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**BEFORE THE**

**FLORIDA PUBLIC SERVICE COMMISSION**

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

Direct Testimony and Exhibits of

**Amanda M. Alderson**

On behalf of

**Federal Executive Agencies**

July 7, 2016

BRUBAKER & ASSOCIATES, INC.

Project 10228

**BEFORE THE**

**FLORIDA PUBLIC SERVICE COMMISSION**

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

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# Direct Testimony of Amanda M. Alderson

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

A Amanda M. Alderson. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

**Q WHAT IS YOUR OCCUPATION?**

A I am a Consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

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

A This information is included in Appendix A to this testimony.

**Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

A This testimony is presented on behalf of Federal Executive Agencies ("FEA"). FEA consists of certain agencies of the United States Government which have offices, facilities, and/or installations in the service area of Florida Power & Light Company ("FPL" or "Company") and purchase electric utility service from FPL.

**Q WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?**

A I will address the filed retail cost of service studies ("COSS") of FPL, the resulting spread of the required revenue increase, and proposed rate design for the Commercial Industrial Load Control ("CILC") class.

My silence in regard to any issue should not be construed as an endorsement of FPL's position.

## I. Summary of Findings and Recommendations

**Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS CONCERNING THE 2017 TEST YEAR AND 2018 SUBSEQUENT YEAR COSS.**

A. My cost of service findings and recommendations are summarized as follows:

1. I find the Company's proposal to use the 12 coincident peak ("CP") 100% demand allocation method to allocate transmission plant costs to be consistent with cost-causation principles, and recommend the Florida Public Service Commission ("Commission") approve the Company's proposal.
2. The Company's proposed change to the production demand allocator from the (1) 12 CP demand and 1/13$^{th}$ energy method to the (2) 12 CP demand and 25% energy method should be rejected.
3. The Company's proposal to use the 12 CP demand and 25% energy allocation method to allocate production plant costs is not reasonable, because it does not reflect demand cost incurrence, illustrated by its inconsistency with the following:
   a. FPL's recently installed generation assets, and planned installations over the next ten years,
   b. FPL's resource planning principles stated in its annual integrated resource plans,

c. FPL's system load characteristics.

I recommend the Commission reject the Company's proposal to significantly increase the energy component of the production cost allocator from 7.7% (1/13th) to 25%.

4. I find the most accurate production demand allocator is a 4 CP Summer or 4 CP/1 CP Summer/Winter allocator for production plant costs. If a change is made, I recommend the Commission adopt a 100% 4 CP production demand allocator.
5. I recommend the Commission direct FPL to conduct a Minimum Distribution Study before its next base rate filing, in an effort to follow the National Association of Regulatory Utility Commissioners ("NARUC") Manual recommendation of customer and demand classification of distribution costs.

**Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS CONCERNING THE COMPANY'S PROPOSED REVENUE SPREAD.**

A I find the Company's proposed revenue spread gradualism constraints to be reasonable in theory, but flawed in application. I recommend the 1.5 times the system average increase gradualism constraint be applied to the total class revenues including all surcharges with the exception of the fuel surcharge, which will produce gradualistic movement toward cost of service for non-fuel rates.

**Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS CONCERNING THE COMPANY'S PROPOSED CILC CLASS RATE DESIGN.**

A My rate design findings and recommendations are summarized as follows:

1. I find the Company's proposal in the instant proceeding to be illogical and not reflective of the Company's own COSS. It should be rejected in favor of a CILC rate design that aligns with the present CILC rate design and follows FPL's own proposed rate structure from its last base rate case.
2. I find the Company's proposal to reduce the CILC and Commercial Demand Rider ("CDR") rate credits in this case unsupported and not cost justified. I recommend the Commission reject the Company's proposal to reduce these interruptible credits and order the Company to prepare a study to estimate the value of these interruptible credits to the FPL system based on avoided peaking resources.

## II. FPL's Proposed Cost of Service Study

**Q HAVE YOU REVIEWED THE COMPANY'S COST OF SERVICE FILING IN THIS PROCEEDING?**

A Yes. I have reviewed the testimony of FPL witness Ms. Renae Deaton and the COSS she has presented therein. The Company has filed two versions of its COSS for the 2017 Test Year and 2018 Subsequent Year. The first version uses the same cost of service allocation methods that the Company filed in its 2012 base rate case, which follow long-standing precedent for Florida investor-owned utilities ("IOU"). The second version uses the Company's proposed production and transmission allocation methods. The Company proposes designing customer rates based off the second COSS version, using new production and transmission allocation methods.[1]

[1] Direct Testimony of FPL witness Deaton, page 7, lines 5-7.

**Q PLEASE DESCRIBE THE COMPANY'S PROPOSED PRODUCTION AND TRANSMISSION PLANT ALLOCATION METHODS.**

A FPL proposes to increase the amount of demand-related production plant costs allocated on an energy basis by switching to a 12 coincident peak ("12 CP") and 25% allocation method from the 12 CP and 1/13th allocation method widely used by Florida IOUs over the last few decades. In addition, FPL proposes to use a 12 CP 100% demand method for transmission plant allocation, except for transmission pull-offs, as opposed to the 12 CP and 1/13th method, which aligned transmission plant and production plant allocation both on the 12 CP and 1/13th allocation method.

## <u>II.A. Transmission Plant Allocation</u>

**Q TURNING FIRST TO TRANSMISSION PLANT ALLOCATION, DO YOU AGREE WITH THE COMPANY'S PROPOSAL TO USE THE 12 CP 100% DEMAND ALLOCATION METHOD?**

A Yes. High voltage transmission plant investment is sized and planned to meet the system's coincident peak demands. Transmission plant should not be considered merely an extension of the production and generation asset investment, and therefore, the allocation methods for production plant and transmission plant need not align in all cases. Further, any classification on energy for the transmission plant is not based on cost-causation principles.

The Federal Energy Regulatory Commission ("FERC") has long held that allocation of high voltage bulk transmission plant costs should be accomplished using the 12 CP 100% demand method. I support the Company's proposal to use this method in its retail COSS.

**Q DOES THE COMPANY PROPOSE ALLOCATING ALL RETAIL TRANSMISSION PLANT ON THE 12 CP 100% DEMAND BASIS?**

A No. The Company's Schedule E-4a Minimum Filing Requirement ("MFR") details the functionalization of transmission plant, and shows approximately 8% of the transmission plant in-service is proposed by FPL to be functionalized in alignment with the production plant class cost functionalization, that is, the 12 CP and 25% method. This 8% subset of transmission plant is labeled GSU, Generator Step-Up assets. I agree that the transmission generator step-up plant should be allocated with production plant costs. These costs reflect the transformation to step up power at the generator for delivery to the high voltage bulk transmission system.

**Q HOW DOES THE COMPANY PROPOSE TO ALLOCATE TRANSMISSION PULL-OFFS?**

A Transmission pull-offs are radial lines, the conductors and equipment that connect high voltage customers directly to the transmission system. FPL proposes to continue its practice of assigning the cost of these assets to the transmission level customers, and then allocating these costs within the assigned classes on a customer basis.

**Q IS THE COMPANY'S PROPOSAL FOR TRANSMISSION PULL-OFF COST ALLOCATION REASONABLE?**

A Yes. These are costs related to connecting transmission customers to the FPL system. Allocating the costs on a customer basis is reasonable.

## II.B. Production Cost Allocation

**Q PLEASE DESCRIBE THE PRODUCTION COST ALLOCATION THAT FPL HAS HISTORICALLY USED.**

A FPL specifically, and Florida IOUs generally, have historically relied upon the 12 CP and 1/13$^{th}$ method to allocate demand-related production plant costs. This method classifies 1/13$^{th}$ of the production costs as energy-related, and allocates those costs on energy requirements. The remaining 12/13$^{ths}$ are classified as demand-related and allocated to classes on the average of the classes' 12 coincident peaks.

**Q PLEASE DESCRIBE MS. DEATON'S PROPOSAL TO CHANGE THE PRODUCTION PLANT COST ALLOCATOR TO USE THE 12 CP AND 25% METHOD?**

A Ms. Deaton proposes to switch to the 12 CP and 25% method from the 12 CP and 1/13$^{th}$ method. The result of this change is that a greater percentage of the demand-related production plant costs would be allocated on an energy basis. Ms. Deaton's proposed change increases the amount of demand-related costs allocated on an energy basis from approximately 7.7% (1/13$^{th}$) to 25%. Ms. Deaton's proposal would continue to allocate the remaining demand-related production charges on a 12 CP basis.

Increasing the amount of demand-related production charges allocated on an energy basis is not supported by cost-causation principles. Generation assets are sized to meet the utility's planned system peaks, and as such, are demand-related costs.

Ms. Deaton's contention that changes in FPL's generation fleet support **any** energy classification of production demand costs, let alone an increased amount, is not supported in this proceeding by either the Company's actual installed and planned generation asset fleet, its system planning principles, or the Company's system characteristics of load use across classes.

**Q HOW DOES MS DEATON SUPPORT HER PROPOSAL TO ALLOCATE A GREATER PERCENTAGE OF DEMAND-RELATED PRODUCTION COSTS ON AN ENERGY BASIS?**

A At page 21 of her direct testimony, Ms Deaton explains:

> 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.

In this passage, Ms. Deaton alludes to the theory of "capital substitution" suggesting that when a utility chooses to install a baseload generating unit with a higher upfront capital cost but lower fuel costs over time, as opposed to a peaking unit with a lower fixed capital cost but higher fuel cost, it can be argued that the utility is substituting demand-related capital costs to obtain fuel savings. The thinking is that, therefore, the capital expenditure that generates these fuel savings could be allocated like a fuel expense, on an energy basis.

**Q PLEASE COMMENT ON THIS THEORY OF CAPITAL SUBSTITUTION.**

A This theory is referenced in the NARUC Manual at page 21 in the paragraph summarizing the classification process for production related costs. The NARUC Manual reads:

> Costs that are based on the generating capacity of the plant, such as depreciation, debt service and return on investment, are demand related costs. Other costs, such as cost of fuel and certain operation

> and maintenance expenses, are directly related to the quantity of energy produced. **In addition, capital costs that reduce fuel costs may be classified as energy related rather than demand related**. (emphasis added)

But the NARUC Manual, last updated in 1992, was predicated on a set of market factors and system resource planning economics that have changed. The differences in fuel costs and capital costs between various generating unit types today are vastly different from the comparative costs of generating units in the 1980s and 1990s, when the Commission last approved the 12 CP and 1/13th method in a fully litigated case.[2] As I explain below, FPL's recently installed and planned future generation capacity additions suggest that a move away from the theory of capital substitution is appropriate, not a move to more fully rely on the theory, as proposed by Ms. Deaton.

## II.B.1. FPL's Recent and Planned Generation Capacity Additions

**Q DOES FPL'S RECENT AND PLANNED GENERATION CAPACITY ADDITIONS SUPPORT THE APPLICATION OF THE CAPITAL SUBSTITUTION THEORY, AS MS. DEATON CLAIMS?**

A No. Ms. Deaton suggests that FPL has installed a considerable amount of baseload and intermediate generating units presumably since FPL's 2012 case when the Company proposed continuation of the 12 CP and 1/13th method. But a review of the generating capacity added over the last five years, and FPL's planned additions included in its 2016 10-year Integrated Resource Plan ("2016 IRP"),[3] shows that gas-fired generation, not coal-fired generation, is the most economical baseload capacity addition.

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[2]For FPL, this was in the 1989 case, Docket No. 890319-EI.
[3]FPL's 2016 IRP, filed April 1, 2016, is titled "2016 Ten Year Power Plant Site Plan."

**Q WHY DOESN'T THE ADDITION OF A SIGNIFICANT AMOUNT OF GAS-FIRED BASELOAD GENERATION CAPACITY SUPPORT USING THE THEORY OF CAPITAL SUBSTITUTION TO ALLOCATE PRODUCTION COSTS?**

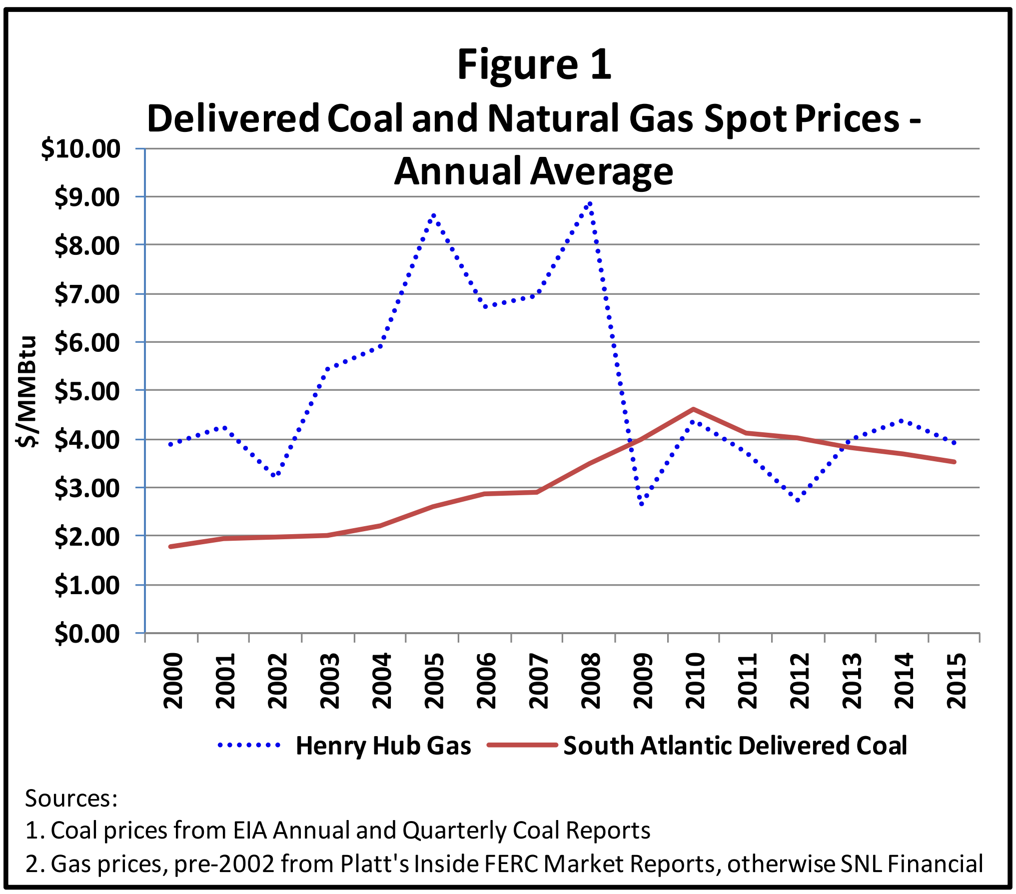
A Capital substitution was historically predicated on the relative capital and fuel cost differential between baseload coal-fired or nuclear units and peaking gas-fired or oil-fired units. Specifically, the theory posits that a high capital cost baseload coal-fired unit can be the least cost generating addition, versus a lower capital cost gas-fired peaking unit, because of the coal unit lower fuel operating cost.

But two factors contradict Ms. Deaton's claim that this theory of capital substitution applies to FPL's generation additions and supports an increase in the energy allocation. First, the fuel cost differential between coal-fired and gas-fired units has contracted, due to market factors, so the fuel savings for which capital may be substituted has reduced dramatically. Second, FPL is no longer installing coal-fired units, instead relying on gas-fired generation as baseload, which has a much lower capital cost than baseload coal units, therefore less capital is incurred for reduced fuel savings. The theory of capital substitution does not fit FPL's actual generation resource mix.

This shift in market economics, and the relative capital costs of the generating units actually installed by FPL suggest that a **smaller percentage** of demand-related production costs should be allocated on energy compared to historical allocation methods. Again, this shows that the Company's proposal to increase the energy allocation percentage is not cost based.

**Q PLEASE EXPLAIN HOW THE CURRENT FUEL COST DIFFERENTIAL BETWEEN UNIT TYPES AFFECTS PRODUCTION COST OF SERVICE.**

A Figure 1 below illustrates the historical price of natural gas and coal delivered to Southeast electric utilities, according to U.S. Department of Energy, Energy Information Administration ("EIA"), Platts, and SNL Financial publications. Historically, the high capital cost of a baseload coal unit might be cost justified given the fuel savings versus a gas-fired peaking unit with lower capital costs. But since the shale gas boon in the U.S., gas costs have fallen dramatically while coal prices have increased. The capital substitution theory is weakened when the fuel savings decreases.



FPL itself has indicated its understanding of the new market economics as it explains why it does not anticipate installing any coal-fired units in the foreseeable future. FPL writes:

> [There are] [s]everal other considerations currently unfavorable to new coal units compared to new natural gas-fired CC units. The first of these is a **significant reduction in the fuel cost difference between coal and natural gas** when compared to the fuel cost difference projected in 2007 which then favored coal; i.e., the projected fuel cost advantage of coal versus natural gas has been significantly reduced. Second is the continuation of **significantly higher capital costs for coal units compared to capital costs for CC units**. Third is the increased fuel efficiency of new CC units compared to projected CC unit efficiencies in 2007. Fourth are existing and proposed environmental regulations, including those that address greenhouse gas emissions, which are unfavorable to new coal units when compared to new CC units. **Consequently, FPL does not believe that new advanced technology coal units are currently economically, politically, or environmentally viable fuel diversity enhancement options in Florida at this time**. (FPL 2016 IRP, page 57, emphasis added.)

**Q PLEASE SUPPORT YOUR CLAIM THAT FPL IS HEAVILY RELYING ON GAS-FIRED GENERATION.**

A The cited quote above from FPL's 2016 IRP shows that it no longer considers coal-fired generation a viable asset choice. FPL's recently installed and planned generation additions prove that this is the case.

Table 1 below shows FPL's installed capacity by size and type since 2005, and the planned capacity additions explained in FPL's 2016 IRP. The table also shows the relative capacity construction and fuel costs for these units. Note that 94% of the capacity additions are either combined cycle ("CC") or combustion turbines ("CT"), which are both primarily gas-fired units.

**Table 1**

**FPL Planned and Recently Added Capacity**

| Power Plant Name | Capacity (MW) | Unit Type | Year in Service | | Construction Cost (2015 $/kW) | Fuel Cost (2015 $/MWh) |
|---|---|---|---|---|---|---|
| Recent Additions[1] | | | | | | |
| West County Energy Center | 4,019 | CC | 2009 | $ | 496 | $31.67 |
| Cape Canaveral Next Gen | 1,355 | CC | 2013 | $ | 682 | $29.72 |
| Riviera Beach Next Gen | 1,344 | CC | 2014 | $ | 863 | $29.85 |
| Port Everglades Next Gen | 1,250 | CC | 2016 | $ | 960 | $0.00 |
| Turkey Point CC | 1,178 | CC | 2007 | $ | 428 | $31.50 |
| Nuclear Uprates | 520 | Nuclear | 2012 | $ | 5,700 | $6.90 |
| DeSoto Next Gen Solar | 25 | PV | 2009 | $ | 5,878 | $0.00 |
| Space Coast Next Gen | 10 | PV | 2010 | $ | 6,198 | $0.00 |
| FPL Solar Circuit (Daytona Rising) | 2 | PV | 2016 | $ | 3,333 | $0.00 |
| Florida Intl University Solar | 2 | PV | 2016 | $ | 4,375 | $0.00 |
| Planned Additions[2] | | | | | | |
| Okeechobee Unit 1 | 1,633 | CC | 2019 | $ | 832 | |
| Unsited 3x1 CC | 1,622 | CC | 2024 | $ | 1,022 | |
| Fort Myers CT | 231 | CT | 2016 | $ | 514 | |
| Lauderdale CT | 231 | CT | 2016 | $ | 482 | |
| New Solar | 156 | PV | 2020 | $ | 1,896 | |
| Babcock Ranch Solar Energy Center | 39 | PV | 2016 | $ | 1,881 | |
| Citrus Solar Energy Center | 39 | PV | 2016 | $ | 1,881 | |
| Manatee Solar (Parrish Facility) | 39 | PV | 2016 | $ | 1,881 | |

Sources:
[1]SNL Financial and 2015 FERC Form 1
[2]2016 FPL IRP pp. 96-103

**Q PLEASE EXPLAIN HOW FPL'S RELIANCE ON GAS-FIRED GENERATION IMPACTS THE COST-BASED APPLICATION OF THE CAPITAL SUBSTITUTION THEORY.**

A The most economical system resource available to FPL currently is gas-fired generation, as evidenced in Table 1 where the vast majority (94%) of capacity additions are either CCs or CTs. Gas-fired generation can be installed in a CT or CC configuration.[4] Table 2 below shows that the installed cost of a CT is approximately $700 per kW, versus approximately $1,000 per kW for a CC. It is true that FPL has elected to incur the slightly higher upfront capital cost for CC units instead of less expensive CT units in order to obtain lower fuel costs due to the higher fuel efficiencies (lower heat rate) of the CC units. But the trade-off between higher capacity costs and lower fuel costs is far more muted than the historical trade-off between coal-fired baseload and gas-fired peaking units.

The historical capital cost differential between coal-fired baseload units and peaking units is about four times,[5] but the current differential between CC units (like the ones FPL has installed) and CTs is only approximately two times.

**Table 2**

**EIA Estimates for Power Plant Capital Costs**

| Unit Type | Fuel Type | Construction Cost (2012 $/kW) |
|---|---|---|
| Advanced Combustion Turbine | Natural Gas | $676 |
| Advanced Combined Cycle | Coal/Gas | $1,023 |
| Solar Photovoltaic | Solar | $3,873 |
| Nuclear | Uranium | $5,530 |

Source: EIA April 2013 Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, page 6, Table 1.

[4] A CC is essentially a CT unit, with an additional heat recovery steam generator, which increases capacity and improves the heat rate efficiency of the unit. The heat rate of a CT is approximately 10,000 BTUs per kWh. The heat rate for a CC is around 6,500 BTUs per kWh.

[5] 1990 overnight cost was approximately $2,500/kW. Source: Power Plants: Characteristics and Costs; Federation of American Scientists report, November 13, 2008.

**Q PLEASE SUMMARIZE YOUR CONCLUSION CONCERNING THE APPLICATION OF THE CAPITAL SUBSTITUTION THEORY TO FPL'S PRODUCTION COST ALLOCATION.**

A The concept of capital substitution suggests that a utility would choose to install a high capital cost baseload unit instead of a lower capital cost peaking unit if fuel operating costs are materially lower because this will ensure lower overall total costs over the projected operating life of the resource. But FPL's own resource mix shows that it is relying significantly on gas-fired CC units, and the capital cost differential between CC units and peaking CTs is half the historical capital cost differential between a coal unit and peaking unit, upon which the capital substitution theory is predicated. Therefore, FPL's recent capacity additions suggest that at a minimum the percentage of demand-related production costs allocated on energy should remain the same, and could even be reduced, but should not increase as proposed by FPL.

## II.B.2. FPL's Resource Planning Principles

**Q IS THERE FURTHER SUPPORT FROM FPL'S PRODUCTION PLANNING PRINCIPLES SUGGESTING THAT AN INCREASE IN THE PERCENTAGE OF DEMAND-RELATED COSTS ALLOCATED ON ENERGY IS UNREASONABLE?**

A Yes. FPL's 2016 IRP explains that the Company has added a third reliability criterion related to system peak demands for determining the appropriate capacity additions it should install over the next 10 years. Historically, up until 2014, FPL used two criteria to determine the amount of generating capacity needed to operate the system safely and reliably. The first criterion relies on a minimum 20% peak period reserve margin for the summer (August) and winter (January) peak hour, the second relies on a maximum loss of load probability ("LOLP") of 0.1 day per year.[6]

FPL's 2016 IRP indicates that beginning in 2014, FPL added a third reliability criterion to the two previously used. The third criterion is a 10% generation-only reserve margin, which places a greater emphasis on the reserve margin at the summer and winter peaks.

FPL has grown concerned about relying too heavily on demand-side management resources during peak periods, and wishes to place a greater emphasis on having adequate installed generation at the time of the system peaks, hence the development of the third reliability criterion using a generation-only reserve margin metric.[7]

**Q PLEASE DEFINE RESERVE MARGIN.**

A A utility's reserve margin is the excess capacity above expected demand at the hours of the annual system peaks of the system. A minimum reserve margin threshold is used by system planners to ensure that the generating capacity is available when demands on the system are at the highest levels taking into account forecasting error and weather fluctuations, in order to greatly reduce the likelihood of brownouts or blackouts.

**Q PLEASE EXPLAIN THE LOLP.**

A LOLP is a metric that determines the probability of load being unavailable to meet resources over the full planning year, calculating the probability of system overload at each daily peak hour.

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[6] FPL 2016 IRP, pp. 35 and 52.
[7] *Id.*, p. 53.

**Q DO FPL'S PRODUCTION SYSTEM PLANNING PRINCIPLES SUPPORT AN INCREASE IN THE AMOUNT OF DEMAND-RELATED PRODUCTION COSTS ALLOCATED ON ENERGY COMPARED TO APPROVED HISTORICAL PRACTICES IN FLORIDA?**

A No. FPL's IRP indicates that the Company is placing a greater emphasis on planning to meet the peak period reserve margin through its addition of a third reliability criterion of a 10% generation-only reserve margin metric. This change in FPL's production system planning principles does not support an increased allocation of demand-related production costs on an energy basis, and instead supports a reduction. FPL is strengthening its reserve margin criteria, placing a greater emphasis on meeting its peak period demands than it has historically.

## II.B.3. FPL's System Load Characteristics

**Q DO THE FPL SYSTEM LOAD CHARACTERISTICS SUPPORT AN INCREASE IN THE AMOUNT OF DEMAND-RELATED PRODUCTION COSTS ALLOCATED ON ENERGY COMPARED TO HISTORICAL METHODS, AS PROPOSED BY MS. DEATON?**

A No. A review of the Company's load characteristics indicates that allocating production demand-related costs on the 12 CPs is unreasonable. Continuing to allocate costs on the 12 CPs while simultaneously increasing the energy allocation moves even further from cost causation. My Exhibit AMA-1 shows a clear pattern of four monthly summer peaks over the past 10 years, and over the projected period from 2016 through 2018. The projected system peaks were provided by FPL in its MFRs and corroborates the fact that FPL expects its system to continue under this

4 CP pattern. The utility was once a winter peaking system before the early 2000s, but the system load characteristics have shifted over time.

There is evidence that supports a winter peak component in the production allocation method. The 2010 system peak for FPL occurred in January, which was the only year over the last 10 that FPL peaked in a non-summer month. Further, FPL's IRP indicates that its system planning principles take into account a minimum reserve margin threshold in the winter peak month of January.[8]

In any case, a greater emphasis on the summer peak months is supported by FPL's load characteristics and system planning, more so than use of the 12 CP which considers peaks throughout the entire calendar year. Especially in the case of Ms. Deaton's proposal to increase the amount of demand-related production cost on an energy basis, it would be of even greater import to reduce the number of coincident peaks included in the demand allocation. Inclusion of an energy component in the production cost allocator is to take into account load use over the full calendar year. It is not necessary to use the 12 CPs across the full calendar year as well for the demand component when the system shows only four clear peaks.

## II.B.4. Alternative 100% Demand Production Allocation Method

**Q HAVE YOU CALCULATED ALTERNATIVE CLASS ALLOCATION FACTORS USING METHODS BESIDES THE 12 CP AND 1/13$^{TH}$, AND 12 CP AND 25%?**

A Yes. My Exhibit AMA-2 provides a comparison of the Company's present and proposed production allocation factors as well as 100% demand allocation factors eliminating the practice of allocating demand-related costs on an energy allocator. I have prepared two possible 100% demand allocation method calculations, one using

[8] *Id*.

the four summer CPs (June-September), the other using and a summer/winter peak method that equally weights both the four summer CPs and the one winter peak in the month of January, which is the forecasted peak winter month according to Florida's IRP[9] and the load forecasting model presented by FPL witness Morley.[10]

It is clear from FPL's system planning principles, its recently installed and planned assets, and its load characteristics that shifting to a greater percentage of the production allocation method on an energy basis is not supported at this time. In fact, these factors support a reduction in the amount of demand-related production costs that are allocated on an energy basis. Further, reliance on the 12 CP metric for the demand-related component of any production cost allocation factor is not justified, and instead either a summer 4 CP or a summer/winter 4 CP / 1 CP is more cost based.

**Q WHAT IS YOUR RECOMMENDED PRODUCTION COST ALLOCATION METHOD?**

A I believe it is justified based on the evidence presented in this proceeding to move to a 100% demand-related cost allocation method using either the four summer peaks or the four summer peaks and one winter peak. The Company's proposed 12 CP and 25% allocation method should be rejected. Continuation of the 12 CP and 1/13$^{th}$ method could be considered a compromised approach.

If the Commission approves a change, it should approve a 100% 4 CP method and reject FPL's proposed 12 CP and 25% method.

[9] *Id.*
[10] Direct Testimony of FPL witness Ms. Morley at 42.

## II.C. Distribution Cost Allocation

**Q HOW THE DOES THE COMPANY PROPOSE TO ALLOCATE DISTRIBUTION COSTS IN THE COSS?**

A Ms. Deaton describes at page 24 of her Direct Testimony that FPL proposes classifying 100% of distribution-related equipment, aside from meters, as demand-related, and using only demand-based allocators to allocate these costs.

**Q WHAT IS YOUR CONCERN WITH THE COMPANY'S 100% DEMAND-RELATED DISTRIBUTION COST ALLOCATION METHOD?**

A Allocating these costs, in FERC Accounts 364-368, which are the costs of poles and towers, underground and overhead lines, and transformers, on a pure demand basis: (1) is not supported by the NARUC Manual; and (2) does not reflect the fact that there is a customer-related component to the cost of the distribution system that is associated with the need to "cover the system."

**Q WHY DO YOU SAY THE NARUC MANUAL DOES NOT SUPPORT THESE DISTRIBUTION-RELATED COSTS BEING CLASSIFIED AS 100% DEMAND-RELATED?**

A Table 6-1 in the NARUC Manual on page 87, replicated below as Table 3, shows clearly that distribution assets in FERC Accounts 360, 361, and 364 through 368 are properly allocated on both a customer- and demand-related allocator.

**TABLE 3**

**Table 6-1 of NARUC Manual – January 1992 Edition**
**Classification of Distribution Plant**

| FERC Uniform System of Accounts No. | Description | Demand Related | Customer Related |
|---|---|---|---|
| | Distribution Plant | | |
| 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 | - | - |

Footnote 2 to the NARUC Manual table explains:

> The amounts between [demand and customer] 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.

In other words, the NARUC Manual leaves open the opportunity for a utility company to determine nearly none (zero) of these costs should be classified as customer-related, but only after completing the appropriate study of its distribution system.

**Q IS THE COMPANY'S PROPOSAL REASONABLE, TO ASSUME 100% OF THESE DISTRIBUTION ASSET COSTS ARE DEMAND RELATED, ABSENT A STUDY OF ITS DISTRIBUTION SYSTEM?**

A No. The distribution system is sized not only to accommodate demand requirements but also to simply connect each customer to the system. This minimum customer connection cost is irrespective of size. The connection equipment necessary is above and beyond the service drop to a customer's premises because there must be an infrastructure to which the service drop can be connected.

Consequently, while a customer's demand requirements will influence the particular size of the distribution facilities installed, the fact that some facilities of at least a minimum size must be constructed relates to the existence and location of customers within the service territory, the distance of conductor, and the number of transformers. Unless these factors are taken into consideration, the COSS will depart from cost-causation.

The central idea behind the minimum system concept is that there is a cost incurred by any utility when it extends its primary or secondary distribution system, replaces a component on those systems, or connects an additional customer to them. By definition, the minimum system comprises every distribution component necessary to provide service, i.e., meters, services, secondary and primary conductors and cables, poles, substations, etc. The cost of the minimum system, however, is only that portion of the total distribution cost the utility must incur to render service to customers. It does not include costs specifically incurred to meet the peak demand of the customers. Therefore, the minimum system cost is rightfully classified as customer-related, and should be allocated on a customer basis, separate and apart from the distribution costs classified as demand-related.

**Q IF IT IS UNREASONABLE TO CONSIDER THESE DISTRIBUTION ASSET COSTS AS 100% DEMAND RELATED, WHAT PERCENTAGE OF THE ALLOCATION SHOULD BE DEMAND RELATED?**

A In order to determine the best estimate of the percentage of total distribution asset costs that are demand related, a utility company would complete a study of its installed distribution assets, typically termed a Minimum Distribution Study.

A Minimum Distribution Study consists of a review of the distribution assets installed on the Company system that would meet the minimum required to serve a customer. For example, the smallest size pole and smallest size cable, conductor, etc. is determined, and the total book cost for that minimum system is established. This total minimum system cost for each distribution asset, separated by FERC Account number, is then allocated on a customer basis. The remainder of distribution asset costs in those FERC Accounts is allocated on a demand basis.

Alternately, the utility company could follow the Zero-Intercept Method, which is similar to the Minimum Distribution Method, but seeks instead to identify the portion of distribution plant costs related to a hypothetical no-load situation. The Zero-Intercept method often requires considerably more data, and the resulting customer/demand split is usually very similar to the results of the Minimum Distribution Study.

In this proceeding, in the absence of an analytical study to determine proper cost classification, I would support any modest movement toward a customer classification if ordered by the Commission.

**Q HAS THE COMMISSION HISTORICALLY APPROVED USE OF A MINIMUM DISTRIBUTION STUDY FOR FLORIDA IOUS?**

A To my knowledge, the Commission has not embraced a Minimum Distribution Study for allocation of Florida IOU distribution costs. The general acceptance of a Minimum Distribution Study in numerous jurisdictions across the country, and the NARUC Manual, suggest efficient distribution system planning does consider number and location of customers served, and the Commission should reconsider its decades-long rejection of the theory.

**Q WHAT IS YOUR RECOMMENDATION CONCERNING THE MINIMUM DISTRIBUTION STUDY?**

A I recommend the Commission order FPL to conduct a Minimum Distribution Study of its system, survey the use of the Minimum Distribution Study in other similarly-situated utilities across the country, with similar customer load characteristics and geographical make-up, and present the findings of these studies to Staff and other interested parties prior to FPL's next base rate case filing.

## III. Revenue Spread - Gradualism

**Q HAS FPL USED GRADUALISM IN ITS DETERMINATION OF THE APPROPRIATE SPREAD OF THE REVENUE INCREASE ACROSS CUSTOMER CLASSES?**

A Yes. FPL witness Ms. Tiffany Cohen indicates in her direct testimony that the Company is proposing to limit any class revenue increase on a total bill basis by 1.5 times the system average increase, and has also set a floor so that all classes get at least 0.5 times the system average increase. The concept of gradualism is appropriate and necessary in this proceeding, but the Company's proposed application is flawed.

FPL recovers a considerable amount of revenue through its fuel rider, which is not a part of base rates, not included in the Company's cost of service studies, and should be excluded from the class revenues when determining the appropriate revenue increase under the gradualism constraints.

**Q WHY SHOULD FUEL REVENUES BE EXCLUDED FROM THE CLASS REVENUE INCREASE GRADUALISM CALCULATIONS?**

A Fuel revenues are not collected through base rates, are highly volatile and largely outside of the Company's control. On the other hand, many of the other surcharges and riders in addition to FPL's base rates do relate to costs that are generally a component of base rates in other jurisdictions, such as purchased power contract capacity costs, interruptible load credits, and certain environmental controls costs. Because the Company is proposing in this case to roll a considerable amount of these surcharge revenues into base rates, it would be inaccurate to calculate a class revenue increase spread under the gradualism constraints on only base rate revenues. The proposed base rate revenues in this proceeding are significantly higher than the present base rate revenues for reasons that include the roll in of surcharge revenue into base rates.

However, fuel revenues recovered outside of base rates make up approximately 70% or more of the total surcharge revenue recovered from FPL customers. As well, total proposed base rate revenues in this proceeding are $6.8 billion, the total clause revenue including fuel for the 2017 Test Year is $4.6 billion, making total surcharge revenue collected by the utility approximately 40% of the total

Company revenue, and fuel surcharge revenue 30% of the Company total. With fuel being a significant component of the total class revenue, it is unreasonable to include these fuel revenues in the class total revenue amount when determining the appropriate spread of the requested revenue increase across classes under the gradualism constraints.

FPL does not propose in this case to roll any fuel surcharge revenue into base rates, unlike other surcharge revenue. If fuel revenues are included when apportioning the revenue spread to classes, the movement closer to cost of service for each class is muted.

**Q WHAT IS YOUR RECOMMENDATION CONCERNING THE GRADUALISM CONSTRAINTS AND THE SPREAD OF THE APPROVED REVENUE INCREASE ACROSS CUSTOMER CLASSES?**

A I agree with the Company's proposed gradualism constraints, that is, limiting the revenue increase for all classes to 1.5 times the system average increase, and ensuring each class gets at least a 0.5 times system average increase. However, I believe these gradualism constraints should be applied to the total class revenues excluding fuel revenues. In addition, I recommend all classes should receive an equal percentage reduction in their total revenue excluding fuel charges if any reduction in revenue requirement is approved by the Commission. My proposals for revenue spread apply equally to any rate change approved by the Commission whether in 2017, 2018, or 2019.

**Q HAVE YOU CALCULATED A PROPOSED REVENUE SPREAD THAT FOLLOWS THE ADJUSTED GRADUALISM CONSTRAINT YOU HAVE PROPOSED ABOVE?**

A Yes. My Exhibit AMA-3 shows an example of my proposed revenue spread removing the estimated fuel surcharge revenue.[11] Exhibit AMA-3 calculates a sample corrected revenue spread using the Company's 12 CP and 1/13th COSS results. However, I maintain that the appropriate transmission cost allocation method is 100% demand 12 CP, and the appropriate production cost allocation method is 100% demand 4 CP summer or 4 CP/1 CP summer/winter. I view the continuation of the 12 CP and 1/13th production demand allocation method a compromise between the Company's and my proposal laid out in this testimony.

Exhibit AMA-3 shows all classes receiving between a 0.5 times and 1.5 times system average increase. It is based off of present electric revenues including the full value of CILC and CDR credits, which I will describe below.

## IV. Rate Design

**Q HOW HAS THE COMPANY PROPOSED TO CHANGE THE CILC AND CDR CREDITS TO INTERRUPTIBLE CUSTOMERS?**

A The Company in this proceeding proposes to reduce by $23 million (37%) the value of CILC and CDR customers' interruptibility. These customers are given a rate credit for the load that they have offered to the Company as non-firm through the CDR Rider, or through the differential between the CILC base rate charges and the

[11]The Company did not provide in its filed testimony or exhibits any detail concerning the total surcharge revenue it estimates for the test year periods for each class. I have used current tariff rates in effect to estimate the class revenue that is recovered through the fuel charge, but the values for the total surcharge revenue included in the test year periods by FPL would be a function of FPL's projections of these various charge rates in the future test year. I have issued a data request seeking the workpapers supporting the calculated class surcharge revenue that the Company included in its revenue spread proposals. When and if the Company provides the fuel surcharge revenue by class, I can update my proposed revenue spread calculations.

otherwise applicable General Service rate charges for firm service. Ms. Cohen indicates very briefly beginning at page 18 that the:

> 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.

Ms. Cohen does not elaborate on the Company's proposed credit levels, nor whether this proposal is cost justified. Lacking any further information on the reasonableness of the Company's proposal, I recommend the Commission reject the Company's proposal to reduce the interruptible credits offered to the CILC and CDR customers. Therefore, as shown on my Exhibit AMA-3, I have developed my target revenue requirements for the CILC and CDR customer classes to include the full level of interruptible credits that are present in the Company's existing rates and were included in the COSS provided by the Company.

**Q IS THE LEVEL OF INTERRUPTIBLE CREDITS INCLUDED IN THE COMPANY'S EXISTING RATES REASONABLE?**

A No, the interruptible credits on a per kW-month basis are less than the estimated cost of a new CT peaking unit. My Table 2 above indicates that the average cost of a new CT peaking unit is approximately $675 per kW-year. Using a 15% fixed cost recovery factor yields an interruptible credit of approximately $8.45 per kW-month. This is the value to FPL of avoiding the construction of an additional peaking generation resource. When the CILC and CDR customers offer their interruptible load to FPL, the Company is able to reduce its system peak demand forecast levels and thereby reduce the amount of peak demand capacity resource cost needed to meet system peak demands.

A review of the Company's MFR E-5 shows the total interruptible credit level the Company includes in its current base rates for CILC customers. The total CILC interruptible credit in the Company's present rates is $41.7 million. Dividing this interruptible credit level by the interruptible billing determinants for the CILC classes results in an actual CILC interruptible credit of only $6.17 per kW-month. This exercise shows that the level of interruptible credits included in the Company's present rates, which are well above the CILC and CDR interruptible credit levels the Company is proposing in this case, are still far below the true value to FPL of these customers' interruptibility.

**Q WHAT IS YOUR PROPOSAL CONCERNING THE APPROPRIATE LEVEL OF INTERRUPTIBLE CREDITS?**

A I propose that the Commission reject the Company's proposal to reduce the interruptible credits in this case. I recommend as well that the Company conduct a study to evaluate the appropriateness of the level of interruptible credits in the present rates in comparison to the true value to the FPL system. FPL should be required to provide the results of this study to Staff and other interested parties prior to filing its next base rate case.

**Q DO YOU HAVE OTHER CONCERNS WITH THE COMPANY'S PROPOSED BASE RATE DESIGN FOR THE CILC CLASS IN THIS PROCEEDING?**

A Yes. The Company's proposed base rate charges for the three CILC rate sub-classes for the 2017 Test Year and 2018 Subsequent Year are economically illogical, do not provide appropriate efficient price signals, and are not reflective of the

Company's own COSS results. Therefore, FPL's proposed changes to the CILC rate should be rejected.

**Q PLEASE EXPLAIN.**

A Table 4 below provides a comparison of the Company's present rate design for the CILC class and its proposed 2017 base rate charges.

**TABLE 4**

**Present and Proposed CILC Base Rate Charges**
(Demand Charges $/kW, Energy Charges ¢/kWh)

| | Present Rates | | | Company's 2017 Proposed Rates | | |
|---|---|---|---|---|---|---|
| | CILC-1G | CILC-1D | CILC-1T | CILC-1G | CILC-1D | CILC-1T |
| | below 69 kV | | >69 kV | below 69 kV | | >69 kV |
| | 200-499 kW | 500 kW+ | | 200-499 kW | 500 kW+ | |
| Load Control Dmd | $1.97 | $1.97 | $1.97 | $3.30 | $4.00 | $4.40 |
| Firm Demand | $8.73 | $8.51 | $8.65 | $12.00 | $14.20 | $16.40 |
| Max (Dist.) Dmd | $3.82 | $3.49 | n/a | $4.90 | $5.50 | n/a |
| Energy | 1.425 | 0.822 | 0.731 | 1.828 | 1.272 | 1.307 |

This comparison illustrates the economically illogical results of the Company's proposed rate design even compared to the Company's present rates. I will elaborate below.

**Q PLEASE EXPLAIN WHY THE COMPANY'S CILC BASE RATE PROPOSAL IS ECONOMICALLY ILLOGICAL.**

A As shown in Table 4 above, the existing CILC rate design reflects a declining charge for generation and transmission service, and for energy consumption, for CILC customers that take service at a higher delivery voltage level. This is economically logical because there are fewer losses serving the customer at transmission level than at the primary and secondary voltage levels. The existing rate structure reflects the reduction in losses through declining rates based on delivery voltage service. In significant contrast, the proposed charges reflect a higher charge for transmission voltage level service than they do for primary and secondary voltage customers. This is economically illogical because the Company holds less generation capacity per unit of demand to serve a transmission voltage level customer than it would need for primary and secondary voltage customers.

For example, due to energy losses during voltage transformation, the Company would need 1.0218 MW to produce 1 MW at a customer's transmission voltage level meter. The difference between generation and meter level energy is a result of the losses that take place through the conductors, and through the transformation process. In comparison, the Company's demand loss study states that it would need 1.0348 MW and 1.0644 MW to put 1 MW through a primary and secondary meter, respectively. The greater amount of production and transmission capacity at the generation level, relative to the meter level, again reflects a greater level of losses incurred by FPL to serve a customer at primary and secondary voltage relative to transmission voltage.

The existing CILC rate design reflects these differences in losses. FPL's proposed rate design distorts this economically logical structure and creates inaccurate and false price signals to customers that take service under the CILC tariff.

**Q PLEASE EXPLAIN WHY YOU BELIEVE THE COMPANY'S PROPOSED REVISIONS TO THE CILC RATE DESIGN DOES NOT FOLLOW ITS OWN COST OF SERVICE.**

A The Company's rate design for higher energy and demand charges for transmission level customers, relative to primary and secondary level customers, is inconsistent with its own class COSS. As shown in Table 5 below, the Company's allocated costs at transmission voltage level on a per-unit basis are lower than the Company's per-unit costs allocated to primary and secondary voltage level customers.

**TABLE 5**

**Results of Company's 12CP and 1/13th COSS**
**Functionalized Unit Charges**
**Including CILC Credit Offset**

| Description | CILC-1G | CILC-1D | CILC-1T |
|---|---|---|---|
| Customer ($/Mo.) | $ 120 | $ 254 | $ 3,201 |
| Production ($/kW) | $ 6.75 | $ 6.32 | $ 6.29 |
| Transmission ($/kW) | $ 1.28 | $ 1.20 | $ 1.20 |
| Distribution ($/kW) | $ 5.25 | $ 4.94 | $ - |
| Energy ($/kWh) | $ 0.00740 | $ 0.00734 | $ 0.00718 |

Source:
1. MFR No. E-6b, Attachment No. 2 (12 CP and 1/13th) and E-5 includes CILC credit offset

Again, FPL's existing rate structure for CILC reflects this cost differential and loss differential, but FPL's proposed pricing structure does not.

**Q PLEASE EXPLAIN WHY THE COMPANY'S PRESENT RATE DESIGN FOR THE CILC CLASS IS MORE REASONABLE THAN ITS PROPOSED AND REVISED RATE DESIGN**

A My support is twofold. First, the Company's COSS support the Company's present rate design more so than the Company's proposed rate design. Table 5 above shows the resultant unit costs classified by demand related production, transmission, energy, distribution and customer charges from the Company's 12 CP and 1/13th COSS. These unit costs present a rate design that tracks proper cost-causation principles. Specifically, the transmission, production, and energy per-unit costs are all lower for higher voltage level customers than they are for the lower voltage level customers.

Second, the Company's own direct testimony in its last base rate case, Docket No. 120015-EI, provides a description of how the present CILC rates were designed. This design follows cost causation, relies on the results of the COSS and its principles therein, and is superior to the CILC rate design presented in the Company's testimony in this instant proceeding. In the 2012 docket, Ms. Deaton's Exhibit RBD-6, page 13 of 22, describes beginning at line 18 that the interruptible demand charge for each of the three CILC sub-classes is identical, and is "based on the class's average transmission demand unit cost." The firm demand charges for the three classes are "based on the class's average production and transmission demand unit cost." The maximum kW charge, or distribution recovery charge for the CILC-1G and CILC-1D classes are "based on the distribution demand revenue requirements divided by the billing demands." Lastly, the energy charges are, as well, based on the rate classes' energy unit costs developed in the Company's COSS.

In contrast, Ms. Cohen describes in the instant proceeding in Exhibit TCC-6, page 16 of 27, at line 22 that "The proposed demand and energy charges were calculated by applying the rate class increase percentage to current rates." This revised proposal ignores the cost-causation principles used in the Company's COSS and the production cost allocation and energy cost allocation to the various rate classes. Ms. Cohen's proposals in the instant proceeding produce a rate design for the three CILC sub-classes that is illogical, do not follow cost-causation principles, nor produce appropriate pricing incentives.

**Q WHAT IS YOUR RECOMMENDED RATE DESIGN IN THIS CASE?**

A I propose that the Company revert to a rate design that is more in line with that which it presented in its last base rate case and used to develop its present base rate charges. Following the rate design description offered by FPL in its 2012 base rate case, I recommend an equal interruptible demand charge for each sub-class set at the classes' average transmission demand unit cost from the approved COSS. I recommend the firm demand charges for the various sub-classes reflect the average production and transmission demand unit costs developed in the approved. Further, I propose the distribution demand charge for the CILC-1G and CILC-1D sub-classes be based on the distribution demand revenue requirements included in the approved COSS, also following the same rate differential between sub-classes as exists in the present rates. Lastly, I propose the energy charges be adjusted to achieve the rate class target revenues I have proposed in my testimony.[12] Each of these rate charge proposals follows the Company's proposal in its 2012 case.

[12]In 2012, the Company proposed an on-peak and off-peak time-differentiated energy rate, but that is not reflected in current or proposed rates in the instant proceeding. Further, the COSS does not allocate energy costs in a time-differentiated manner, and therefore does not provide a cost basis for designing a time-differentiated energy charge.

**Q HAVE YOU DEVELOPED PROPOSED CILC BASE RATES?**

A Yes. My Exhibit AMA-4 illustrates the development of my proposed rates for the CILC sub-classes following the procedure I have outlined above. Page 1 of Exhibit AMA-4 provides the COSS results from the Company's 12 CP and 1/13$^{th}$ model, taking into account the full value of the CILC credits. I then calculate proposed CILC base rate charges based on the functionalized COSS unit costs. Page 2 of Exhibit AMA-4 compares the Company's proposed revenue targets to my total revenue targets for each sub-class and shows how my proposed rates produce the target revenue requirements.

Table 6 below shows a comparison of the Company's present CILC base rates and my proposed CILC base rates. This comparison shows that the appropriate rate design principles following cost causation of the relative voltage level customers and price signal principles are followed under my proposal.

These proposed rates are offered at FPL's proposed cost of service for illustration purposes only. A reduction to FPL's revenue requirement should be taken into account in designing the CILC rates.

**TABLE 6**

**Present and FEA Proposed CILC Base Rate Charges**
(Demand Charges $/kW, Energy Charges ¢/kWh)

| | Present Rates | | | FEA 2017 Proposed Rates | | |
|---|---|---|---|---|---|---|
| | CILC-1G | CILC-1D | CILC-1T | CILC-1G | CILC-1D | CILC-1T |
| | below 69 kV | | >69 kV | below 69 kV | | >69 kV |
| | 200-499 kW | 500 kW+ | | 200-499 kW | 500 kW+ | |
| Load Control Dmd | $1.97 | $1.97 | $1.97 | $1.20 | $1.20 | $1.20 |
| Firm Demand | $8.73 | $8.51 | $8.65 | $7.96 | $7.52 | $7.50 |
| Max (Dist.) Dmd | $3.82 | $3.49 | n/a | $4.54 | $4.21 | n/a |
| Energy | 1.425 | 0.822 | 0.731 | 1.813 | 1.476 | 1.311 |

**Q DO YOUR ABOVE PROPOSED BASE RATES REFLECT YOUR RECOMMENDED CHANGES TO THE PRODUCTION COST ALLOCATOR YOU HAVE MADE IN THIS TESTIMONY?**

A No. The Company's workpapers filed in this case did not provide a working cost of service model from which I could make any adjustments to develop my recommended cost of service results. Therefore, I have designed rates to follow the Company's 12 CP and 1/13$^{th}$ production and transmission cost allocation method, with changes to the rate design to include the full CILC interruptible credit amount, and to follow a 1.5 times system average gradualism constraint on the non-fuel revenue. However, I maintain that the appropriate transmission cost allocation method is 100% demand 12 CP, and the appropriate production cost allocation method is 100% demand 4 CP summer or 4 CP/1 CP summer/winter method. I view the continuation of the 12 CP and 1/13$^{th}$ production demand allocation method a compromise between the Company's proposal and mine laid out in this testimony.

**Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A Yes, it does.

# Qualifications of Amanda M. Alderson

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

A Amanda Alderson. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

**Q PLEASE STATE YOUR OCCUPATION.**

A I am a Consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

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

A I graduated from the University of Illinois at Urbana-Champaign in 2008 where I received my Bachelor of Arts in Economics, with minor studies in Statistics and International Business. I earned my Masters of Business Administration Degree with a concentration in Logistics and Operations Management upon graduation from the University of Missouri-St. Louis in 2011.

I joined BAI in 2008 as an analyst. Then, in September 2011, I joined the consulting team of BAI.

I have worked on various issues including embedded and marginal cost of service studies, rate design, power procurement and portfolio management, contract negotiation and environmental and sustainability compliance management.

In the regulated arena, I have evaluated cost of service studies and rate designs proffered by other parties in cases for various utilities, including in New York, Indiana, Missouri, Oregon, Quebec, Nova Scotia, and others. I have conducted bill audits, rate forecasts and tariff rate optimization studies. I have performed utility investment prudence reviews with respect to such items as fuel, purchased power and renewable energy investments.

I have also provided support to clients with facilities in deregulated markets, including drafting supply requests for proposals, evaluating supply bids, and auditing competitive supply bills. I have also prepared and presented to clients reports that monitor the electric market and recommend strategic hedging transactions.

BAI was formed in April 1995. BAI and its predecessor firm have participated in more than 700 regulatory proceedings in forty states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

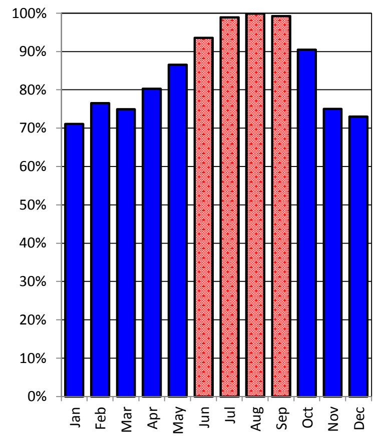
In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation.

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

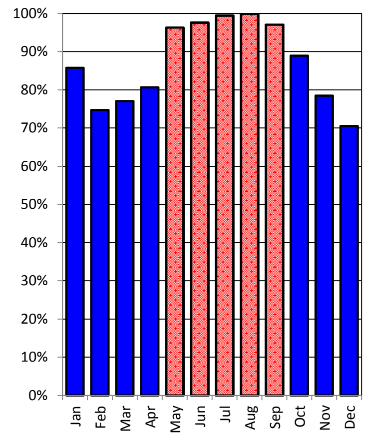
# Florida Power and Light

## Monthly Peak Demands as a Percent of the Annual System Peak

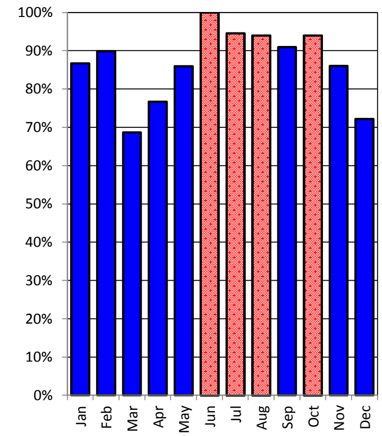
### Calendar Year 2007



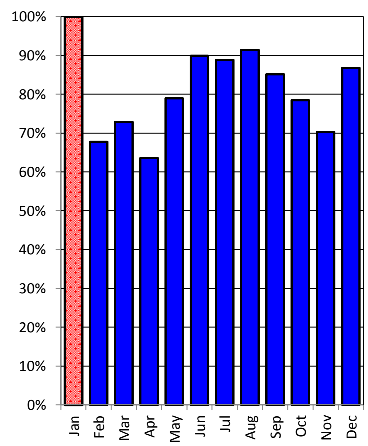

### Calendar Year 2008



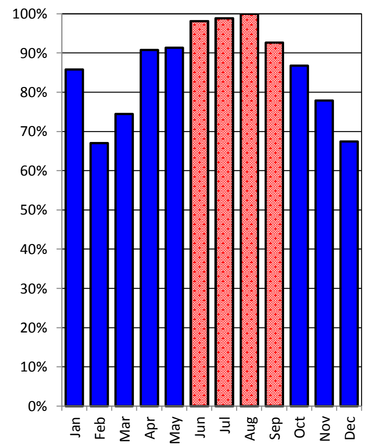

### Calendar Year 2009



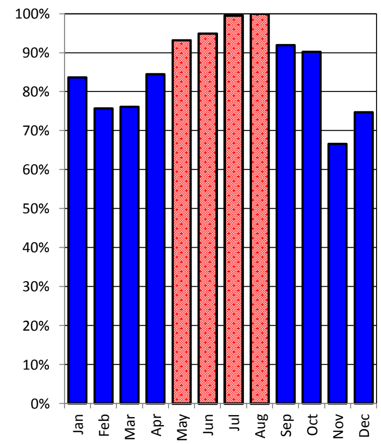

### Calendar Year 2010




### Calendar Year 2011




### Calendar Year 2012




Monthly Peaks are Greater than 92%

Other Monthly Peak Demands

Sources:

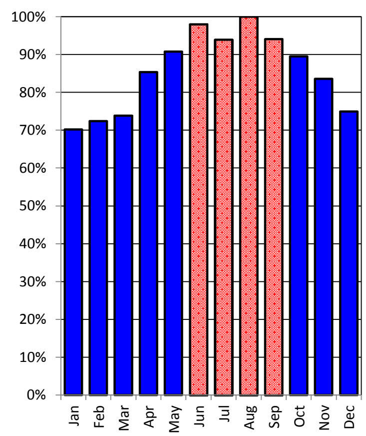
[1] Calendar Year data taken from FPL FERC Form 1

[2] Projected Year data taken from MFR Schedule E-18

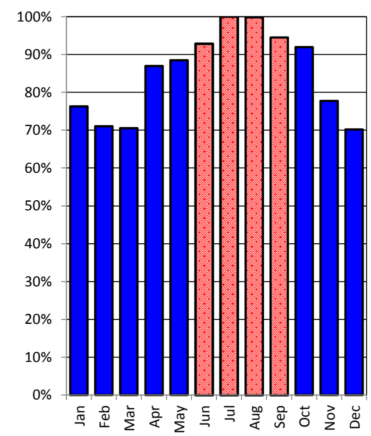
# Florida Power and Light

## Monthly Peak Demands as a Percent of the Annual System Peak

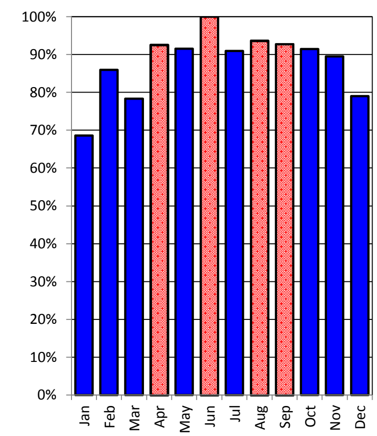
### Calendar Year 2013



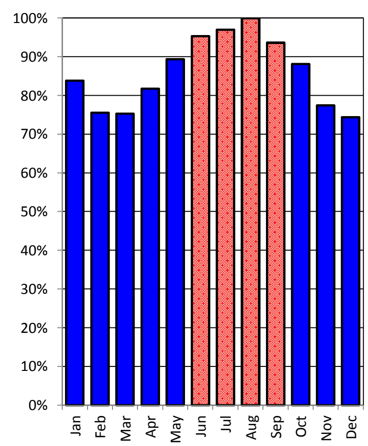

### Calendar Year 2014



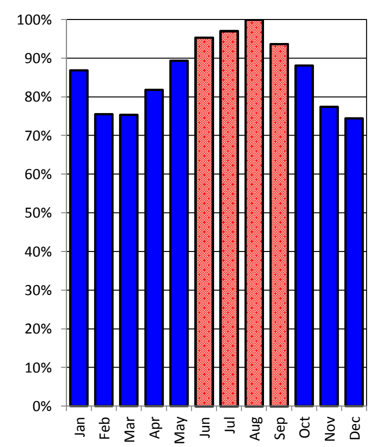

### Calendar Year 2015



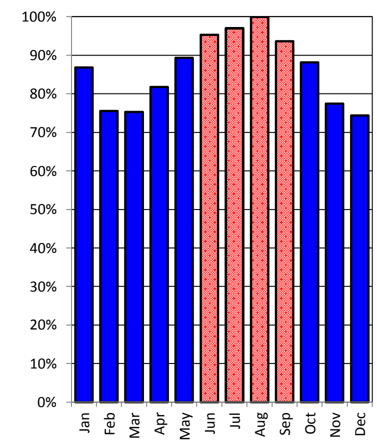

### Projected Year 2016




### Projected Year 2017




### Projected Year 2018




Monthly Peaks are Greater than 92%

Other Monthly Peak Demands

Sources:

[1] Calendar Year data taken from FPL FERC Form 1

[2] Projected Year data taken from MFR Schedule E-18

# Florida Power & Light Company

## Comparison of Production Allocation Factors

| Line | Rate Schedule | Company Proposed 12CP & 25% | Company Present 12CP & 1/13th | Summer/Winter 4CP/1CP | Summer 4CP |
|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) |
| 1 | CILC-1D | 2.0167% | 1.9079% | 1.7437% | 1.7191% |
| 2 | CILC-1G | 0.0782% | 0.0744% | 0.0681% | 0.0671% |
| 3 | CILC-1T | 1.0689% | 1.0005% | 0.8780% | 0.8694% |
| 4 | GS(T)-1 | 5.6011% | 5.6080% | 5.5562% | 5.9726% |
| 5 | GSCU-1 | 0.0502% | 0.0467% | 0.0412% | 0.0404% |
| 6 | GSD(T)-1 | 22.2958% | 21.8789% | 20.7930% | 21.4242% |
| 7 | GSLD(T)-1 | 9.0183% | 8.8381% | 8.1953% | 8.2982% |
| 8 | GSLD(T)-2 | 1.8865% | 1.7839% | 1.6006% | 1.5982% |
| 9 | GSLD(T)-3 | 0.1276% | 0.1209% | 0.1089% | 0.1074% |
| 10 | MET | 0.0776% | 0.0762% | 0.0730% | 0.0711% |
| 11 | OL-1 | 0.0303% | 0.0162% | 0.0087% | 0.0000% |
| 12 | OS-2 | 0.0077% | 0.0072% | 0.0058% | 0.0042% |
| 13 | RS(T)-1 | 57.4764% | 58.4645% | 60.8077% | 59.7642% |
| 14 | SL-1 | 0.1748% | 0.0944% | 0.0526% | 0.0000% |
| 15 | SL-2 | 0.0234% | 0.0218% | 0.0192% | 0.0188% |
| 16 | SST-DST | 0.0095% | 0.0091% | 0.0079% | 0.0084% |
| 17 | SST-TST | 0.0570% | 0.0515% | 0.0402% | 0.0366% |
| 18 | Total Retail | 100.0000% | 100.0000% | 100.0000% | 100.0000% |

Source: Response to FIPUG's 1st POD No. 9, COS Roadmap 4-23-2016.xlsx.
Note: Summer 4CP months used are June-September; Winter 1CP month is January.

# FLORIDA POWER AND LIGHT COMPANY

## Revenue Spread for 2017 Test Year

**($ in Millions)**

| Line | Description | Present Base Rate Revenues with Full CILC CDR Credits[1] | Present Electric Revenues with Full Credit Offset[2] | 12CP & 1/13th COSS Proposed Equalized ROR: Electric Revenues[3] | 12CP & 1/13th COSS Proposed Equalized ROR: CILC/CDR Reverse Credit Reduction[4] | 12CP & 1/13th COSS Proposed Equalized ROR: Base Rate Increase | Total Clause Revenue[5] | Less Fuel Revenue[6] | Non-Fuel Percent | Relative Increase | Gradualism Constraints | Spread Remainder | FEA Proposed Increase[7] | FEA Percent Increase | Relative Increase |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) |
| | | | | | | | | | | Max 1.5x: | 16.58% | | | | |
| | | | | | | | | | | Min 0.5x: | 5.53% | | | | |
| 1 | CILC-1D | $ 60.64 | $ 87.80 | $ 112.26 | $ (9.94) | $ 14.51 | $ 110.22 | $ 65.81 | 10.98% | 0.99 | $ 14.51 | $ 0.99 | $ 15.50 | 11.72% | 1.06 |
| 2 | CILC-1G | 3.16 | 4.11 | 4.50 | (0.37) | 0.02 | 4.17 | 2.52 | 0.34% | 0.03 | 0.32 | 0.00 | 0.32 | 5.55% | 0.50 |
| 3 | CILC-1T | 22.16 | 35.87 | 45.98 | (5.23) | 4.87 | 60.68 | 35.95 | 8.04% | 0.73 | 4.87 | 0.33 | 5.21 | 8.59% | 0.78 |
| 4 | GS(T)-1 | 369.14 | 369.37 | 389.43 | | 20.06 | 257.11 | 149.33 | 4.20% | 0.38 | 26.37 | 1.36 | 27.73 | 5.81% | 0.53 |
| 5 | GSCU-1 | 4.18 | 4.19 | 3.77 | | (0.41) | 2.86 | 1.76 | -7.75% | (0.70) | 0.29 | | 0.29 | 5.53% | 0.50 |
| 6 | GSD(T)-1 | 1,131.51 | 1,138.57 | 1,331.54 | (2.20) | 190.76 | 1,088.96 | 643.61 | 12.04% | 1.09 | 190.76 | 12.95 | 203.71 | 12.86% | 1.16 |
| 7 | GSLD(T)-1 | 369.41 | 381.37 | 530.57 | (4.15) | 145.05 | 442.23 | 260.21 | 25.75% | 2.33 | 93.42 | | 93.42 | 16.58% | 1.50 |
| 8 | GSLD(T)-2 | 75.33 | 78.38 | 106.15 | (1.07) | 26.69 | 103.11 | 61.49 | 22.24% | 2.01 | 19.90 | | 19.90 | 16.58% | 1.50 |
| 9 | GSLD(T)-3 | 4.56 | 4.57 | 5.62 | | 1.05 | 6.99 | 4.14 | 14.22% | 1.29 | 1.05 | 0.07 | 1.13 | 15.18% | 1.37 |
| 10 | MET | 4.09 | 4.10 | 4.59 | | 0.50 | 3.84 | 2.26 | 8.78% | 0.79 | 0.50 | 0.03 | 0.53 | 9.38% | 0.85 |
| 11 | OL-1 | 14.05 | 14.05 | 12.58 | | (1.47) | 4.59 | 2.31 | -8.97% | (0.81) | 0.90 | | 0.90 | 5.53% | 0.50 |
| 12 | OS-2 | 0.99 | 0.99 | 1.43 | | 0.44 | 0.49 | 0.27 | 35.93% | 3.25 | 0.20 | | 0.20 | 16.58% | 1.50 |
| 13 | RS(T)-1 | 3,504.59 | 3,506.97 | 3,948.76 | | 441.79 | 2,491.31 | 1,425.76 | 9.66% | 0.87 | 441.79 | 29.99 | 471.78 | 10.32% | 0.93 |
| 14 | SL-1 | 91.27 | 91.27 | 96.19 | | 4.92 | 26.31 | 13.21 | 4.71% | 0.43 | 5.77 | 0.33 | 6.10 | 5.85% | 0.53 |
| 15 | SL-2 | 1.51 | 1.51 | 1.36 | | (0.15) | 1.34 | 0.82 | -7.19% | (0.65) | 0.11 | | 0.11 | 5.53% | 0.50 |
| 16 | SST-DST | 0.80 | 0.80 | 0.92 | | 0.12 | 0.87 | 0.29 | 8.70% | 0.79 | 0.12 | 0.01 | 0.13 | 9.29% | 0.84 |
| 17 | SST-TST | 4.40 | 4.40 | 2.90 | | (1.50) | 3.20 | 2.12 | -27.31% | (2.47) | 0.30 | | 0.30 | 5.53% | 0.50 |
| 18 | Total Company | $ 5,661.80 | $ 5,728.33 | $ 6,598.57 | $ (22.97) | $ 847.27 | $4,608.29 | $2,671.85 | 11.05% | 1.00 | $ 801.20 | $ 46.07 | $ 847.27 | 11.05% | 1.00 |
| | | | | | | | | | | Remainder: | $ 46.07 | | | | |

**Sources and Notes:**

[1] MFR E-5

[2] MFR E-1, Attachment 1, adds $62 million in CILC/CDR credits and $4 million Unbilled and Service revenues

[3] MFR E-1, Attachment 2 (12 CP and 1/13th)

[4] MFR E-14, Attachment 5

[5] MFR E-14, Attachment 2, p. 31

[6] Estimated based on class kWh in MFR E-14, Attachment 2, and Fuel Adjustment rates effective 4/1/2016

[7] FEA proposed revenue increase maintains the CILC/CDR credits at existing levels.

# FLORIDA POWER AND LIGHT COMPANY

## Revenue Spread for 2017 Test Year

**($ in Millions)**

| Line | Description | Present Non-Fuel Electric Revenues[1] | Company Proposed Electric Revenue Increase[2] | | | FEA Proposed Base Rate Increase[3] | | |
|---|---|---|---|---|---|---|---|---|
| | | | Revenues | Percent | Index | Revenues | Percent | Index |
| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
| 1 | CILC-1D | $ 132.20 | $ 24.63 | 18.63% | **1.64** | $ 15.50 | 11.72% | 1.06 |
| 2 | CILC-1G | 5.76 | 0.52 | 9.03% | 0.80 | 0.32 | 5.55% | 0.50 |
| 3 | CILC-1T | 60.60 | 11.96 | 19.74% | **1.74** | 5.21 | 8.59% | 0.78 |
| 4 | GS(T)-1 | 477.15 | 22.43 | 4.70% | **0.41** | 27.73 | 5.81% | 0.53 |
| 5 | GSCU-1 | 5.29 | 0.04 | 0.68% | **0.06** | 0.29 | 5.53% | 0.50 |
| 6 | GSD(T)-1 | 1,583.92 | 221.28 | 13.97% | 1.23 | 203.71 | 12.86% | 1.16 |
| 7 | GSLD(T)-1 | 563.39 | 102.55 | 18.20% | **1.60** | 93.42 | 16.58% | 1.50 |
| 8 | GSLD(T)-2 | 120.01 | 22.59 | 18.83% | **1.66** | 19.90 | 16.58% | 1.50 |
| 9 | GSLD(T)-3 | 7.42 | 1.31 | 17.60% | **1.55** | 1.13 | 15.18% | 1.37 |
| 10 | MET | 5.67 | 0.58 | 10.20% | 0.90 | 0.53 | 9.38% | 0.85 |
| 11 | OL-1 | 16.34 | 0.10 | 0.59% | **0.05** | 0.90 | 5.53% | 0.50 |
| 12 | OS-2 | 1.22 | 0.19 | 15.41% | 1.36 | 0.20 | 16.58% | 1.50 |
| 13 | RS(T)-1 | 4,572.53 | 454.22 | 9.93% | 0.88 | 471.78 | 10.32% | 0.93 |
| 14 | SL-1 | 104.38 | 7.53 | 7.22% | 0.64 | 6.10 | 5.85% | 0.53 |
| 15 | SL-2 | 2.02 | 0.01 | 0.70% | **0.06** | 0.11 | 5.53% | 0.50 |
| 16 | SST-DST | 1.38 | 0.14 | 10.06% | 0.89 | 0.13 | 9.29% | 0.84 |
| 17 | SST-TST | 5.49 | 0.04 | 0.65% | **0.06** | 0.30 | 5.53% | 0.50 |
| 18 | Total Company | $ 7,664.77 | $ 870.1 | 11.35% | 1.00 | $ 847.27 | 11.05% | 1.00 |

**Sources and Notes:**

[1] Exhibit AMA-3, page 1, Col. (2) + Col. (6) - Col. (7)

[2] MFR E-14, Attachment 2
Includes reductions to CILC/CDR revenues collected from the ECCR,
but excludes Unbilled and Misc. Service Charge revenues.

[3] FEA proposed revenue increase maintains the CILC/CDR credits at existing levels.

# FLORIDA POWER AND LIGHT COMPANY
## FEA Proposed CILC Rate Design

| | | Per Company's COSS (12 CP and 1/13th) | | | |
|---|---|---|---|---|---|
| **Line** | **Description** | **CILC-1G** | **CILC-1D** | **CILC-1T** | **Total** |
| | | (1) | (2) | (3) | (4) |
| | **Billing Units from COSS Unit Cost Calculations (Annual)**[1] | | | | |
| 1 | Demand kW | 204,233 | 5,184,883 | 2,778,867 | 8,167,983 |
| 2 | Energy MWh | 101,624 | 2,687,420 | 1,508,335 | 4,297,379 |
| 3 | No. of Bills | 744 | 3,336 | 204 | 4,284 |
| | **Billing Units from Rate Design Workpapers (Annual)**[2] | | | | |
| 4 | Max. kW | 275,810 | 6,058,815 | - | 6,334,625 |
| 5 | Load Control On-Peak kW | 206,603 | 4,390,087 | 2,155,696 | 6,752,386 |
| 6 | Firm On-Peak kW | 5,776 | 671,984 | 579,519 | 1,257,279 |
| 7 | Transformation kW | 5,596 | 1,363,076 | - | 1,368,672 |
| 8 | On-Peak MWh | 27,726 | 708,614 | 382,659 | 1,118,999 |
| 9 | Off-Peak MWh | 73,897 | 1,978,807 | 1,125,676 | 3,178,380 |
| 10 | Total MWh | 101,624 | 2,687,420 | 1,508,335 | 4,297,379 |
| 11 | No. of Bills | 744 | 3,336 | 204 | 4,284 |
| | **Revenue Requirements ($000)**[1] | | | | |
| 12 | Customer | $ 89 | $ 849 | $ 653 | $ 1,591 |
| 13 | Production Demand | 2,173 | 55,509 | 28,966 | 86,648 |
| 14 | Transmission | 412 | 10,556 | 5,537 | 16,505 |
| 15 | Distribution | 1,073 | 25,616 | - | 26,689 |
| 16 | Production Energy | 752 | 19,725 | 10,825 | 31,302 |
| 17 | Total Cost of Firm Service | $ 4,499 | $ 112,255 | $ 45,981 | $ 162,735 |
| 18 | Existing CILC Credits[3] | $ 945 | $ 27,076 | $ 13,667 | $ 41,688 |
| | **Unit Costs Based on COSS Incl. CILC Credits** | | | | |
| 19 | Customer ($/Mo.) | $ 120 | $ 254 | $ 3,201 | |
| 20 | Production Demand ($/kW) | 6.75 | 6.32 | 6.29 | 6.32 |
| 21 | Transmission ($/kW) | 1.28 | 1.20 | 1.20 | 1.20 |
| 22 | Distribution Demand ($/kW) | 5.25 | 4.94 | - | 4.95 |
| 23 | Production Energy ($/kWh) | 0.00740 | 0.00734 | 0.00718 | 0.00728 |
| | **FEA Proposed Rate Design** | | | | |
| 24 | Customer ($/Month) | $ 125.00 | $ 275.00 | $ 3,200.00 | |
| 25 | Max. Demand Charge ($/kW) - Dist. | 4.54 | 4.21 | - | |
| 26 | Load Control On-Peak ($/kW) - Trans. | 1.20 | 1.20 | 1.20 | |
| 27 | Firm On-Peak ($/kW) - Prod. & Trans. | 7.96 | 7.52 | 7.50 | |
| 28 | Transformation Credit ($/kW) | (0.23) | (0.23) | (0.23) | |
| 29 | On-Peak Energy ($/kWh) | 0.01815 | 0.01478 | 0.01311 | |
| 30 | Off-Peak Energy ($/kWh) | 0.01815 | 0.01478 | 0.01311 | |
| | **Determination of kWh Charge** | | | | |
| 31 | Target Revenues After Gradualism Constraints[4] | $ 3,482 | $ 76,140 | $ 27,366 | |
| 32 | Remaining Amount to Collect from kWh Charge | $ 1,844 | $ 39,707 | $ 19,780 | |
| 33 | Energy kWh Charge | $ 0.01815 | $ 0.01478 | $ 0.01311 | |

**Sources**

[1] MFR E-6b, Attachment 2 (12 CP and 1/13th)
[2] MFR E-14, Attachment 2
[3] MFR E-5
[4] Exhibit AMA-3

# FLORIDA POWER AND LIGHT COMPANY
## Proof of Revenue at FEA Proposed CILC Rates

| Line | Description | Annual Billing Units[1] | Company Proposed[1] Rates | Company Proposed[1] Revenues | FEA Proposed[2] Rates | FEA Proposed[2] Revenues |
|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) |
| | **CILC-1G** | | | | | |
| 1 | Customer | 744 | $ 125.00 | $ 93,000 | $ 125.00 | $ 93,000 |
| 2 | On-Peak kWh | 27,726,439 | $ 0.01828 | $ 506,839 | $ 0.01815 | $ 503,235 |
| 3 | Off-Peak kWh | 73,897,063 | $ 0.01828 | $ 1,350,838 | $ 0.01815 | $ 1,341,232 |
| 4 | Max. kW | 275,810 | $ 4.90 | $ 1,351,469 | $ 4.54 | $ 1,252,177 |
| 5 | Load Control On-Peak kW | 206,603 | $ 3.30 | $ 681,790 | $ 1.20 | $ 247,924 |
| 6 | Firm On-Peak kW | 5,776 | $ 12.00 | $ 69,312 | $ 7.96 | $ 45,977 |
| 7 | Transformation kW | 5,596 | $ (0.23) | $ (1,287) | $ (0.23) | $ (1,287) |
| 8 | Total | | | $ 4,051,961 | | $ 3,482,257 |
| | **CILC-1D** | | | | | |
| 9 | Customer | 3,336 | $ 275.00 | $ 917,400 | $ 275.00 | $ 917,400 |
| 10 | On-Peak kWh | 708,613,584 | $ 0.01272 | $ 9,013,565 | $ 0.01478 | $ 10,473,309 |
| 11 | Off-Peak kWh | 1,978,806,807 | $ 0.01272 | $ 25,170,423 | $ 0.01478 | $ 29,246,765 |
| 12 | Max. kW | 6,058,815 | $ 5.50 | $ 33,323,483 | $ 4.21 | $ 25,507,611 |
| 13 | Load Control On-Peak kW | 4,390,087 | $ 4.00 | $ 17,560,348 | $ 1.20 | $ 5,268,104 |
| 14 | Firm On-Peak kW | 671,984 | $ 14.20 | $ 9,542,173 | $ 7.52 | $ 5,053,320 |
| 15 | Transformation kW | 1,363,076 | $ (0.23) | $ (313,507) | $ (0.23) | $ (313,507) |
| 16 | Total | | | $ 95,213,883 | | $ 76,153,001 |
| | **CILC-1T** | | | | | |
| 17 | Customer | 204 | $ 3,200.00 | $ 652,800 | $ 3,200.00 | $ 652,800 |
| 18 | On-Peak kWh | 382,658,931 | $ 0.01307 | $ 5,001,352 | $ 0.01311 | $ 5,016,659 |
| 19 | Off-Peak kWh | 1,125,676,383 | $ 0.01307 | $ 14,712,590 | $ 0.01311 | $ 14,757,617 |
| 20 | Max. kW | - | $ - | $ - | $ - | $ - |
| 21 | Load Control On-Peak kW | 2,155,696 | $ 4.40 | $ 9,485,062 | $ 1.20 | $ 2,586,835 |
| 22 | Firm On-Peak kW | 579,519 | $ 16.40 | $ 9,504,112 | $ 7.50 | $ 4,346,393 |
| 23 | Transformation kW | - | $ (0.23) | $ - | $ (0.23) | $ - |
| 24 | Total | | | $ 39,355,917 | | $ 27,360,304 |
| 25 | **CILC Class Total** | | | **$ 138,621,761** | | **$ 106,995,562** |
| 26 | **Difference between FEA and Company Proposed CILC Revenues[3]** | | | | | **$ 31,626,199** |

**Sources and Notes**

[1] MFR No. E-14, Attachment 2, pages 2-4

[2] Exhibit AMA-4, page 1

[3] Difference reflects existing level of CILC credits, and use of the 12CP and 1/13th cost allocation methodology