units. Once determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and customer-related costs. Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method (to be discussed). The following describes the methodologies for determining the minimum size for distribution plant Accounts 364, 365, 366, 367, 368, and 369.

1. Account 364 - Poles, Towers, and Fixtures

- Determine the average installed book cost of the minimum height pole currently being installed.
- Multiply the average book cost by the number of poles to find the customer component. Balance of plant account is the demand component.

2. Account 365 - Overhead Conductors and Devices

- Determine minimum size conductor currently being installed.
- Multiply average installed book cost per mile of minimum size conductor by the number of circuit miles to determine the customer component. Balance of plant account is demand component. (Note: two conductors in minimum system.)

3. Accounts 366 and 367 - Underground Conduits, Conductors, and Devices

- Determine minimum size cable currently being installed.
- Multiply average installed book cost per mile of minimum size cable by the circuit miles to determine the customer component. Balance of plant Account 367 is demand component. (Note: one cable with ground sheath is minimum system.) Account 366 conduit is assigned, basedon ratio of cable account.
- Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component. Balance of plant account is demand component.

4. Account 368 - Line Transformers

- Determine minimum size transformer currently being installed.

- Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component.

5. Account 369 - Services

- Determine minimum size and average length of services currently being installed.
- Estimate cost of minimum size service and multiply by number of services to get customer component.
- If overhead and underground services are booked separately, they should be handled separately. Most companies do not book service by size. This requires an engineering estimate of the cost of the minimum size, average length service. The resultant estimate is usually higher than the average book cost. In addition, the estimate should be adjusted for the average age of service, using a trend factor.

B. The Minimum-Intercept Method

The minimum-intercept method seeks to identify that portion of plant related to a hypothetical no-load or zero-intercept situation. This requires considerably more data and calculation than the minimum-size method. In most instances, it is more accurate, although the differences may be relatively small. The technique is to relate installed cost to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no-load intercept. The cost related to the zero-intercept is the customer component. The following describes the methodologies for determining the minimum intercept for distribution-plant Accounts 364, 365, 366, 367, and 368.

1. Account 364 - Poles, Towers, and Fixtures

- Determine the number, investment, and average installed book cost of distribution poles by height and class of pole. (Exclude stubs for guying.)
- Determine minimum intercept of pole cost by creating a regression equation, relating classes and heights of poles, and using the Class 7 cost intercept for each pole of equal height weighted by the number of poles in each height category.
- Multiply minimum intercept cost by total number of distribution poles to get customer component.

- Balance of pole investment is assigned to demand component.

- Total account dollars are assigned based on ratio of pole investment. (Transformer platforms in Account 364 are all demand-related. They should be removed before determining the account ratio of customer- and demand-related costs, and then they should be added to the demand portion of Account 364.)

2. Account 365 - Overhead Conductors and Devices

- If accounts are divided between primary and secondary voltages, develop a customer component separately for each. The total investment is assigned to primary and secondary; then the customer component is developed for each. Since conductors generally are of many types and sizes, select those sizes and types which represent the bulk of the investment in this account, if appropriate.

- When developing the customer component, consider only the investment in conductors, and not such devices as circuit breakers, insulators, switches, etc. The investment in these devices will be assigned later between the customer and demand component, based on the conductor assignment.

  - Determine the feet, investment, and average installed book cost per foot for distribution conductors by size and type.

  - Determine minimum intercept of conductor cost per foot using cost per foot by size and type of conductor weighted by feet or investment in each category, and developing a cost for the utility's minimum size conductor.

  - Multiply minimum intercept cost by the total number of circuit feet times 2. (Note that circuit feet, not conductor feet, are used to get customer component.)

  - Balance of conductor investment is assigned to demand.

  - Total primary or secondary dollars in the account, including devices, are assigned to customer and demand components based on conductor investment ratio.

3. Accounts 366 and 367 - Underground Conduits, Conductors, and Devices

- The customer demand component ratio is developed for conductors and applied to conduits. Underground conductors are generally booked by type and size of conductor for both one-conductor (I/c) cable and three-conductor (3/c) cables. If conductors are booked by voltage, as between primary and secondary, a customer component is developed for each. If network and URD investments are segregated, a customer component must be developed for each.

- The conductor sizes and types for the customer component derivation are restricted to I/c cable. Since there are generally many types and sizes of I/c cable, select those sizes and types which represent the bulk of the investment, when appropriate.

  - Determine the feet, investment, and average installed book cost per foot for I/c cables by size and type of cable.

  - Determine minimum intercept of cable cost per foot using cost per foot by size and type of cable weighted by feet of investment in each category.

  - Multiply minimum intercept cost by the total number of circuit feet (I/c cable with sheath is considered a circuit) to get customer component.

  - Balance of cable investment is assigned to demand.

  - Total dollars in Accounts 366 and 367 are assigned to customer and demand components based on conductor investment ratio.

4. Account 368 - Line Transformers

- The line transformer account covers all sizes and voltages for single- and three-phase transformers. Only single-phase sizes up to and including 50 KVA should be used in developing the customer components. Where more than one primary distribution voltage is used, it may be appropriate to use the transformer price from one or two predominant, selected voltages.

  - Determine the number, investment, and average installed book cost per transformer by size and type (voltage).

  - Determine zero intercept of transformer cost using cost per transformer by type, weighted by number for each category.

  - Multiply zero intercept cost by total number of line transformers to get customer component.

  - Balance of transformer investment is assigned to demand component.

  - Total dollars in the account are assigned to customer and demand components based on transformer investment ratio from customer and demand components.

C. The Minimum-System vs. Minimum-Intercept Approach

When selecting a method to classify distribution costs into demand and customer costs, the analyst must consider several factors. The minimum-intercept method can sometimes produce statistically unreliable results. The extension of the regression equation beyond the boundaries of the data normally will intercept the Y axis at a positive value. In some cases, because of incorrect accounting data or some other abnormality in the data, the regression equation will intercept the Y axis at a negative value. When this happens, a review of the accounting data must be made, and suspect data deleted.

The results of the minimum-size method can be influenced by several factors. The analyst must determine the minimum size for each piece of equipment: "Should the minimum size be based upon the minimum size equipment currently installed, historically installed, or the minimum size necessary to meet safety requirements?" The manner in which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs.

Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.

When allocating distribution costs determined by the minimum-size method, some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs.

Advocates of the minimum-intercept method contend that this problem does not exist when using their method. The reason is that the customer cost derived from the minimum-intercept method is based upon the zero-load intercept of the cost curve. Thus, the customer cost of a particular piece of equipment has no demand cost in it whatsoever.

D. Other Accounts

The preceding discussion of the merits of minimum-system versus the zero-intercept classification schemes will affect the major distribution-plant accounts for FERC Accounts 364 through 368. Several other plant accounts remain to be classified. While the classification of the following distribution-plant accounts is an important step, it is not as controversial as the classification of substations, poles, transformers, and conductors.

1. Account 369 - Services

This account is generally classified as customer-related. Classification of services may also include a demand component to reflect the fact that larger customers will require more costly service drops.

2. Account 370 - Meters

Meters are generally classified on a customer basis. However, they may also be classified using a demand component to show that larger-usage customers require more expensive metering equipment.

3. Account 371 - Installations on Customer Premises

This account is generally classified as customer-related and is often directly assigned. The kind of equipment in this account often influences how this account is treated. The equipment in this account is owned by the utility, but is located on the customer's side of the meter. A utility will often include area lighting equipment in this account and assign the investment directly to the lighting customer class.

4. Account 373 - Street Lighting and Signal Systems

This account is generally customer-related and is directly assigned to the street customer class.

III. ALLOCATION OF THE DEMAND AND CUSTOMER COMPONENTS OF DISTRIBUTION PLANT

After completing the classification of distribution plant accounts, the next major step in the cost of service process is to allocate the classified costs. Generally, determining the distribution-demand allocator will require more data and analysis than determining the customer allocators. Following are procedures used to calculate the demand and customer allocation factors.

A. Development of the Distribution Demand Allocators

There are several factors to consider when allocating the demand components of distribution plant. Distribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads. Distribution substations are designed to meet the maximum load from the distribution feeders emanating from the substation.

Similarly, when designing primary and secondary distribution feeders, the distribution engineer ensures that sufficient conductor and transformer capacity is available to meet the customer's loads at the primary- and secondary-distribution service levels. Local area loads are the major factors in sizing distribution equipment. Consequently, customer-class noncoincident demands (NCPs) and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of distribution facilities. The customer-class load characteristic used to allocate the demand component of distribution plant (whether customer class NCPs or the summation of individual customer maximum demands) depends on the load diversity that is present at the equipment to be allocated. The load diversity at distribution substations and primary feeders is usually high. For this reason, customer-class peaks are normally used for the allocation of these facilities. The facilities nearer the customer, such as secondary feeders and line transformers, have much lower load diversity. They are normally allocated according to the individual customer's maximum demands. Although these are the methods normally used for the allocation of distribution demand costs, some exceptions exist.

The load diversity differences for some utilities at the transmission and distribution substation levels may not be large. Consequently, some large distribution substations may be allocated using the same method as the transmission system. Before the cost analyst selects a method to allocate the different levels of distribution facilities, he must know the design and operational characteristics of the distribution system, as well as the demand losses at each level of the distribution system.

As previously indicated, the distribution system consists of several levels. The first level starts at the distribution substation, and the last level ends at the customer's meters. Power losses occur at each level and should be included in the demand allocators. Power losses are incorporated into the demand allocators by showing different demand loss factors at each predominant voltage level. The demand loss factor used to develop the primary-distribution demand allocator will be slightly larger than the demand loss factor used to develop the secondary demand allocator. When developing the distribution demand allocator, be aware that some customers take service at different voltage levels.

Cost analysts developing the allocator for distribution of substations or primary demand facilities must ensure that only the loads of those customers who benefit from these facilities are included in the allocator. For example, the loads of customers who take service at transmission level should not be reflected in the distribution substation or primary demand allocator. Similarly, when analysts develop the allocator for secondary demand facilities, the loads for customers served by the primary distribution system should not be included.

Utilities can gather load data to develop demand allocators, either through their load research program or their transformer load management program. In most cases, the load research program gathers data from meters on the customers' premises. A more complex procedure is to use the transformer load management program.

This procedure involves simulating load profiles for the various classes of equipment on the distribution system. This provides information on the nature of the load diversity between the customer and the substation, and its effect on equipment cost. Determining demand allocators through simulation provides a first-order load approximation, which represents the peak load for each type of distribution equipment.

The concept of peak load or "equipment peak" for each piece of distribution equipment can be understood by considering line transformers. If a given transformer's loading for each hour of a month can be calculated, a transformer load curve can be developed. By knowing the types of customers connected to each load management transformer, a simulated transformer load profile curve can be developed for the system. This can provide each customer's class demand at the time of the transformer's peak load. Similarly, an equipment peak can be defined for equipment at each level of the distribution system. Although the equipment peak obtained by this method may not be ideal, it will closely approximate the actual peak. Thus, this method should reflect the different load diversities among customers at each level of the distribution system. An illustration of the simulation procedure is provided in Appendix 6-A.

B. Allocation of Customer-Related Costs

When the demand-customer classification has been completed, most of the assumptions will have been made that affect the results of the completed cost of service study.

The allocation of the customer-related portion of the various plant accounts is based on the number of customers by classes of service, with appropriate weightings and adjustments. Weighting factors reflect differences in characteristics of customers within a given class, or between classes. Within a class, for instance, we may want to give more weighting of a certain plant account to rural customers, as compared to urban customers. The metering account is a clear example of an account requiring weighting for differences between classes. A metering arrangement for a single industrial customer may be 20 to 80 times as costly as the metering for one residential customer.

While customer allocation factors should be weighted to offset differences among various types of customers, highly refined weighting factors or detailed and time consuming studies may not seem worthwhile. Such factors applied in this final step of the cost study may affect the final results much less than such basic assumptions as the demand-allocation method or the technique for determining demand-customer classifications.

Expense allocations generally are based on the comparable plant allocator of the various classes. For instance, maintenance of overhead lines is generally assumed to be directly related to plant in overhead conductors and devices. Exceptions to this rule will occur in some accounts. Meter expenses, for example, are often a function of maintenance and testing schedules related more to revenue per customer than to the cost of the meters themselves.

EXHIBIT NO. ___ (SJB-6)

TAMPA ELECTRIC COMPANY
MINIMUM DISTRIBUTION SYSTEM ANALYSIS
SUMMARY BY DISTRIBUTION ACCOUNT

Account No.	Description	Percentage Functional Cost Component		
		Customer	Capacity	Total
364	Poles	64%	36%	100%
365,366,367	Conductors	9%	91%	100%
368	Transformers	24%	76%	100%
369	Services	100%	0%	100%
370	Metering	100%	0%	100%

TAMPA ELECTRIC COMPANY
MINIMUM DISTRIBUTION SYSTEM ANALYSIS
ZERO-INTERCEPT CALCULATION TO DETERMINE CUSTOMER COMPONENT

Conductors		Transformers	
y	x	y	x
$/ft.	MCM Size	$/unit	KVA Size
0.69	66.63	1689	15
0.83	133.10	1921	25
1.59	336.00	2145	37.5
		2388	50
		3165	75
		3789	100
		6019	167

	Conductors	Transformers
Linear Line Attribute:	Y = mx + b	Y = mx + b
m = slope	0.0034	28.5077
b = zero-intercept	0.42	1,105

TAMPA ELECTRIC COMPANY
MINIMUM DISTRIBUTION SYSTEM ANALYSIS
ACCOUNT 364 - POLES

Line No.			Reference Note
1	Current unit cost of least costly framed distribution pole	$ 795.59	a
	Times:	x	
2	Total quantity of distribution poles in A/C 364	308,658	b
	Equals:		
3	Total current cost of distribution poles in A/C 364 valued on the basis of least costly pole	$ 245,565,218	
	Divided by:	/	
4	Total Current Replacement Cost of Account 364 - Poles	$ 382,747,838	c
	Equals:		
5	Calculated % Customer Cost Component of Account 364-Poles	64%	

Notes:
- a Per Distribution Engineering current cost estimate.
- b Per Company pole count analysis of A/C 364.
- c Per input data to TECO's most recent Storm Damage Study.

TAMPA ELECTRIC COMPANY
MINIMUM DISTRIBUTION SYSTEM ANALYSIS
ACCOUNTS' 365 & 367 - CONDUCTORS AND DEVICES

Line No.			Reference Note
1	Minimum size conductor current cost based on zero-intercept determination in $/ft.	$ 0.42	a
	Times:	x	
2	Total footage quantity of conductors installed in A/C's 365 & 367	187,550,988	b
	Equals:		
3	Total current cost of conductors in A/C 367 valued on basis of minimum unit cost	$ 78,771,415	
	Times:	x	
4	Ancillaries Factor	1.26	c
	Equals:		
5	Total current cost of all facilities in A/C's 365 & 367 valued on basis of minimum unit cost	$ 99,251,983	
	Divided by:	/	
6	Total Estimated Replacement Cost of Accounts 365 & 367	$ 1,138,119,878	d
	Equals:		
7	Calculated % Customer Cost Component of Accounts 365 & 367- Conductors & Devices	9%	

Notes:

a Per zero-intercept calculation for conductors.
b Per Plant Accounting Dept.'s detailed records of facilities in A/C's 365 & 367 as of EOY 2011.
c Reflects proportional cost of ancillary facilities in Plant Accounting's records for A/C 365 & 367 that support the conductors' units of property.
d Per input data to TECO's most recent Storm Damage Study.
Account 366, conduit, is assumed to have same classification as being derived herein for account 367.

TAMPA ELECTRIC COMPANY
MINIMUM DISTRIBUTION SYSTEM ANALYSIS
ACCOUNT 368 - TRANSFORMERS

Line No.				Reference Note
1	Minimum size transformer cost based on zero-intercept determination in $/unit	$	1,105	a
	Times:		x	
2	Total number of distribution transformer units in A/C 368 installed		163,977	b
	Equals:			
3	Total current cost of transformer units in A/C 368 valued on the basis of minimum unit cost	$	181,115,821	
	Times:		x	
4	Ancillaries Factor		1.33	c
	Equals:			
5	Total current cost of all facilities in A/C 368 valued on basis of minimum unit cost	$	240,684,815	
	Divided by:		/	
6	Total Estimated Current Replacement Cost of Account 368	$	1,019,315,127	d
	Equals:			
7	Calculated % Customer Cost Component of Account 368-Transformers		24%	

Notes:

- a Per zero-intercept calculation for transformers.
- b Per Plant Accounting Dept.'s detailed records of facilities in A/C 368 as of EOY 2011.
- c Reflects proportional cost of ancillary facilities in Plant Accounting's records for A/C 368 that support the transformers' units of property.
- d Per input data to TECO's most recent Storm Damage Study.

EXHIBIT NO. ___ (SJB-7)

MDS Customer/Demand Percentages by FERC Account

Account	%Customer	%Demand
364	65.2%	34.8%
365	13.2%	86.8%
366	3.9%	96.1%
367	4.8%	95.2%
368	25.4%	74.6%
369	100%	0%
370	100%	0%

EXHIBIT NO. ___ (SJB-8)

Analysis of FPL Account 364 Minimum Size Poles

Retirement Unit	Quantity	Cost	Unit Cost
36400 - Poles, Towers & Fixtures			
400.130 :POLE, WOOD 25/30 FT	174,085	55,724,257	320.10
400.135 :POLE, WOOD 35/40/45 FT	825,871	708,929,981	858.40
Average Cost of Small Poles	1,006,762	792,188,505	786.87
Repricing of All Poles at Minimum Cost	**1,168,532**	**919,480,094**	**786.87**
Account No. 364 Balance (per "Inputs Primary Secondary Split")		**1,318,788,311**	
Customer Component		**919,480,094**	
Demand Component		**399,308,217**	
Customer Component Percent		**69.7%**	
Demand Component Percent		**30.3%**	

Florida Power & Light Company
Docket No. 160021-EI
OPC's Seventh Set of Interrogatories
Interrogatory No. 192
Attachment No. 1
Tab 1 of 1

Pole Balance by type/height

Account 364.1 as of December 2014 and December 2015

Gl Account	Utility Account	As Of Year	Pole Category	Retirement Unit	Quantity	Cost
101000 Electric Plant In Service	36400 - Poles, Towers & Fixtures	2014	Wood Pole	400.130 :POLE, WOOD 25/30 FT	175,368	$ 55,913,778.80
101000 Electric Plant In Service	36400 - Poles, Towers & Fixtures	2014	Wood Pole	400.135 :POLE, WOOD 35/40/45 FT	829,245	$ 697,532,472.52
101000 Electric Plant In Service	36400 - Poles, Towers & Fixtures	2014	Wood Pole	400.150 :POLE, WOOD 50/55/60 FT	67,155	$ 104,110,767.86
101000 Electric Plant In Service	36400 - Poles, Towers & Fixtures	2014	Wood Pole	400.165 :POLE, WOOD 65 FT and >	1,567	$ 4,302,447.58
				As of 2014 Pole Total	**1,073,335**	**$ 861,859,466.76**
101000 Electric Plant In Service	36400 - Poles, Towers & Fixtures	2015	Wood Pole	400.130 :POLE, WOOD 25/30 FT	174,085	$ 55,724,256.73
101000 Electric Plant In Service	36400 - Poles, Towers & Fixtures	2015	Wood Pole	400.135 :POLE, WOOD 35/40/45 FT	825,871	$ 708,929,981.13
101000 Electric Plant In Service	36400 - Poles, Towers & Fixtures	2015	Wood Pole	400.150 :POLE, WOOD 50/55/60 FT	69,449	$ 113,171,930.25
101000 Electric Plant In Service	36400 - Poles, Towers & Fixtures	2015	Wood Pole	400.165 :POLE, WOOD 65 FT and >	1,565	$ 4,485,106.30
				As of 2015 Pole Total	**1,070,970**	**$ 882,311,274.41**

Interrogatory No. 13
Attachment No. 1
Tab 1 of 1

Number of distribution poles booked to FERC Account No. 364
as of December 31, 2015

Utility Account	**36400 - Poles, Towers & Fixtures**
Pole Types (by Retirement Unit)	**Quantity**
400.101 : TRANSMISSION POLE/W TOPP	0
400.130 :POLE, WOOD 25/30 FT	174,085
400.135 :POLE, WOOD 35/40/45 FT	825,871
400.150 :POLE, WOOD 50/55/60 FT	69,449
400.165 :POLE, WOOD 65 FT and >	1,565
400.230 : POLE,CONCRETE 30'	2,787
400.235 :POLE, CONCRETE 35/40/45 F	47,334
400.251 :POLE, CONCRETE 50/55/60 F	46,267
400.263 :POLE, CONCRETE 65 FT and	1,158
400.300 : POLE, STL/METAL	12
400.440 : POLE,LAMINATED, ALL SIZE	4
Grand Total	**1,168,532**

EXHIBIT NO. ___ (SJB-9)

COST OF SERVICE STUDY - 12 CP and 1/13th w/MDS
2017 AT PRESENT RATES
($000 WHERE APPLICABLE)

	Total Retail	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3
RATE BASE -										
Electric Plant In Service	43,122,297	679,289	27,284	276,137	2,575,101	26,726	8,230,769	3,267,345	643,783	34,845
Accum Depreciation & Amortization	(13,074,538)	(198,799)	(8,042)	(79,561)	(783,065)	(8,338)	(2,432,958)	(961,572)	(188,731)	(10,127)
Net Plant In Service	30,047,759	480,490	19,242	196,576	1,792,036	18,388	5,797,810	2,305,774	455,052	24,718
Plant Held For Future Use	233,315	4,247	166	1,861	13,461	117	49,521	19,996	4,012	245
Construction Work in Progress	747,987	12,518	495	5,755	44,278	461	147,321	58,810	11,822	750
Net Nuclear Fuel	630,075	15,678	597	8,603	35,101	413	151,865	61,743	14,687	987
Total Utility Plant	31,659,136	512,932	20,501	212,795	1,884,876	19,380	6,146,518	2,446,322	485,573	26,700
Working Capital - Assets	3,552,622	61,881	2,444	28,479	219,228	2,669	689,042	272,867	58,349	3,381
Working Capital - Liabilities	(2,675,642)	(45,102)	(1,784)	(20,265)	(166,656)	(2,033)	(509,414)	(201,184)	(42,574)	(2,410)
Working Capital - Net	876,981	16,779	659	8,214	52,572	636	179,628	71,683	15,775	970
Total Rate Base	32,536,116	529,711	21,160	221,009	1,937,448	20,016	6,326,146	2,518,005	501,348	27,670
REVENUES -										
Sales of Electricity	5,728,329	87,801	4,110	35,873	369,374	4,185	1,138,574	381,366	78,385	4,567
Other Operating Revenues	193,876	1,248	51	433	12,807	151	18,146	5,966	1,241	54
Total Operating Revenues	5,922,205	89,049	4,161	36,306	382,182	4,336	1,156,720	387,332	79,626	4,621
EXPENSES -										
Operating & Maintenance Expense	(1,354,606)	(21,694)	(863)	(9,366)	(85,954)	(1,077)	(248,991)	(97,785)	(20,512)	(1,115)
Depreciation Expense	(1,672,107)	(26,659)	(1,074)	(11,574)	(100,547)	(1,053)	(319,566)	(126,328)	(25,132)	(1,439)
Taxes Other Than Income Tax	(578,191)	(9,221)	(370)	(3,795)	(34,709)	(364)	(111,089)	(44,062)	(8,745)	(476)
Amortization of Property Losses	6,182	87	4	27	386	5	1,084	425	84	4
Gain or Loss on Sale of Plant	5,759	97	4		340	2	1,222	502	95	
Total Operating Expenses	(3,592,963)	(57,390)	(2,299)	(24,708)	(220,485)	(2,487)	(677,340)	(267,247)	(54,210)	(3,027)
Net Operating Income Before Taxes	2,329,242	31,659	1,863	11,598	161,697	1,849	479,380	120,084	25,416	1,594
Income Taxes	(711,051)	(9,143)	(599)	(3,194)	(51,319)	(600)	(148,735)	(31,553)	(6,874)	(455)
NOI Before Curtailment Adjustment	1,618,192	22,516	1,264	8,404	110,378	1,250	330,645	88,531	18,542	1,139
Curtailment Credit Revenue	587							388	130	70
Reassign Curtailment Credit Revenue	(587)	(11)	(0)	(6)	(33)	(0)	(127)	(51)	(10)	(1)
Net Curtailment Credit Revenue		(11)	(0)	(6)	(33)	(0)	(127)	336	119	69
Net Curtailment NOI Adjustment		(7)	(0)	(3)	(20)	(0)	(78)	206	73	42
Net Operating Income (NOI)	1,618,192	22,509	1,264	8,400	110,358	1,249	330,567	88,737	18,615	1,181
Rate of Return (ROR)	4.97%	4.25%	5.97%	3.80%	5.70%	6.24%	5.23%	3.52%	3.71%	4.27%
Parity At Present Rates	1.000	0.854	1.201	0.764	1.145	1.255	1.051	0.709	0.747	0.858

COST OF SERVICE STUDY - 12 CP and 1/13th w/MDS
2017 AT PRESENT RATES
($000 WHERE APPLICABLE)

	Total Retail	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3
EQUALIZED RATE OF RETURN (ROR) -										
Equalized Base Revenue Requirements	5,728,329	94,054	3,766	40,097	346,553	3,771	1,112,597	440,864	88,687	4,885
Other Operating Revenues (Equalized)	193,876	1,248	51	433	12,807	151	18,146	5,966	1,241	54
Total Equalized Revenue Requirements	5,922,205	95,302	3,817	40,531	359,361	3,922	1,130,743	446,830	89,928	4,939
Revenue Requirements Deficiency (Excess)		6,253	(344)	4,225	(22,821)	(414)	(25,977)	59,498	10,302	318
Revenue Requirements Index (1)	100.0%	93.4%	109.0%	89.6%	106.4%	110.6%	102.3%	86.7%	88.5%	93.6%

(1) (Total Revenues / Total Equalized Revenue Requirements)

Note: Totals may not add due to rounding.

	Total Retail	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3
Equalized Rate of Return (ROR)	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%
TARGET REVENUE REQUIREMENTS DEFICIENCY										
Base Revenue Requirements	870,239	20,356	219	10,110	28,797	117	142,367	126,531	23,648	1,055
Other Operating Revenues - Misc Service Charges	(3,885)	2	0	0	(29)	2	105	15	3	0
Target Revenue Requirements Deficiency	866,354	20,358	219	10,110	28,768	119	142,472	126,547	23,652	1,055
Target Revenue Requirements	6,788,559	109,407	4,381	46,416	410,950	4,455	1,299,192	513,878	103,278	5,675
TARGET REVENUE REQUIREMENTS INDEX	87.2%	78.5%	91.5%	78.2%	95.0%	110.5%	85.7%	72.3%	74.2%	81.4%

COST OF SERVICE STUDY - 12 CP and 1/13th w/MDS
2017 AT PRESENT RATES
($000 WHERE APPLICABLE)

	MET	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
RATE BASE -								
Electric Plant In Service	28,213	99,219	8,935	26,587,758	604,971	8,017	5,651	18,253
Accum Depreciation & Amortization	(8,240)	(39,820)	(2,788)	(8,121,073)	(221,878)	(2,374)	(1,670)	(5,501)
Net Plant In Service	19,973	59,399	6,147	18,466,685	383,093	5,643	3,981	12,752
Plant Held For Future Use	173	121	41	138,064	1,055	49	34	151
Construction Work in Progress	500	1,188	120	454,395	8,875	151	88	457
Net Nuclear Fuel	525	576	62	335,168	3,298	193	68	511
Total Utility Plant	21,171	61,284	6,370	19,394,311	396,322	6,037	4,172	13,872
Working Capital - Assets	2,357	4,657	615	2,150,784	52,952	801	421	1,698
Working Capital - Liabilities	(1,731)	(3,249)	(469)	(1,635,703)	(40,961)	(589)	(320)	(1,197)
Working Capital - Net	627	1,408	145	515,082	11,991	212	101	501
Total Rate Base	21,797	62,692	6,516	19,909,393	408,312	6,248	4,273	14,373
REVENUES -								
Sales of Electricity	4,095	14,051	992	3,506,972	91,273	1,508	801	4,401
Other Operating Revenues	50	652	24	151,900	1,091	16	13	32
Total Operating Revenues	4,145	14,703	1,016	3,658,872	92,364	1,525	815	4,433
EXPENSES -								
Operating & Maintenance Expense	(840)	(1,644)	(251)	(840,203)	(23,304)	(291)	(164)	(552)
Depreciation Expense	(1,125)	(4,044)	(328)	(1,027,387)	(24,624)	(316)	(201)	(711)
Taxes Other Than Income Tax	(383)	(1,114)	(117)	(355,665)	(7,648)	(110)	(76)	(247)
Amortization of Property Losses	4	20	2	3,914	134	1	1	2
Gain or Loss on Sale of Plant	4	7	3	3,440	40	1	2	
Total Operating Expenses	(2,340)	(6,775)	(692)	(2,215,902)	(55,402)	(715)	(438)	(1,508)
Net Operating Income Before Taxes	1,805	7,928	324	1,442,970	36,962	810	377	2,925
Income Taxes	(573)	(2,706)	(86)	(441,867)	(11,892)	(279)	(121)	(1,056)
NOI Before Curtailment Adjustment	1,233	5,222	238	1,001,103	25,071	532	256	1,869
Curtailment Credit Revenue								
Reassign Curtailment Credit Revenue	(0)	(0)	(0)	(346)	(0)	(0)	(0)	(0)
Net Curtailment Credit Revenue	(0)	(0)	(0)	(346)	(0)	(0)	(0)	(0)
Net Curtailment NOI Adjustment	(0)	(0)	(0)	(212)	(0)	(0)	(0)	(0)
Net Operating Income (NOI)	1,232	5,222	238	1,000,891	25,071	531	256	1,869
Rate of Return (ROR)	5.65%	8.33%	3.65%	5.03%	6.14%	8.51%	5.99%	13.00%
Parity At Present Rates	1.137	1.675	0.735	1.011	1.235	1.710	1.203	2.615

COST OF SERVICE STUDY - 12 CP and 1/13th w/MDS
2017 AT PRESENT RATES
($000 WHERE APPLICABLE)

	MET	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
EQUALIZED RATE OF RETURN (ROR) -								
Equalized Base Revenue Requirements	3,853	10,620	1,132	3,489,540	83,508	1,149	731	2,520
Other Operating Revenues (Equalized)	50	652	24	151,900	1,091	16	13	32
Total Equalized Revenue Requirements	3,903	11,272	1,156	3,641,440	84,600	1,165	744	2,552
Revenue Requirements Deficiency (Excess)	(242)	(3,430)	140	(17,432)	(7,765)	(360)	(71)	(1,882)
Revenue Requirements Index [1]	106.2%	130.4%	87.9%	100.5%	109.2%	130.9%	109.5%	173.7%

[1] (Total Revenues / Total Equalized Revenue Requirements)

Note: Totals may not add due to rounding.

	MET	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
Equalized Rate of Return (ROR)	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%
TARGET REVENUE REQUIREMENTS DEFICIENCY								
Base Revenue Requirements	339	(1,776)	314	516,706	3,105	(194)	43	(1,499)
Other Operating Revenues - Misc Service Charges	0	15	0	(4,002)	2	0	0	0
Target Revenue Requirements Deficiency	339	(1,761)	314	512,705	3,107	(193)	43	(1,499)
Target Revenue Requirements	4,483	12,942	1,330	4,171,576	95,472	1,331	858	2,934
TARGET REVENUE REQUIREMENTS INDEX	89.3%	110.9%	70.1%	89.3%	95.0%	110.5%	87.3%	151.1%

EXHIBIT NO. ___ (SJB-10)

COST OF SERVICE STUDY 12CP and 1/13th w/MDS
2018 AT PRESENT RATES
($000 WHERE APPLICABLE)

	Total Retail	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3
RATE BASE -										
Electric Plant In Service	45,511,408	708,525	28,465	288,791	2,731,325	28,739	8,627,783	3,423,358	668,938	36,391
Accum Depreciation & Amortization	(14,227,659)	(216,641)	(8,753)	(88,610)	(853,171)	(9,076)	(2,654,354)	(1,049,621)	(204,681)	(11,215)
Net Plant In Service	31,283,750	491,884	19,713	200,181	1,878,154	19,663	5,973,430	2,373,738	464,258	25,175
Plant Held For Future Use	242,917	4,407	172	1,977	14,017	123	51,546	20,819	4,147	260
Construction Work in Progress	807,675	13,471	533	6,251	47,883	501	159,041	63,510	12,679	800
Net Nuclear Fuel	606,781	15,009	571	8,369	33,798	400	146,121	59,427	14,041	960
Total Utility Plant	32,941,123	524,771	20,989	216,777	1,973,852	20,687	6,330,136	2,517,494	495,124	27,195
Working Capital - Assets	3,609,415	62,188	2,457	28,789	223,281	2,730	696,640	275,805	58,471	3,417
Working Capital - Liabilities	(2,679,641)	(44,700)	(1,769)	(20,139)	(167,327)	(2,053)	(507,583)	(200,418)	(42,072)	(2,394)
Working Capital - Net	929,774	17,488	688	8,651	55,954	677	189,057	75,386	16,399	1,023
Total Rate Base	33,870,897	542,259	21,677	225,428	2,029,806	21,364	6,519,193	2,592,880	511,523	28,218
REVENUES -										
Sales of Electricity	5,766,631	87,705	4,103	36,199	371,457	4,234	1,143,029	382,968	78,196	4,633
Other Operating Revenues	200,898	1,313	54	461	13,302	157	19,068	6,297	1,300	57
Total Operating Revenues	5,967,529	89,018	4,157	36,660	384,759	4,391	1,162,097	389,265	79,495	4,690
EXPENSES -										
Operating & Maintenance Expense	(1,403,655)	(22,315)	(887)	(9,679)	(89,131)	(1,118)	(257,446)	(101,134)	(21,029)	(1,152)
Depreciation Expense	(1,749,006)	(27,474)	(1,108)	(11,956)	(105,665)	(1,120)	(331,566)	(130,944)	(25,821)	(1,486)
Taxes Other Than Income Tax	(615,473)	(9,660)	(388)	(3,958)	(37,165)	(397)	(117,112)	(46,421)	(9,129)	(497)
Amortization of Property Losses	10,587	166	7	68	637	7	2,018	802	157	9
Gain or Loss on Sale of Plant	10,759	181	7		639	4	2,277	936	176	
Total Operating Expenses	(3,746,789)	(59,102)	(2,369)	(25,525)	(230,685)	(2,623)	(701,829)	(276,762)	(55,646)	(3,126)
Net Operating Income Before Taxes	2,220,740	29,916	1,788	11,135	154,074	1,768	460,268	112,503	23,849	1,563
Income Taxes	(645,029)	(8,124)	(557)	(2,872)	(46,883)	(551)	(137,116)	(26,846)	(5,947)	(426)
NOI Before Curtailment Adjustment	1,575,711	21,792	1,231	8,263	107,190	1,217	323,152	85,657	17,902	1,137
Curtailment Credit Revenue	596							395	130	71
Reassign Curtailment Credit Revenue	(596)	(11)	(0)	(6)	(33)	(0)	(129)	(52)	(10)	(1)
Net Curtailment Credit Revenue		(11)	(0)	(6)	(33)	(0)	(129)	343	120	70
Net Curtailment NOI Adjustment		(7)	(0)	(4)	(21)	(0)	(79)	210	74	43
Net Operating Income (NOI)	1,575,711	21,786	1,231	8,259	107,170	1,217	323,073	85,867	17,976	1,180
Rate of Return (ROR)	4.65%	4.02%	5.68%	3.66%	5.28%	5.70%	4.96%	3.31%	3.51%	4.18%
Parity At Present Rates	1.000	0.864	1.220	0.788	1.135	1.225	1.065	0.712	0.755	0.899

COST OF SERVICE STUDY 12CP and 1/13th w/MDS
2018 AT PRESENT RATES
($000 WHERE APPLICABLE)

	Total Retail	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3
EQUALIZED RATE OF RETURN (ROR) -										
Equalized Base Revenue Requirements	5,766,631	93,314	3,741	39,831	350,686	3,869	1,110,762	439,629	87,685	4,848
Other Operating Revenues (Equalized)	200,898	1,313	54	461	13,302	157	19,068	6,297	1,300	57
Total Equalized Revenue Requirements	5,967,529	94,627	3,795	40,291	363,988	4,027	1,129,829	445,926	88,985	4,905
Revenue Requirements Deficiency (Excess)		5,609	(362)	3,632	(20,771)	(364)	(32,267)	56,661	9,489	216
Revenue Requirements Index [1]	100.0%	94.1%	109.5%	91.0%	105.7%	109.0%	102.9%	87.3%	89.3%	95.6%

[1] (Total Revenues / Total Equalized Revenue Requirements)

Note: Totals may not add due to rounding.

	Total Retail	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3
Equalized Rate of Return (ROR)	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%
TARGET REVENUE REQUIREMENTS DEFICIENCY - [(1]										
Base Revenue Requirements	1,137,370	23,756	363	11,176	47,169	349	185,810	143,425	26,606	1,160
Other Operating Revenues - Misc Service Charges	(3,777)	2	0	0	(7)	2	107	15	3	0
Target Revenue Requirements Deficiency	1,133,593	23,758	363	11,176	47,162	351	185,917	143,440	26,609	1,160
Target Revenue Requirements	7,101,122	112,776	4,520	47,836	431,921	4,742	1,348,014	532,705	106,104	5,850
TARGET REVENUE REQUIREMENTS INDEX	87.2%	78.5%	91.5%	78.2%	95.0%	110.5%	85.7%	72.3%	74.2%	81.4%

COST OF SERVICE STUDY 12CP and 1/13th w/MDS
2018 AT PRESENT RATES
($000 WHERE APPLICABLE)

	MET	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
RATE BASE -								
Electric Plant In Service	29,434	104,828	9,513	28,151,554	640,547	8,534	5,976	18,706
Accum Depreciation & Amortization	(8,977)	(42,411)	(2,969)	(8,831,322)	(235,549)	(2,634)	(1,796)	(5,878)
Net Plant In Service	20,457	62,417	6,545	19,320,232	404,998	5,900	4,180	12,828
Plant Held For Future Use	179	122	42	143,781	1,081	52	35	158
Construction Work in Progress	538	1,231	128	491,034	9,363	166	95	453
Net Nuclear Fuel	503	548	60	323,015	3,215	188	65	490
Total Utility Plant	21,677	64,318	6,774	20,278,062	418,657	6,306	4,375	13,929
Working Capital - Assets	2,374	4,729	636	2,189,967	54,994	821	430	1,688
Working Capital - Liabilities	(1,716)	(3,291)	(481)	(1,641,447)	(42,159)	(596)	(324)	(1,173)
Working Capital - Net	658	1,439	155	548,520	12,835	225	106	515
Total Rate Base	22,335	65,756	6,928	20,826,582	431,492	6,531	4,481	14,444
REVENUES -								
Sales of Electricity	4,093	17,809	992	3,530,657	93,814	1,539	802	4,402
Other Operating Revenues	52	673	24	156,896	1,180	18	14	34
Total Operating Revenues	4,145	18,482	1,017	3,687,552	94,994	1,557	815	4,435
EXPENSES -								
Operating & Maintenance Expense	(865)	(1,696)	(264)	(871,429)	(24,474)	(304)	(172)	(561)
Depreciation Expense	(1,162)	(4,250)	(349)	(1,079,001)	(25,839)	(332)	(210)	(723)
Taxes Other Than Income Tax	(401)	(1,200)	(128)	(380,307)	(8,258)	(118)	(81)	(254)
Amortization of Property Losses	7	21	2	6,540	139	2	1	4
Gain or Loss on Sale of Plant	8	13	6	6,430	76	2	4	
Total Operating Expenses	(2,413)	(7,112)	(733)	(2,317,767)	(58,356)	(750)	(458)	(1,534)
Net Operating Income Before Taxes	1,732	11,370	284	1,369,786	36,638	807	357	2,902
Income Taxes	(531)	(4,017)	(65)	(398,209)	(11,460)	(273)	(110)	(1,043)
NOI Before Curtailment Adjustment	1,201	7,353	219	971,577	25,178	534	247	1,859
Curtailment Credit Revenue								
Reassign Curtailment Credit Revenue	(0)	(0)	(0)	(351)	(0)	(0)	(0)	(0)
Net Curtailment Credit Revenue	(0)	(0)	(0)	(351)	(0)	(0)	(0)	(0)
Net Curtailment NOI Adjustment	(0)	(0)	(0)	(216)	(0)	(0)	(0)	(0)
Net Operating Income (NOI)	1,201	7,353	219	971,361	25,177	534	247	1,859
Rate of Return (ROR)	5.38%	11.18%	3.16%	4.66%	5.83%	8.18%	5.51%	12.87%
Parity At Present Rates	1.156	2.404	0.680	1.003	1.254	1.757	1.185	2.766

COST OF SERVICE STUDY 12CP and 1/13th w/MDS
2018 AT PRESENT RATES
($000 WHERE APPLICABLE)

	MET	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
EQUALIZED RATE OF RETURN (ROR) -								
Equalized Base Revenue Requirements	3,829	10,810	1,160	3,526,604	85,493	1,164	739	2,467
Other Operating Revenues (Equalized)	52	673	24	156,896	1,180	18	14	34
Total Equalized Revenue Requirements	3,881	11,482	1,185	3,683,499	86,673	1,182	753	2,500
Revenue Requirements Deficiency (Excess)	(264)	(7,000)	168	(4,053)	(8,321)	(375)	(63)	(1,935)
Revenue Requirements Index [(1)]	106.8%	161.0%	85.8%	100.1%	109.6%	131.7%	108.3%	177.4%

[(1)] (Total Revenues / Total Equalized Revenue Requireme

Note: Totals may not add due to rounding.

	MET	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
Equalized Rate of Return (ROR)	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%
TARGET REVENUE REQUIREMENTS DEFICIENCY - [(1]								
Base Revenue Requirements	483	(4,814)	400	696,890	6,118	(157)	87	(1,452)
Other Operating Revenues - Misc Service Charges	0	15	0	(3,918)	2	0	0	0
Target Revenue Requirements Deficiency	483	(4,799)	400	692,972	6,121	(157)	87	(1,452)
Target Revenue Requirements	4,628	13,683	1,417	4,380,524	101,114	1,401	903	2,984
TARGET REVENUE REQUIREMENTS INDEX	89.3%	110.9%	70.1%	89.3%	95.0%	110.5%	87.3%	151.1%

EXHIBIT NO. ___ (SJB-11)

COST OF SERVICE STUDY - 12 CP and 25% w/MDS
2017 AT PRESENT RATES
($000 WHERE APPLICABLE)

	Total Retail	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3
RATE BASE -										
Electric Plant In Service	43,122,297	700,012	28,013	289,165	2,573,779	27,400	8,310,170	3,301,665	663,318	36,120
Accum Depreciation & Amortization	(13,074,538)	(204,195)	(8,232)	(82,953)	(782,721)	(8,514)	(2,453,635)	(970,509)	(193,818)	(10,459)
Net Plant In Service	30,047,759	495,816	19,781	206,212	1,791,058	18,886	5,856,536	2,331,156	469,500	25,661
Plant Held For Future Use	233,315	4,313	168	1,903	13,457	120	49,775	20,105	4,074	249
Construction Work in Progress	747,987	12,688	501	5,862	44,267	467	147,973	59,092	11,982	761
Net Nuclear Fuel	630,075	15,678	597	8,603	35,101	413	151,865	61,743	14,687	987
Total Utility Plant	31,659,136	528,495	21,049	222,580	1,883,883	19,886	6,206,148	2,472,096	500,243	27,657
Working Capital - Assets	3,552,622	62,170	2,454	28,661	219,210	2,678	690,152	273,347	58,622	3,398
Working Capital - Liabilities	(2,675,642)	(45,280)	(1,791)	(20,377)	(166,645)	(2,039)	(510,097)	(201,480)	(42,742)	(2,421)
Working Capital - Net	876,981	16,890	663	8,284	52,565	639	180,055	71,867	15,880	977
Total Rate Base	32,536,116	545,385	21,712	230,864	1,936,448	20,525	6,386,203	2,543,963	516,123	28,634
REVENUES -										
Sales of Electricity	5,728,329	87,801	4,110	35,873	369,374	4,185	1,138,574	381,366	78,385	4,567
Other Operating Revenues	193,876	1,250	51	435	12,807	151	18,156	5,970	1,244	54
Total Operating Revenues	5,922,205	89,051	4,162	36,307	382,181	4,336	1,156,729	387,336	79,628	4,621
EXPENSES -										
Operating & Maintenance Expense	(1,354,606)	(21,668)	(862)	(9,350)	(85,955)	(1,077)	(248,893)	(97,743)	(20,488)	(1,114)
Depreciation Expense	(1,672,107)	(27,607)	(1,107)	(12,169)	(100,487)	(1,083)	(323,196)	(127,897)	(26,026)	(1,497)
Taxes Other Than Income Tax	(578,191)	(9,489)	(379)	(3,964)	(34,692)	(373)	(112,115)	(44,505)	(8,997)	(493)
Amortization of Property Losses	6,182	93	4	30	385	5	1,104	433	89	4
Gain or Loss on Sale of Plant	5,759	97	4		340	2	1,222	502	95	
Total Operating Expenses	(3,592,963)	(58,574)	(2,340)	(25,453)	(220,409)	(2,526)	(681,879)	(269,209)	(55,327)	(3,099)
Net Operating Income Before Taxes	2,329,242	30,477	1,821	10,854	161,772	1,811	474,851	118,126	24,302	1,522
Income Taxes	(711,051)	(8,587)	(579)	(2,844)	(51,354)	(582)	(146,604)	(30,632)	(6,350)	(421)
NOI Before Curtailment Adjustment	1,618,192	21,890	1,242	8,010	110,418	1,229	328,247	87,494	17,952	1,101
Curtailment Credit Revenue	587							388	130	70
Reassign Curtailment Credit Revenue	(587)	(11)	(0)	(6)	(33)	(0)	(127)	(51)	(10)	(1)
Net Curtailment Credit Revenue		(11)	(0)	(6)	(33)	(0)	(127)	336	119	69
Net Curtailment NOI Adjustment		(7)	(0)	(3)	(20)	(0)	(78)	206	73	42
Net Operating Income (NOI)	1,618,192	21,884	1,242	8,007	110,398	1,229	328,169	87,700	18,025	1,143
Rate of Return (ROR)	4.97%	4.01%	5.72%	3.47%	5.70%	5.99%	5.14%	3.45%	3.49%	3.99%
Parity At Present Rates	1.000	0.807	1.150	0.697	1.146	1.204	1.033	0.693	0.702	0.802

COST OF SERVICE STUDY - 12 CP and 25% w/MDS
2017 AT PRESENT RATES
($000 WHERE APPLICABLE)

	Total Retail	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3
EQUALIZED RATE OF RETURN (ROR) -										
Equalized Base Revenue Requirements	5,728,329	96,346	3,847	41,538	346,407	3,846	1,121,376	444,659	90,847	5,026
Other Operating Revenues (Equalized)	193,876	1,250	51	435	12,807	151	18,156	5,970	1,244	54
Total Equalized Revenue Requirements	5,922,205	97,596	3,898	41,973	359,214	3,997	1,139,532	450,629	92,090	5,080
Revenue Requirements Deficiency (Excess)		8,545	(264)	5,665	(22,967)	(339)	(17,198)	63,293	12,462	459
Revenue Requirements Index [(1)]	100.0%	91.2%	106.8%	86.5%	106.4%	108.5%	101.5%	86.0%	86.5%	91.0%

[(1)] (Total Revenues / Total Equalized Revenue Requirements)

Note: Totals may not add due to rounding.

	Total Retail	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3
Equalized Rate of Return (ROR)	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%
TARGET REVENUE REQUIREMENTS DEFICIENCY										
Base Revenue Requirements	870,239	23,065	314	11,813	28,624	205	152,745	131,017	26,202	1,221
Other Operating Revenues - Misc Service Charges	(3,885)	2	0	0	(29)	2	105	15	3	0
Target Revenue Requirements Deficiency	866,354	23,067	315	11,813	28,595	207	152,851	131,032	26,205	1,221
Target Revenue Requirements	6,788,559	112,118	4,476	48,120	410,777	4,543	1,309,580	518,368	105,833	5,842
TARGET REVENUE REQUIREMENTS INDEX	87.2%	78.5%	91.5%	78.2%	95.0%	110.5%	85.7%	72.3%	74.2%	81.4%

COST OF SERVICE STUDY - 12 CP and 25% w/MDS
2017 AT PRESENT RATES
($000 WHERE APPLICABLE)

	MET	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
RATE BASE -								
Electric Plant In Service	28,467	101,902	9,031	26,399,608	620,290	8,332	5,712	19,314
Accum Depreciation & Amortization	(8,306)	(40,519)	(2,813)	(8,072,079)	(225,867)	(2,456)	(1,686)	(5,777)
Net Plant In Service	20,161	61,383	6,218	18,327,529	394,424	5,876	4,026	13,537
Plant Held For Future Use	174	130	41	137,464	1,104	50	34	154
Construction Work in Progress	502	1,210	121	452,850	9,001	154	89	466
Net Nuclear Fuel	525	576	62	335,168	3,298	193	68	511
Total Utility Plant	21,362	63,299	6,442	19,253,011	407,827	6,273	4,218	14,668
Working Capital - Assets	2,361	4,694	616	2,148,154	53,166	805	422	1,712
Working Capital - Liabilities	(1,733)	(3,272)	(470)	(1,634,084)	(41,093)	(592)	(320)	(1,206)
Working Capital - Net	628	1,422	146	514,070	12,073	213	101	507
Total Rate Base	21,990	64,721	6,588	19,767,081	419,900	6,486	4,319	15,175
REVENUES -								
Sales of Electricity	4,095	14,051	992	3,506,972	91,273	1,508	801	4,401
Other Operating Revenues	50	652	24	151,878	1,093	16	13	32
Total Operating Revenues	4,145	14,703	1,016	3,658,850	92,366	1,525	815	4,434
EXPENSES -								
Operating & Maintenance Expense	(840)	(1,641)	(251)	(840,435)	(23,286)	(290)	(164)	(551)
Depreciation Expense	(1,137)	(4,166)	(333)	(1,018,784)	(25,325)	(330)	(204)	(760)
Taxes Other Than Income Tax	(386)	(1,149)	(119)	(353,233)	(7,846)	(114)	(77)	(260)
Amortization of Property Losses	4	21	2	3,867	138	1	1	3
Gain or Loss on Sale of Plant	4	7	3	3,440	40	1	2	
Total Operating Expenses	(2,354)	(6,928)	(697)	(2,205,146)	(56,278)	(733)	(442)	(1,569)
Net Operating Income Before Taxes	1,791	7,775	319	1,453,704	36,088	792	373	2,865
Income Taxes	(566)	(2,634)	(84)	(446,918)	(11,480)	(270)	(119)	(1,028)
NOI Before Curtailment Adjustment	1,225	5,141	235	1,006,786	24,608	522	254	1,837
Curtailment Credit Revenue								
Reassign Curtailment Credit Revenue	(0)	(0)	(0)	(346)	(0)	(0)	(0)	(0)
Net Curtailment Credit Revenue	(0)	(0)	(0)	(346)	(0)	(0)	(0)	(0)
Net Curtailment NOI Adjustment	(0)	(0)	(0)	(212)	(0)	(0)	(0)	(0)
Net Operating Income (NOI)	1,225	5,141	235	1,006,574	24,608	522	254	1,837
Rate of Return (ROR)	5.57%	7.94%	3.57%	5.09%	5.86%	8.05%	5.88%	12.11%
Parity At Present Rates	1.120	1.597	0.718	1.024	1.178	1.618	1.182	2.434

COST OF SERVICE STUDY - 12 CP and 25% w/MDS
2017 AT PRESENT RATES
($000 WHERE APPLICABLE)

	MET	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
EQUALIZED RATE OF RETURN (ROR) -								
Equalized Base Revenue Requirements	3,881	10,917	1,143	3,468,737	85,202	1,183	738	2,637
Other Operating Revenues (Equalized)	50	652	24	151,878	1,093	16	13	32
Total Equalized Revenue Requirements	3,931	11,569	1,167	3,620,615	86,295	1,200	751	2,669
Revenue Requirements Deficiency (Excess)	(214)	(3,134)	151	(38,235)	(6,071)	(325)	(64)	(1,764)
Revenue Requirements Index (1)	105.4%	127.1%	87.1%	101.1%	107.0%	127.1%	108.5%	166.1%

(1) (Total Revenues / Total Equalized Revenue Requirements)

Note: Totals may not add due to rounding.

	MET	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
Equalized Rate of Return (ROR)	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%
TARGET REVENUE REQUIREMENTS DEFICIENCY								
Base Revenue Requirements	372	(1,426)	326	492,114	5,108	(152)	51	(1,361)
Other Operating Revenues - Misc Service Charges	0	15	0	(4,002)	2	0	0	0
Target Revenue Requirements Deficiency	372	(1,410)	326	488,112	5,110	(152)	51	(1,360)
Target Revenue Requirements	4,517	13,293	1,342	4,146,962	97,476	1,372	866	3,073
TARGET REVENUE REQUIREMENTS INDEX	89.3%	110.9%	70.1%	89.3%	95.0%	110.5%	87.3%	151.1%

EXHIBIT NO. ___ (SJB-12)

COST OF SERVICE STUDY 12CP and 25% w/MDS
2018 AT PRESENT RATES
($000 WHERE APPLICABLE)

	Total Retail	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3
RATE BASE -										
Electric Plant In Service	45,511,408	729,535	29,204	302,217	2,729,990	29,430	8,708,722	3,458,354	688,711	37,705
Accum Depreciation & Amortization	(14,227,659)	(222,738)	(8,967)	(92,506)	(852,784)	(9,277)	(2,677,841)	(1,059,776)	(210,418)	(11,597)
Net Plant In Service	31,283,750	506,797	20,237	209,710	1,877,206	20,153	6,030,882	2,398,578	478,293	26,108
Plant Held For Future Use	242,917	4,468	174	2,016	14,013	125	51,782	20,921	4,204	264
Construction Work in Progress	807,675	13,711	541	6,404	47,868	509	159,964	63,909	12,905	815
Net Nuclear Fuel	606,781	15,009	571	8,369	33,798	400	146,121	59,427	14,041	960
Total Utility Plant	32,941,123	539,985	21,524	226,499	1,972,885	21,187	6,388,748	2,542,835	509,443	28,146
Working Capital - Assets	3,609,415	62,459	2,466	28,963	223,264	2,739	697,684	276,256	58,726	3,434
Working Capital - Liabilities	(2,679,641)	(44,835)	(1,774)	(20,226)	(167,318)	(2,057)	(508,106)	(200,645)	(42,200)	(2,403)
Working Capital - Net	929,774	17,623	693	8,737	55,946	682	189,578	75,612	16,526	1,031
Total Rate Base	33,870,897	557,609	22,217	235,236	2,028,831	21,869	6,578,326	2,618,447	525,969	29,177
REVENUES -										
Sales of Electricity	5,766,631	87,705	4,103	36,199	371,457	4,234	1,143,029	382,968	78,196	4,633
Other Operating Revenues	200,898	1,315	54	462	13,302	157	19,077	6,301	1,302	57
Total Operating Revenues	5,967,529	89,020	4,157	36,661	384,759	4,391	1,162,106	389,269	79,498	4,690
EXPENSES -										
Operating & Maintenance Expense	(1,403,655)	(22,290)	(886)	(9,662)	(89,133)	(1,117)	(257,347)	(101,091)	(21,005)	(1,150)
Depreciation Expense	(1,749,006)	(28,434)	(1,142)	(12,570)	(105,604)	(1,151)	(335,266)	(132,544)	(26,725)	(1,546)
Taxes Other Than Income Tax	(615,473)	(9,928)	(397)	(4,129)	(37,148)	(405)	(118,142)	(46,867)	(9,381)	(514)
Amortization of Property Losses	10,587	171	7	71	637	7	2,037	810	162	9
Gain or Loss on Sale of Plant	10,759	181	7		639	4	2,277	936	176	
Total Operating Expenses	(3,746,789)	(60,299)	(2,411)	(26,290)	(230,609)	(2,662)	(706,441)	(278,756)	(56,773)	(3,201)
Net Operating Income Before Taxes	2,220,740	28,721	1,746	10,372	154,150	1,729	455,665	110,513	22,725	1,489
Income Taxes	(645,029)	(7,553)	(537)	(2,508)	(46,920)	(532)	(134,919)	(25,896)	(5,410)	(390)
NOI Before Curtailment Adjustment	1,575,711	21,168	1,209	7,864	107,230	1,197	320,746	84,617	17,314	1,098
Curtailment Credit Revenue	596							395	130	71
Reassign Curtailment Credit Revenue	(596)	(11)	(0)	(6)	(33)	(0)	(129)	(52)	(10)	(1)
Net Curtailment Credit Revenue		(11)	(0)	(6)	(33)	(0)	(129)	343	120	70
Net Curtailment NOI Adjustment		(7)	(0)	(4)	(21)	(0)	(79)	210	74	43
Net Operating Income (NOI)	1,575,711	21,161	1,209	7,860	107,210	1,197	320,667	84,827	17,388	1,141
Rate of Return (ROR)	4.65%	3.79%	5.44%	3.34%	5.28%	5.47%	4.87%	3.24%	3.31%	3.91%
Parity At Present Rates	1.000	0.816	1.169	0.718	1.136	1.176	1.048	0.696	0.711	0.841

COST OF SERVICE STUDY 12CP and 25% w/MDS
2018 AT PRESENT RATES
($000 WHERE APPLICABLE)

	Total Retail	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3
EQUALIZED RATE OF RETURN (ROR) -										
Equalized Base Revenue Requirements	5,766,631	95,497	3,818	41,225	350,547	3,941	1,119,169	443,264	89,739	4,985
Other Operating Revenues (Equalized)	200,898	1,315	54	462	13,302	157	19,077	6,301	1,302	57
Total Equalized Revenue Requirements	5,967,529	96,812	3,872	41,687	363,849	4,099	1,138,245	449,565	91,041	5,042
Revenue Requirements Deficiency (Excess)		7,792	(285)	5,026	(20,910)	(292)	(23,861)	60,296	11,543	352
Revenue Requirements Index (1)	100.0%	92.0%	107.4%	87.9%	105.7%	107.1%	102.1%	86.6%	87.3%	93.0%

(1) (Total Revenues / Total Equalized Revenue Requirements)

Note: Totals may not add due to rounding.

	Total Retail	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3
Equalized Rate of Return (ROR)	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%
TARGET REVENUE REQUIREMENTS DEFICIENCY - (										
Base Revenue Requirements	1,137,370	26,452	458	12,899	46,998	437	196,196	147,915	29,143	1,329
Other Operating Revenues - Misc Service Charges	(3,777)	2	0	0	(7)	2	107	15	3	0
Target Revenue Requirements Deficiency	1,133,593	26,454	458	12,899	46,991	440	196,303	147,930	29,146	1,329
Target Revenue Requirements	7,101,122	115,474	4,615	49,560	431,750	4,831	1,358,409	537,199	108,644	6,019
TARGET REVENUE REQUIREMENTS INDEX	87.2%	78.5%	91.5%	78.2%	95.0%	110.5%	85.7%	72.3%	74.2%	81.4%

COST OF SERVICE STUDY 12CP and 25% w/MDS
2018 AT PRESENT RATES
($000 WHERE APPLICABLE)

	MET	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
RATE BASE -								
Electric Plant In Service	29,693	107,532	9,611	27,959,668	656,359	8,860	6,037	19,782
Accum Depreciation & Amortization	(9,052)	(43,196)	(2,997)	(8,775,640)	(240,138)	(2,729)	(1,814)	(6,190)
Net Plant In Service	20,641	64,336	6,614	19,184,028	416,221	6,131	4,223	13,592
Plant Held For Future Use	180	130	42	143,221	1,127	53	35	161
Construction Work in Progress	541	1,261	129	488,844	9,543	169	95	465
Net Nuclear Fuel	503	548	60	323,015	3,215	188	65	490
Total Utility Plant	21,864	66,275	6,845	20,139,109	430,107	6,542	4,419	14,708
Working Capital - Assets	2,377	4,764	637	2,187,490	55,198	825	430	1,702
Working Capital - Liabilities	(1,718)	(3,308)	(482)	(1,640,206)	(42,262)	(598)	(324)	(1,180)
Working Capital - Net	659	1,456	155	547,284	12,937	227	106	522
Total Rate Base	22,524	67,732	7,000	20,686,393	443,044	6,769	4,525	15,230
REVENUES -								
Sales of Electricity	4,093	17,809	992	3,530,657	93,814	1,539	802	4,402
Other Operating Revenues	52	673	24	156,874	1,182	18	14	34
Total Operating Revenues	4,145	18,482	1,017	3,687,531	94,995	1,557	816	4,436
EXPENSES -								
Operating & Maintenance Expense	(864)	(1,692)	(263)	(871,665)	(24,455)	(304)	(172)	(560)
Depreciation Expense	(1,174)	(4,374)	(354)	(1,070,229)	(26,562)	(347)	(213)	(772)
Taxes Other Than Income Tax	(404)	(1,235)	(129)	(377,864)	(8,459)	(122)	(82)	(268)
Amortization of Property Losses	7	22	2	6,495	143	2	1	5
Gain or Loss on Sale of Plant	8	13	6	6,430	76	2	4	
Total Operating Expenses	(2,428)	(7,266)	(738)	(2,306,833)	(59,257)	(768)	(462)	(1,595)
Net Operating Income Before Taxes	1,717	11,216	279	1,380,698	35,738	789	354	2,840
Income Taxes	(524)	(3,944)	(62)	(403,418)	(11,031)	(264)	(108)	(1,013)
NOI Before Curtailment Adjustment	1,194	7,272	216	977,280	24,708	524	245	1,827
Curtailment Credit Revenue								
Reassign Curtailment Credit Revenue	(0)	(0)	(0)	(351)	(0)	(0)	(0)	(0)
Net Curtailment Credit Revenue	(0)	(0)	(0)	(351)	(0)	(0)	(0)	(0)
Net Curtailment NOI Adjustment	(0)	(0)	(0)	(216)	(0)	(0)	(0)	(0)
Net Operating Income (NOI)	1,193	7,272	216	977,065	24,707	524	245	1,827
Rate of Return (ROR)	5.30%	10.74%	3.09%	4.72%	5.58%	7.74%	5.42%	12.00%
Parity At Present Rates	1.139	2.308	0.664	1.015	1.199	1.665	1.165	2.579

COST OF SERVICE STUDY 12CP and 25% w/MDS
2018 AT PRESENT RATES
($000 WHERE APPLICABLE)

	MET	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
EQUALIZED RATE OF RETURN (ROR) -								
Equalized Base Revenue Requirements	3,856	11,090	1,171	3,506,673	87,136	1,198	745	2,579
Other Operating Revenues (Equalized)	52	673	24	156,874	1,182	18	14	34
Total Equalized Revenue Requirements	3,908	11,764	1,195	3,663,548	88,317	1,216	759	2,612
Revenue Requirements Deficiency (Excess)	(237)	(6,719)	178	(23,983)	(6,678)	(341)	(56)	(1,823)
Revenue Requirements Index [1]	106.1%	157.1%	85.1%	100.7%	107.6%	128.1%	107.4%	169.8%

[1] (Total Revenues / Total Equalized Revenue Requireme

Note: Totals may not add due to rounding.

	MET	OL-1	OS-2	RS(T)-1	SL-1	SL-2	SST-DST	SST-TST
Equalized Rate of Return (ROR)	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%	6.71%
TARGET REVENUE REQUIREMENTS DEFICIENCY - (								
Base Revenue Requirements	517	(4,467)	412	672,267	8,147	(115)	95	(1,314)
Other Operating Revenues - Misc Service Charges	0	15	0	(3,918)	2	0	0	0
Target Revenue Requirements Deficiency	517	(4,452)	412	668,350	8,149	(115)	95	(1,314)
Target Revenue Requirements	4,661	14,030	1,429	4,355,881	103,145	1,442	910	3,122
TARGET REVENUE REQUIREMENTS INDEX	89.3%	110.9%	70.1%	89.3%	95.0%	110.5%	87.3%	151.1%

EXHIBIT NO. ___ (SJB-13)

FLORIDA PUBLIC SERVICE COMMISSION

COMPANY: FLORIDA POWER & LIGHT COMPANY
AND SUBSIDIARIES

DOCKET NO.: 160021-EI

EXPLANATION: By rate schedule, calculate revenues under present and proposed rates for the test year. If any customers are to be transferred from one schedule to another, show revenues separately for the transfer group. Correction factors are used for historic test years only. The total base revenue by class must equal that shown in Schedule E-13a. The billing units must equal those shown in Schedule E-15. Provide total number of bills, mWh's, and billing kWh for each rate schedule (including standard and time of use customers) and transfer group.

Type of Data Shown:
X Projected Test Year Ended 12/31/17
__ Prior Year Ended __/__/__
__ Historical Test Year Ended __/__/__

Witness: Tiffany C. Cohen

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		Present Revenue Calculation			Proposed Revenue Calculation			
Line No.	TYPE OF CHARGES	UNITS	CHARGE/UNIT	$ REVENUE	UNITS	CHARGE/UNIT	$ REVENUE	Percent Increase
1	**54 - CILC-1D - Commercial/Industrial Load Control (Distribution)**							
2								
3	Customer	3,336	$ 168.63	$ 562,550	3,336	$ 275.00	$ 917,400	
4								
5	Non-Fuel Energy Charge							
6	On Peak	708,613,584	$ 0.00822	$ 5,824,804	708,613,584	$ 0.01272	$ 9,013,565	
7	Off Peak	1,978,806,807	$ 0.00822	$ 16,265,792	1,978,806,807	$ 0.01272	$ 25,170,423	
8	Demand Charge							
9	Max Demand	6,058,815	$ 3.49	$ 21,145,264	6,058,815	$ 5.50	$ 33,323,483	
10	Load Control On-Peak	4,390,087	$ 2.54	$ 11,150,821	4,390,087	$ 4.00	$ 17,560,348	
11	Firm On-Peak	671,984	$ 9.08	$ 6,101,615	671,984	$ 14.20	$ 9,542,173	
12								
13	Transformation Credit	1,363,076	$ (0.30)	$ (408,923)	1,363,076	$ (0.23)	$ (313,507)	
14								
15	Total			60,641,923			95,213,883	57.01%
16								
17								
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25								
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32								
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34								
35								
36	The present rates shown above are current approved rates adjusted for West County Unit 3 capacity clause factors,							
37	which revenue is classified as base revenue for surveillance reporting purposes consistent with FPL's 2012 Rate Settlement approved in Commission Order No. PSC 13-0023-S-EI.							

Supporting Schedules: E-14, E-15

Recap Schedules: E-13a

EXHIBIT NO. ___ (SJB-14)

Florida Power & Light Company
Docket No. 150085-EG
Staff's First Data Request
Request No. 22
Page 1 of 1

Q.
For each demand response program, please discuss whether the company considered reducing the credit provided to customers. As part of this response, please discuss the impacts a lower credit would have on existing participation levels.

A.
FPL did not contemplate reducing the credits in its demand response programs. All of FPL's open demand response programs are very cost-effective under the Rate Impact Measure (RIM) test, so no reductions are required. Further, the credit amounts for the Commercial/Industrial Load Control and Commercial/Industrial Demand Reduction programs were approved by the Commission as part of the settlement of FPL's last base rate case (Order No. PSC-13-0023-S-EI), that extend through the end of 2016.

FPL has proposed to migrate customers on FPL's closed Residential On Call tariff to the open Residential Load Control tariff. Although this represents a reduction of the credits that would be paid to some of the closed tariff participants, this isn't a credit reduction for the residential program per se because new participants are only able to receive credits from the open tariff to which FPL has not proposed any credit reductions.

Though there could be some existing participation loss from the residential closed tariff customers who are being transferred to the open tariff, FPL believes the program will maintain more than sufficient participation to meet its DSM Goals. Additionally, FPL has been able to recruit approximately 560,000 participants with the credit amounts of the open tariff. FPL does not have an assessment of the impact of lower credits on the existing participation for its open Residential Load Control tariff or its business demand response programs because lowering the credits was not contemplated.

EXHIBIT NO. ___ (SJB-15)

RATE IMPACT TEST
PROGRAM METHOD SELECTED: REV_REQ
PROGRAM NAME: **Commercial/Industrial Demand Reduction**

(1) YEAR	(2) INCREASED SUPPLY COSTS $(000)	(3) UTILITY PROGRAM COSTS $(000)	(4) INCENTIVES $(000)	(5) REVENUE LOSSES $(000)	(6) OTHER COSTS $(000)	(7) TOTAL COSTS $(000)	(8) AVOIDED GEN UNIT & FUEL BENEFITS $(000)	(9) AVOIDED T&D BENEFITS $(000)	(10) REVENUE GAINS $(000)	(11) OTHER BENEFITS $(000)	(12) TOTAL BENEFITS $(000)	(13) NET BENEFITS $(000)	(14) CUMULATIVE DISCOUNTED NET BENEFITS $(000)
2014	0	0	0	0	0	0	0	0	0	0	0	0	0
2015	0	15	356	2	0	372	4	0	0	0	4	(368)	(342)
2016	0	25	1,091	6	0	1,122	18	0	0	0	18	(1,104)	(1,297)
2017	0	37	1,883	10	0	1,930	25	0	0	0	25	(1,905)	(2,829)
2018	0	49	2,676	16	0	2,741	40	0	0	0	40	(2,701)	(4,849)
2019	0	44	3,073	20	0	3,137	6,795	0	0	(2)	6,793	3,656	(2,306)
2020	0	45	3,073	20	0	3,138	5,814	0	0	(3)	5,811	2,673	(578)
2021	0	46	3,073	21	0	3,140	5,599	0	0	(3)	5,596	2,456	899
2022	0	47	3,073	21	0	3,141	5,942	0	0	(3)	5,940	2,798	2,464
2023	0	49	3,073	22	0	3,143	6,080	0	0	(2)	6,078	2,935	3,991
2024	0	50	3,073	22	0	3,145	5,813	0	0	(3)	5,810	2,665	5,280
2025	0	51	3,073	23	0	3,146	5,922	0	0	(3)	5,919	2,773	6,526
2026	0	52	3,073	23	0	3,148	6,116	0	0	(2)	6,114	2,966	7,767
2027	0	54	3,073	24	0	3,150	5,812	0	0	(3)	5,810	2,660	8,801
2028	0	55	3,073	24	0	3,152	6,195	0	0	(2)	6,193	3,041	9,901
2029	0	56	3,073	25	0	3,154	5,819	0	0	(3)	5,816	2,662	10,796
2030	0	58	3,073	25	0	3,156	6,087	0	0	(2)	6,085	2,929	11,712
2031	0	59	3,073	26	0	3,158	5,935	0	0	(3)	5,932	2,774	12,519
2032	0	61	3,073	27	0	3,160	6,262	0	0	(3)	6,259	3,099	13,357
2033	0	62	3,073	29	0	3,164	5,933	0	0	(3)	5,931	2,767	14,053
2034	0	64	3,073	30	0	3,166	6,016	0	0	(3)	6,013	2,846	14,719
2035	0	65	3,073	31	0	3,169	6,058	0	0	(3)	6,056	2,887	15,347
2036	0	67	3,073	33	0	3,172	6,065	0	0	(3)	6,062	2,889	15,931
2037	0	69	3,073	34	0	3,175	5,960	0	0	(3)	5,957	2,782	16,454
2038	0	70	3,073	35	0	3,178	5,827	0	0	(3)	5,824	2,647	16,917
2039	0	72	3,073	36	0	3,181	6,046	0	0	(3)	6,043	2,863	17,383
2040	0	74	3,073	37	0	3,183	5,914	0	0	(3)	5,911	2,728	17,795
2041	0	76	3,073	38	0	3,186	5,920	0	0	(3)	5,917	2,731	18,179
2042	0	78	3,073	39	0	3,189	6,072	0	0	(3)	6,069	2,880	18,556
2043	0	80	3,073	41	0	3,193	6,013	0	0	(3)	6,009	2,816	18,898
2044	0	82	3,073	42	0	3,197	5,865	0	0	(3)	5,861	2,665	19,200
2045	0	84	3,073	44	0	3,200	6,008	0	0	(3)	6,005	2,804	19,495
2046	0	86	3,073	45	0	3,204	6,137	0	0	(3)	6,134	2,930	19,781
2047	0	88	3,073	47	0	3,208	6,058	0	0	(4)	6,054	2,847	20,040
2048	0	90	3,073	49	0	3,212	6,037	0	0	(4)	6,033	2,822	20,279
	0	0	0	0	0	0	0	0	0	0	0	0	
	0	0	0	0	0	0	0	0	0	0	0	0	
	0	0	0	0	0	0	0	0	0	0	0	0	
	0	0	0	0	0	0	0	0	0	0	0	0	
	0	0	0	0	0	0	0	0	0	0	0	0	
	0	0	0	0	0	0	0	0	0	0	0	0	
	0	0	0	0	0	0	0	0	0	0	0	0	
	0	0	0	0	0	0	0	0	0	0	0	0	
NOM.	0	2,058	98,187	965	0	101,210	180,208	0	0	(85)	180,123	78,913	
NPV	0	600	31,835	259	0	32,694	52,996	0	0	(23)	52,973	20,279	

Discount Rate 7.54 %

Benefit/Cost Ratio (Col(12) / Col(7)) : **1.62**

EXHIBIT NO. ___ (SJB-16)

SFHHA Proposed 2017 Revenue Distribution
12 CP and 1/13th with MDS Cost of Service Study
1.5 Limitation Applied to Base Revenue Increase

Rate Class	Present Operating Revenues	Proposed Operating Revenues	Proposed Equalized Increase	Proposed Unbilled Revenues - Allocated on Sales	Proposed Misc. Service Charges	Total Revenue Requirements less Unbilled and Misc. Service Charges	Reverse Additional CILC/CDR Credits	Base Adjustment	Rounding adjustment
CILC-1D	89,049	109,407	20,358	3	2	20,353	-	(813)	-
CILC-1G	4,161	4,381	219	0	0	219	-	-	15
CILC-1T	36,306	46,416	10,110	2	0	10,108	-	(2,141)	-
GS(T)-1	382,182	410,950	28,768	7	(29)	28,790	-	-	1,963
GSCU-1	4,336	4,455	119	0	2	117	-	-	8
GSD(T)-1	1,156,720	1,299,192	142,472	29	105	142,338	-	-	9,707
GSLD(T)-1	387,332	513,878	126,547	12	15	126,520	-	(41,526)	-
GSLD(T)-2	79,626	103,278	23,652	3	3	23,646	-	(6,173)	-
GSLD(T)-3	4,621	5,675	1,055	0	0	1,054	-	(40)	-
MET	4,145	4,483	339	0	0	338	-	-	23
OL-1	14,703	12,942	(1,761)	0	15	(1,777)	-	1,873	-
OS-2	1,016	1,330	314	0	0	314	-	(91)	-
RS(T)-1	3,658,872	4,171,576	512,705	64	(4,002)	516,643	-	-	35,235
SL-1	92,364	95,472	3,107	1	2	3,105	-	-	212
SL-2	1,525	1,331	(193)	0	0	(194)	-	208	-
SST-DST	815	858	43	0	0	43	-	-	3
SST-TST	4,433	2,934	(1,499)	0	0	(1,499)	-	1,537	-
Total Retail	**5,922,205**	**6,788,559**	**866,354**	**120**	**(3,885)**	**$ 870,119**	**-**	**(47,166)**	**47,166**

SFHHA Proposed 2017 Revenue Distribution
12 CP and 1/13th with MDS Cost of Service Study
1.5 Limitation Applied to Base Revenue Increase

Rate Class	Total Proposed Increase - Base	Unbilled Revenues - Allocated on Sales	Misc. Service Charges	Total Proposed Increase	Total Proposed Revenues	Clause Revenues	Proposed Operating Revenues (with Clauses)	Percent Increase (with Clauses)	Percent Increase (without Clauses)
CILC-1D	19,540	3	2	19,545	108,594	110,216	218,810	9.81%	21.95%
CILC-1G	234	0	0	234	4,396	4,168	8,563	2.81%	5.63%
CILC-1T	7,967	2	0	7,968	44,274	60,678	104,952	8.22%	21.95%
GS(T)-1	30,754	7	(29)	30,732	412,913	257,108	670,021	4.81%	8.04%
GSCU-1	125	0	2	127	4,463	2,863	7,326	1.77%	2.93%
GSD(T)-1	152,045	29	105	152,180	1,308,900	1,088,962	2,397,861	6.78%	13.16%
GSLD(T)-1	84,994	12	15	85,020	472,352	442,231	914,583	10.25%	21.95%
GSLD(T)-2	17,473	3	3	17,479	97,105	103,115	200,220	9.56%	21.95%
GSLD(T)-3	1,014	0	0	1,014	5,635	6,994	12,629	8.73%	21.95%
MET	362	0	0	362	4,506	3,842	8,349	4.53%	8.72%
OL-1	96	0	15	112	14,815	4,593	19,408	0.58%	0.76%
OS-2	223	0	0	223	1,239	494	1,734	14.76%	21.95%
RS(T)-1	551,877	64	(4,002)	547,939	4,206,811	2,491,313	6,698,124	8.91%	14.98%
SL-1	3,317	1	2	3,319	95,684	26,309	121,993	2.80%	3.59%
SL-2	14	0	0	14	1,539	1,335	2,874	0.50%	0.95%
SST-DST	46	0	0	46	861	869	1,730	2.74%	5.67%
SST-TST	38	0	0	38	4,472	3,205	7,677	0.50%	0.87%
Total Retail	**870,119**	**120**	**(3,885)**	**866,354**	**6,788,559**	**4,608,295**	**11,396,854**	**8.23%**	**14.63%**

EXHIBIT NO. ___ (SJB-17)

SFHHA Proposed 2017 Revenue Distribution
12 CP and 25% with MDS Cost of Service Study
1.5 Limitation Applied to Base Revenue Increase

Rate Class	Present Operating Revenues	Proposed Operating Revenues	Proposed Equalized Increase	Proposed Unbilled Revenues - Allocated on Sales	Proposed Misc. Service Charges	Total Revenue Requirements less Unbilled and Misc. Service Charges	Reverse Additional CILC/CDR Credits	Base Adjustment	Rounding adjustment
CILC-1D	89,051	112,118	23,067	3	2	23,062	-	(3,521)	-
CILC-1G	4,162	4,476	315	0	0	314	-	-	27
CILC-1T	36,307	48,120	11,813	2	0	11,811	-	(3,844)	-
GS(T)-1	382,181	410,777	28,595	7	(29)	28,618	-	-	2,499
GSCU-1	4,336	4,543	207	0	2	205	-	-	18
GSD(T)-1	1,156,729	1,309,580	152,851	29	105	152,716	-	-	13,334
GSLD(T)-1	387,336	518,368	131,032	12	15	131,005	-	(46,011)	-
GSLD(T)-2	79,628	105,833	26,205	3	3	26,199	-	(8,726)	-
GSLD(T)-3	4,621	5,842	1,221	0	0	1,221	-	(207)	-
MET	4,145	4,517	372	0	0	372	-	-	32
OL-1	14,703	13,293	(1,410)	0	15	(1,426)	-	1,522	-
OS-2	1,016	1,342	326	0	0	326	-	(103)	-
RS(T)-1	3,658,850	4,146,962	488,112	64	(4,002)	492,051	-	-	42,963
SL-1	92,366	97,476	5,110	1	2	5,107	-	-	446
SL-2	1,525	1,372	(152)	0	0	(152)	-	167	-
SST-DST	815	866	51	0	0	51	-	-	4
SST-TST	4,434	3,073	(1,360)	0	0	(1,361)	-	1,399	-
Total Retail	**5,922,205**	**6,788,559**	**866,354**	**120**	**(3,885)**	**$ 870,119**	**-**	**(47,166)**	**47,166**

SFHHA Proposed 2017 Revenue Distribution
12 CP and 25% with MDS Cost of Service Study
1.5 Limitation Applied to Base Revenue Increase

Rate Class	Total Proposed Increase - Base	Unbilled Revenues - Allocated on Sales	Misc. Service Charges	Total Proposed Increase	Total Proposed Revenues	Clause Revenues	Proposed Operating Revenues (with Clauses)	Percent Increase (with Clauses)	Percent Increase (without Clauses)
CILC-1D	19,541	3	2	19,546	108,597	110,216	218,813	9.81%	21.95%
CILC-1G	342	0	0	342	4,504	4,168	8,671	4.11%	8.22%
CILC-1T	7,967	2	0	7,969	44,276	60,678	104,954	8.22%	21.95%
GS(T)-1	31,116	7	(29)	31,094	413,276	257,108	670,383	4.86%	8.14%
GSCU-1	223	0	2	225	4,561	2,863	7,424	3.13%	5.19%
GSD(T)-1	166,051	29	105	166,185	1,322,914	1,088,962	2,411,876	7.40%	14.37%
GSLD(T)-1	84,994	12	15	85,021	472,357	442,231	914,588	10.25%	21.95%
GSLD(T)-2	17,473	3	3	17,479	97,108	103,115	200,223	9.56%	21.95%
GSLD(T)-3	1,014	0	0	1,014	5,635	6,994	12,629	8.73%	21.95%
MET	404	0	0	404	4,549	3,842	8,391	5.06%	9.75%
OL-1	96	0	15	112	14,815	4,593	19,408	0.58%	0.76%
OS-2	223	0	0	223	1,239	494	1,734	14.76%	21.95%
RS(T)-1	535,013	64	(4,002)	531,075	4,189,925	2,491,313	6,681,238	8.64%	14.51%
SL-1	5,553	1	2	5,556	97,922	26,309	124,231	4.68%	6.01%
SL-2	14	0	0	14	1,539	1,335	2,874	0.50%	0.95%
SST-DST	56	0	0	56	870	869	1,740	3.30%	6.83%
SST-TST	38	0	0	38	4,472	3,205	7,677	0.50%	0.87%
Total Retail	**870,119**	**120**	**(3,885)**	**866,354**	**6,788,559**	**4,608,295**	**11,396,854**	**8.23%**	**14.63%**