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**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

In re: Petition for rate increase by
Florida Power & Light Company
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DOCKET NO.: 20210015-EI
FILED AND SERVED: June 21, 2021

**THE FLORIDA INDUSTRIAL POWER USERS GROUP'S**
**<u>NOTICE OF FILING TESTIMONY OF JEFF POLLOCK</u>**

The Florida Industrial Power Users Group (FIPUG), provides notice that it has filed the testimony of Jeff Pollock in the above-referenced docket this 21st day of June, 2021. The testimony is attached to this Notice of Service.

DATED this 21st day of June 2021.

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## CERTIFICATE OF SERVICE

I **HEREBY CERTIFY** that a true and correct copy of the foregoing has been furnished by electronic mail this 21st day of June 2021 to the following:

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**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

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# DIRECT TESTIMONY AND EXHIBITS OF JEFFRY POLLOCK

**ON BEHALF OF**
**THE FLORIDA INDUSTRIAL POWER USERS GROUP**

J. POLLOCK
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**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

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## LIST OF EXHIBITS

## GLOSSARY OF ACRONYMS

| Term | Definition |
|---|---|
| **4CP** | Four Coincident Peak |
| **12CP** | Twelve Coincident Peak |
| **AEO** | Annual Energy Outlook |
| **CCGT** | Combined Cycle Gas Turbine |
| **CCOSS** | Class Cost-of-Service Study |
| **CDR** | Commercial/Industrial Demand Reduction |
| **CILC** | Commercial/Industrial Load Control |
| **CONE** | Cost of New Entry |
| **CPVRR** | Cumulative Present Value Revenue Requirement |
| **CT** | Combustion Turbine |
| **DSM** | Demand Side Management |
| **ECCR** | Energy Conservation Cost Recovery |
| **EIA** | Energy Information Administration |
| **Exelon** | Exelon Generation Company LLC |
| **F.A.C.** | Florida Administrative Code |
| **FIPUG** | Florida Industrial Power Users Group |
| **FPL or Company** | Florida Power & Light Company |
| **FRCC** | Florida Reliability Coordinating Council |
| **GSD** | General Service Demand |
| **GSLD** | General Service Large Demand |
| **Gulf Power** | Gulf Power Company |
| **kW / kWh** | Kilowatt / Kilowatt-Hour |
| **MDS** | Minimum Distribution System |
| **MISO** | Midcontinent Independent System Operator, Inc. |
| **MFRs** | Minimum Filing Requirements |
| **MW** | Megawatt |
| **NRC** | Nuclear Regulatory Commission |
| **O&M** | Operation and Maintenance |
| **ROE** | Return on Equity |
| **RSAM** | Reserve Surplus Amortization Mechanism |
| **SoBRA** | Solar Base Rate Adjustment |
| **St. Lucie** | St. Lucie Nuclear Plant |
| **TCJA** | 2017 Tax Cuts and Jobs Act |
| **TECO** | Tampa Electric Company |

# Direct Testimony of Jeffry Pollock

## 1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

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

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

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

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

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

A I have a Bachelor of Science in electrical engineering and a Master of Business Administration from Washington University. Since graduation, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in the United States and in several Canadian provinces. This includes frequent appearances in rate cases and other regulatory proceedings before this Commission. I have testified in Florida Power & Light Company's (FPL's) 2009, 2012 and 2016 rate cases. My qualifications are documented in **Appendix A.** A list of my appearances is provided in **Appendix B** to this testimony.

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

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

**Q WHAT ISSUES DO YOU ADDRESS?**

A I am addressing the following issues:

- FPL's proposed Four-Year Rate Plan including the continuation of the Reserve Surplus Amortization Mechanism (RSAM) and 2024-2025 Solar Base Rate Adjustments (SoBRAs);
- Class Cost-of-Service Study (CCOSS);
- Class revenue allocation; and
- FPL's proposal to reduce the incentive payments to customers participating in two load management programs — Commercial/Industrial Load Control (CILC) and Commercial/Industrial Demand Reduction Rider (CDR) — by 33%.

**Q ARE THERE ANY OTHER WITNESSES TESTIFYING ON BEHALF OF FLORIDA INDUSTRIAL POWER USERS GROUP?**

A Yes. My colleague, Ms. LaConte, will address FPL's proposed cost of capital, the mechanism to adjust rates to reflect a change in the federal corporate income tax rate, the recovery of costs associated with the retirement of Scherer Unit 4, and rate case expense amortization.

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

A Yes. I am sponsoring **Exhibits JP-1** through **JP-14.**

**Q ARE YOU ACCEPTING FPL'S POSITIONS ON THE ISSUES NOT ADDRESSED IN YOUR DIRECT TESTIMONY?**

A No. In various places, I use FPL's proposed revenue requirement to illustrate certain cost allocation and rate design principles. One should not interpret the fact that I do not address every issue raised by FPL as support of its proposals.

## Summary

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

A My findings and recommendations are as follows:

### Four-Year Rate Plan

- The proposed Four-Year Rate Plan would increase base revenues by $2.042 billion ($2.245 billion without continuing the RSAM) for the years 2022 through 2025.

- The 2022 and 2023 base rate increases would be based on two fully projected future test years. This practice eliminates regulatory lag.

- Various elements of the Four-Year Rate Plan, such as continuing the RSAM and the two SoBRA adjustments, would guarantee that FPL achieves at the top end of the return on equity (ROE) authorized by the Commission. The guarantee is the result of how FPL has used the RSAM in the past and the effect of authorizing the two proposed additional solar plant base rate increases in 2024 and 2025 without subjecting FPL to any earnings test.

- Eliminating regulatory lag, while enabling a utility to always achieve the highest authorized earnings substantially mitigates FPL's regulatory risk. Accordingly, if the Four-Year Rate Plan is approved, FPL's authorized ROE should be at or below the national average.

- Providing a utility guaranteed earnings is contrary to the regulatory compact. The regulatory compact provides the utility an *opportunity* to earn a reasonable return on the investments (not a *guarantee*) that are used and useful in providing electricity service and to recover reasonable and necessary operating expenses.

- The Commission should return to more traditional ratemaking practices by discontinuing use of the RSAM as proposed by FPL and rejecting the proposed 2023 base rate increase unless FPL files a complete set of updated minimum filing requirements (MFRs).

### Reserve Surplus Amortization Mechanism

- The RSAM is a tool that can be used under certain very specific circumstances to temporarily mitigate the impact of large rate increases. The premise for using an RSAM is that the utility has a large surplus in its depreciation reserve based on the results of a contemporaneous depreciation study. The RSAM uses this surplus to reduce annual depreciation expense for a limited time period. However, once the surplus has been exhausted and normal depreciation expense is restored, rates will be higher. This is because (with RSAM) reducing depreciation expense results in higher net plant (than in the absence of an RSAM). Thus, the RSAM is not cost-free. In effect, the RSAM is a loan to customers (*i.e.,* temporarily lower base rates) that they will repay with interest at the utility's authorized cost of capital.

- FPL's current rates are higher because of the RSAM.

- FPL does not have a surplus depreciation reserve based on its 2021 Depreciation Study. The Study reveals a $437 million reserve *deficit*.

- The continuation of the RSAM is contingent on extending the lives of the St. Lucie Nuclear Plant (St. Lucie) and FPL's combined cycle gas turbine (CCGT) and solar units, and reverting to the depreciation parameters used in the 2016 Depreciation Study for certain transmission and distribution assets. However, the CCGT and solar life extensions are clearly hypothetical. FPL has offered no assurances that extending the lifespans of its CCGTs from 40 to 50 years and its solar plants from 30 to 35 years is either feasible or cost-effective.

- For example, a key assumption justifying the continuation of the RSAM in the 2016 rate case was extending the planned retirement date of Scherer Unit 4 from 2039 to 2052. In this proceeding, FPL is proposing to retire Scherer Unit 4 in 2022. Further, it is now demanding full recovery with a regulatory return on the unamortized plant balance, even though it used the Scherer 4 surplus depreciation to earn at the top end of its authorized ROE in every reporting period since the 2016 rates were implemented.

- FPL has misused the RSAM. Because of the RSAM, FPL was able to achieve actual earnings at the top end of its authorized ROE in nearly every reporting period since the RSAM was first implemented in the 2010 rate case. Thus, the RSAM has provided a windfall to FPL's shareholder. FPL could have instead used surplus depreciation to mitigate future costs, rather than boost shareholder earnings.

- The absence of an actual depreciation reserve surplus and FPL's past misuse of the RSAM mean that the continuation of the RSAM is no longer in the public interest. The Commission should reject the RSAM.

- Regardless of the disposition of the RSAM, it is probable that FPL will successfully obtain a 20-year life extension for the St. Lucie plant. Because a 20-year life extension will significantly reduce annual depreciation expense, the Commission should order FPL to create a regulatory liability commencing in the month following Nuclear Regulatory Commission (NRC) approval of the license extension. The St. Lucie regulatory liability would require FPL to retain the lower depreciation expense for the benefit of FPL's customers, rather than FPL's shareholder. The accumulated balance can be used to mitigate future base rate increases.

**Solar Base Rate Adjustments**

- The two proposed SoBRAs are single-issue or "piecemeal" ratemaking. Piecemeal ratemaking occurs when rates are adjusted outside of a general rate case. Thus, the amount of the SoBRA increases ignores whether any base rate increase is needed to allow FPL to earn its authorized return.

- It is unclear whether the Commission can approve the SoBRAs other than in a general rate case or separate stand-alone limited proceeding.

- The proposed solar projects are not necessary to meet a reliability need. FPL's sole justification for the proposed solar projects is that they are cost-effective; that is, they will result in lower rates. Accordingly, FPL has discretion about when to place these projects into service.

- The in-service date of the 2024 solar projects can be deferred to 2025 without jeopardizing reliability.

- The Commission should reject the 2024-2025 SoBRAs.

- Regardless of the disposition of the SoBRAs, the Commission should require FPL to provide guarantees that customers are realizing the benefits claimed by FPL. Such guarantees should include disallowing costs for failing to meet minimum annual capacity factor requirements and if the solar projects have not achieved the promised benefits as determined in a forensic analysis quantifying the costs actually incurred and the direct benefits actually provided by its various solar investments.

**Class Cost-of-Service Study**

- Of the two CCOSSs FPL filed in this proceeding (a "Base" study and an "MDS" study), the MDS (minimum distribution system) study is the most accurate. However, there are significant flaws with FPL's MDS study.

- The first flaw is that the CCOSS is internally inconsistent. This is because FPL imputed the CDR/CILC incentive payments collected in the Energy Conservation Cost Recovery (ECCR) clause, rather than what would have been collected during the test year.

- The second flaw is the imputed incentives were not recognized in the CCOSS as an additional cost recoverable from customer classes. As a result, the earned rates of return derived in the CCOSS at present rates are overstated. FPL's earnings are the same with or without the incentive payments.

- The third flaw is that production and transmission demand-related costs were allocated to customer classes using the Twelve Coincident Peak (12CP) method. 12CP gives equal weighting to power demands that occur in each of the 12 months of the year. FPL, however, is a strongly summer-peaking utility. Summer peak demands drive the need to install capacity to maintain system reliability.

• Unless these flaws are corrected, the CCOSS will not provide a reasonable basis for determining a proper cost-based revenue allocation.

• The first flaw can be corrected by imputing incentive payments using test-year billing determinants. This would increase the imputed incentives to $80.9 million.

• The second flaw can be corrected as follows:

  - Directly assign the $80.9 million of imputed incentive payments to the CILC, GSD, and GSLD customer classes.

  - Allocate the $80.9 million to all customer classes in a manner consistent with the allocation of production demand-related costs, because the incentive payments recognize the avoided production capacity-related costs attributable to the CDR/CILC load management programs.

• The third flaw can be corrected by using the Four Coincident Peak (4CP) method. The 4CP method is based on demands that occur coincident with FPL's summer period (June through September) demands. 4CP recognizes that it is the summer peak demands that primarily drive the need for new capacity additions to maintain reliability. The projected summer peaks are consistently 20% higher than the projected winter peaks. FPL also experiences its lowest reserve margins during the summer months. This is also when the transmission system experiences its lowest load carrying capability.

- FPL's MDS analysis should be adopted. MDS classifies a portion of the distribution network as a customer-related cost. This is consistent with the principles of cost causation; that is, it better reflects the drivers that cause a utility to incur these costs. MDS is also an accepted practice. For example, both Gulf Power Company (Gulf Power) and Tampa Electric Company (TECO) have used the MDS approach to setting rates.

- Regardless of whether MDS is approved, the separation of distribution network investment between primary and secondary voltage as used in FPL's MDS CCOSS should be approved because it provides a more consistent treatment between conductors (*i.e.,* overhead lines and underground conductors) and their corresponding support structures (*i.e.,* poles, towers, fixtures, and underground conduit) than in FPL's "Base" study.

- I have corrected FPL's MDS CCOSS and presented the results under both the 12CP and 4CP methods.

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

- The Commission's long-standing policy has been to move all rates closer to cost using a proper CCOSS.

- FPL's proposed class revenue allocation should be rejected because it is derived from its highly flawed "Base" CCOSS. Base rates would more than double for some classes and increase by 180% for other classes. Former Gulf Power customers transferring to FPL's GSLD rates would experience greater rate shock than FPL's customers. By any definition, base rate increases of this magnitude would be rate shock and violate the principle of gradualism.

- Correcting the flaws with FPL's MDS CCOSS would substantially remove any rate shock. I present two alternative proposals based on the two corrected CCOSSs that I am sponsoring.

- A general rate case is the only venue in which gradualism can be properly applied. The principle of gradualism means placing reasonable limits on base rate increases to avoid rate shock.

- FPL's application of gradualism, however, fails to prevent rate shock because FPL uses total revenues, rather than base rate revenues, to measure the impact of a base rate increase. Total revenues include costs recovered in other cost-recovery mechanisms (*i.e.,* fuel and purchased power, energy conservation, environmental, capacity, and storm hardening). These cost recovery mechanisms are not at issue in this case.

- FPL is seeking four base rate increases. Therefore, measuring the impact of those proposed increases on base revenues is the proper way to measure the impact and to apply gradualism to mitigate rate shock.

- The proper application of gradualism would be to limit the increase to any customer class to not exceed 1.5 times the system average base revenue increase, and no class should receive a rate decrease.

**<u>CILC/CDR Monthly Incentive</u>**

- FPL is once again proposing drastic reductions in the incentive payments under the CILC and CDR load management programs. In this case, the proposal is a 33% reduction. In 2016, FPL proposed a 37% reduction.

- The incentive payments compensate CILC and CDR customers for agreeing to curtail load to alleviate any emergency conditions or capacity shortages, either power supply or transmission, or whenever system load, actual or projected, would otherwise require the use of peaking generators. Curtailments can also occur when any Peninsular Florida utility experiences an emergency condition or shortage. There are no limits to the frequency and duration of the curtailments under the CILC program.

- FPL's proposal to reduce the incentive payments by 33% is judgmental. It is, in part, informed by FPL's observation that its projections of generation capital costs have declined and by the results of a production cost simulation model, AURORA, to measure the cost-effectiveness of the CILC/CDR programs over a 46-year study period (2022 to 2068).

- Notwithstanding that AURORA has never been used to measure the cost-effectiveness of any demand side management (DSM) program, the results would justify only a very small reduction in the monthly incentive for the CILC/CDR programs to remain cost-effective; certainly not 33%.

- The AURORA model results should be disregarded because it measures total production costs, which includes capital, fixed expenses, and variable costs, such as fuel. However, the CILC/CDR programs avoid capital and fixed expenses. Changes in variable costs are not relevant. In fact, the Commission has always used avoided generation capital costs to determine whether it is cost-effective to implement, expand, or close a load management program.

- Although FPL's projections of avoided generation capital costs may have declined, actual capital costs have either increased or remained relatively unchanged. Since 2012, the capital cost of capacity installed by FPL has increased from $676 per kW to $847 per kW. Further, the capital costs projected by the Energy Information Administration (EIA) in its Annual Energy Outlook (AEO) reports have also steadily increased since 2012. The Midwest Independent System Operator, Inc. (MISO) uses projected generation capital costs to determine the cost of new entry (CONE) in its annual Planning Resource Auctions. I have observed no discernable trend (up or down) in MISO's projected CONE prices since 2013.

- The intrinsic value of load management programs is the amount of generation capacity and the associated costs that have been avoided as a result of a utility providing non-firm service options, such as CILC and CDR. There is no dispute that these programs have allowed FPL to construct less generation capacity (approximately 977 MW based on maintaining a 20% reserve margin). Further, FPL has installed over 7,500 MW of capacity since 2012 at costs ranging from $379 per kW to over $1,600 per kW. On average, the installed costs of this capacity was $847 per kW ($667 per kW excluding the solar plants).

- By not having to firm-up the CILC/CDR load, FPL avoided at least $667 per kW of capital costs. This cost avoidance would translate into a net benefit of $9.78 per kW-month. The current CILC/CDR monthly incentive is $8.70 per kW-month.

- Even if FPL had constructed only combustion turbine (CT) units, the net benefit would be $9.00 per kW-month, which is higher than the current $8.70 per kW-month incentive.

- Based on evidence of the capital costs actually avoided, the current CILC/CDR monthly incentive should not be reduced by 33% as FPL is proposing.

## 2. FOUR-YEAR RATE PLAN

**Q WHAT ARE THE KEY ELEMENTS OF FPL'S PROPOSED FOUR-YEAR RATE PLAN?**

A The Four-Year Rate Plan would run from 2022-2025. The key elements of the plan are:

- Cumulative base revenue increases of $2.042 billion[1], consisting of two base rate increases using the fully-projected future test years 2022 and 2023 and two SoBRA increases in 2024 and 2025;
- The continuation of the RSAM;
- The continuation of the storm cost recovery mechanism as approved in FPL's 2016 rate settlement;
- Accelerating the amortization of unprotected excess accumulated deferred income taxes resulting from the 2017 Tax Cuts and Jobs Act (TCJA); and
- A mechanism to timely address possible changes in the federal corporate income tax rate.[2]

**Q ARE ANY OF ABOVE COMPONENTS ESSENTIAL TO FPL'S FOUR-YEAR RATE PLAN?**

A Yes. FPL witness, Robert Barrett, stated that three of the above components — continuation of the RSAM, the 2024-25 SoBRAs, and accelerated amortization of unprotected excess deferred income taxes — are essential to the Company's ability to commit to its Four-Year Rate Plan.[3]

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[1] FPL's Petition lists total annual revenue increases of $1.108 billion to be effective January 1, 2022 and $607 million to be effective January 1, 2023, resulting in a cumulative increase of $1.715 billion. However, the $1.715 billion does not include the proposed 33% reduction in the CILC/CDR incentives, certain revenue adjustments and unbilled revenues.

[2] Petition at 2.

[3] Direct Testimony of Robert E. Barrett at 13.

**Q HOW DOES THE FOUR-YEAR RATE PLAN COMPARE TO A TRADITIONAL RATE CASE?**

A In a traditional rate case, a utility would request one base rate increase using a single test year. Further, when a fully projected future test year is used, it would be based on an approved corporate budget. In this case, however, only the projected 2022 test year is based on FPL's official corporate budget and per-books financial forecast, which were approved in the fall of 2020.[4] The projected 2023 test year is not based on an approved corporate budget. Further, FPL is not proposing to update the 2023 test year to reflect an approved corporate budget.[5]

**Q IS IT A COMMON PRACTICE TO USE TWO FULLY PROJECTED FUTURE TEST YEARS IN A GENERAL RATE CASE?**

A No.

**Q SHOULD THE 2023 INCREASE BE APPROVED AS FILED?**

A No. The 2023 increase should be rejected unless FPL files a complete set of updated MFRs.

**Q ARE OTHER ASPECTS OF FPL'S FOUR-YEAR RATE PLAN INCONSISTENT WITH TRADITIONAL RATEMAKING?**

A Yes. As previously stated, FPL is seeking two SoBRA increases. They would be implemented in 2024 and 2025. At this time, FPL estimates that each SoBRA would increase base revenues by an additional $140 million per year. The actual SoBRA increases would depend on the construction costs.

[4] FPL Response to FIPUG Interrogatory No. 29.

[5] FPL Response to FIPUG Interrogatory No. 33.

**Q WHY IS FPL SEEKING TWO SOBRA INCREASES?**

A The proposed SoBRA increases reflect FPL's plan to install 1,788 megawatts (MWs) of solar projects.[6]

**Q WERE THE PROPOSED SOBRA REVENUE INCREASES DERIVED IN THE SAME MANNER AS THE 2022-2023 BASE REVENUE INCREASES?**

A No. Unlike the 2022/23 base rate increases, the proposed SoBRAs would not be "needs based;" that is, they are not derived from a revenue requirements analysis. A revenue requirements analysis determines whether a base revenue increase is needed to provide FPL a reasonable opportunity to earn a reasonable return on the facilities that are used and useful in providing electricity to its customers.

It is unclear how the Commission can approve the SoBRAs because they would not be subject to the detailed investigation of FPL's earnings that typically occurs in a general rate case.

Further, this additional solar capacity is simply not needed. As discussed later, the Florida Reliability Coordinating Council (FRCC) projections reveal that Peninsular Florida will have sufficient reserve margins absent the planned solar projects.

**Q ARE THERE ANY INCONSISTENCIES BETWEEN FPL'S PROPOSED FOUR-YEAR RATE PLAN AND TRADITIONAL RATEMAKING?**

A Yes. The proposed Four-Year Rate Plan would virtually guarantee that FPL continues to achieve earnings at the top end of its authorized earnings range. Yet, as Ms. LaConte testifies, FPL's claimed revenue requirements are based on an excessive cost of capital. Specifically, FPL's proposed cost of capital is based on a "financial"

[6] Petition at 2.

capital structure consisting of 59.6% common equity and an 11.5% return on equity (ROE). As Ms. LaConte testifies, the proposed 59.6% financial common equity ratio is approximately 787 basis points higher than the national average equity ratio for investor owned electric utilities having a comparable "A" bond rating as FPL. Ms. LaConte also states that the proposed 11.5% ROE is 195 basis points higher than the national average ROE authorized by state regulatory commissions for vertically integrated electric utilities. If approved, FPL's pre-tax cost of capital would be the highest of any vertically integrated electric utility in the nation.

FPL's extremely high cost of capital is incompatible with a rate plan that would guarantee FPL's future earnings.

**Q WOULD ALL FPL CUSTOMERS BE AFFECTED EQUALLY BY FPL'S FOUR-YEAR RATE PLAN?**

A No. The proposed 2022-23 base rate increases would average 23.2%. However, FPL's larger customers, mainly Florida's businesses, would experience much more drastic increases: 59.4% for CILC customers; 42.4% increases for Rate GSLD customers. These increases are 2.6 and 1.8 times the system average increase. Former Gulf Power customers transferring to FPL's GSLD rates would receive even higher base rate increases. Base rate increases of this magnitude would result in rate shock and violate the principle of gradualism.

## 3. RESERVE SURPLUS AMORTIZATION MECHANISM

**Q WHAT IS THE RSAM?**

A The RSAM uses a surplus depreciation reserve to *temporarily* reduce the utility's future revenue requirements. Thus, one advantage of the RSAM is that it can mitigate short-term rate increases. Once a depreciation reserve surplus has been exhausted, the utility may require higher rates to maintain its authorized return.

For example, when FPL originally implemented the RSAM as a result of the 2010 Rate Order, the 2009 Depreciation Study revealed that the accumulated depreciation reserve was $1.2 billion higher than necessary to support timely capital recovery.[7] The Commission directed FPL to amortize $894 million of depreciation reserve surplus as a credit over the four-year period ending 2013.[8] Thus, the premise behind the RSAM is that the utility has a significant depreciation reserve surplus as determined in a contemporaneous depreciation study. As discussed later, FPL's 2021 Depreciation Study revealed a $437 million reserve *deficit*, not a surplus.[9]

**Q IS THE RSAM A NORMAL FACET OF UTILITY RATEMAKING?**

A No. Normally base rates are set to reflect the depreciation and dismantlement expenses as determined in contemporaneous depreciation and dismantlement studies. These studies provide the best information about the key depreciation parameters: lifespans, salvage value, removal cost and interim capital additions and retirements of each of the utility's long-lived assets. These parameters are subject to

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[7] *In re: 2009 depreciation and dismantlement study by Florida Power & Light Company*, Docket No. 090130-EI, Order No. PSC-10-0153-FOF-EI at 199 (Mar. 17, 2010).

[8] *Id.* at 87.

[9] Direct Testimony of Ned A. Allis, Exhibit NWA-1 at 102.

change as circumstances warrant. For example, if a nuclear plant receives a 20-year extension to its operating life, it can significantly reduce the applicable nuclear depreciation rates. Thus, the RSAM might be warranted if a current depreciation study reveals a potential surplus using the best available information.

**Q IS AN RSAM COST-FREE TO CUSTOMERS?**

A No. Although RSAM would reduce depreciation expense in the near-term, future base rates would be higher because:

1. After the depreciation surplus has been exhausted, pre-RSAM depreciation expense would be restored, thereby raising base revenue requirements, and
2. Future rate base would be higher because RSAM slows down the build-up of the accumulated depreciation reserve.

Although FPL's Four-Year Rate Plan would temporarily mitigate base rate increases in 2022 and 2023, FPL customers would pay (and are currently paying) higher rates (now and) in the future.

Therefore, the RSAM is akin to loaning money to customers (in the form of lower base electric rates) in the short-term that customers will have to repay with interest at FPL's authorized cost of capital.

**Q HAVE FPL CUSTOMERS PAID HIGHER ELECTRIC RATES BECAUSE OF THE RSAM?**

A Yes. For example, in its Petition to initiate the 2012 rate case, FPL cited the cumulative impact of the RSAM approved in the 2010 Rate Order as accounting for $104 million of its proposed test-year revenue increase.[10] The RSAM was continued in both the 2012 and 2016 rate cases. Thus, FPL's rates are higher today because of the RSAM.

**Q IF THE RSAM IS NOT COST-FREE, WHY DID THE COMMISSION APPROVE AN RSAM FOR FPL?**

A The reasons supporting the RSAM are more aptly described in the Commission's Order[11]:

> We believe that the very presence of a reserve imbalance indicates the existence of intergenerational inequity. Based on what is known today, the life estimates of yesterday are now viewed as being too short. FPL has lengthened the life span estimates for its production plants. Net salvage estimates have changed. This does not mean however, that past life and salvage estimates were wrong. Disregarding the fact that settlements were reached in 2002 and 2005 that addressed depreciation and many other matters, the last time this Commission actually conducted a thorough review and analysis of FPL's depreciation parameters was in Order No. PSC-99-0073-FOF-EI, issued January 8, 1999, in Docket No. 971660-EI, <u>In re: 1997 depreciation study by Florida Power & Light Company</u>. Conditions, Company plans, and regulatory requirements change. OPC witness Pous acknowledged that depreciation parameters change over time simply because depreciation is a projection of anticipated events in the future. FRF recognized in its brief that in a depreciation study review, a goal has been to align the actual and theoretical reserve positions for all accounts.
>
> We agree with FPL that current and future customers will receive the benefit of the existing reserve surplus through lower depreciation rates. If the reserve surplus is reduced, the depreciation reserve will increase, thereby, all things remaining equal, causing depreciation rates and future revenue requirements to naturally increase. At the present time, it can be argued that the current reserve surplus results in prospective depreciation rates that are artificially low. This is the beauty or the beast of the remaining life rate methodology. A surplus means that under present expectations more than enough has been

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[10] *In re: Petition for rate increase by Florida Power & Light Company*, Docket No. 120015-EI, Petition at 15-16 (March 19, 2012).

[11] *In re: Petition for increase in rates by Florida Power & Light Company*, Docket No. 080677-EI, Order No. PSC-10-0153-FOF-EI at 83 (Mar. 17, 2010).

> recovered, so there is a smaller amount left to be recovered over the average remaining life. Conversely, the presence of a reserve deficit means that not enough has been recovered to date, so the depreciation rate must increase to make up the difference in the future. (quote footnotes omitted)

**Q HAS FPL MAINTAINED A LARGE DEPRECIATION RESERVE SURPLUS SINCE THE 2010 RATE ORDER?**

A No. In its 2016 rate case, FPL's Depreciation Study showed a $100 million reserve *deficit*.[12] Despite changing the depreciation parameters to *create* a $1 billion surplus,[13] the 2021 Depreciation Study filed in this rate case now shows a $437 million depreciation reserve deficit.[14] Thus the premise for continuing the RSAM no longer exists today.

**Q HAVE ANY OF THE REVISED DEPRECIATION PARAMETERS FAILED TO MATERIALIZE?**

A Yes. The $1 billion surplus reserve assumed that Scherer Unit 4 would be retired in 2052.[15] The 2016 Depreciation Study established a 2039 retirement date.[16] In this case, FPL is now proposing to retire Scherer Unit 4 in 2022. Thus, FPL reaped the benefit of the additional depreciation surplus caused by the assumed life extension of

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[12] *In re: Petition for rate increase by Florida Power & Light Company*, Docket No. 160021-EI, Direct Testimony and Exhibits of Ned W. Allis, Exhibit NWA-1 (Mar. 15, 2016). The amount was not affected by the Errata filed on Aug. 16, 2016.

[13] Docket No. 160021-EI, Order No. PSC-16-0560-AS-EI, *Order Approving Settlement Agreement* at 3 (Dec. 15, 2016).

[14] Direct Testimony of Ned Allis, Exhibit NWA-1 at 102.

[15] Docket No. 160021-EI, *Order Approving Settlement Agreement*, Attachment A, Exhibit D at 2 (Dec. 15, 2016).

[16] *Id.*, *Direct Testimony and Exhibits of Ned W. Allis*, Exhibit NWA-1 (Mar. 15, 2016). The amount was not affected by the Errata filed on Aug. 16, 2016.

Scherer Unit 4, but it is now seeking cost recovery of an even larger remaining balance of the unit, along with a full regulatory return on the unamortized balance, over ten years. FIPUG witness LaConte addresses FPL's Scherer Unit 4 cost recovery proposal.

**Q IF THE CURRENT DEPRECIATION STUDY REVEALS A LARGE DEFICIT, HOW DOES FPL JUSTIFY CONTINUING THE RSAM?**

A FPL proposes to continue the RSAM by, once again, changing the lifespans and other parameters that were derived in the 2021 Depreciation Study. These changes, and their estimated impacts, are summarized in Table 1.

**Table 1**
**Depreciation Parameters Contributing To the Proposed RSAM[17]**
**($Millions)**

| Description | Lifespan Extension (Years) | 2022 Impact | 2023 Impact |
|---|---|---|---|
| **St. Lucie Nuclear** | 20 | $130.9 | $133.4 |
| **Combined Cycle Gas Turbines** | 10 | $120.8 | $126.8 |
| **Solar Plants** | 5 | | |
| **Other Assets** | Various | $13.0 | $10.8 |
| **Total** | | $238.7 | $249.4 |

For example, FPL is assuming that St. Lucie would receive a 20-year extension of its operating license. Increasing St. Lucie's lifespan by 20 years, alone would lower the associated depreciation expense by $133.4 million in 2023. Similarly, FPL is

[17] Direct Testimony of Keith Ferguson, Exhibit KF-3(B) at 1.

proposing extended lifespans for its CCGTs and solar plants that would result in a further $120.8 and $126.8 million per year reduction in depreciation expense in years 2022 and 2023, respectively.

These *after-the-fact* changes to the lifespans developed in FPL's 2021 Depreciation Study are the drivers that would *transform* an otherwise large deficit in the accumulated depreciation reserve into a surplus.

**Q ARE THE PROPOSED LIFESPAN EXTENSIONS SHOWN IN TABLE 1 REASONABLE?**

A No, with one notable exception. First, there is no actual experience of a CCGT plant achieving a 50-year lifespan, or a utility scale solar plant achieving a 35-year lifespan. Second, decisions to extend the life of a CCGT will depend on whether the added capital investment to keep the plant running would be cost effective. However, with on-going improvements in generation technology that have dramatically improved the efficiency of CCGTs, it would be farfetched to assume that an existing CCGT (using current technology) would continue to be cost-effective for an additional 10 years.

To use an analogy, just because it may be feasible to drive a 20-year old car for another 20 years, this cannot be accomplished without incurring significant maintenance expense to replace worn out parts. At some point, the cost of buying a new car will be more than outweighed by the higher maintenance and lower gas mileage of the 20-year old car.

Second, I would note that FPL constructed and operated CCGTs in the 1970s. These plants have long since been retired and none were in operation for a period approaching 50 years.

Finally, with respect to solar plants, no utility-scale solar plant has achieved a 35-year lifespan. In fact, the industry considers a 30-35 year lifespan to be a stretch goal.[18]

**Q YOU MENTIONED ONE EXCEPTION TO EXTENDING THE LIFESPANS DERIVED IN FPL'S 2021 DEPRECIATION STUDY. WHAT IS THAT EXCEPTION?**

A FPL's proposal to extend the lifespan of the St. Lucie is more realistic because FPL successfully extended the lifespan of its Turkey Point Nuclear Plant from 60 to 80 years. Exelon Generation Company LLC (Exelon) also received approval for a 20-year extension of the operating license at its Peach Bottom Atomic Power Station. So, unlike CCGTs and solar plants, there is actual experience in the nuclear industry to extend the operating license by an additional 20 years. The license extensions that have been approved will result in both Turkey Point Nuclear Plant and Peach Bottom Atomic Power Station having 80-year lifespans.

**Q DOES THE ST. LUCIE NUCLEAR PLANT EXCEPTION WARRANT CONTINUING THE RSAM?**

A No. First, FPL has stated that it will not file a request with the NRC for an extended operating license until August 2021.[19] Based on FPL's experience with Turkey Point and Exelon's experience with Peach Bottom Atomic Power Station, the NRC process required 20 months from filing to approval. Thus, the outcome for St. Lucie will not be

[18] For example: https://www.greentechmedia.com/articles/read/europes-solar-market-grapples-with-35-year-plant-lifespans; https://www.paradisesolarenergy.com/blog/solar-panel-degradation-and-the-lifespan-of-solar-panels

[19] Direct Testimony of Keith Ferguson at 15.

known until sometime during the first quarter of 2023. FPL's RSAM proposal, however, assumes that it will receive the benefit of the 20-year operating license extension in 2022.

**Q IS CONTINUING THE RSAM IN THE PUBLIC INTEREST?**

A No. I have supported the RSAM when a utility demonstrated a significant depreciation reserve surplus in a current depreciation study. Absent a surplus, continuing the RSAM would not be in the public interest. Further, FPL has misused the RSAM. Since the RSAM was approved in the 2010 Rate Order, FPL has *managed* its earnings to consistently achieve a ROE at the upper end of the authorized range. For example, during the period 2010-2013, FPL used the RSAM to achieve an ROE at or slightly below 11% ROE in the vast majority of the reporting periods. Beginning in 2014 and continuing through 2017 FPL's achieved ROE was 11.5% in the vast majority of the reporting periods. Thereafter, FPL's achieved ROE has been 11.6%.[20]

Thus, FPL's shareholder has been the primary beneficiary of the RSAM because the RSAM has allowed FPL to consistently achieve very high earned ROEs. Had FPL opted to use the RSAM to achieve earnings at only the minimum or mid-point ROE, less of the Reserve Amount would have been exhausted. Any remaining Reserve Amount could have been used to mitigate future revenue requirements.

**Q IS THERE ANY PRECEDENT FOR A UTILITY ACHIEVING THE MAXIMUM AUTHORIZED RETURN ON EQUITY?**

A No. Most utilities struggle to earn their authorized returns. The RSAM guarantees

[20] FPL Response to FIPUG ROG No. 22.

that FPL will always earn the maximum authorized ROE. Under these circumstances, the RSAM has fundamentally changed the regulatory paradigm.

**Q PLEASE EXPLAIN.**

A The regulatory paradigm provides an opportunity for a utility to earn a reasonable return on its investments in the facilities that are used and useful in providing electric service to customers. The RSAM has clearly replaced the opportunity to earn with guaranteed earnings.

**Q WHAT DO YOU RECOMMEND?**

A The RSAM should not be continued. The premise behind the RSAM no longer exists because FPL does not have a substantial depreciation reserve surplus. In fact, the opposite is true; FPL has a substantial depreciation reserve *deficit*.

**Q SHOULD THE COMMISSION TAKE ANY ACTION IN THE EVENT THAT FPL SUCCESSFULLY OBTAINS A 20-YEAR EXTENSION OF THE OPERATING LICENSE AT THE ST. LUCIE PLANT?**

A Yes. As previously stated, it is probable that FPL will successfully obtain a 20-year life extension for the St. Lucie plant. Because a 20-year life extension will significantly reduce annual depreciation expense, the Commission should order FPL to create a regulatory liability commencing in the month following NRC approval of the license extension. The St. Lucie regulatory liability would require FPL to retain the lower depreciation expense for the benefit of FPL's customers, rather than FPL's shareholder. The accumulated balance can be used to mitigate future base rate increases.

## 4. SOLAR BASE RATE ADJUSTMENTS

**Q WHY SHOULD THE COMMISSION REJECT THE PROPOSED SOLAR BASE RATE ADJUSTMENTS?**

A The proposed SoBRAs are a form of single-issue or "piecemeal" ratemaking. Piecemeal ratemaking occurs when rates are adjusted outside of a general rate case. Adjusting base rates outside of a rate case, however, assumes that the utility experiences no changes in either base revenues or associated costs that would affect its earnings potential. This is in stark contrast to traditional ratemaking in which a utility is allowed to increase revenues, but only in the amount necessary to provide an opportunity to earn the authorized return on investment. Because the SoBRAs are not *needs-based*, FPL could continue to earn excessive returns.

**Q DOES THE COMMISSION CONDUCT THE SAME INVESTIGATION IN A SOBRA FILING THAT IT CONDUCTS IN A GENERAL RATE CASE?**

A No. Unlike in a general rate case, the Commission does not conduct a detailed investigation of a utility's earnings in a SoBRA filing. Thus, there is no independent analysis and no determination whether a specific revenue increase is needed to provide an opportunity to FPL to earn its authorized rate of return.

**Q HAS FPL PROVIDED ANY ANALYSIS DEMONSTRATING THE NEED FOR THE TWO PROPOSED SOLAR BASE RATE ADJUSTMENT INCREASES?**

A No.[21]

[21] FPL Response to FIPUG Interrogatory No. 21; Deposition of Robert E. Barrett (June 11, 2021).

**Q IF THE SOBRAS ARE NOT NEEDS-BASED, CAN THEY BE APPROVED AS PART OF A FOUR-YEAR RATE PLAN?**

A No. It is my (non-legal) understanding that the Commission cannot approve a change in a utility's base rates, except in a general rate case or through a separate stand-alone limited proceeding under Rule 25-6.0431, Florida Administrative Code (F.A C.) The latter procedure is designed to streamline a rate increase when a major asset is placed in service immediately after the test year and the inability to timely adjust base rates would have a demonstrably large impact on a utility's earned rate of return. The proposed SoBRAs do not meet either qualification. Further, they are integral to, rather than separate from, FPL's proposed Four-Year Rate Plan, not stand-alone limited proceedings.

**Q YOU PREVIOUSLY STATED THAT PIECEMEAL RATEMAKING ASSUMES NO CHANGE IN THE UTILITY'S OTHER REVENUES AND OTHER COSTS. IS IT POSSIBLE THAT FPL'S FUTURE REVENUES COULD BE HIGHER AND FUTURE COSTS COULD BE LOWER?**

A Yes. FPL continues to experience unprecedented customer and load growth. Sales growth generates additional base rate revenues. These additional revenues can offset future increases in costs.

**Q DO INCREASES IN COSTS NECESSARILY REQUIRE HIGHER BASE RATES?**

A No. Maintaining the integrity of the ratemaking process also means ensuring that rates are adjusted only when necessary. Just because a utility's costs may be increasing is not a sufficient reason to raise rates. To understand why, think of a rate as consisting of two components: (1) the amount of costs to be recovered and (2) the applicable billing units (e.g., kW, kWh) or sales. If costs increase but sales also increase by the same degree, rates should remain the same. It is only when the change in costs differs from the corresponding change in sales that rates should also change. When costs increase faster than sales, rates will increase, and vice versa. Further, the amount of a required rate increase is not driven solely by the change in costs. It will also depend on the relative change between costs and sales.

For example, if costs increase by 10 percent and sales increase by 6 percent, rates should increase by only 4 percent. Thus, it is critical to analyze both the changes in costs as well as impact of load growth and the resulting increase in revenues.

**Q DOES FPL NEED THE SOBRA INCREASES?**

A No. The proposed solar projects are not necessary to meet a reliability need. FPL's sole justification for the proposed solar projects is that they are cost-effective; that is, they will result in lower rates. Accordingly, FPL has discretion about when to place these projects into service. Even if FPL places the solar projects in service as planned, there is no evidence that FPL's costs are increasing faster than its increase in revenues due to load growth.

**Q WHY DO YOU SAY THE SOLAR PROJECTS ARE NOT NEEDED FOR RELIABILITY?**

A FPL is projecting it will have sufficient reserves even without the 2024 solar plant additions. This is demonstrated in **Exhibit JP-1**.

**Q DID YOU MAKE ANY ADJUSTMENTS TO FPL'S PROJECTED RESERVE MARGINS?**

A Yes. FPL has assumed that solar projects provide approximately 50% of their nameplate capacity during the summer peaks and zero capacity during the winter peaks. These assumptions are not supported by the facts. This is shown in **Exhibit JP-1**, page 2, which measures the power output of FPL's solar projects coincident with the monthly peaks since 2017. As can be seen, FPL's solar projects have contributed to both the summer and winter peaks. On average, the solar projects produced power at 57% of their nameplate capacity during FPL's monthly peaks since 2017. Therefore, I restated the installed capacity to reflect solar power output at 57% of nameplate in quantifying both the summer and winter peak reserve margins.

**Q WILL DEFERRING THE IN-SERVICE DATES OF FPL'S SOLAR PROJECTS IMPACT RELIABILITY FOR PENINSULAR FLORIDA?**

A No. The FRCC is projecting that summer reserve margins will be well-above the 20% reference level. The absence of 1,788 MW of solar capacity will not cause Peninsular Florida to fall below a 20% summer reserve margin. This is shown in **Exhibit JP-2**.

**Q DO THE SOBRAS RAISE ANY OTHER CONCERNS?**

A Yes. FPL has asserted that the solar projects are cost-effective. However, other than placing a cap on the construction cost, FPL has not provided any guarantee that customers will fully realize the benefits claimed by FPL. Because the solar projects are not designed to meet a capacity need, the Commission should require FPL to stand behind its promises by imposing performance standards and other requirements, such as a forensic analysis of the actual savings from the solar projects to ensure that the promised benefits have actually materialized. FPL is required to meet certain minimal performance standards for its thermal generating resources. Because the benefits of solar projects include lower energy costs, at a minimum, FPL should be subject to annual operating guarantees to ensure that energy savings benefits are indeed realized.

**Q WHAT REQUIREMENTS SHOULD BE PLACED ON FPL TO DEMONSTRATE THAT ITS SOLAR PROJECTS HAVE PROVIDED THE PROMISED BENEFITS?**

A FPL's solar projects should be required to provide energy at the capacity factor assumed by FPL in determining cost-effectiveness. Further, FPL should periodically provide forensic studies that quantify the direct costs and benefits provided by FPL's solar investments. The Commission should disallow cost recovery if FPL fails to meet either the performance guarantees or if the projected benefits have not been achieved.

**Q WHAT DO YOU RECOMMEND?**

A The Commission should reject the two proposed SoBRA base revenue increases. Further, going forward with solar generating units, the Commission should require FPL to provide minimum performance guarantees and to provide a forensic analysis demonstrating that its solar investments have provided the promised benefits to customers.

## 5. CLASS COST-OF-SERVICE STUDY

**Q WHAT IS A CLASS COST-OF-SERVICE STUDY?**

A A CCOSS is an analysis used to determine each class's responsibility for the utility's costs. Thus, it determines whether the revenues a class generates cover the class's cost of service. A CCOSS separates the utility's total costs into portions incurred on behalf of the various customer groups. Most of a utility's costs are incurred to jointly serve many customers. For purposes of rate design and revenue allocation, customers are grouped into homogeneous customer classes according to their usage patterns and service characteristics. A more in-depth discussion of the procedures and key principles underlying CCOSSs is provided in **Appendix C**.

**Q HAS FPL FILED ANY CLASS COST-OF-SERVICE STUDIES IN THIS PROCEEDING?**

A Yes. FPL filed two CCOSSs. FPL's "Base" study was provided in MFR Schedule E-1. FPL also filed an "Alternate" CCOSS.[22]

**Q WHAT IS THE DIFFERENCE BETWEEN THE BASE AND ALTERNATE CLASS COST-OF-SERVICE STUDIES?**

A The Alternate CCOSS used different methods to allocate the costs of FPL's distribution network. The distribution network includes plant investment FERC Account Nos. 364-367 and related expenses. The Alternate study used the Minimum Distribution System (MDS) to classify distribution network costs between demand and customer-related costs. It also provided a different separation between primary and secondary voltage distribution plant.

[22] Direct Testimony of Tara B. DuBose, Exhibit TBD-3.

**Q WHICH STUDY IS PREFERABLE?**

A As explained later, FPL's Alternate (*i.e.,* MDS) study is far preferable to the Base study. However, both the Base and MDS CCOSSs are flawed.

**Q WHAT ARE THE FLAWS WITH FPL'S BASE AND MDS COST STUDIES?**

A The flaws are:

- First, consistent with the Matching Principle FPL properly adjusted the base revenues of the non-firm classes (*i.e.,* CILC and GSD/GSLD) to "impute" the incentive payments paid to CILC/CDR customers. In doing so, FPL understated the adjustment because it used the incentive payments collected in the ECCR clause rather than repricing test-year non-firm base revenues at the firm rates. From a cost allocation perspective, the imputed incentive payments are a test-year proxy for the incentive payments that are ultimately recovered in the ECCR. By mixing the ECCR and test-year ratemaking, FPL's CCOSS is internally inconsistent.

- Second, FPL failed to allocate the imputed incentives as an additional cost recoverable from customer classes, and as a result, the earned rates of return derived in the CCOSS at present rates are overstated. FPL's earnings are the same with or without the incentive payments.

- Third, production and transmission demand-related costs were allocated to customer classes using the 12CP method. 12CP gives equal weighting to power demands that occur in each of the 12 months of the year. FPL, however, is a strongly summer-peaking utility. Summer peak demands drive the need to install capacity to maintain system reliability.

**Q HOW SHOULD THESE FLAWS BE CORRECTED?**

A First, the incentive payments imputed to the non-firm classes should be quantified using *test-year* assumptions, and they should be allocated to customer classes as recoverable costs in determining the required base rate revenues. The test-year imputed incentive payments are $80.9 million. They should be directly assigned to the CILC and GSD/GSLD classes as shown in Table 2 below.

| **Table 2<br>Test-Year Incentive Payments<br>($000)** | |
|---|---|
| **Customer Class** | **Amount** |
| **CILC-1D** | $34,410 |
| **CILC-1G** | $1,150 |
| **CILC-1T** | $14,410 |
| **GSD** | $13,135 |
| **GSLD-1** | $13,089 |
| **GSLD-2** | $4,691 |
| **Total** | $80,865 |
| **Source**: **Exhibits JP-3** and **JP-4** | |

The $80.9 million should be allocated to all customer classes as a production demand-related cost.

Second, production and transmission demand-related costs should be allocated to customer classes using the 4CP method. The 4CP method is based on demands that occur coincident with FPL's summer period (June through September) demands.

Correcting FPL's MDS study for these flaws would show that the CILC and most of the GSLD customer classes are currently providing rates of return that are much closer to, if not significantly above, parity. Thus, the CILC and GSLD classes should not receive drastically above-average base rate increases as FPL is proposing.

**Q DO YOU HAVE ANY OTHER RECOMMENDATIONS?**

A Yes. FPL uses a proprietary model to generate its CCOSS. Thus, Intervenors cannot access the model either to conduct a full audit or to run alternative scenarios. FPL is one of the few utilities in the country that does not provide a working version of its CCOSS model in its general rate cases. Accordingly, the Commission should order FPL to provide a working version of its CCOSS in future rate cases.

**<u>Imputed Incentive Payments</u>**

**Q DO FPL'S CLASS COST-OF-SERVICE STUDIES INCLUDE CUSTOMER CLASSES THAT RECEIVE BOTH FIRM AND NON-FIRM SERVICE?**

A Yes. The customer classes defined in FPL's CCOSSs include customers who receive both firm and non-firm service. The CILC classes (*i.e.,* CILC-1D, CILC-1G, and CILC-1T) receive primarily non-firm service. Some of the customers in the GSD, GSLD-1, and GSLD-2 classes take non-firm service under the CDR Rider.

**Q HOW ARE COSTS ALLOCATED TO THE NON-FIRM CLASSES?**

A FPL allocates costs to the non-firm classes using the same methodologies and load data that is used to allocate costs to the firm classes. The entire CILC and GSD/GSLD class loads are included in the demand and energy allocation factors used to allocate production demand and energy-related costs. Thus, despite receiving non-firm service, the CILC and GSD/GSLD classes are not treated any differently from a cost allocation perspective as the firm customer classes.

**Q DOES FPL MAKE ANY ADJUSTMENTS TO RECOGNIZE THE NON-FIRM NATURE OF THE SERVICE PROVIDED TO THE CILC AND GSD/GSLD CLASSES?**

A Yes. FPL adjusted the test-year base revenues by imputing the incentive payments currently paid to the non-firm customers under the CILC and CDR programs. The imputed incentive payments reflect the additional base revenues that the non-firm classes would have paid if they were receiving firm service during the test year.

**Q WHY IS IT APPROPRIATE TO ADJUST THE NON-FIRM CLASS BASE REVENUES BY THE IMPUTED INCENTIVE PAYMENTS?**

A FPL's CCOSS assumes that both the firm and non-firm customer classes are receiving firm service. Consistent with the "Matching Principle" and to ensure that the CCOSS results are accurate, it is appropriate to impute the incentive payments paid to the non-firm classes so that the base revenues reflect the level these classes would provide if they were taking firm service. The Matching Principle means applying consistent assumptions in determining both revenues and costs. By imputing the incentive payments, both the revenues and allocated costs are based on consistent assumptions.

**Q HOW SHOULD THE IMPUTED INCENTIVES BE DETERMINED?**

A The imputed incentives should reflect the additional base revenues that the non-firm classes would have paid during the test year if they had received firm service under the otherwise applicable firm rate schedules. For example, if CILC-1T customers were receiving firm service, they would be priced under the GSLD-3 rate schedule. Similarly, if CILC-1D (CILC-1G) customers were receiving firm service, they would be priced under the GSLD-1 and GSLD-2 (GSD) rate schedules.

The imputed incentives would be quantified differently for the CDR Rider customers because they are already taking service on a firm rate schedule. Specifically, the imputed incentives would be the product of the CDR Monthly Incentive and the test-year interruptible billing demand.

**Q DO YOU AGREE WITH THE APPROACH USED BY FPL TO DETERMINE THE COST TO SERVE THE NON-FIRM CLASSES?**

A No. There are two significant problems with the way the non-firm classes (*i.e.,* CILC, GSD/GSLD) were treated in FPL's CCOSSs.

First, the imputed incentives reflect the incentive payments collected in the ECCR. This approach is internally inconsistent because the incentive payments collected in the ECCR are not based on adjusted test-year sales. The imputed revenues should be quantified using test-year assumptions.

Second, imputing the incentive payments should be earnings neutral. This is because FPL collects the same amount of base revenues irrespective of how the incentives are accounted for in a CCOSS. That is, from a cost-allocation perspective, the test-year imputed incentive payments represent additional costs to serve FPL's firm customers. Because the imputed incentive payments are production demand-related costs, they should have been allocated to customer classes in a similar manner as all other production demand-related costs. FPL, however, skipped this very important and essential second step. As a result, FPL overstated the earned rates of return at present rates.

**Q DOES FPL USE A SIMILAR PROCEDURE TO ALLOCATE THE CURTAILABLE CREDITS IN ITS COST STUDIES?**

A Yes. The cost of providing incentives to curtailable customers is recovered in base rates rather than through the ECCR as applies to the CDR/CILC incentives.

**Q DOES IT MATTER THAT THE CDR/CILC INCENTIVES ARE RECOVERED IN THE ECCR AND NOT IN BASE RATES?**

A No. The CCOSS measures how FPL's base rate costs should be allocated to each customer class. This process is independent of how the costs eligible for recovery in separate cost recovery mechanisms, such as the ECCR, are quantified and recovered.

Further, imputing test-year incentive payments preserves the Matching Principle, thereby ensuring the integrity of the CCOSS results. The fact that imputed revenues may reflect the incentives FPL recovers in the ECCR is irrelevant.

**Q TURNING TO YOUR FIRST CONCERN, HOW SHOULD THE IMPUTED INCENTIVE PAYMENTS HAVE BEEN QUANTIFIED?**

A FPL's CCOSS measures the cost to provide firm service for all customer classes. This includes the CILC customers whose service, in reality, is mostly non-firm. To be internally consistent and recognizing the fact that the CILC base revenues reflect the lower cost to provide non-firm service, the CILC and GSD/GSLD class revenues must be restated at the level these customers would have paid *during the test year* if they were taking service under one of the otherwise applicable firm rates (*e.g.*, GSD or GSLD). Thus, the first step should be to correct the amount of the imputed incentive payments to the non-firm classes by using test-year billing determinants.

**Q HOW MUCH ADDITIONAL BASE REVENUES SHOULD BE IMPUTED TO THE NON-FIRM CUSTOMER CLASSES?**

A **Exhibit JP-3** shows the derivation of the test-year imputed incentive payments. Specifically, I repriced the CILC revenues by applying the otherwise applicable firm rate schedule to the test-year CILC billing determinants.

For example, **Exhibit JP-3,** page 1 shows the derivation of the test-year incentive payments imputed to the CILC-1T class. The applicable firm service rate would be either GSLD-3 or GSLDT-3. Repricing CILC-1T at these rates would result in an imputed base revenue adjustment of approximately $14.41 million.

**Exhibit JP-3,** pages 2 and 3 provides a similar analysis for the CILC-1D class. As can be seen on page 3, approximately $34.41 million should be imputed to this class using test-year assumptions. The $34.41 million was derived by repricing CILC-1D on the GSLD-1 and GSLD-2 standard and Time-of-Use rates.

**Exhibit JP-3,** page 4 shows imputed base revenues of $1.15 million for the CILC-1G class. The $1.15 million adjustment was based on repricing the test-year CILC-1G billing determinants on GSD-1 and GSDT-1 rates.

**Exhibit JP-4** quantifies the test-year imputed incentives for the GSD, GSLD-1, and GSLD-2 classes. The imputed incentives are the product of the current CDR Monthly Incentive ($8.70 per kW) and the test-year utility controlled demand. The resulting total CDR payments of $31 million should imputed to the GSD, GSLD-1, and GSLD-2 classes in the CCOSS. I would note that this amount is higher than the $29.3 million of CDR incentive payments that FPL imputed in its CCOSSs. The difference reflects test-year adjustments.

**Q HOW SHOULD THE IMPUTED CILC/CDR INCENTIVES BE ALLOCATED?**

A First, the test-year imputed CILC/CDR incentives quantified in **Exhibit JP-3** and **Exhibit JP-4** should be directly assigned to the CILC and GSD/GSLD class base revenues. Second, because the imputed incentives are the test-year proxy for the incentive payments, they should be allocated to customer classes using the production demand allocation factors. Further, as demonstrated below, the allocation should be based on the amount of firm load served by customer class.

**Q CAN YOU ILLUSTRATE WHY THE IMPUTED INCENTIVES SHOULD BE ALLOCATED BASED ON THE AMOUNT OF FIRM LOAD SERVED BY CUSTOMER CLASS?**

A Yes. **Exhibit JP-5** shows two different methods of allocating production plant and related costs to non-firm customers.

*Method 1* excludes non-firm load from the CCOSS. The premise behind *Method 1* is that the utility does not install any production capacity to serve non-firm load. This is a reasonable premise because FPL removes non-firm load (including CILC and CDR) to quantify its summer and winter peak reserve margins. The reserve margins are the primary metric used to assess resource adequacy.

*Method 2* reflects the basic approach that FPL used in its CCOSS (*i.e.,* to treat non-firm load as firm) except that the imputed incentive payments are allocated to the firm classes. As can be seen, the two treatments are mathematically equivalent, but only if the imputed incentive payments are allocated to firm loads, which FPL failed to do.

The illustration shows the allocation of $10,000 in production capacity costs to two equal size classes: A and B. Class A is comprised of only firm load, while Class B's load is 50% firm and 50% non-firm. The non-firm load provides $1,500 in revenue. *Method 1* allocates zero production capacity costs to interruptible customers (column 4, line 8). The non-firm revenues are used to lower the cost to provide firm service (columns 2 and 3, line 9). This results in allocating the $10,000 as follows: Class A

$5,667; Class B $4,333 ($2,833 plus $1,500), of which the firm load would be charged $2,833.

*Method 2* treats non-firm load as firm. Thus, it imputes additional revenues to Class B, and these imputed revenues are allocated to both classes based on the amount of firm load. The imputed revenues are the difference between the revenues that the non-firm customers would have paid under the firm rates (or $2,500) and the actual non-firm revenues (or $1,500). Thus, in the illustration, the imputed revenues are $1,000. As can be seen on line 13, the $10,000 of production capacity costs is allocated as follows: Class A $5,667; Class B $4,333 ($2,833 + $1,500), of which firm Class B customers are allocated $2,833. However, this is the same allocation as if no production capacity costs were allocated to non-firm load in the first place (*i.e., Method 1*).

**Q WHAT DO YOU CONCLUDE FROM THE EXAMPLE SHOWN IN EXHIBIT JP-5?**

A First, the example demonstrates the application of the Matching Principle to correctly quantify and impute additional base revenues that reflect the differences in revenues under the non-firm and firm rate schedules during the test year. FPL's revenue adjustments were based on amounts recovered in the ECCR, which are clearly different than the test-year incentive payments.

Second, the example demonstrated that the imputed incentive payments must be reallocated to customer classes based on each class's firm load. This second step, which is missing from FPL's Base and Alternate CCOSSs, recognizes that the incentives paid to non-firm customers benefit firm customers.

**Q HAVE YOU APPLIED THE APPROACH DEMONSTRATED IN EXHIBIT JP-5 TO FPL'S CLASS COST-OF-SERVICE STUDIES?**

A Yes. **Exhibit JP-6** shows how test-year imputed incentive payments derived in **Exhibit JP-3** and **Exhibit JP-4** were directly assigned to the CILC and GSD/GSLD class base revenues (line 6). As can be seen, the test-year imputed incentive payments are $80.9 million. This compares to $74.5 million in FPL's CCOSSs.[23]

I then derived a firm production demand allocator by removing from FPL's 12CP allocation factors (line 7) the estimated non-firm load in the CILC and GSD/CILC classes (line 8). The test-year imputed incentive payments imputed to the CILC and GSD/GSLD classes were then reallocated to customer classes (line 11) based on each class's percentage of firm load (line 10).

**Q HAVE YOU REVISED FPL'S MDS CLASS COST-OF-SERVICE STUDY WITH THE CORRECTIONS MADE TO THE QUANTIFICATION AND ALLOCATION OF THE TEST-YEAR INCENTIVE PAYMENTS?**

A Yes. **Exhibit JP-7** is a corrected version of FPL's MDS CCOSS. In this study, the CILC, GSD, GSLD-1, and GSLD-2 class revenues were adjusted consistent with the methodology shown in **Exhibit JP-6** to recognize what the these customers would have been charged if they had been taking service on the otherwise applicable firm rate during the test year.

[23] MFR Schedule E-5, Test Consolidated With RSAM, line 6.

**Q WHAT DO THE RESULTS OF YOUR CORRECTED MDS CLASS COST-OF-SERVICE STUDY DEMONSTRATE?**

A Correcting quantification and allocation of the imputed incentive payments moves the CILC classes to either above or just below parity as shown on **Exhibit JP-7**, page 1, line 24. These are significant changes from FPL's Base study.

## Allocation of Production and Transmission Costs

**Q HOW IS FPL PROPOSING TO ALLOCATE PRODUCTION AND TRANSMISSION PLANT AND RELATED COSTS?**

A FPL is proposing to use the 12CP and 1/13$^{th}$ average demand to allocate production plant and related costs. Effectively, this method allocates 92.3% (12/13ths) using the 12CP method and 7.7% (1/13$^{th}$) on average demand. Average demand is equivalent to year-round energy usage. FPL uses 12CP to allocate transmission plant.

**Q DO YOU HAVE ANY CONCERNS ABOUT THE 12CP METHOD?**

A Yes. 12CP gives approximately equal weighting to the power demands that occur during each of the 12 monthly system peaks. In other words, 12CP assumes that the demands occurring in the spring and fall months are as critical to system reliability as meeting summer period demands. Thus, giving substantial weighting to the non-summer months in allocating production and transmission costs ignores the reality that FPL is a strongly summer-peaking utility. This is demonstrated in **Exhibit JP-8**. As can be seen, there are substantial differences in FPL's monthly system peak demands. The demands during the summer months are consistently much closer to the annual system peak than the peak demands in the non-summer months. Based on FPL's projections, the summer peak demands are expected to be more than 20% higher than the expected winter peak demands.

**Q IS SYSTEM RELIABILITY A MORE SIGNIFICANT CONCERN DURING THE SUMMER MONTHS?**

A Yes. **Exhibit JP-1** showed that FPL's reserve margins are projected to be significantly lower during the summer months than in the winter months. This means that system reliability is being driven primarily by the projected summer peak demands. Further, transmission lines have less load carrying capability during the summer months. Accordingly, both production and transmission plant and related costs should be allocated to customer classes using a method that reflects summer period demands.

**Q WHAT ALLOCATION METHOD WOULD RECOGNIZE THESE REALITIES?**

A The 4CP method better reflects the realities that FPL is a strongly summer-peaking utility and that summer period demands are more critical to maintaining the reliability of the bulk power system.

**Q HAVE YOU QUANTIFIED THE IMPACT OF USING 4CP RATHER THAN 12CP TO ALLOCATE PRODUCTION AND TRANSMISSION DEMAND-RELATED COSTS?**

A Yes. **Exhibit JP-9** estimates the impact of using 4CP (instead of 12CP) on each class's revenue requirement. The 12CP and 4CP demand allocation factors are shown in columns 1 and 2, respectively. The impact was derived by comparing the allocated production and transmission demand-related costs in FPL's CCOSS (columns 3 and 4) to the corresponding allocations had 4CP been used instead of 12CP (columns 5 and 6). As can be seen in column 7, using the 4CP method would reduce the GSLD and CILC class revenue requirements by $32.7 million and $10.7 million, respectively.

**Q WHAT DO YOU RECOMMEND?**

A The Commission should require FPL to adopt the 4CP method to allocate production and transmission plant and related costs. FPL should also re-run its MDS CCOSS to allocate production and transmission demand-related costs using the 4CP method.

**Minimum Distribution System**

**Q EARLIER YOU STATED A PREFERENCE FOR FPL'S MDS COST STUDY. WHY SHOULD FPL'S MDS COST STUDY BE USED FOR SETTING RATES IN THIS PROCEEDING?**

A The MDS classifies a portion of the distribution network as a customer-related cost. This is in stark contrast to FPL's Base CCOSS, in which all distribution network costs are considered demand-related. As further discussed below, classifying a portion of the distribution network as a customer-related cost is consistent with the principles of cost causation; that is, it better reflects the factors that cause a utility to incur these costs.

**Q WHAT ARE DISTRIBUTION NETWORK COSTS?**

A The electric distribution network consists of FPL's investment in poles, towers, fixtures, overhead lines and line transformers. These investments are booked to FERC Account Nos. 364, 365, 366, 367 and 368.

**Q WHAT FACTORS CAUSE A UTILITY TO INVEST IN AN ELECTRIC DISTRIBUTION NETWORK?**

A The purpose of the electric distribution network is to deliver power from the transmission grid to the customer, where it is eventually consumed. Thus, the central roles of the distribution network are to:

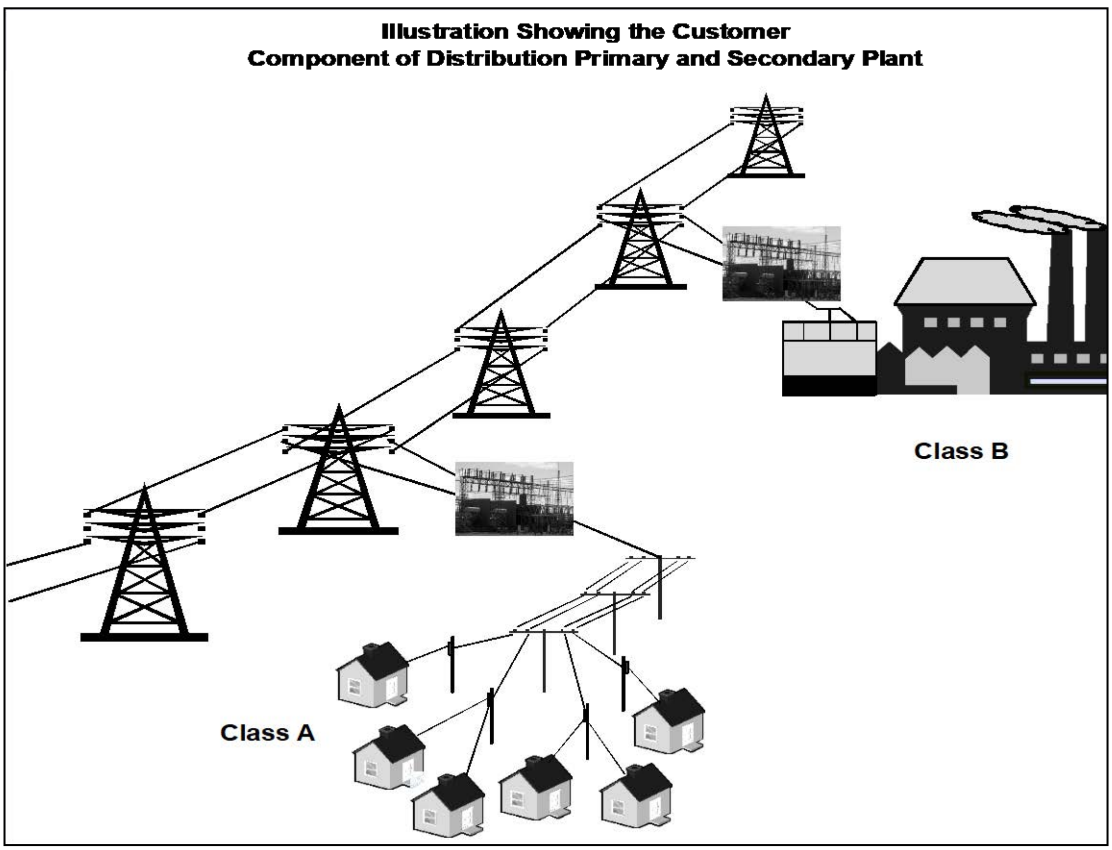
- Provide access to a safe, delivery-ready power grid (*i.e.*, a customer-related cost); and
- Meet customers' peak electrical power needs (*i.e.*, a demand-related cost).

Providing access to a safe, delivery-ready power grid requires not only a physical connection that meets all construction and safety standards, but also the voltage support, which is provided by the distribution network infrastructure. Clearly, these costs are related to the existence of the customer. This is why classifying a portion of the distribution network as customer-related is consistent with cost causation. In other words, investments that must be made solely to attach a customer to the system are clearly customer-related. These customer-related costs should be allocated based on the number of customers served rather than peak demand.

**Q WHY WOULD CLASSIFYING ALL DISTRIBUTION NETWORK COSTS TO DEMAND NOT BE CONSISTENT WITH COST CAUSATION?**

A Although the distribution network is sized to meet expected peak demand, it must also provide the direct connection to the customer while providing the necessary voltage support to allow power to flow to the customer. Absent a distribution network and the voltage support it provides, electricity cannot flow to customers. Thus, this investment is essential and unrelated to the amount of power and energy consumed by customers, which is why classifying these costs entirely to demand is not consistent with cost causation.

If FPL were to provide only a minimum amount of electric power to each customer, it would still have to construct nearly the same miles of distribution lines because they are required to serve every customer. The poles, conductors and transformers would not need to be as large as they are now if every customer were supplied only a minimum level of service, but there is a definite limit to the size to which they could be reduced. Consider the diagram below, which shows the distribution network for a utility with two customer classes, A and B.



The physical distribution network necessary to attach Class A, a residential subdivision for example, is designed to serve the same load as the distribution feeder serving Class B, a large shopping center or small factory. Clearly, a much more extensive distribution system is required to attach a multitude of small customers than to attach a single larger customer, even though the total demand of each customer class is the same.

**Q IS IT A RECOGNIZED PRACTICE TO CLASSIFY A PORTION OF THE ELECTRIC DISTRIBUTION NETWORK AS CUSTOMER-RELATED?**

A Yes. For example, the National Association of Regulatory Utility Commissioners' Electric Utility Cost Allocation Manual states that:

> Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system.[24]

**Q WHAT DO YOU RECOMMEND?**

A The Commission should approve the use of the MDS in setting base rates in this proceeding. Gulf Power and TECO use the MDS approach in setting base rates and the MDS methodology more fairly allocates costs between user groups. The MDS approach recognizes that there are additional customer-related costs to provide distribution service (other than the meter and service drop), and it allocates these costs based on the number of customers. MDS is consistent with cost causation, is an

[24] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, at 90 (Jan. 1992).

accepted industry practice, and the Commission previously approved its use for Gulf Power and TECO.

## Primary/Secondary Voltage Separation

**Q WHY DOES A CLASS COST-OF-SERVICE STUDY DISTINGUISH BETWEEN THE SERVICE PROVIDED AT PRIMARY AND SECONDARY VOLTAGE?**

A The vast majority of FPL's electricity sales are delivered at secondary voltage. The cost to provide secondary service is more expensive than the cost to provide primary or transmission service for two reasons. First, FPL has to invest in additional distribution facilities to transform voltage from transmission to primary and then from primary to secondary distribution. Thus, in contrast to primary service, secondary distribution service requires additional transformation. Second, more energy is lost when delivering energy at lower voltages (*i.e.*, secondary) than at higher voltages (*i.e.*, primary).

For these reasons, it is essential to accurately quantify the respective costs to provide primary and secondary distribution service. That process requires identifying the investments that are used to provide distribution service, both at primary and secondary voltages.

**Q HOW MUCH DISTRIBUTION NETWORK INVESTMENT DID FPL ASSIGN TO PRIMARY AND SECONDARY DELIVERY?**

A Table 3 summarizes how FPL separated network distribution between primary and secondary distribution in its Base CCOSS.

**Table 3**
**Functionalization of Distribution Plant**
**FERC Account Nos. 364 - 367[25]**
**Base Study**

| Description | Account No. | Primary | Secondary |
|---|---|---|---|
| **Poles, Towers, Fixtures** | 364 | 97.3% | 2.6% |
| **Overhead Conductors** | 365 | 81.6% | 18.2% |
| **Underground Conduit** | 366 | 91.8% | 8.2% |
| **Underground Conductors** | 367 | 87.3% | 12.7% |

The primary/secondary split was based on an analysis of retiring distribution plant.[26]

Q **DO YOU HAVE ANY CONCERNS WITH HOW FPL SEPARATED PRIMARY AND SECONDARY DISTRIBUTION INVESTMENT?**

A Yes. As shown in Table 3, 97% of FPL's investment in poles, towers and fixtures would be assigned to primary service and only 2.6% would be assigned to secondary service. However, only 82% of the overhead conductors (which are supported by the poles, towers and fixtures) were assigned to primary delivery and 18% were assigned to secondary delivery. Similarly, FPL assigned 91.8% of the underground conduit to primary even though a lesser share of the underground conductors (which are supported by the underground conduit) were assigned to primary. Thus, it appears that there are internal inconsistencies in how FPL separated the primary and secondary investments in these FERC Accounts.

[25] MFR Schedule E-10 (Test Year, Consolidated, With RSAM), Attachment 4.

[26] FPL Response to FIPUG Interrogatory No. 40.

**Q DID YOU OBSERVE THE SAME PROBLEMS IN FPL'S MDS CLASS COST-OF-SERVICE STUDY?**

A No. Table 4 summarizes the percentage of distribution plant assigned to Primary and Secondary in FPL's MDS CCOSS. The percentages of plant in FERC Account Nos. 364-367 assigned to primary are more consistent than in FPL's Base CCOSS. Thus, this study provides a more consistent treatment between the conductors (*i.e.,* overhead lines and underground conductors) and their corresponding support structures (*i.e.,* poles, towers, fixtures, and underground conduit) than in FPL's "Base" study.

**Table 4**
**Functionalization of Distribution Plant**
**FERC Account Nos. 364 - 367[27]**
**MDS Study**

| Description | Account No. | Primary | Secondary |
|---|---|---|---|
| **Poles, Towers, Fixtures** | 364 | 72.5% | 27.5% |
| **Overhead Conductors** | 365 | 84.9% | 15.1% |
| **Underground Conduit** | 366 | 87.7% | 12.3% |
| **Underground Conductors** | 367 | 88.0% | 12.0% |

**Q WHAT DO YOU RECOMMEND?**

A The Commission should approve the MDS for allocating distribution plant. However, should the Commission reject MDS, it should nevertheless adopt the primary/secondary separation in FPL's MDS CCOSS.

[27] Direct Testimony of Tara B. DuBose, Exhibit TBD-7.

## 6. CLASS REVENUE ALLOCATION

**Q WHAT IS CLASS REVENUE ALLOCATION?**

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

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

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

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

A Gradualism is a concept that is applied to avoid rate shock; that is, no class should receive an overly-large or abrupt rate increase. Thus, rates should move gradually to cost rather than all at once because moving rates immediately to cost would result in rate shock to the affected customers.

**Q ARE THERE ANY EXTENUATING CIRCUMSTANCES THAT WARRANT PARTICULAR ATTENTION TO GRADUALISM IN THIS PROCEEDING?**

A Yes. The economy is recovering from the COVID-19 pandemic. In this post-pandemic environment, the Commission should avoid imposing very large electric base rate increases at this time.

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

A Yes. Cost-based rates are fair (because each class's rates reflect its cost to serve, no more and no less; they are efficient (because, when coupled with a cost-based rate design, customers are provided with the proper incentive to minimize their costs, which will, in turn, minimize the costs to the utility); they enhance revenue stability (because changes in revenues due to changes in sales will translate into offsetting changes in costs); and they encourage conservation (because cost-based rates will send the proper price signals to customers, thereby allowing customers to make rational consumption decisions).

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

A Yes. The Commission's support for cost-based rates is longstanding and unequivocal.

**Q DOES FPL'S PROPOSED CLASS REVENUE ALLOCATION FOLLOW THESE PRINCIPLES?**

A No, not entirely. FPL's proposed class revenue allocation would move all rates much closer or immediately to cost based on the results of its Base CCOSS. As previously discussed, FPL's Base CCOSS is seriously flawed and, at a minimum, should incorporate the MDS and my recommended changes in the amount and allocation of the incentive payments. However, for FPL's largest customers who are in the GSLD and CILC rate schedules, FPL's proposed class revenue allocation would result in rate shock. This is shown in Table 5.

**Q PLEASE EXPLAIN TABLE 5.**

A Table 5 shows FPL's proposed base rate increases for the major customer classes in 2022 and the cumulative base rate increase through 2023. These increases are also expressed as a percentage of the retail average base rate increase (*i.e.,* the relative increase).

**Table 5**
**FPL's Proposed Base Rate Increases**
**With RSAM**[28]

| Customer Class | 2022 Increase | | Cumulative 2023 Increases | |
|---|---|---|---|---|
| | Percent | Relative Increase | Percent | Relative Increase |
| **Residential** | 10.6% | 69% | 17.4% | 75% |
| **GS/GSCU** | 14.1% | 92% | 21.8% | 94% |
| **GSD** | 24.4% | 160% | 34.0% | 146% |
| **GSLD** | 28.0% | 184% | 42.4% | 183% |
| **CILC** | 46.4% | 305% | 59.4% | 256% |
| **MET** | 19.3% | 127% | 27.5% | 118% |
| **Lighting (SL, OS)** | 8.5% | 56% | 10.9% | 47% |
| **Standby (SST)** | 4.4% | 29% | 6.2% | 27% |
| **Total Retail** | 15.2% | 100% | 23.2% | 100% |

For example, if the class's increase is equal to the retail average base rate increase, the relative increase would be 100%. A class that is receiving an above-system average increase would have a relative increase above 100, and vice versa for a class that receives a below-system average increase.

[28] MFR Schedule E-8 2022 and 2023.

As Table 5 demonstrates, the proposed 2022 base rate increases for the GSLD and CILC classes would be 184% and 305%, respectively, of the retail system average increase. The cumulative 2023 base rate increases would be 183% and 256%, respectively, of the retail system average increase.

By any definition, relative base rate increases of the magnitude FPL is proposing for the GSLD and CILC classes would be rate shock.

**Q WOULD FORMER LARGE GULF POWER CUSTOMERS EXPERIENCE SIMILAR BASE RATE INCREASES AS CURRENT FPL CUSTOMERS?**

A No. Former Gulf Power customers eligible for FPL's GSLD rate schedules would experience even higher base rate increases than similarly situated FPL customers. This is demonstrated in Table 6.

**Table 6**
**Base Rate Increases With RSAM For Customers Transferring to FPL's GSLD Rate Schedules**

| Rate Schedule | Existing Utility | 2022 Increase | Cumulative 2023 Increases |
|---|---|---|---|
| **GSLD-1** | **FPL** | 24.1% | 38.1% |
| | **Gulf** | 162.4% | 45.7% |
| **GSLD-2** | **FPL** | 19.6% | 33.6% |
| | **Gulf** | 79.6% | 67.2% |
| **GSLD-3** | **FPL** | 21.6% | 37.9% |
| | **Gulf** | 37.5% | 51.5% |
| **FPL Customers** | | 22.9% | 37.0% |
| **Gulf Power Customers** | | 82.6% | 50.9% |

The proposed Transition Rider would mitigate but not eliminate the disparate base rate increases shown in Table 6.

**Q HOW DO YOU RECONCILE THE IMPACTS SHOWN IN TABLES 4 AND 5 WITH FPL'S CLAIMS THAT IT IS FOLLOWING GRADUALISM PRINCIPLES?**

A FPL's definition of gradualism is flawed because it is based on expressing the proposed *base* revenue increases as a percentage of the *total* revenues from each class. This is not an apples-to-apples comparison. Total revenues include base revenues as well as the revenues collected under FPL's five separate cost recovery mechanisms:

- Fuel and Purchased Power.
- Energy Conservation.
- Capacity.
- Environmental.
- Storm Protection.

However, the costs recovered in these cost recovery mechanisms are not directly impacted in a base rate case. Thus, FPL's definition of gradualism is inapt in this proceeding when only the base rates are at issue.

**Q WHICH APPROACH (TOTAL REVENUE OR BASE REVENUE) BETTER MEASURES THE IMPACT ON CUSTOMER CLASSES?**

A FPL is seeking four separate and distinct ***base*** rate increases in this application. Measuring the impact of those proposed increases on ***base*** revenues is the only proper way to measure the impact and to assess whether FPL's proposed class revenue allocation results in rate shock. Gradualism is not considered in any of the other cost-recovery mechanisms. Therefore, a general rate case is the only venue in which gradualism can be properly applied. Because a general rate case only addresses changes in base revenue, gradualism should be measured relative to base rate impacts.

**Q HAVE YOU DEVELOPED AN ALTERNATIVE CLASS REVENUE ALLOCATION BASED ON YOUR REVISED CLASS COST-OF-SERVICE STUDIES?**

A Yes. **Exhibit JP-10** uses FPL's MDS study with the corrections to the level and allocation of the incentive payments. My recommendation would result in moving the major rate classes to cost. **Exhibit JP-11** uses FPL's MDS study, the 4CP method to allocate production and transmission demand-related costs, and the corrections to the level and allocation of the incentive payments. In both cases, no class would receive a decrease or an increase more than 1.5 times the system average base rate increase.

## 7. CILC/CDR MONTHLY INCENTIVE

**Q WHAT IS THE CILC PROGRAM?**

A CILC program is a non-firm tariff option in which customers agree to curtail load at FPL's direction. The curtailment conditions in the CILC tariff are as follows:

> The Customer's controllable load served under this Rate Schedule is subject to control when such control alleviates any emergency conditions or capacity shortages, either power supply or transmission, or whenever system load, actual or projected, would otherwise require the peaking operation of the Company's generators. Peaking operation entails taking base loaded units, cycling units or combustion turbines above the continuous rated output, which may overstress the generators.[29]

Further, under the Commission's Rules:

> (4) Treatment of Non-Firm Load. If non-firm load (i.e., customers receiving service under load management, interruptible, curtailable, or similar tariffs) is relied upon by a utility when calculating its planned or operating reserves, the utility shall be required to make such reserves available to maintain the firm service requirements of other utilities.[30]

Thus, a CILC customer may be curtailed due to a capacity shortage or emergency anywhere in Peninsular Florida. By allowing FPL to curtail controllable load when resources are needed to maintain system reliability (that is, when there are insufficient resources to meet customer demand), FPL can maintain service to firm (*i.e.*, non-interruptible) customers. For this reason, FPL removes CILC loads in assessing resource adequacy. Thus, CILC is a lower quality of service than firm power because it can be interrupted as described above. In exchange for an agreement to curtail load at FPL's control, CILC customers pay a lower base rate than firm customers.

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[29] FPL Tariff, Commercial/Industrial Load Control Program, Fourth Revised Sheet No. 8.652 (Nov. 15, 2002).

[30] Rule 25-6.035 F.A.C.

**Q HOW ARE CILC CUSTOMERS COMPENSATED FOR THE CAPACITY THEY PROVIDE FPL?**

A The Load-Control On-Peak demand charge is a reduced rate that reflects the current value of non-firm capacity. The other applicable demand charges (*i.e.,* Firm On-Peak and Maximum Demand) recover the allocated transmission and distribution demand-related costs and are, thus, similar in concept to FPL's other firm rates.

**Q WHAT IS THE CDR PROGRAM?**

A Rider CDR is an optional rate available as follows:

> Available to any commercial or industrial customer receiving service under Rate Schedules GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, GSLDT-2, GSLD-3, GSLDT-3, or HLFT through the execution of a Commercial/Industrial Demand Reduction Rider Agreement in which the load control provisions of this rider can feasibly be applied.[31]

As with CILC, non-firm load can be curtailed by FPL at any time (with some limitations) under a wide range of circumstances. The tariff states:

> <u>Control Condition:</u>
>
> The Customer's controllable load served under this Rider is subject to control when such control alleviates any emergency conditions or capacity shortages, either power supply or transmission, or whenever system load, actual or projected, would otherwise require the peaking operation of the Company's generators. Peaking operation entails taking base loaded units, cycling units or combustion turbines above the continuous rated output, which may overstress the generators.
>
> <u>Frequency</u>: The Control Conditions will typically result in less than fifteen (15) Load Control Periods per year and will not exceed twenty-five (25) Load

[31] FPL Tariff, Commercial/Industrial Demand Reduction Rider, Twenty-Second Revised Sheet No. 8.680 (Jan. 1, 2021).

> Control Periods per year. Typically, the Company will not initiate a Load Control Period within six (6) hours of a previous Load Control Period.
>
> Notice: The Company will provide one (1) hour's advance notice or more to a Customer prior to controlling the Customer's controllable load. Typically, the Company will provide advance notice of four (4) hours or more prior to a Load Control Period.
>
> Duration: The duration of a single Load Control Period will typically be three (3) hours and will not exceed six (6) hours. In the event of an emergency, such as a Generating Capacity Emergency (see Definitions) or a major disturbance, greater frequency, less notice, or longer duration than listed above may occur. If such an emergency develops, the Customer will be given 15 minutes' notice. Less than 15 minutes' notice may only be given in the event that failure to do so would result in loss of power to firm service customers or the purchase of emergency power to serve firm service customers. The Customer agrees that the Company will not be liable for any damages or injuries that may occur as a result of providing no notice or less than one (1) hour's notice.[32]

**Q YOU PREVIOUSLY DESCRIBED HOW FPL PROVIDES NON-FIRM SERVICE UNDER RATES CILC AND RIDER CDR. APPROXIMATELY HOW MUCH NON-FIRM LOAD IS SERVED UNDER THESE TARIFF OPTIONS?**

A The service provided under the CILC and Rider CDR tariff options account for about 814 MW.[33]

**Q ARE THE CILC/CDR SERVICE OPTIONS THE ONLY NON-FIRM RATE OPTIONS OFFERED BY FPL?**

A No. FPL provides approximately 1,800 MW of non-firm load. Thus, there are other load management programs besides CILC and CDR.

[32] *Id.,* Second Revised Sheet No. 8.681 (Mar. 30, 2004).

[33] Direct Testimony of Dr. Steven R. Sim at 17.

**Q FPL IS PROPOSING TO REDUCE THE INCENTIVE PAYMENTS TO CILC AND CDR BY 33%. IS FPL PROPOSING TO REDUCE INCENTIVES PAID UNDER OTHER NON-FIRM LOAD OPTIONS IN THIS PROCEEDING?**

A No, not to my knowledge.

**Q HOW WOULD A 33% REDUCTION IN INCENTIVES PAID TO CILC AND CDR CUSTOMERS IMPACT BASE RATES CHARGED TO THESE CUSTOMERS?**

A A 33% reduction in the incentive payments under the CILC program accounts for about $15.1 million of FPL's proposed base revenue increase to the CILC classes. This one change alone reflects about 30% of FPL's proposed 2022 base revenue increase to the CILC classes. Reducing the Rider CDR credits from $8.70 per kW to $5.80 per kW would account for about $9.2 million or approximately 1.8% of the base revenue increases allocated to the GSD and GSLD classes.[34]

These are in addition to the increases resulting from FPL's flawed CCOSSs, which were discussed previously.

**Q WHAT IS THE BASIS FOR FPL'S PROPOSAL TO REDUCE THE INCENTIVES PAID TO CILC AND CDR CUSTOMERS?**

A FPL witness, Dr. Steven R. Sim, stated that the 33% reduction was based, in part, on the analysis provided in his direct testimony; specifically, Exhibit SRS-2 which supplemented Dr. Sim's testimony in the 2019 Demand Side Management (DSM) Goals docket (Docket No. 20190015-EG). However, had FPL relied solely on Dr. Sim's new cost-effectiveness analysis, the reduction would have been approximately

[34] FPL MFR E05 Test Consolidated with RSAM.

3% rather than 33%. Thus, the decision to reduce the incentives by 33% was based in large part on judgment, something acknowledged by Dr. Sim during his deposition.[35]

**Q HAVE YOU ANALYZED EXHIBIT SRS-2?**

A Yes. Exhibit SRS-2 presents the results of a cost-benefit analysis using the AURORA production cost simulation model. The model projected system production costs over the period 2020 through 2068.[36]

System production costs include both fixed and variable costs. Fixed costs include the capital costs of future capacity additions and any incremental fixed operation and maintenance expenses. Variable costs include system-wide fuel costs and variable operation and maintenance expense. Thus, the cumulative present value revenue requirement (CPVRR) net benefit analysis FPL performed includes both fixed and variable costs.

**Q HOW WAS THE AURORA MODEL USED TO DETERMINE THE NET BENEFITS OF THE CDR AND CILC PROGRAMS?**

A FPL calculated the CPVRR net benefits using two AURORA model runs:

1. Assuming the continuation of the CDR and CILC programs (that provide approximately 814 MW of capacity); and
2. Without the CDR and CILC programs.

The difference between the CPVRR net benefits with and without the CDR and CILC programs is supposed to measure the long-term benefit of these programs to FPL's customers.

[35] Deposition of Steven R. Sim (Jun. 9, 2021).

[36] Direct Testimony of Dr. Steven R. Sim at 46.

**Q BASED ON THIS ANALYSIS, WHAT INCENTIVE PAYMENT WOULD BE CONSIDERED COST-EFFECTIVE FOR FPL CUSTOMERS?**

A The net benefits derived in Exhibit SRS-2 would support a monthly incentive payment of $8.45 per kW.[37] This is only a 3% reduction from the current incentive.

**Q WHY THEN IS FPL PROPOSING TO REDUCE THE INCENTIVE PAYMENT TO $5.80 PER KW?**

A FPL has assumed that the monthly incentive payments would increase as future base rates are implemented. Further, Dr. Sim asserted that capital costs would continue to decline in the future, thereby purportedly eroding the cost-effectiveness of the CDR and CILC programs.

**Q ARE ANY OF THESE ASSUMPTIONS VALID?**

A No. First, any decline in future capital cost should have already been recognized in the AURORA model runs. This is because the AURORA model calculates fixed and variable costs of new generation based on assumptions about future capital costs and commodity prices, among other assumptions. Second, FPL's assertion that the monthly incentive levels would increase in subsequent years is sheer speculation and would only occur (if at all) in a SoBRA increase. Finally, as discussed later, the current $8.70 per kW monthly incentive is more than cost-effective based on the costs that FPL has avoided due to the CDR and CILC programs.

[37] FPL Response to FRF Interrogatory No. 2.

**Q IS FPL'S COST-EFFECTIVENESS ANALYSIS OF THE CDR AND CILC PROGRAMS VALID?**

A No. The primary benefit of the CDR and CILC programs is to defer future capacity additions. However, the AURORA model quantifies both fixed (*i.e.,* capacity) and variable (*i.e.,* energy) costs. Thus, AURORA is the wrong tool to measure the cost-effectiveness of load management programs. Second, the analysis presented in Exhibit SRS-2 misconstrues the role of cost-effectiveness tests in setting rates.

**Q PLEASE EXPLAIN.**

A Determining the cost-effectiveness of a rate is different from determining whether a particular DSM or load management program should be offered or expanded. The former is a ratemaking issue, while the latter is a resource planning issue.

**Q HOW IS RESOURCE PLANNING DIFFERENT FROM RATEMAKING?**

A Resource planning is, by definition, forward looking; whereas ratemaking reflects past decisions and costs that have mostly been incurred in the past as well as the projected additional costs for the test year. Specifically, resource planning identifies the range of options that can allow a utility to meet its future needs at the lowest reasonable cost. In the context of non-firm service, resource planning can determine whether it is cost-effective to implement, expand, or close a particular option to new business.

Ratemaking addresses the recovery of costs associated with the utility's existing resources, which include both supply side and demand-side resources, once the Commission has determined that the resource is both prudent and reasonable. The costs of those resources are recoverable in rates. Importantly, the costs eligible for recovery in rates are not adjusted even if the resource may no longer be cost-effective. For example, if an existing CCGT is no longer cost-effective because it can no longer compete with other resource options, the utility is still allowed to recover those costs in rates because the Commission has deemed them to be prudent and reasonable.

When used in the context of evaluating non-firm service, the reasonableness of any non-firm rate can be assessed by determining whether the utility has actually avoided constructing new capacity and quantifying the costs associated with this avoided capacity. If the Commission determines that a non-firm rate option is no longer providing benefits to the general body of ratepayers, it can require the utility to close the rate to new business.

**Q DO THE COMMISSION'S RULES ADDRESS COST-EFFECTIVENESS TESTS IN GENERAL?**

A Yes. Cost-effectiveness is addressed in the Commission's rule on Non-Firm Electric Service.[38] Specifically:

> Purpose. The purposes of this rule are: to define the character of non-firm electric service and various types thereof; to require a procedure for determining a utility's maximum level of non-firm load; and to establish other minimum terms and conditions for the provision of non-firm electric service.

**Q HOW IS COST-EFFECTIVENESS DEFINED?**

A Cost-effectiveness is defined as follows:

> (c) "Cost effective" in the context of non-firm service shall be based on avoided costs. It shall be defined as the net economic deferral or avoidance of

[38] Rule 25-6.0438(2) F.A.C.

> additional production plant construction by the utility or in other measurable economic benefits in excess of all relevant costs accruing to the utility's general body of ratepayers.[39]

**Q HOW ARE COST-EFFECTIVENESS TESTS USED?**

A Cost-effectiveness tests are used in the conservation goals dockets to determine the maximum level of non-firm load; specifically, whether a new DSM or load management program should be implemented and/or whether an existing program should either be expanded or closed to new business.

**Q HAS THE COMMISSION EVER USED A PRODUCTION COST SIMULATION MODEL TO EVALUATE COST-EFFECTIVENESS?**

A No. In the past, the Commission has prescribed a model to evaluate the cost-effectiveness of DSM and load management programs. This model evaluated the avoided costs of capacity (and energy for DSM programs) and the estimated costs (*i.e.*, the incentives paid to participating customers). Thus, it was a targeted resource planning model. Importantly, the results informed the Commission whether it would be cost-effective to allow new participants into a specific program. If the model showed that a program was no longer cost-effective, the remedy was to close the program to new business.

[39] Rule 25-6-0438(3)(c) F.A.C.

**Q IS REPLACING THE COMMISSION'S PRESCRIBED COST-EFFECTIVENESS MODEL WITH THE AURORA PRODUCTION COST SIMULATION MODEL PROBLEMATIC?**

A Yes. As previously explained, the AURORA model captures not only changes in fixed costs, but also the variable costs associated with future resource plans. However, the primary benefit of the CDR and CILC load management programs is to reduce future capacity additions that result in lower fixed costs. Thus, FPL's use of the AURORA model introduces other variables besides the impact on future capacity additions and fixed costs that are unrelated to determine the cost-effectiveness of the CDR and CILC programs.

**Q ARE THE BENEFITS DERIVED FROM THE AURORA MODEL ACCURATE?**

A The accuracy of the AURORA model results cannot be verified without conducting a detailed audit. However, auditing the model would require obtaining a temporary user license at a significant cost. Given the statutorily-imposed time constraints, a general rate case is not a proper forum to fully vet a model that has never before been used to measure the cost-effectiveness.

**Q ARE THERE ANY OTHER REASONS WHY THE COMMISSION SHOULD QUESTION THE RESULTS OF THE AURORA MODEL?**

A Exhibit SRS-2 is based on just one AURORA model scenario. Other than including and then removing the CDR and CILC programs, no other scenarios were provided. Normally, resource planning models examine multiple scenarios that examine a wide range of assumptions, including different levels of load growth, inflation and commodity prices. Absent a robust analysis that considers a wide range of scenarios, it would be impossible to validate the model results even if there were sufficient time and available resources.

**Q DR. SIM ASSERTS THAT DECLINING CAPITAL COSTS ARE A PRIMARY FACTOR BEHIND FPL'S JUDGMENT TO REDUCE THE INCENTIVE PAYMENTS BY 33%. WHAT IS THE BASIS FOR THIS STATEMENT?**

A Specifically, Dr. Sim stated that, in 2009, FPL projected that the avoided unit would have a capital cost of $974 per kW. However, by 2019, FPL projected that the same avoided unit would have a capital cost of only $663 per kW. This is a 32% decrease.[40]

**Q HAVE YOU SEEN EVIDENCE THAT GENERATION CAPITAL COSTS HAVE DECLINED AS DR. SIM'S ASSERTS?**

A No. **Exhibit JP-12** shows the trends in generation capital costs. First, I have tabulated the overnight construction costs of CT generating units as compiled in the EIA's AEO reports dating back to 2013. As can be seen, the projected overnight costs in the most recent AEO report for 2021 are higher than the corresponding projected overnight construction costs in the 2013 AEO report.

Second, I have provided a history of the CONE prices published by MISO in its annual PRA. The CONE prices shown reflect the cost to construct a new CT in MISO local resource Zone 9, which includes Louisiana, Mississippi and Texas (along the

[40] *In re: Commission review of numeric conservation goals* (Florida Power & Light Company); Docket No. 20190015-EG, Direct Testimony of Steven R. Sim at 25-26 (Apr. 12, 2019).

Gulf Coast). As can be seen, the CONE prices have varied over time. However, there is no discernable decline (certainly not 32%) as suggested by Dr. Sim.

**Q HAVE FPL'S GENERATION CAPITAL COSTS DECLINED?**

A No. If capital costs are declining as Dr. Sim asserts, one would also expect that the capital costs of generation capacity additions would also be declining. However, FPL's installed generation capital costs have steadily increased since 2012. This is shown in **Exhibit JP-13**. FPL's most recent thermal capacity addition, the Dania Clean Energy Center, is expected to cost $762 per kW (line 12). Increasing capital costs, coupled with the fact that FPL's installed capacity costs have averaged $847 per kW (well above $663 per kW), further invalidates FPL's new cost-effectiveness analysis, which assumes a continued decline of capital costs.

**Q DOES FPL'S PROPOSAL TO REDUCE THE CDR AND CILC INCENTIVES BY 33% RAISE ANY OTHER CONCERNS?**

A Yes. Dr. Sim assumes that reducing the incentives to the levels that customers were paid in the distant past would have no adverse consequences; that is, customers would not be motivated to switch from non-firm to firm service. However, he has not provided any customer survey assessing potential customer impacts of a 33% reduction in the CDR and CILC incentives.

**Q IS THERE ANY REASON TO BELIEVE THAT CUSTOMERS WOULD CONTINUE THEIR PARTICIPATION IN THE CDR AND CILC PROGRAMS IF THE INCENTIVES ARE REDUCED BY 33%?**

A No. Non-firm service is not cost-free. Curtailments could occur at any time when capacity is insufficient throughout Peninsular Florida, not just in FPL's service territory. Thus, CDR and CILC participants have to incur costs to be able to safely curtail load when notified. Reducing the incentive payments by 33% substantially changes the customer's assessment of the risks and benefits of the programs. If the participants believe that the benefits of remaining on non-firm service will be substantially reduced and are no longer justified by the risks, as FPL is proposing in this case, they may decide to convert to firm service.

**Q WHAT WOULD HAPPEN IF ALL THE CDR AND CILC LOAD WERE TO CONVERT FROM NON-FIRM TO FIRM SERVICE?**

A FPL would have to install additional capacity to firm up the CDR and CILC loads. Assuming a 20% reserve margin, 814 MW of CDR and CILC non-firm load would require an additional 977 MW of capacity.

If that additional capacity had been installed over the period 2012 through 2021, FPL would have incurred an average installed cost of additional capacity of about $667 per kW (excluding solar capacity), as shown in **Exhibit JP-13**.

Using $667 per kW as the average installed cost of incremental capacity, the annual cost avoided by a transmission level customer taking non-firm service was approximately $9.78 per kW per month. The $9.78 per kW per month avoided capacity cost is derived on page 1 of **Exhibit JP-14**. It is based on FPL's test year carrying charges. This is higher than the current $8.70 per kW CDR Monthly Incentive.

**Q THE $667 PER KW AVOIDED CAPITAL COST ASSUMES THAT FPL WOULD HAVE INSTALLED THE SAME MIX OF THERMAL GENERATION TO FIRM-UP THE CDR AND CILC LOADS. WHAT IF FPL HAD INSTALLED COMBUSTION TURBINES INSTEAD OF CCGTS AND SOLAR PLANTS?**

A **Exhibit JP-14,** page 2 quantifies the avoided cost of non-firm capacity had FPL installed CTs during this period to firm-up the CDR and CILC loads. As can be seen, the corresponding annual revenue requirement avoided by a transmission level customer taking non-firm service was $9.00 per kW per month. This amount is also higher than the current CDR Monthly Incentive.

**Q HAVE THE CDR AND CILC PROGRAMS PROVIDED (AND CONTINUE TO PROVIDE) BENEFITS TO THE GENERAL BODY OF FPL CUSTOMERS?**

A Yes. The capacity costs avoided by providing non-firm service under the CDR Rider and CILC rate schedule exceed the incentive payments to these customers. Hence, from a ratemaking perspective, both the CDR and CILC programs are cost-effective.

**Q WHAT DO YOU RECOMMEND?**

A The Commission should reject FPL's proposal to drastically reduce the CDR credit. There is no evidence that capital costs have declined, certainly not by the magnitude estimated by Dr. Sim.

## 8. CONCLUSION

**Q WHAT FINDINGS SHOULD THE COMMISSION MAKE BASED ON THE ISSUES ADDRESSED IN YOUR TESTIMONY?**

A The Commission should make the following findings:

- Reject the 2023 subsequent year increase unless FPL files a complete set of updated MFRs.
- Reject the continuation of the RSAM.
- Reject the 2024 and 2025 SoBRAs.
- Reject FPL's "Base" class cost-of-service study.
- Adopt FPL's minimum distribution system analysis, including the separation between primary and secondary investment, in allocating distribution network costs.
- Correct the three flaws in FPL's MDS class cost-of-service study as follows:
  - Adjust the imputed incentives to $80.9 million.
  - Directly assign the $80.9 million to the CILC, GSD, and GSLD customer classes as shown in Table 2 of my testimony.
  - Allocate the $80.9 million as a cost to all customer classes based on each class's proportion of firm load.
  - Use the 4CP (rather than the 12CP) method to allocate production and transmission demand-related costs.
- Reject FPL's proposed application of gradualism in determining its class revenue allocation.
- Approve a class revenue allocation based on the corrections to FPL's MDS study.
- Reject FPL's proposed 33% reduction to the CILC/CDR monthly incentive payments.

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

A Yes.

# APPENDIX A

## Qualifications of Jeffry Pollock

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

A Jeffry Pollock. My business mailing address is 12647 Olive Blvd., Suite 585, St. Louis, Missouri 63141.

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

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

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

A I have a Bachelor of Science Degree in Electrical Engineering and a Master's Degree in Business Administration from Washington University. I have also completed a Utility Finance and Accounting course.

Upon graduation in June 1975, I joined Drazen-Brubaker & Associates, Inc. (DBA). DBA was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. From April 1995 to November 2004, I was a managing principal at Brubaker & Associates (BAI).

During my career, I have been engaged in a wide range of consulting assignments including energy and regulatory matters in both the United States and several Canadian provinces. This includes preparing financial and economic studies of investor-owned, cooperative and municipal utilities on revenue requirements, cost of service and rate design, tariff review and analysis, conducting site evaluations, advising clients on electric restructuring issues, assisting clients to procure and manage electricity in both competitive and regulated markets, developing and issuing requests for proposals (RFPs), evaluating RFP responses and contract negotiation and developing and presenting seminars on electricity issues.

I have worked on various projects in 28 states and several Canadian provinces, and have testified before the Federal Energy Regulatory Commission, the Ontario Energy Board, and the state regulatory commissions of Alabama, Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, Ohio, Pennsylvania, South Carolina, Texas, Virginia, Washington, and Wyoming. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Board of Directors of the South Carolina Public Service Authority (a.k.a. Santee Cooper), the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court.

**Q PLEASE DESCRIBE J. POLLOCK, INCORPORATED.**

A J. Pollock assists clients to procure and manage energy in both regulated and competitive markets. The J. Pollock team also advises clients on energy and regulatory issues. Our clients include commercial, industrial and institutional energy consumers. J. Pollock is a registered broker and Class I aggregator in the State of Texas.

# APPENDIX B
## Testimony Filed in Regulatory Proceedings
## by Jeffry Pollock

| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| ENTERGY ARKANSAS, LLC | Arkansas Electric Energy Consumers, Inc. | 20-067-U | Surrebuttal | AR | Certificate of Environmental Compatibility and Public Need | 6/17/2021 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 20-00238-UT | Rebuttal | NM | Rate Design | 6/9/2021 |
| DTE GAS COMPANY | Association of Businesses Advocating Tariff Equity | U-20940 | Direct | MI | Class Cost-of-Service Study; Rate Design | 6/3/2021 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 51415 | Supplemental Direct | TX | Retail Behind-The-Meter-Generation; Class Cost of Service Study; Class Revenue Allocation; LGS-T Rate Design; Time-of-Use Fuel Rate | 5/17/2021 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 20-00238-UT | Direct | NM | Class cost-of-service study, class revenue allocation, LGS-T rate design, TOU Fuel Charge | 5/17/2021 |
| ENTERGY ARKANSAS, LLC | Arkansas Electric Energy Consumers, Inc. | 20-067-U | Direct | AR | Certificate of Environmental Compatibility and Public Need | 5/6/2021 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 51625 | Direct | TX | Fuel Factor Formula; Time Differentiated Costs; Time-of-Use Fuel Factor | 4/5/2021 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 51415 | Direct | TX | ATC Tracker, Behind-The-Meter Generation; Class Cost-of-Service Study; Class Revenue Allocation; Large Lighting and Power Rate Design; Synchronous Self-Generation Load Charge | 3/31/2021 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 51215 | Direct | TX | Certificate of Convenience and Necessity for the Liberty County Solar Facility | 3/5/2021 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 50997 | Cross Rebuttal | TX | Rate Case Expenses | 1/28/2021 |
| PPL ELECTRIC UTILITIES CORPORATION | PPL Industrial Customer Alliance | M-2020-3020824 | Supplemental | PA | Energy Efficiency and Conservation Plan | 1/27/2021 |
| CENTRAL HUDSON GAS & ELECTRIC | Multiple Intervenors | 20-E-0428 / 20-G-0429 | Rebuttal | NY | Distribution cost classification; revised Electric Embedded Cost-of-Service Study; revised Distribution Mains Study | 1/22/2020 |
| MIDAMERICAN ENERGY COMPANY | Tech Customers | EPB-2020-0156 | Reply | IA | Emissions Plan | 1/21/2021 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 50997 | Direct | TX | Disallowance of Unreasonable Mine Development Costs; Amortization of Mine Closure Costs; Imputed Capacity | 1/7/2021 |
| CENTRAL HUDSON GAS & ELECTRIC | Multiple Intervenors | 20-E-0428 / 20-G-0429 | Direct | NY | Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Revenue Decoupling Mechanism | 12/22/2020 |
| NIAGARA MOHAWK POWER CORP. | Multiple Intervenors | 20-E-0380 / 20-G-0381 | Rebuttal | NY | AMI Cost Allocation Framework | 12/16/2020 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 51381 | Direct | TX | Generation Cost Recovery Rider | 12/8/2020 |

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|---|---|---|---|---|---|---|
| NIAGARA MOHAWK POWER CORP. | Multiple Intervenors | 20-E-0380 / 20-G-0381 | Direct | NY | Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Earnings Adjustment Mechanism; Advanced Metering Infrastructure Cost Allocation | 11/25/2020 |
| LUBBOCK POWER & LIGHT | Texas Industrial Energy Consumers | 51100 | Direct | TX | Test Year; Wholesale Transmission Cost of Service and Rate Design | 11/6/2020 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20889 | Direct | MI | Scheduled Lives, Cost Allocation and Rate Design of Securitization Bonds | 10/30/2020 |
| CHEYENNE LIGHT, FUEL AND POWER COMPANY | HollyFrontier Cheyenne Refining LLC | 20003-194-EM-20 | Cross-Answer | WY | PCA Tariff | 10/16/2020 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 20-00143 | Direct | NM | RPS Incentives; Reassignment of non-jurisdictional PPAs | 9/11/2020 |
| ROCKY MOUNTAIN POWER | Wyoming Industrial Energy Consumers | 20000-578-ER-20 | Cross | WY | Time-of-Use period definitions; ECAM Tracking of Large Customer Pilot Programs | 9/11/2020 |
| ROCKY MOUNTAIN POWER | Wyoming Industrial Energy Consumers | 20000-578-ER-20 | Direct | WY | Class Cost-of-Service Study; Time-of-Use period definitions; Interruptible Service and Real-Time Day Ahead Pricing pilot programs | 8/7/2020 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 50790 | Direct | TX | Hardin Facility Acquisition | 7/27/2020 |
| PHILADELPHIA GAS WORKS | Philadelphia Industrial and Commercial Gas Users Group | 2020-3017206 | Surrebuttal | PA | Interruptible transportation tariff; Allocation of Distribution Mains; Universal Service and Energy Conservations; Gradualism | 7/24/2020 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20697 | Rebuttal | MI | Energy Weighting, Treatment of Interruptible Load; Allocation of Distribution Capacity Costs; Allocation of CVR Costs | 7/14/2020 |
| PHILADELPHIA GAS WORKS | Philadelphia Industrial and Commercial Gas Users Group | 2020-3017206 | Rebuttal | PA | Distribution Main Allocation; Design Day Demand; Class Revenue Allocation; Balancing Provisions | 7/13/2020 |
| PECO ENERGY COMPANY | Philadelphia Area Industrial Energy Users Group | 2020-3019290 | Rebuttal | PA | Network Integration Transmission Service Costs | 7/9/2020 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20697 | Direct | MI | Class Cost-of-Service Study;Financial Compensation Method; General Interruptible Service Credit | 6/24/2020 |
| PHILADELPHIA GAS WORKS | Philadelphia Industrial and Commercial Gas Users Group | 2020-3017206 | Direct | PA | Class Cost-of-Service Study; Class Revenue Allocation; Rate Design | 6/15/2020 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20650 | Rebuttal | MI | Distribution Mains Classification and Allocation | 5/5/2020 |
| GEORGIA POWER COMPANY | Georgia Association of Manufacturers and Georgia Industrial Group | 43011 | Direct | GA | Fuel Cost Recovery Natural Gas Price Assumptions | 5/1/2020 |

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|---|---|---|---|---|---|---|
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20650 | Direct | MI | Class Cost-of-Service Study; Transportation Rate Design; Gas Demand Response Pilot Program; Industry Association Dues | 4/14/2020 |
| ROCKY MOUNTAIN POWER | Wyoming Industrial Energy Consumers | 90000-144-XI-19 | Direct | WY | Coal Retirement Studies and IRP Scenarios | 4/1/2020 |
| DTE GAS COMPANY | Association of Businesses Advocating Tariff Equity | U-20642 | Direct | MI | Class Cost-of-Service Study; Class Revenue Allocation; Infrastructure Recovery Mechanism; Industry Association Dues | 3/24/2020 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 49831 | Cross | TX | Radial Transmission Lines; Allocation of Transmission Costs; SPP Administrative Fees; Load Dispatching Expenses; Uncollectible Expense | 3/10/2020 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 19-00315-UT | Direct | NM | Time-Differentiated Fuel Factor | 3/6/2020 |
| SOUTHERN PIONEER ELECTRIC COMPANY | Western Kansas Industrial Electric Consumers | 20-SPEE-169-RTS | Direct | KS | Class Revenue Allocation | 3/2/2020 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 49831 | Direct | TX | Schedule 11 Expenses; Depreciation Expense (Rev. Req. Phase Testimony) | 2/10/2020 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 49831 | Direct | TX | Class-Cost-of-Service Study; Class Revenue Allocation; Rate Design (Rate Design Phase Testimony) | 2/10/2020 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 19-00134-UT | Direct | NM | Renewable Portfolio Standard Rider | 2/5/2020 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 19-00170-UT | Settlement | NM | Settlement Support of Rate Design, Cost Allocation and Revenue Requirement | 1/20/2020 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 49737 | Direct | TX | Certificate of Convenience and Necessity | 1/14/2020 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 19-00170-UT | Rebuttal | NM | Class Cost-of-Service Study; Class Revenue Allocation | 12/20/2019 |
| ALABAMA POWER COMPANY | Alabama Industrial Energy Consumers | 32953 | Direct | AL | Certificate of Convenience and Necessity | 12/4/2019 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 19-00170-UT | Direct | NM | Class Cost-of-Service Study; Class Revenue Allocation; Rate Design | 11/22/2019 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 49616 | Cross | TX | Contest proposed changes in the Fuel Factor Formula | 10/17/2019 |
| GEORGIA POWER COMPANY | Georgia Association of Manufacturers and Georgia Industrial Group | 42516 | Direct | GA | Return on Equity; Capital Structure; Coal Combustion Residuals Recovery; Class Revenue Allocation; Rate Design | 10/17/2019 |
| NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION | Multiple Intervenors | 19-E-0378 / 19-G-0379<br>19-E-0380 / 19-G-0381 | Rebuttal | NY | Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design | 10/15/2019 |

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|---|---|---|---|---|---|---|
| NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION | Multiple Intervenors | 19-E-0378 / 19-G-0379 19-E-0380 / 19-G-0381 | Direct | NY | Electric and Gas Embedded Cost of Service; Class Revenue Allocation; Rate Design; Amortization of Regulatory Liabilties; AMI Cost Allocation | 9/20/2019 |
| AEP TEXAS INC. | Texas Industrial Energy Consumers | 49494 | Cross-Rebuttal | TX | ERCOT 4CPs; Class Revenue Allocation; Customer Support Costs | 8/13/2019 |
| AEP TEXAS INC. | Texas Industrial Energy Consumers | 49494 | Direct | TX | Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Transmission Line Extensions | 7/25/2019 |
| CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC | Texas Industrial Energy Consumers | 49421 | Cross-Rebuttal | TX | Class Cost-of-Service Study | 6/19/2019 |
| CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC | Texas Industrial Energy Consumers | 49421 | Direct | TX | Class Cost-of-Service Study; Rate Design; Transmission Service Facilities Extensions | 6/6/2019 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 48973 | Direct | TX | Prudence of Solar PPAs, Imputed Capacity, treatment of margins from Off-System Sales | 5/21/2019 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20322 | Rebuttal | MI | Classification of Distribution Mains; Allocation of Working Gas in Storage and Storage | 4/29/2019 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20322 | Direct | MI | Class Cost-of-Service Study; Transportation Rate Design | 4/5/2019 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 49042 | Cross-Rebuttal | TX | Transmsision Cost Recovery Factor | 3/21/2019 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 49057 | Direct | TX | Transmsision Cost Recovery Factor | 3/18/2019 |
| DUKE ENERGY PROGRESS, LLC | Nucor Steel - South Carolina | 2018-318-E | Direct | SC | Class Cost-of-Service Study, Class Revenue Allocation, LGS Rate Design, Depreciation Expense | 3/4/2019 |
| ENTERGY ARKANSAS, LLC | Arkansas Electric Energy Consumers, Inc. | 18-037 | Settlement | AR | Testimony in Support of Settlement | 3/1/2019 |
| ENERGY+ INC. | Toyota Motor Manufacturing Canada | EB-2018-0028 | Updated Evidence | ON | Class Cost-of-Service Study, Distribution and Standby Distribution Rate Design | 2/15/2019 |
| ENTERGY ARKANSAS, LLC | Arkansas Electric Energy Consumers, Inc. | 18-037 | Surrebuttal | AR | Solar Energy Purchase Option Tariff | 2/14/2019 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 48847 | Direct | TX | Fuel Factor Formulas | 1/11/2019 |
| ENTERGY ARKANSAS, LLC | Arkansas Electric Energy Consumers, Inc. | 18-037 | Direct | AR | Solar Energy Purchase Option Tariff | 1/10/2019 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20165 | Direct | MI | Integrated Resources Plan; Projected Rate Impact, Risk Assessment; Early Retirement of Coal Units; Financial Compensation Mechanism | 10/15/2018 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20134 | Rebuttal | MI | Class Cost-of-Service Study; Average Historical Profile; Distribution Cost Classification and Allocation; Rate Design | 10/1/2018 |

# APPENDIX B
## Testimony Filed in Regulatory Proceedings
## by Jeffry Pollock

| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| ENERGY+ INC. | Toyota Motor Manufacturing Canada | EB-2018-0028 | Initial Evidence | ON | Class Cost-of-Service Study, Distribution and Standby Distribution Rate Design | 9/27/2018 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-20134 | Direct | MI | Investment Recovery Mechanism, Litigation surcharge, Class Cost-of-Service Study, Class Revenue Allocation, Rate Design | 9/10/2018 |
| KANSAS GAS AND ELECTRIC COMPANY | Occidental Chemical Corporation | 18-KG&E-303-CON | Rebuttal | KS | Benefits of the Interruptible Load Provided in the Special Contract | 8/29/2018 |
| TEXAS-NEW MEXICO POWER COMPANY | Texas Industrial Energy Consumers | 48401 | Cross-Rebuttal | TX | 4CP Moderation Adjustment | 8/28/2018 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 48371 | Cross-Rebuttal | TX | Class Cost-of-Service Study; Schedule FERC | 8/16/2018 |
| TEXAS-NEW MEXICO POWER COMPANY | Texas Industrial Energy Consumers | 48401 | Direct | TX | Tax Cuts and Jobs Act; Rider TCRF; 4CP Moderation Adjustment | 8/13/2018 |
| PECO ENERGY COMPANY | Philadelphia Area Industrial Energy Users Group | 2018-3000164 | Surrebuttal | PA | Post Test-Year Adjustment; Tax Cuts and Jobs Act; Class Cost-of-Service Study; Distribution System Improvement Charge | 8/8/2018 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 48371 | Direct | TX | Revenue Requirements; Tax Cuts and Jobs Act; Riders | 8/1/2018 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 48371 | Direct | TX | Class Cost-of-Service Study; Firm, Interruptible and Standby Rate Design | 8/1/2018 |
| PECO ENERGY COMPANY | Philadelphia Area Industrial Energy Users Group | 2018-3000164 | Rebuttal | PA | Class Cost-of-Service Study; Class Revenue Allocation | 7/24/2018 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 48233 | Cross-Rebuttal | TX | Allocation of TCJA reduction | 7/19/2018 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 48233 | Direct | TX | Allocation of TCJA reduction | 7/5/2018 |
| PECO ENERGY COMPANY | Philadelphia Area Industrial Energy Users Group | 2018-3000164 | Direct | PA | Post Test-Year Adjustment; Tax Cuts and Jobs Act; Class Cost-of-Service Study; Class Revenue Allocation | 6/26/2018 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 47527 | Cross-Rebuttal | TX | Class Cost-of-Service Study; Revenue Allocation | 5/22/2018 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 17-00255-UT | Rebuttal | NM | Class Cost-of-Service Study; Revenue Allocation | 5/2/2018 |
| ENTERGY ARKANSAS, INC. | Arkansas Electric Energy Consumers, Inc. | 17-041 | Stipulation | AR | Support of Stipulation | 4/27/2018 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 47527 | Direct | TX | Present Base Revenues<br>Class Cost-of-Service Study; Class Revenue Allocation; Rate Design | 4/25/2018 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 47527 | Direct | TX | Tax Cuts and Jobs Act; SPP Transmission and Wheeling Costs; Depreciation Rate; LLPPAs; Imputed Capacity; Off-System Sales Margins | 4/25/2018 |

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| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 17-00255-UT | Direct | NM | Class Cost-of-Service Study; Revenue Requirements; Revenue Allocation | 4/13/2018 |
| ENTERGY ARKANSAS, INC. | Arkansas Electric Energy Consumers, Inc. | 17-041 | Surrebuttal | AR | Certificate of Convenience and Necessity | 4/6/2018 |
| METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY, PENNSYLVANIA POWER COMPANY AND WEST PENN POWER COMPANY | MEIUG, PICA and WPPII | 2017-2637855<br>2017-2637857<br>2017-2637858<br>2017-2637866 | Rebuttal | PA | Recovery of NITS Charges | 3/22/2018 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 46936 | 2nd Supplemental Direct | TX | Support of Stipulation | 3/2/2018 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-18424 | Direct | MI | Class Cost of Service | 2/28/2018 |
| ENTERGY ARKANSAS, INC. | Arkansas Electric Energy Consumers, Inc. | 17-041 | Direct | AR | Certificate of Convenience and Necessity | 2/23/2018 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 47553 | Direct | TX | Off-System Sales Margins; Renewable Energy Credits | 2/20/2018 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 47461 | 2nd Supplemental Direct | TX | Certificate of Convenience and Necessity | 2/7/2018 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 47461 | Supplemental Direct | TX | Certificate of Convenience and Necessity | 1/4/2018 |
| CENTRAL HUDSON GAS & ELECTRIC | Multiple Intervenors | 17-E-0459/G-0460 | Rebuttal | NY | Electric and Gas Embedded Class Cost of Service; Class Revenue Allocation; Gas Rate Design; Revenue Decoupling Mechanism | 12/18/2017 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 17-00044-UT | Supplemental Direct | NM | Support of Unanimous Comprehensive Stipulation | 12/11/2017 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 47461 | Direct | TX | Certificate of Convenience and Necessity | 12/4/2017 |
| CENTRAL HUDSON GAS & ELECTRIC | Multiple Intervenors | 17-E-0459/G-0460 | Direct | NY | Electric and Gas Embedded Class Cost of Service; Class Revenue Allocation; Customer Charges; Revenue Decoupling Mechanism; Carbon Program and EAM | 11/21/2017 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 17-00044-UT | Direct | NM | Certificate of Convenience and Necessity | 10/24/2017 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 46936 | Cross-Rebuttal | TX | Certificate of Convenience and Necessity | 10/23/2017 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 46936 | Supplemental Direct | TX | Certificate of Convenience and Necessity | 10/6/2017 |
| KENTUCKY POWER COMPANY | Kentucky League of Cities | 2017-00179 | Direct | KY | Class Cost-of-Service Study; Class Revenue Allocation | 10/3/2017 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 46936 | Direct | TX | Certificate of Convenience and Necessity | 10/2/2017 |

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| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| NIAGARA MOHAWK POWER CORP. | Multiple Intervenors | 17-E-0238 / 17-G-0239 | Rebuttal | NY | Electric/Gas Embedded Class Cost of Service; Class Revenue Allocation; Electric/Gas Rate Design | 9/15/2017 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-18322 | Rebuttal | MI | Class Cost-of-Service Study, Rate Design | 9/7/2017 |
| PENNSYLVANIA-AMERICAN WATER COMPANY | Pennsylvania-American Water Large Users Group | R-2017-2595853 | Rebuttal | PA | Rate Design | 8/31/2017 |
| NIAGARA MOHAWK POWER CORP. | Multiple Intervenors | 17-E-0238 / 17-G-0239 | Direct | NY | Electric/Gas Embedded Class Cost of Service; Class Revenue Allocation; Electric/Gas Rate Design, Electric/Gas Rate Modifiers, AMI Cost Allocation | 8/25/2017 |
| CONSUMERS ENERGY COMPANY | Association of Businesses Advocating Tariff Equity | U-18322 | Direct | MI | Revenue Requirement, Class Cost-of-Service Study, Rate Design | 8/10/2017 |
| FLORIDA POWER & LIGHT COMPANY, DUKE ENERGY FLORIDA, LLC, AND TAMPA ELECTRIC COMPANY | Florida Industrial Power Users Group | 170057 | Direct | FL | Fuel Hedging Practices | 8/10/2017 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 46449 | Cross-Rebuttal | TX | Class Revenue Allocation and Rate Design | 5/19/2017 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 46449 | Direct | TX | Revenue Requirement, Class Cost-of-Service Study, Class Revenue Allocation and Rate Design | 4/25/2017 |
| KENTUCKY UTILITIES COMPANY | Kentucky League of Cities | 2016-00370 | Supplemental Direct | KY | Class Cost-of-Service Study; Class Revenue Allocation | 4/14/2017 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 46416 | Direct | TX | Certificate of Convenience and Necessity - Montgomery County Power Station | 3/31/2017 |
| SHARYLAND UTILITIES, L.P. | Texas Industrial Energy Consumers | 45414 | Cross-Rebuttal | TX | Cost Allocation Issues; Class Revenue Allocation | 3/16/2017 |
| ENTERGY LOUISIANA, LLC | Occidental Chemical Corporation | U-34283 | Direct* | LA | Approval to Construct Lake Charles Power Station | 3/13/2017 |
| LOUISVILLE GAS AND ELECTRIC COMPANY | Louisville/Jefferson Metro Government | 2016-00371 | Direct | KY | Revenue Requirement Issues; Class Cost-of-Service Study Electric/Gas; Class Revenue Allocation Electric/Gas | 3/3/2017 |
| KENTUCKY UTILITIES COMPANY | Kentucky League of Cities | 2016-00370 | Direct | KY | Revenue Requirement Issues; Class Cost-of-Service Study; Class Revenue Allocation | 3/3/2017 |
| SHARYLAND UTILITIES, L.P. | Texas Industrial Energy Consumers | 45414 | Direct | TX | Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; TCRF Allocation Factors; McAllen Division Deferrals | 2/28/2017 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 46025 | Direct | TX | Long-Term Purchased Power Agreements | 12/12/2016 |

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| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| NORTHERN STATES POWER COMPANY | Xcel Large Industrials | 15-826 | Surrebuttal | MN | Settlement, Cost-of-Service Study, Class Revenue Allocation, Interruptible Rates, Renew-A-Source | 10/18/2016 |
| NORTHERN STATES POWER COMPANY | Xcel Large Industrials | 15-826 | Rebuttal | MN | Class Cost-of-Service Study, Class Revenue Allocation | 9/23/2016 |
| VICTORY ELECTRIC COOPERATION ASSOCIATION, INC. | Western Kansas Industrial Electric Consumers | 16-VICE-494-TAR | Surrebuttal | KS | Formula-Based Rate Plan | 9/22/2016 |
| NATIONAL FUEL GAS DISTRIBUTION CORPORATION | Multiple Intervenors | 16-G-0257 | Rebuttal | NY | Embedded Class Cost of Service; Class Revenue Allocation; Rate Design | 9/16/2016 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 45524 | Cross-Rebuttal | TX | Class Cost-of-Service Study; | 9/7/2016 |
| METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER | MEIUG, PICA and WPPII | 2016-2537349<br>2016-2537352<br>2016-2537359 | Surrebuttal | PA | Post-Test Year Sales Adjustment; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design | 8/31/2016 |
| VICTORY ELECTRIC COOPERATION ASSOCIATION, INC. | Western Kansas Industrial Electric Consumers | 16-VICE-494-TAR | Direct | KS | Formula-Based Rate Plan | 8/30/2016 |
| WESTERN COOPERATIVE ELECTRIC ASSOCIATION, INC. | Western Kansas Industrial Electric Consumers | 16-WSTE-496-TAR | Direct | KS | Formula-Based Rate Plan and Debt Service Payments | 8/30/2016 |
| NATIONAL FUEL GAS DISTRIBUTION CORPORATION | Multiple Intervenors | 16-G-0257 | Direct | NY | Embedded Class Cost of Service; Class Revenue Allocation; Rate Design | 8/26/2016 |
| METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER | MEIUG, PICA and WPPII | 2016-2537349<br>2016-2537352<br>2016-2537359 | Rebuttal | PA | Class Cost-of-Service; Class Revenue Allocation | 8/17/2016 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 45524 | Direct | TX | Revenue Requirement; Class Cost-of-Service; Revenue Allocation; Rate Design | 8/16/2016 |
| METROPOLITAN EDISON COMPANY; PENNSYLVANIA ELECTRIC COMPANY AND WEST PENN POWER | MEIUG, PICA and WPPII | 2016-2537349<br>2016-2537352<br>2016-2537359 | Direct | PA | Post-Test Year Sales Adjustment; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design | 7/22/2016 |
| FLORIDA POWER & LIGHT COMPANY | Florida Industrial Power Users Group | 160021 | DIrect | FL | Multi-Year Rate Plan, Construction Work in Progress; Cost of Capital; Class Revenue Allocation; Class Cost-of-Service Study; Rate Design | 7/7/2016 |
| CENTERPOINT ENERGY ARKANSAS GAS | Arkansas Gas Consumers, Inc. | 15-098-U | Supplemental | AR | Support for Settlement Stipulation | 7/1/2016 |
| MIDAMERICAN ENERGY COMPANY | Tech Customers | RPU-2016-0001 | Direct | IA | Application of Advanced Ratemaking Principles to Wind XI | 6/21/2016 |
| NORTHERN STATES POWER COMPANY | Xcel Large Industrials | 15-826 | Direct | MN | Class Cost-of-Service Study, Class Revenue Allocation, Multi-Year Rate Plan, Rate Design | 6/14/2016 |

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| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| CENTERPOINT ENERGY ARKANSAS GAS | Arkansas Gas Consumers, Inc. | 15-098-U | Surrebuttal | AR | Incentive Compensation, Class Cost-of-Service Study, Class Revenue Allocation, LCS-1 Rate Design | 6/7/2016 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 15-00296-UT | Direct | NM | Support of Stipulation | 5/13/2016 |
| CHEYENNE LIGHT, FUEL AND POWER COMPANY | Dyno Nobel, Inc. and HollyFrontier Cheyenne Refining LLC | 20003-146-ET-15 | Cross | WY | Large Power Contract Service Tariff | 4/15/2016 |
| CENTERPOINT ENERGY ARKANSAS GAS | Arkansas Gas Consumers, Inc. | 15-098-U | Direct | AR | Incentive Compensation, Class Cost-of-Service Study, Class Revenue Allocation, Act 725, Formula Rate Plan | 4/14/2016 |
| CHEYENNE LIGHT, FUEL AND POWER COMPANY | Dyno Nobel, Inc. and HollyFrontier Cheyenne Refining LLC | 20003-146-ET-15 | Direct | WY | Large Power Contract Service Tariff | 3/18/2016 |
| ENTERGY LOUISIANA, LLC, ENTERGY GULF STATES LOUISIANA, L.L.C., AND ENTERGY LOUISIANA POWER, LLC | Occidental Chemical Corporation | U-33770 | Cross-Answering | LA | Approval to Construct St. Charles Power Station | 2/26/2016 |
| NORTHERN INDIANA PUBLIC SERVICE COMPANY | NLMK-Indiana | 44688 | Cross-Answering | IN | Cost-of-Service Study, Rider 775 | 2/16/2016 |
| ENTERGY LOUISIANA, LLC, ENTERGY GULF STATES LOUISIANA, L.L.C., AND ENTERGY LOUISIANA POWER, LLC | Occidental Chemical Corporation | U-33770 | Direct | LA | Approval to Construct St. Charles Power Station | 1/21/2016 |
| EL PASO ELECTRIC COMPANY | Freeport-McMoRan Copper & Gold, Inc. | 44941 | Cross-Rebuttal | TX | Class Cost-of-Service Study, Class Revenue Allocation; Rate Design | 1/15/2016 |
| ENTERGY ARKANSAS, INC. | Arkansas Electric Energy Consumers, Inc. | 15-015 | Supplemental | AR | Support for Settlement Stipulation | 12/31/2015 |
| EL PASO ELECTRIC COMPANY | Freeport-McMoRan Copper & Gold, Inc. | 44941 | Direct | TX | Class Cost-of-Service Study, Class Revenue Allocation; Rate Design | 12/11/2015 |
| ENTERGY ARKANSAS, INC. | Arkansas Electric Energy Consumers, Inc. | 15-015 | Surrebuttal | AR | Post-Test-Year Additions; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Riders; Formula Rate Plan | 11/24/2015 |
| MID-KANSAS ELECTRIC COMPANY, LLC, PRAIRIE LAND ELECTRIC COOPERATIVE, INC., SOUTHERN PIONEER ELECTRIC COMPANY, THE VICTORY ELECTRIC COOPERATIVE ASSOCIATION, INC., AND WESTERN COOPERATIVE ELECTRIC ASSOCIATION, INC. | Western Kansas Industrial Electric Consumers | 16-MKEE-023 | Direct | KS | Formula Rate Plan for Distribution Utility | 11/17/2015 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 45084 | Direct | TX | Transmission Cost Recovery Factor Revenue Increase. | 11/17/2015 |
| GEORGIA POWER COMPANY | Georgia Industrial Group and Georgia Association of Manufacturers | 39638 | Direct | GA | Natural Gas Price Assumptions, IFR Mechanism, Seasonal FCR-24 Rates, Imputed Capacity | 11/4/2015 |
| NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION | Multiple Intervenors | 15-E-0283<br>15-G-0284<br>15-E-0285<br>15-G-0286 | Rebuttal | NY | Electric and Gas Embedded Class Cost-of-Service Studies, Class Revenue Allocation | 10/13/2015 |

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|---|---|---|---|---|---|---|
| ENTERGY ARKANSAS, INC. | Arkansas Electric Energy Consumers, Inc. | 15-015 | Direct | AR | Post-Test-Year Additions; Class Cost-of-Service Study; Class Revenue Allocation; Rate Design; Riders; Formula Rate Plan | 9/29/2015 |
| NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION | Multiple Intervenors | 15-E-0283<br>15-G-0284<br>15-E-0285<br>15-G-0286 | Direct | NY | Electric and Gas Embedded Class Cost-of-Service Studies, Class Revenue Allocation, Electric Rate Design | 9/15/2015 |
| SHARYLAND UTILITIES | Texas Industrial Energy Consumers | 44620 | Cross-Rebuttal | TX | Transmission Cost Recovery Factor Class Allocation Factors. | 9/8/2015 |
| ENTERGY ARKANSAS, INC. | Arkansas Electric Energy Consumers, Inc. | 14-118 | Surrebuttal | AR | Proposed Acquisition of Union Power Station Power Block 2 and Cost Recovery | 8/21/2015 |
| SHARYLAND UTILITIES | Texas Industrial Energy Consumers | 44620 | Direct | TX | Transmission Cost Recovery Factor Class Allocation Factors | 8/7/2015 |
| PECO ENERGY COMPANY | Philadelphia Area Industrial Energy Users Group | 2015-2468981 | Surrebuttal | PA | Class Cost-of-Service,  Capacity Reservation Rider | 8/4/2015 |
| WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO. | Occidental Chemical Corporation | 15-WSEE-115-RTS | Cross-Answering | KS | Class Cost-of-Service Study, Revenue Allocation | 7/22/2015 |
| PECO ENERGY COMPANY | Philadelphia Area Industrial Energy Users Group | 2015-2468981 | Rebuttal | PA | Class Cost-of-Service, Class Revenue Allocation, Rate Design, Capacity Reservation Rider, Revenue Deoupling | 7/21/2015 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Occidental Permian Ltd. | 15-00083 | Direct | NM | Long-Term Purchased Power Agreements | 7/10/2015 |
| ENTERGY ARKANSAS, INC. | Arkansas Electric Energy Consumers, Inc. | 15-014 | Surrebuttal | AR | Solar Power Purchase  Agreement | 7/10/2015 |
| WESTAR ENERGY INC. and KANSAS GAS & ELECTRIC CO. | Occidental Chemical Corporation | 15-WSEE-115-RTS | Direct | KS | Class Cost-of-Service and Electric Distrbution Grid Resiliency Program | 7/9/2015 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 43958 | Supplemental DIrect | TX | Certificiate of Need for Union Power Station Power Block 1 | 7/7/2015 |
| ENTERGY ARKANSAS, INC. | Arkansas Electric Energy Consumers, Inc. | 14-118 | Direct | AR | Proposed Acquisition of Union Power Station Power Block 2 and Cost Recovery | 7/2/2015 |
| PECO ENERGY COMPANY | Philadelphia Area Industrial Energy Users Group | 2015-2468981 | Direct | PA | Class Cost-of-Service, Class Revenue Allocation, Rate Design, Capacity Reservation Rider | 6/23/2015 |
| ENTERGY ARKANSAS, INC. | Arkansas Electric Energy Consumers, Inc. | 15-014-U | Direct | AR | Solar Power Purchase  Agreement | 6/19/2015 |
| FLORIDA POWER & LIGHT COMPANY | Florida Industrial Power Users Group | 150075 | Direct | FL | Cedar Bay Power Purchase Agreement | 6/8/2015 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 43695 | Cross-Rebuttal | TX | Class Cost of Service Study; Class Revenue Allocation | 6/8/2015 |

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| UTILITY | ON BEHALF OF | DOCKET | TYPE | STATE / PROVINCE | SUBJECT | DATE |
|---|---|---|---|---|---|---|
| FLORIDA POWER AND LIGHT COMPANY, DUKE ENERGY FLORIDA, GULF POWER COMPANY, TAMPA ELECTRIC COMPANY | Florida Industrial Power Users Group | 140226 | Surrebuttal | FL | Opt-Out Provision | 5/20/2015 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 43695 | Direct | TX | Post-Test Year Adjustments; Weather Normalization | 5/15/2015 |
| SOUTHWESTERN PUBLIC SERVICE COMPANY | Texas Industrial Energy Consumers | 43695 | Direct | TX | Class Cost of Service Study; Class Revenue Allocation | 5/15/2015 |
| ENTERGY TEXAS, INC. | Texas Industrial Energy Consumers | 43958 | Direct | TX | Certificiate of Need for Union Power Station Power Block 1 | 4/29/2015 |
| SOUTHWESTERN ELECTRIC POWER COMPANY | Texas Industrial Energy Consumers | 42370 | Cross-Rebuttal | TX | Allocation and recovery of Municipal Rate Case Expenses and the proposed Rate-Case-Expense Surcharge Tariff. | 1/27/2015 |
| WEST PENN POWER COMPANY | West Penn Power Industrial Intervenors | 2014-2428742 | Surrebuttal | PA | Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider | 1/6/2015 |
| PENNSYLVANIA ELECTRIC COMPANY | Penelec Industrial Customer Alliance | 2014-2428743 | Surrebuttal | PA | Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider | 1/6/2015 |
| METROPOLITAN EDISON COMPANY | Med-Ed Industrial Users Group | 2014-2428745 | Surrebuttal | PA | Class Cost-of-Service Study; Class Revenue Allocation; Large Commercial and Industrial Rate Design; Storm Damage Charge Rider | 1/6/2015 |

## APPENDIX C

## Procedures and Key Principles of a CCOSS

**Q WHAT PROCEDURES ARE USED IN A COST-OF-SERVICE STUDY?**

A The basic procedure for conducting a CCOSS is fairly simple. First, we identify the different types of costs (functionalization), determine their primary causative factors (classification), and then apportion each item of cost among the various rate classes (allocation). Adding up the individual pieces gives the total cost for each class.

Identifying the utility's different levels of operation is a process referred to as functionalization. The utility's investments and expenses are separated into production, transmission, distribution, and other functions. To a large extent, this is done in accordance with the Uniform System of Accounts developed by FERC.

Once costs have been functionalized, the next step is to identify the primary causative factor (or factors). This step is referred to as classification. Costs are classified as demand-related, energy-related or customer-related. Demand (or capacity) related costs vary with peak demand, which is measured in kilowatts (kWs). This includes production, transmission, and some distribution investment and related fixed O&M expenses. As explained later, peak demand determines the amount of capacity needed for reliable service. Energy-related costs vary with the production of energy, which is measured in kilowatt-hours (kWhs). Energy-related costs include fuel and variable O&M expense. Customer-related costs vary directly with the number of customers and include expenses such as meters, service drops, billing, and customer service.

Each functionalized and classified cost must then be allocated to the various customer classes. This is accomplished by developing allocation factors that reflect the percentage of the total cost that should be paid by each class. The allocation factors should reflect cost-causation; that is, the degree to which each class caused the utility to incur the cost.

**Q WHAT KEY PRINCIPLES ARE RECOGNIZED IN A CLASS COST-OF-SERVICE STUDY?**

A A properly conducted CCOSS recognizes several key cost-causation principles. First, customers are served at different delivery voltages. This affects the amount of investment the utility must make to deliver electricity to the meter. Second, since cost-causation is also related to how electricity is used, both the timing and rate of energy consumption (i.e., demand) are critical. Because electricity cannot be stored for any significant time period, a utility must acquire sufficient generation resources and construct the required transmission facilities to meet the maximum projected demand, including a reserve margin as a contingency against forced and unforced outages, severe weather, and load forecast error. Customers that use electricity during the critical peak hours cause the utility to invest in generation and transmission facilities. Finally, customers who self-serve all or a portion of their power needs from BTMG will have dramatically different load characteristics than customers who purchase all or most of the power from the utility. Thus, they should be costed separately.

**Q WHAT FACTORS CAUSE THE PER-UNIT COSTS TO DIFFER AMONG CUSTOMER CLASSES?**

A Factors that affect the per-unit cost include whether a customer's usage is constant or fluctuating (load factor), whether the utility must invest in transformers and distribution systems to provide the electricity at lower voltage levels, the amount of electricity that a customer uses, and the quality of service (*e.g.,* firm or non-firm). In general, industrial consumers are less costly to serve on a per-unit basis because they:

- Operate at higher load factors;
- Take service at higher delivery voltages; and
- Use more electricity per customer.

Further, non-firm service is a lower quality of service than firm service. Thus, non-firm service is less costly per unit than firm service for customers that otherwise have the same characteristics. This explains why some customers pay lower average rates than others.

For example, the difference in the losses incurred to deliver electricity at the various delivery voltages is a reason why the per-unit energy cost to serve is not the same for all customers. More losses occur to deliver electricity at distribution voltage (either primary or secondary) than at transmission voltage, which is generally the level at which industrial customers take service. This means that the cost per kWh is lower for a transmission customer than a distribution customer. The cost to deliver a kWh at primary distribution, though higher than the per-unit cost at transmission, is lower than the delivered cost at secondary distribution.

In addition to lower losses, transmission customers do not use the distribution system. Instead, transmission customers construct and own their own distribution systems. Thus, distribution system costs are not allocated to transmission level customers who do not use that system. Distribution customers, by contrast, require substantial investments in these lower voltage facilities to provide service. Secondary distribution customers require more investment than either primary distribution or primary substation customers. More investment is required to serve a primary distribution than a primary substation customer. This results in a different cost to serve each type of customer.

Two other cost drivers are efficiency and size. These drivers are important because most fixed costs are allocated on either a demand or customer basis. Efficiency can be measured in terms of load factor. Load factor is the ratio of Average Demand (*i.e.*, energy usage divided by the number of hours in the period) to peak demand. A customer that operates at a high load factor is more efficient than a lower load factor customer because it requires less capacity for the same amount of energy. For example, assume that two customers purchase the same amount of energy, but one customer has an 80% load factor and the other has a 40% load factor. The 40% load factor customers would have twice the peak demand of the 80% load factor customers, and the utility would therefore require twice as much capacity to serve the 40% load factor customer as the 80% load factor. Said differently, the fixed costs to serve a high load factor customer are spread over more kWh usage than for a low load factor customer.

**BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION**

| | |
|---|---|
| **In re: Petition for rate increase by Florida Power & Light Company** | **DOCKET NO. 20210015-EI**<br>**Filed: June 21, 2021** |

## AFFIDAVIT OF JEFFRY POLLOCK

State of Missouri )
) SS
County of St. Louis )

Jeffry Pollock, being first duly sworn, on his oath states:

1. My name is Jeffry Pollock. I am President of J. Pollock, Incorporated, 12647 Olive Blvd., Suite 585, St. Louis, Missouri 63141. We have been retained by Florida Industrial Power Users Group to testify in this proceeding on its behalf;

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony and Exhibits, which have been prepared in written form for introduction into evidence in Florida Public Service Commission Docket No. 20210015-EI; and,

3. I hereby swear and affirm that the answers contained in my testimony and the information in my exhibits are true and correct.

Jeffry Pollock

Subscribed and sworn to before me this 21st day of June 2021.

Kitty Turner, Notary Public
Commission #: 15390610

My Commission expires on April 25, 2023.

KITTY TURNER
Notary Public - Notary Seal
State of Missouri
Commissioned for Lincoln County
My Commission Expires: April 25, 2023
Commission Number: 15390610

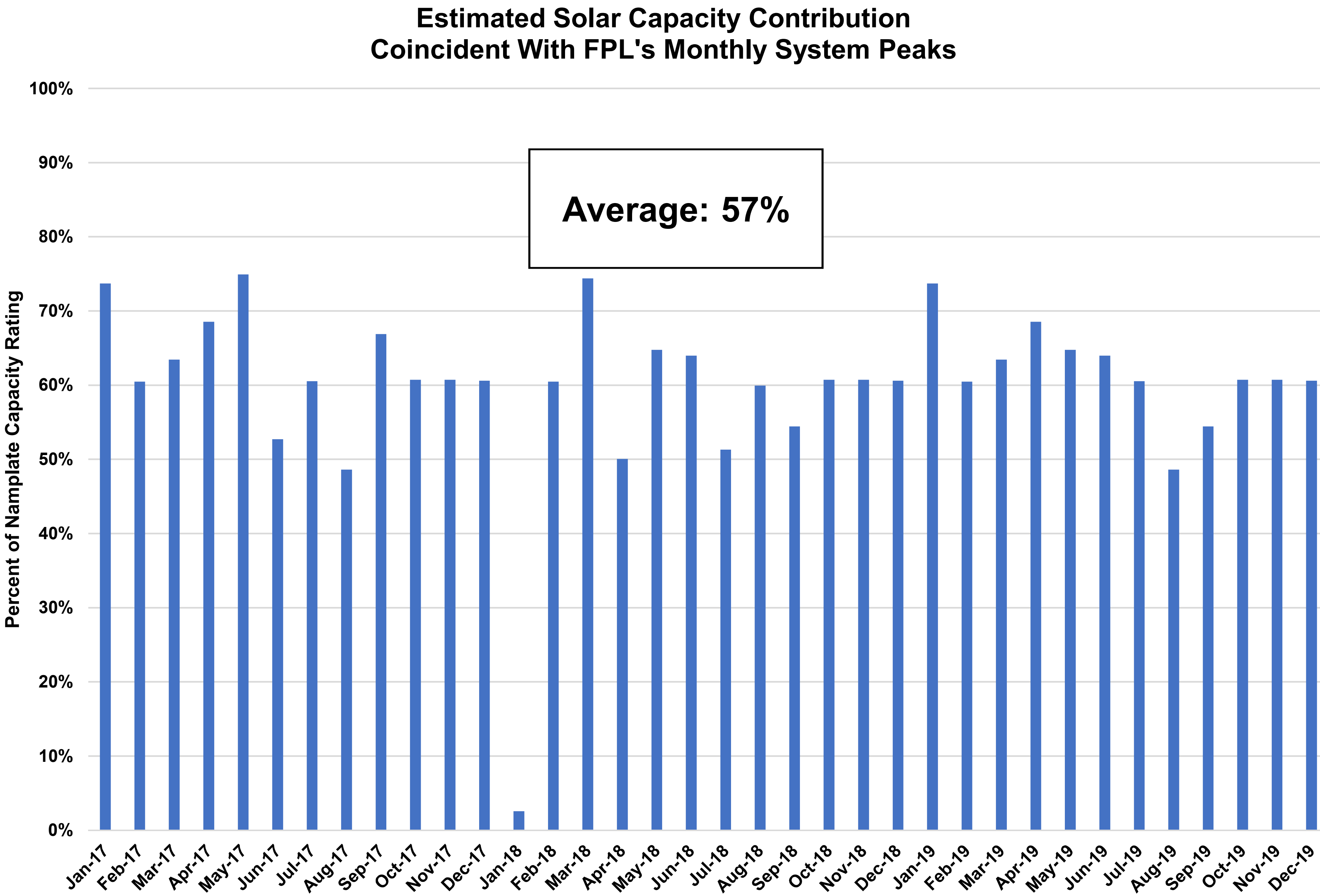
# FLORIDA POWER & LIGHT COMPANY

## Projected Summer and Winter Reserve Margins
## Assuming 2024 Solar Additions Deferred Until 2025
## 2021 - 2030

| Line | Year | Projected Peak Demand (MW) | Non-Firm Load (MW) | Projected Firm Peak Demand (MW) | Adjusted Firm Capacity* (MW) | Adjusted Reserve Margin (%) |
|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) |
| | **Summer** | | | | | |
| 1 | 2021 | 27,083 | 1,827 | 25,256 | 31,820 | **26.0%** |
| 2 | 2022 | 27,277 | 1,886 | 25,391 | 32,096 | **26.4%** |
| 3 | 2023 | 27,771 | 1,943 | 25,828 | 31,731 | **22.9%** |
| 4 | 2024 | 28,278 | 2,006 | 26,272 | 31,441 | **19.7%** |
| 5 | 2025 | 28,675 | 2,050 | 26,625 | 32,486 | **22.0%** |
| 6 | 2026 | 29,051 | 2,084 | 26,967 | 33,030 | **22.5%** |
| 7 | 2027 | 29,340 | 2,118 | 27,222 | 33,499 | **23.1%** |
| 8 | 2028 | 29,721 | 2,152 | 27,569 | 34,147 | **23.9%** |
| 9 | 2029 | 30,233 | 2,186 | 28,047 | 35,125 | **25.2%** |
| 10 | 2030 | 30,832 | 2,221 | 28,611 | 36,203 | **26.5%** |
| | **Winter** | | | | | |
| 11 | 2021 | 22,242 | 1,371 | 20,871 | 32,564 | **56.0%** |
| 12 | 2022 | 22,461 | 1,406 | 21,055 | 31,643 | **50.3%** |
| 13 | 2023 | 22,869 | 1,443 | 21,426 | 33,296 | **55.4%** |
| 14 | 2024 | 23,287 | 1,482 | 21,805 | 32,042 | **46.9%** |
| 15 | 2025 | 23,624 | 1,527 | 22,097 | 33,076 | **49.7%** |
| 16 | 2026 | 23,957 | 1,556 | 22,401 | 33,623 | **50.1%** |
| 17 | 2027 | 24,199 | 1,585 | 22,614 | 34,093 | **50.8%** |
| 18 | 2028 | 24,552 | 1,615 | 22,937 | 34,733 | **51.4%** |
| 19 | 2029 | 24,916 | 1,644 | 23,272 | 35,712 | **53.5%** |
| 20 | 2030 | 25,289 | 1,673 | 23,616 | 36,789 | **55.8%** |

**Source:** Ten Year Power Plant Site Plan 2021 - 2030 (Schedules 1, 7 and 8).

***** Firm Capacity Includes Solar at 57% of Nameplate Capacity (page 2).


Estimated Solar Capacity Contribution
Coincident With FPL's Monthly System Peaks
Average: 57%
Percent of Namplate Capacity Rating
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Jan-17 Feb-17 Mar-17 Apr-17 May-17 Jun-17 Jul-17 Aug-17 Sep-17 Oct-17 Nov-17 Dec-17 Jan-18 Feb-18 Mar-18 Apr-18 May-18 Jun-18 Jul-18 Aug-18 Sep-18 Oct-18 Nov-18 Dec-18 Jan-19 Feb-19 Mar-19 Apr-19 May-19 Jun-19 Jul-19 Aug-19 Sep-19 Oct-19 Nov-19 Dec-19

# FLORIDA POWER & LIGHT COMPANY
## FRCC Projected Summer and Winter Peak Reserve Margins
## Excluding the 2024 Solar Plant Additions
## 2019-2029

| | | | FRCC Base Case | | | | 2024 Solar Additions Deferred To 2025 | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Line | Year | Net Firm Peak Demand (MW) | Total Available Capacity (MW) | Firm Solar Capability (MW) | Reserve Margin (MW) | Reserve Margin (%) | Total Available Capacity (MW) | Firm Solar Capability (MW) | Reserve Margin (MW) | Reserve Margin (%) |
| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) |
| | **Summer** | | | | | | | | | |
| 1 | 2020 | 45,349 | 56,365 | 1,260 | 11,016 | **24.3%** | 56,365 | 1,260 | 11,016 | **24.3%** |
| 2 | 2021 | 45,680 | 56,358 | 1,568 | 10,678 | **23.4%** | 56,358 | 1,568 | 10,678 | **23.4%** |
| 3 | 2022 | 48,388 | 61,339 | 1,908 | 12,951 | **26.8%** | 61,339 | 1,908 | 12,951 | **26.8%** |
| 4 | 2023 | 48,862 | 61,374 | 2,117 | 12,512 | **25.6%** | 61,374 | 2,117 | 12,512 | **25.6%** |
| 5 | 2024 | 49,292 | 61,380 | 2,326 | 12,088 | **24.5%** | 61,171 | 2,117 | 11,879 | **24.1%** |
| 6 | 2025 | 49,807 | 61,663 | 2,590 | 11,856 | **23.8%** | 61,663 | 2,590 | 11,856 | **23.8%** |
| 7 | 2026 | 50,358 | 61,962 | 3,012 | 11,604 | **23.0%** | 61,962 | 3,012 | 11,604 | **23.0%** |
| 8 | 2027 | 50,925 | 61,831 | 3,434 | 10,906 | **21.4%** | 61,831 | 3,434 | 10,906 | **21.4%** |
| 9 | 2028 | 51,463 | 62,292 | 3,686 | 10,829 | **21.0%** | 62,292 | 3,686 | 10,829 | **21.0%** |
| 10 | 2029 | 52,236 | 63,425 | 3,880 | 11,189 | **21.4%** | 63,425 | 3,880 | 11,189 | **21.4%** |
| | **Winter** | | | | | | | | | |
| 11 | 2020 | 41,852 | 57,613 | 0 | 15,761 | **37.7%** | 57,613 | 0 | 15,761 | **37.7%** |
| 12 | 2021 | 44,392 | 60,428 | 0 | 16,036 | **36.1%** | 60,428 | 0 | 16,036 | **36.1%** |
| 13 | 2022 | 44,821 | 62,332 | 0 | 17,511 | **39.1%** | 62,332 | 0 | 17,511 | **39.1%** |
| 14 | 2023 | 45,233 | 61,100 | 0 | 15,867 | **35.1%** | 61,100 | 0 | 15,867 | **35.1%** |
| 15 | 2024 | 45,567 | 60,816 | 0 | 15,249 | **33.5%** | 60,816 | 0 | 15,249 | **33.5%** |
| 16 | 2025 | 46,161 | 60,776 | 0 | 14,615 | **31.7%** | 60,776 | 0 | 14,615 | **31.7%** |
| 17 | 2026 | 46,549 | 60,596 | 0 | 14,047 | **30.2%** | 60,596 | 0 | 14,047 | **30.2%** |
| 18 | 2027 | 47,100 | 59,981 | 0 | 12,881 | **27.3%** | 59,981 | 0 | 12,881 | **27.3%** |
| 19 | 2028 | 47,612 | 60,652 | 0 | 13,040 | **27.4%** | 60,652 | 0 | 13,040 | **27.4%** |
| 20 | 2029 | 48,165 | 60,882 | 0 | 12,717 | **26.4%** | 60,882 | 0 | 12,717 | **26.4%** |

**Source:** Florida Reliability Coordinating Council 2020 Regional Load & Resource Plan.

# FLORIDA POWER & LIGHT COMPANY
## CILC Incentive Payments Using Test-Year Assumptions
## Projected Test Year Ending December 31, 2022

| | | | Rate | | | Revenue | | |
|---|---|---|---|---|---|---|---|---|
| Line | TYPE OF CHARGES | UNITS | CILC-1T | GSLD-3 | GSLDT-3 | CILC-1T | GSLD-3 | GSLDT-3 |
| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
| 1 | Customer Charge | 204 | $ 2,341.40 | $ 2,113.52 | $ 2,113.52 | $ 477,646 | $ 431,158 | $ 431,158 |
| 2 | | | | | | | | |
| 3 | Non-Fuel Energy Charge | | | | | | | |
| 4 | On-Peak | 377,272,780 | $ 0.00983 | $ 0.01134 | $ 0.01295 | $ 3,708,591 | $ 4,278,273 | $ 4,885,682 |
| 5 | Off-Peak | 1,127,224,612 | $ 0.00983 | $ 0.01134 | $ 0.01077 | $ 11,080,618 | $ 12,782,727 | $ 12,140,209 |
| 6 | | | | | | | | |
| 7 | Demand Charge | | | | | | | |
| 8 | Load Control On-Peak | 2,108,105 | $ 3.37 | $ 9.83 | $ 9.83 | $ 7,104,314 | $ 20,722,672 | $ 20,722,672 |
| 9 | Firm On-Peak | 573,916 | $ 12.30 | $ 9.83 | $ 9.83 | $ 7,059,167 | $ 5,641,594 | $ 5,641,594 |
| 10 | | | | | | | | |
| 11 | Total | | | | | $ 29,430,336 | $ 43,856,425 | $ 43,821,316 |
| 12 | **CILC-1T Revenue Adjustment** | | | | | $\boxed{\textbf{\$ 14,410,000}}$ | $ 14,426,089 | $ 14,390,980 |

# FLORIDA POWER & LIGHT COMPANY
## CILC Incentive Payments Using Test-Year Assumptions
## Projected Test Year Ending December 31, 2022

| | | | Rate | | | | |
|---|---|---|---|---|---|---|---|
| Line | TYPE OF CHARGES | UNITS | CILC-1D | GSLD-1 | GSLDT-1 | GSLD-2 | GSLDT-2 |
| | | (1) | (2) | (3) | (4) | (5) | (6) |
| 1 | Customer Charge | 3,084 | $ 264.00 | $ 79.40 | $ 79.40 | $ 238.03 | $ 238.03 |
| 2 | | | | | | | |
| 3 | Non-Fuel Energy Charge | | | | | | |
| 4 | On-Peak | 668,328,591 | $ 0.01060 | $ 0.01754 | $ 0.02871 | $ 0.01578 | $ 0.02451 |
| 5 | Off-Peak | 1,866,958,482 | $ 0.01060 | $ 0.01754 | $ 0.01265 | $ 0.01578 | $ 0.01236 |
| 6 | | | | | | | |
| 7 | Demand Charge | | | | | | |
| 8 | Max Demand | 5,787,462 | $ 4.44 | $ 12.18 | $ - | $ 12.68 | $ - |
| 9 | Load Control On-Peak | 4,172,227 | $ 3.17 | | $ 12.18 | | $ 12.68 |
| 10 | Firm On-Peak | 577,568 | $ 11.50 | | $ 12.18 | | $ 12.68 |
| 11 | | | | | | | |
| 12 | Transformation Credit | 1,334,903 | $ (0.15) | $ (0.15) | $ (0.15) | $ (0.15) | $ (0.15) |
| 13 | | | | | | | |
| 14 | Total | | | | | | |
| 15 | **CILC-1D Revenue Adjustment** | | | | | | |

# FLORIDA POWER & LIGHT COMPANY
## CILC Incentive Payments Using Test-Year Assumptions
## Projected Test Year Ending December 31, 2022

| | | Revenue | | | | |
|---|---|---|---|---|---|---|
| Line | TYPE OF CHARGES | CILC-1D | GSLD-1 | GSLDT-1 | GSLD-2 | GSLDT-2 |
| | | (7) | (8) | (9) | (10) | (11) |
| 1 | Customer Charge | $ 814,176 | $ 244,870 | $ 244,870 | $ 734,085 | $ 734,085 |
| 2 | | | | | | |
| 3 | Non-Fuel Energy Charge | | | | | |
| 4 | On-Peak | $ 7,084,283 | $ 11,722,483 | $ 19,187,714 | $ 10,546,225 | $ 16,380,734 |
| 5 | Off-Peak | $ 19,789,760 | $ 32,746,452 | $ 23,617,025 | $ 29,460,605 | $ 23,075,607 |
| 6 | | | | | | |
| 7 | Demand Charge | | | | | |
| 8 | Max Demand | $ 25,696,331 | $ 70,491,287 | $ - | $ 73,385,018 | $ - |
| 9 | Load Control On-Peak | $ 13,225,960 | $ - | $ 50,817,725 | $ - | $ 52,903,838 |
| 10 | Firm On-Peak | $ 6,642,032 | $ - | $ 7,034,778 | $ - | $ 7,323,562 |
| 11 | | | | | | |
| 12 | Transformation Credit | $ (200,235) | $ (200,235) | $ (200,235) | $ (200,235) | $ (200,235) |
| 13 | | | | | | |
| 14 | Total | $ 73,052,306 | $115,004,857 | $100,701,876 | $113,925,697 | $100,217,590 |
| 15 | **CILC-1D Revenue Adjustment** | **$ 34,410,000** | $ 41,952,550 | $ 27,649,569 | $ 40,873,391 | $ 27,165,284 |

# FLORIDA POWER & LIGHT COMPANY
## CILC Incentive Payments Using Test-Year Assumptions
## Projected Test Year Ending December 31, 2022

| | | | Rate | | | Revenue | | |
|---|---|---|---|---|---|---|---|---|
| Line | TYPE OF CHARGES | UNITS | CILC-1G | GSD-1 | GSDT-1 | CILC-1G | GSD-1 | GSDT-1 |
| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
| 1 | Customer Charge | 780 | $ 158.62 | $ 26.48 | $ 26.48 | $ 123,724 | $ 20,654 | $ 20,654 |
| 2 | | | | | | | | |
| 3 | Non-Fuel Energy Charge | | | | | | | |
| 4 | On-Peak | 30,154,470 | $ 0.01575 | $ 0.02221 | $ 0.04530 | $ 474,933 | $ 669,731 | $ 1,365,998 |
| 5 | Off-Peak | 82,036,537 | $ 0.01575 | $ 0.02221 | $ 0.01198 | $ 1,292,075 | $ 1,822,031 | $ 982,798 |
| 6 | | | | | | | | |
| 7 | Demand Charge | | | | | | | |
| 8 | Max Demand | 287,708 | $ 4.23 | $ 9.97 | $ - | $ 1,217,005 | $ 2,868,449 | $ - |
| 9 | Load Control On-Peak | 214,172 | $ 2.78 | | $ 9.97 | $ 595,398 | $ - | $ 2,135,295 |
| 10 | Firm On-Peak | 15,541 | $ 10.57 | | $ 9.97 | $ 164,268 | $ - | $ 154,944 |
| 11 | | | | | | | | |
| 12 | Transformation Credit | 5,890 | $ (0.15) | $ (0.15) | $ (0.15) | $ (884) | $ (884) | $ (884) |
| 13 | | | | | | | | |
| 14 | Total | | | | | $ 3,866,520 | $ 5,379,982 | $ 4,658,805 |
| 15 | **CILC-1G Revenue Adjustment** | | | | | **$ 1,150,000** | $ 1,513,462 | $ 792,285 |

## FLORIDA POWER & LIGHT COMPANY
### CDR Incentive Payments Using Test-Year Assumptions
### Projected Test Year Ending December 31, 2022

| Line | Customer Class | Rate Schedule | Interruptible Billing Demand (kW) | Incentive Payments ($000) |
|---|---|---|---|---|
| | | (1) | (2) | (3) |
| 1 | GSD | 72: GSD-1 | 38,968 | |
| 2 | | 70: GSDT-1 | 1,375,119 | |
| 3 | | 170: HLFT-1 | 7,727 | |
| 4 | | Gulf LPT | 87,988 | |
| 5 | | Total | 1,509,803 | $13,135 |
| 6 | GSLD-1 | 62: GSLD-1 | 154,916 | |
| 7 | | 64: GSLDT-1 | 1,304,550 | |
| 8 | | 164: HLFT-2 | 32,049 | |
| 9 | | Gulf LPT | 12,951 | |
| 10 | | Total | 1,504,467 | $13,089 |
| 11 | GSLD-2 | 63: GSLD-2 | 163,721 | |
| 12 | | 65: GSLDT-2 | 290,887 | |
| 13 | | 165: HLFT-3 | 84,557 | |
| 14 | | Total | 539,165 | $4,691 |

# FLORIDA POWER & LIGHT COMPANY
## Allocation of Costs to Non-Firm Customer Classes

| Line | Description | Total | Class A | Class B Firm | Class B Non-Firm |
|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) |
| | **Assumptions** | | | | |
| 1 | Peak Demand | 1,000 | 500 | 250 | 250 |
| 2 | Percent of Total | | 50% | 25% | 25% |
| 3 | Firm Peak Demand | 750 | 500 | 250 | - |
| 4 | Percent of Total | | 67% | 33% | 0% |
| 5 | Production Capacity Revenues | | | | $ 2,500 |
| 6 | Imputed Incentive Payments | | | | $ (1,000) |
| 7 | Net Revenue | | | | $ 1,500 |
| | ***Method 1:* Allocate No Production Capacity Costs to Non-Firm Loads** | | | | |
| 8 | Production Capacity Costs | $ 10,000 | $ 6,667 | $ 3,333 | $ - |
| 9 | Less: Non-Firm Revenue | $ - | $ (1,000) | $ (500) | $ 1,500 |
| 10 | Revenue Requirement | $ 10,000 | $ 5,667 | $ 2,833 | $ 1,500 |
| | ***Method 2:* Treat Non-Firm Load as Firm and Allocate the Imputed Incentive Payments to Firm Load** | | | | |
| 11 | Production Capacity Costs | $ 10,000 | $ 5,000 | $ 2,500 | $ 2,500 |
| 12 | Imputed Incentive Payments | $ - | $ 667 | $ 333 | $ (1,000) |
| 13 | Revenue Requirement | $ 10,000 | $ 5,667 | $ 2,833 | $ 1,500 |

# FLORIDA POWER & LIGHT COMPANY

## Derivation of Revenues at Present and Proposed Rates
## Using Test-Year CDR/CILC Incentive Payments
## Projected Year Ending December 31, 2022
## (Dollar Amounts in $000)

| Line | Description of Source | Total | CILC-1D | CILC-1G | CILC-1T | GS(T)-1 | GSCU-1 | GSD(T)-1 | GSLD(T)-1 | GSLD(T)-2 | GSLD(T)-3 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) |
| | **PRESENT REVENUES -** | | | | | | | | | | |
| 1 | **ELECTRICITY SALES:** | | | | | | | | | | |
| 2 | RETAIL SALES - BASE REVENUES | 7,530,593 | 73,052 | 3,867 | 29,430 | 571,840 | 4,280 | 1,388,256 | 436,920 | 128,741 | 24,121 |
| 3 | RETAIL SALES - ADJUSTMENTS | 107,829 | 1,065 | 56 | 433 | 8,155 | 61 | 19,973 | 6,288 | 1,844 | 341 |
| 4 | UNBILLED REVENUES - FPSC | (523) | (11) | (0) | (6) | (36) | (0) | (121) | (44) | (16) | (4) |
| 5 | *TOTAL ELECTRICITY SALES* | 7,637,900 | 74,106 | 3,922 | 29,857 | 579,959 | 4,341 | 1,408,108 | 443,164 | 130,568 | 24,459 |
| 6 | **CDR/CILC INCENTIVES** | 80,885 | 34,410 | 1,150 | 14,410 | | | 13,135 | 13,089 | 4,691 | |
| | **REALLOCATE CDR/CILC INCENTIVES** | | | | | | | | | | |
| 7 | 12 CP Demand | 100.00000% | 1.58670% | 0.07473% | 0.84164% | 7.59555% | 0.03939% | 21.71571% | 7.99669% | 2.51936% | 0.59438% |
| 8 | Percent of Interruptible Load | | 88% | 93% | 79% | | | 2% | 8% | 10% | |
| 9 | 12 CP Firm Demand | 96.51411% | 0.19294% | 0.00506% | 0.18010% | 7.59555% | 0.03939% | 21.23321% | 7.36077% | 2.27687% | 0.59438% |
| 10 | Percent of 12CP Firm Demand | 100.00000% | 0.19991% | 0.00524% | 0.18661% | 7.86989% | 0.04082% | 22.00011% | 7.62662% | 2.35911% | 0.61585% |
| 11 | Reallocated CDR/CILC Incentives | (80,885) | (162) | (4) | (151) | (6,366) | (33) | (17,795) | (6,169) | (1,908) | (498) |
| 12 | Total Revenue Adjustment | | 34,248 | 1,146 | 14,259 | (6,366) | (33) | (4,659) | 6,920 | 2,783 | (498) |
| 13 | *TOTAL ELECTRICITY SALES* | 7,637,900 | 108,355 | 5,068 | 44,116 | 573,593 | 4,308 | 1,403,448 | 450,084 | 133,351 | 23,961 |
| | **PROPOSED INCREASES** | | | | | | | | | | |
| 14 | RETAIL SALES - BASE REVENUES | 1,146,430 | 33,088 | 1,434 | 14,812 | 80,853 | 167 | 338,862 | 118,377 | 38,767 | 8,024 |
| 15 | RETAIL SALES - ADJUSTMENTS | (13,618) | (195) | (9) | (79) | (1,006) | (7) | (2,685) | (983) | (307) | (55) |
| 16 | UNBILLED REVENUES - FPSC | (122) | (3) | (0) | (2) | (8) | (0) | (28) | (10) | (4) | (1) |
| 17 | *TOTAL ELECTRICITY SALES* | 1,132,690 | 32,890 | 1,425 | 14,731 | 79,839 | 161 | 336,149 | 117,384 | 38,456 | 7,968 |
| 18 | **Change in CDR/CILC Incentives** | (24,248) | (10,695) | (401) | (3,986) | | | (3,505) | (4,137) | (1,523) | |
| 19 | Spread to Customer Classes | 24,248 | 48 | 1 | 45 | 1,908 | 10 | 5,335 | 1,849 | 572 | 149 |
| 20 | Total Revenue Adjustment | 0 | (10,647) | (399) | (3,941) | 1,908 | 10 | 1,829 | (2,288) | (951) | 149 |
| 21 | *TOTAL PROPOSED INCREASE* | 1,132,690 | 22,243 | 1,026 | 10,790 | 81,747 | 170 | 337,978 | 115,096 | 37,505 | 8,118 |

# FLORIDA POWER & LIGHT COMPANY
## Derivation of Revenues at Present and Proposed Rates
## Using Test-Year CDR/CILC Incentive Payments
## Projected Year Ending December 31, 2022
## (Dollar Amounts in $000)

| Line | Description of Source | MET | OL-1 | OS-2 | RS(T)-1 | SL-1 | SL-1M | SL-2 | SL-2M | SST-DST | SST-TST |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (11) | (12) | (13) | (14) | (15) | (16) | (17) | (18) | (19) | (20) |
| | **PRESENT REVENUES -** | | | | | | | | | | |
| 1 | **ELECTRICITY SALES:** | | | | | | | | | | |
| 2 | RETAIL SALES - BASE REVENUES | 4,067 | 14,463 | 1,055 | 4,719,188 | 120,893 | 907 | 1,884 | 205 | 1,526 | 5,897 |
| 3 | RETAIL SALES - ADJUSTMENTS | 59 | 203 | 15 | 67,489 | 1,699 | 13 | 26 | 3 | 21 | 85 |
| 4 | UNBILLED REVENUES - FPSC | (0) | (0) | (0) | (280) | (2) | (0) | (0) | (0) | (0) | (0) |
| 5 | *TOTAL ELECTRICITY SALES* | 4,126 | 14,666 | 1,070 | 4,786,398 | 122,590 | 920 | 1,911 | 209 | 1,547 | 5,982 |
| 6 | **CDR/CILC INCENTIVES** | | | | | | | | | | |
| | **REALLOCATE CDR/CILC INCENTIVES** | | | | | | | | | | |
| 7 | 12 CP Demand | 0.05967% | | 0.00493% | 56.89326% | | 0.00054% | 0.02136% | 0.00116% | 0.00050% | 0.05441% |
| 8 | Percent of Interruptible Load | | | | | | | | | | |
| 9 | 12 CP Firm Demand | 0.05967% | | 0.00493% | 56.89326% | | 0.00054% | 0.02136% | 0.00116% | 0.00050% | 0.05441% |
| 10 | Percent of 12CP Firm Demand | 0.06183% | | 0.00511% | 58.94813% | | 0.00056% | 0.02213% | 0.00120% | 0.00052% | 0.05637% |
| 11 | Reallocated CDR/CILC Incentives | (50) | | (4) | (47,680) | | (0) | (18) | (1) | (0) | (46) |
| 12 | Total Revenue Adjustment | (50) | | (4) | (47,680) | | (0) | (18) | (1) | (0) | (46) |
| 13 | *TOTAL ELECTRICITY SALES* | 4,076 | 14,666 | 1,066 | 4,738,718 | 122,590 | 919 | 1,893 | 208 | 1,547 | 5,936 |
| | **PROPOSED INCREASES** | | | | | | | | | | |
| 14 | RETAIL SALES - BASE REVENUES | 785 | 410 | 198 | 499,089 | 10,906 | 97 | 215 | 24 | (1,073) | 1,395 |
| 15 | RETAIL SALES - ADJUSTMENTS | (7) | (23) | (2) | (8,047) | (201) | (2) | (3) | (0) | (2) | (5) |
| 16 | UNBILLED REVENUES - FPSC | (0) | (0) | (0) | (65) | (0) | (0) | (0) | (0) | (0) | (0) |
| 17 | *TOTAL ELECTRICITY SALES* | 778 | 387 | 196 | 490,976 | 10,705 | 96 | 212 | 23 | (1,075) | 1,390 |
| 18 | **Change in CDR/CILC Incentives** | | | | | | | | | | |
| 19 | Spread to Customer Classes | 15 | | 1 | 14,294 | | 0 | 5 | 0 | 0 | 14 |
| 20 | Total Revenue Adjustment | 15 | | 1 | 14,294 | | 0 | 5 | 0 | 0 | 14 |
| 21 | *TOTAL PROPOSED INCREASE* | 793 | 387 | 197 | 505,270 | 10,705 | 96 | 217 | 24 | (1,075) | 1,404 |

# FLORIDA POWER & LIGHT COMPANY
## Summary of Class Cost-of-Service Study Results
## MDS; Test-Year CDR/CILC Incentive Payments
## Projected Year Ending December 31, 2022
## (Dollar Amounts in $000)

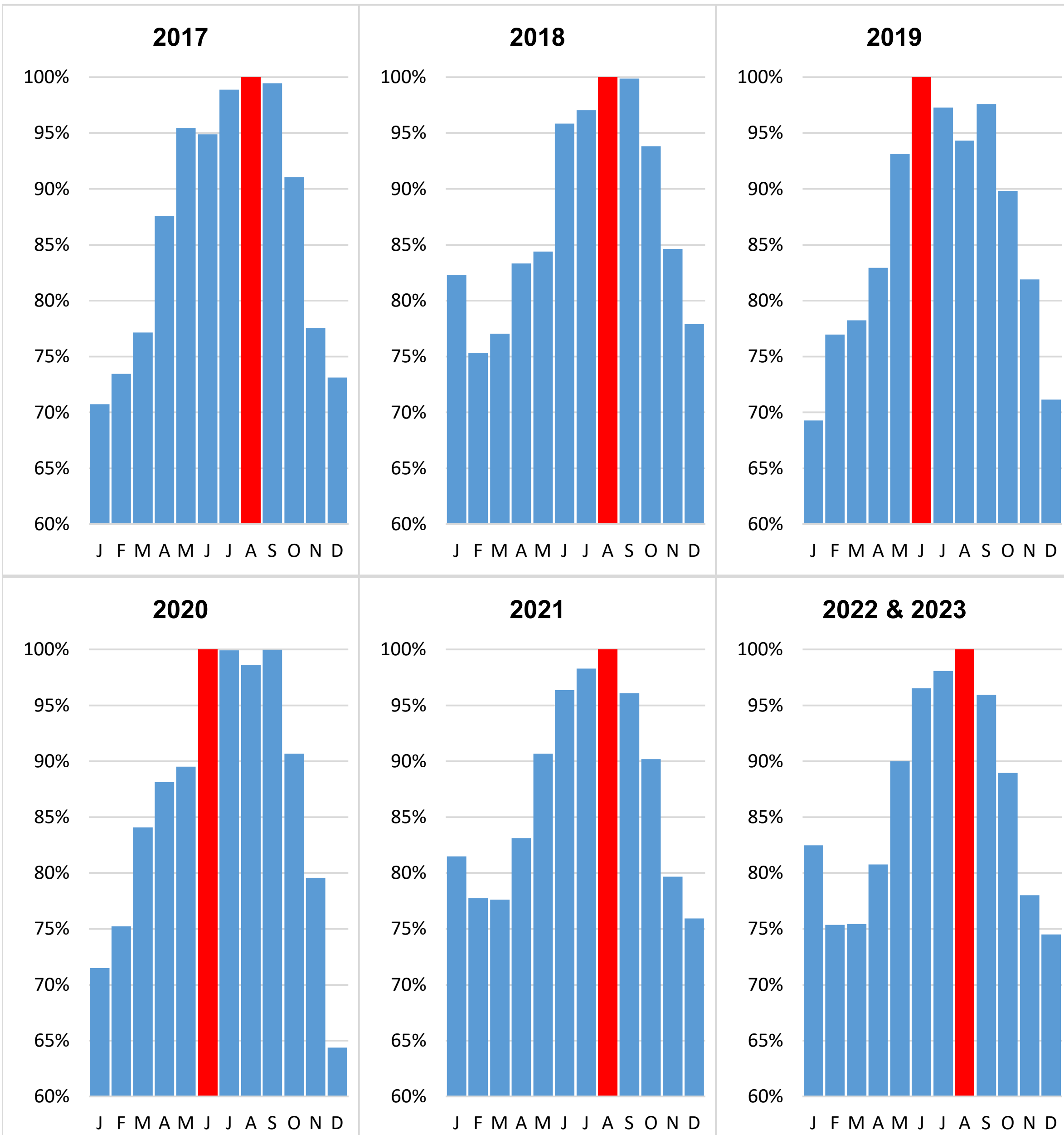
| Line | Description | Total | CILC-1D | CILC-1G | CILC-1T | GS(T)-1 | GSCU-1 | GSD(T)-1 | GSLD(T)-1 | GSLD(T)-2 | GSLD(T)-3 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) |
| | **PROJECTED ROR AT PRESENT RATES -** [1] | | | | | | | | | | |
| 1 | Total Rate Base | 55,507,996 | 692,907 | 33,071 | 310,561 | 4,262,984 | 35,435 | 9,635,849 | 3,488,294 | 1,092,000 | 216,249 |
| | Operating Revenues - | | | | | | | | | | |
| 2 | Sales of Electricity | 7,637,900 | 108,355 | 5,068 | 44,116 | 573,593 | 4,308 | 1,403,448 | 450,084 | 133,351 | 23,961 |
| 3 | Other Operating Revenues | 226,337 | 1,723 | 80 | 667 | 16,494 | 118 | 26,217 | 8,603 | 2,607 | 478 |
| 4 | Total Operating Revenues | 7,864,237 | 110,077 | 5,148 | 44,783 | 590,087 | 4,426 | 1,429,665 | 458,687 | 135,957 | 24,439 |
| 5 | Total Operating Expenses | (4,948,306) | (65,559) | (3,081) | (29,953) | (376,853) | (3,132) | (877,627) | (308,115) | (96,952) | (19,427) |
| 6 | Net Curtailment NOI Adjustment | (0) | (5) | (0) | (3) | (26) | (0) | (74) | 210 | 96 | (2) |
| 7 | Net Operating Income (NOI) | 2,915,931 | 44,513 | 2,067 | 14,827 | 213,207 | 1,293 | 551,964 | 150,782 | 39,101 | 5,010 |
| 8 | Rate of Return (ROR) | 5.25% | 6.42% | 6.25% | 4.77% | 5.00% | 3.65% | 5.73% | 4.32% | 3.58% | 2.32% |
| 9 | Parity at Present Rates | 1.00 | 1.22 | 1.19 | 0.91 | 0.95 | 0.69 | 1.09 | 0.82 | 0.68 | 0.44 |
| | **PROPOSED INCREASES -** [2] | | | | | | | | | | |
| 10 | Base Revenues | 1,146,430 | 33,088 | 1,434 | 14,812 | 80,853 | 167 | 338,862 | 118,377 | 38,767 | 8,024 |
| 11 | Base Revenue - Adjustments | (13,618) | (195) | (9) | (79) | (1,006) | (7) | (2,685) | (983) | (307) | (55) |
| 12 | Change in CILC/CDR Credit Offset | 0 | (10,647) | (399) | (3,941) | 1,908 | 10 | 1,829 | (2,288) | (951) | 149 |
| 13 | Unbilled Revenues | (122) | (3) | (0) | (2) | (8) | (0) | (28) | (10) | (4) | (1) |
| 14 | Miscellaneous Service Charges | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 15 | Total Proposed Increases | 1,132,690 | 22,243 | 1,026 | 10,790 | 81,747 | 170 | 337,978 | 115,096 | 37,505 | 8,118 |
| | **PROJECTED ROR AT PROPOSED RATES -** | | | | | | | | | | |
| 16 | Total Rate Base | 55,507,996 | 692,907 | 33,071 | 310,561 | 4,262,984 | 35,435 | 9,635,849 | 3,488,294 | 1,092,000 | 216,249 |
| | Operating Revenues - | | | | | | | | | | |
| 17 | Sales of Electricity | 8,770,590 | 130,598 | 6,093 | 54,906 | 655,340 | 4,478 | 1,741,426 | 565,180 | 170,856 | 32,078 |
| 18 | Other Operating Revenues | 226,337 | 1,723 | 80 | 667 | 16,494 | 118 | 26,217 | 8,603 | 2,607 | 478 |
| 19 | Total Operating Revenues | 8,996,927 | 132,321 | 6,174 | 55,573 | 671,834 | 4,596 | 1,767,643 | 573,783 | 173,463 | 32,557 |
| 20 | Total Operating Expenses | (5,236,672) | (71,222) | (3,342) | (32,700) | (397,665) | (3,176) | (963,671) | (337,416) | (106,500) | (21,494) |
| 21 | Net Curtailment NOI Adjustment | (0) | (5) | (0) | (3) | (26) | (0) | (74) | 210 | 96 | (2) |
| 22 | Net Operating Income (NOI) | 3,760,255 | 61,094 | 2,831 | 22,870 | 274,143 | 1,420 | 803,898 | 236,576 | 67,058 | 11,061 |
| 23 | Rate of Return (ROR) | 6.77% | 8.82% | 8.56% | 7.36% | 6.43% | 4.01% | 8.34% | 6.78% | 6.14% | 5.11% |
| 24 | Parity at Proposed Rates | 1.000 | 1.302 | 1.264 | 1.087 | 0.949 | 0.592 | 1.232 | 1.001 | 0.906 | 0.755 |

# FLORIDA POWER & LIGHT COMPANY
## Summary of Class Cost-of-Service Study Results
## MDS; Test-Year CDR/CILC Incentive Payments
## Projected Year Ending December 31, 2022
## (Dollar Amounts in $000)

| Line | Description | MET | OL-1 | OS-2 | RS(T)-1 | SL-1 | SL-1M | SL-2 | SL-2M | SST-DST | SST-TST |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (11) | (12) | (13) | (14) | (15) | (16) | (17) | (18) | (19) | (20) |
| | **PROJECTED ROR AT PRESENT RATES** | | | | | | | | | | |
| 1 | Total Rate Base | 26,153 | 142,083 | 4,636 | 34,713,649 | 810,340 | 4,809 | 10,834 | 2,022 | 5,265 | 20,854 |
| | Operating Revenues - | | | | | | | | | | |
| 2 | Sales of Electricity | 4,076 | 14,666 | 1,066 | 4,738,718 | 122,590 | 919 | 1,893 | 208 | 1,547 | 5,936 |
| 3 | Other Operating Revenues | 59 | 777 | 13 | 167,098 | 1,292 | 19 | 30 | 5 | 19 | 39 |
| 4 | Total Operating Revenues | 4,134 | 15,442 | 1,078 | 4,905,816 | 123,883 | 938 | 1,922 | 213 | 1,566 | 5,976 |
| 5 | Total Operating Expenses | (2,451) | (10,785) | (489) | (3,079,055) | (70,273) | (497) | (1,083) | (170) | (529) | (2,275) |
| 6 | Net Curtailment NOI Adjustment | (0) | 0 | (0) | (194) | 0 | (0) | (0) | (0) | (0) | (0) |
| 7 | Net Operating Income (NOI) | 1,683 | 4,657 | 589 | 1,826,567 | 53,610 | 441 | 839 | 43 | 1,037 | 3,700 |
| 8 | Rate of Return (ROR) | 6.44% | 3.28% | 12.71% | 5.26% | 6.62% | 9.17% | 7.75% | 2.12% | 19.70% | 17.74% |
| 9 | Parity at Present Rates | 1.23 | 0.62 | 2.42 | 1.00 | 1.26 | 1.75 | 1.47 | 0.40 | 3.75 | 3.38 |
| | **PROPOSED INCREASES -** (2) | | | | | | | | | | |
| 10 | Base Revenues | 785 | 410 | 198 | 499,089 | 10,906 | 97 | 215 | 24 | (1,073) | 1,395 |
| 11 | Base Revenue - Adjustments | (7) | (23) | (2) | (8,047) | (201) | (2) | (3) | (0) | (2) | (5) |
| 12 | Change in CILC/CDR Credit Offset | 15 | 0 | 1 | 14,294 | 0 | 0 | 5 | 0 | 0 | 14 |
| 13 | Unbilled Revenues | (0) | (0) | (0) | (65) | (0) | (0) | (0) | (0) | (0) | (0) |
| 14 | Miscellaneous Service Charges | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 15 | Total Proposed Increases | 793 | 387 | 197 | 505,270 | 10,705 | 96 | 217 | 24 | (1,075) | 1,404 |
| | **PROJECTED ROR AT PROPOSED RATE** | | | | | | | | | | |
| 16 | Total Rate Base | 26,153 | 142,083 | 4,636 | 34,713,649 | 810,340 | 4,809 | 10,834 | 2,022 | 5,265 | 20,854 |
| | Operating Revenues - | | | | | | | | | | |
| 17 | Sales of Electricity | 4,868 | 15,053 | 1,262 | 5,243,988 | 133,295 | 1,015 | 2,110 | 231 | 472 | 7,340 |
| 18 | Other Operating Revenues | 59 | 777 | 13 | 167,098 | 1,292 | 19 | 30 | 5 | 19 | 39 |
| 19 | Total Operating Revenues | 4,927 | 15,830 | 1,275 | 5,411,086 | 134,587 | 1,034 | 2,140 | 236 | 491 | 7,380 |
| 20 | Total Operating Expenses | (2,653) | (10,884) | (539) | (3,207,689) | (72,998) | (521) | (1,138) | (176) | (255) | (2,633) |
| 21 | Net Curtailment NOI Adjustment | (0) | 0 | (0) | (194) | 0 | (0) | (0) | (0) | (0) | (0) |
| 22 | Net Operating Income (NOI) | 2,274 | 4,946 | 736 | 2,203,202 | 61,589 | 513 | 1,001 | 60 | 236 | 4,747 |
| 23 | Rate of Return (ROR) | 8.70% | 3.48% | 15.87% | 6.35% | 7.60% | 10.66% | 9.24% | 2.99% | 4.48% | 22.76% |
| 24 | Parity at Proposed Rates | 1.284 | 0.514 | 2.343 | 0.937 | 1.122 | 1.573 | 1.364 | 0.441 | 0.661 | 3.360 |

# FLORIDA POWER & LIGHT COMPANY

## System Load Analysis
## FPL Stand-Alone (2017-2021)
## Consolidated (2022 & 2023)



## FLORIDA POWER & LIGHT COMPANY
### Change in Class Revenue Requirements Using the 4CP Method
### Of Allocating Production and Transmission Demand-Related Costs

| | | Allocation Factors | | Allocation Using 12CP | | Allocation Using 4CP | | |
|---|---|---|---|---|---|---|---|---|
| Line | Customer Class | 12CP | 4CP | Production | Transmission | Production | Transmission | Difference |
| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
| 1 | **RS(T)-1** | 56.8933% | 58.72030% | $2,107,106 | $552,256 | $2,174,702 | $569,977 | $85,317 |
| 2 | **GSD(T)-1** | 21.7157% | 20.95611% | $803,365 | $210,561 | $775,238 | $203,191 | ($35,497) |
| 3 | **GSLD(T)-1** | 7.9967% | 7.46772% | $295,404 | $77,505 | $275,854 | $72,376 | ($24,678) |
| 4 | **GS(T)-1** | 7.5956% | 7.49202% | $281,176 | $73,694 | $277,334 | $72,688 | ($4,848) |
| 5 | **GSLD(T)-2** | 2.5194% | 2.33314% | $93,039 | $24,420 | $86,160 | $22,615 | ($8,685) |
| 6 | **CILC-1D** | 1.5867% | 1.45867% | $58,661 | $15,375 | $53,926 | $14,134 | ($5,976) |
| 7 | **CILC-1T** | 0.8416% | 0.74762% | $31,122 | $8,157 | $27,644 | $7,246 | ($4,389) |
| 8 | **GSLD(T)-3** | 0.5944% | 0.60946% | $21,982 | $5,762 | $22,540 | $5,908 | $703 |
| 9 | **CILC-1G** | 0.0747% | 0.06840% | $2,763 | $724 | $2,529 | $663 | ($295) |
| 10 | **SST-1(T)** | 0.0544% | 0.03590% | $2,008 | $526 | $1,325 | $347 | ($862) |
| 11 | **METRO** | 0.0597% | 0.05132% | $2,206 | $578 | $1,897 | $497 | ($390) |
| 12 | **GSCU** | 0.0394% | 0.03482% | $1,456 | $382 | $1,287 | $337 | ($213) |
| 13 | **SL-2** | 0.0214% | 0.01717% | $790 | $207 | $635 | $166 | ($196) |
| 14 | **OS-2** | 0.0049% | 0.00488% | $182 | $48 | $180 | $47 | ($3) |
| 15 | **SL-2M** | 0.0012% | 0.00103% | $43 | $11 | $38 | $10 | ($6) |
| 16 | **SL-1M** | 0.0005% | 0.00079% | $20 | $5 | $29 | $8 | $11 |
| 17 | **SST-1(D)** | 0.0005% | 0.00065% | $19 | $5 | $24 | $6 | $7 |
| 18 | **SL-1** | 0.0000% | 0.00000% | $0 | $0 | $0 | $0 | $0 |
| 19 | **OL-1** | 0.0000% | 0.00000% | $0 | $0 | $0 | $0 | $0 |
| 20 | **Total Retail** | 100.0000% | 100.00000% | $3,701,342 | $970,218 | $3,701,342 | $970,218 | $0 |

Sources:
FPL MFR E-11 TEST Consolidated, FPL (CONSOLIDATED) - 2022 Test Year Load Data Forecast,
FPL MFR E-6b - Cost of Service Study - Unit Costs (with RSAM),
FPL Jurisdictional Separation Study and Retail Cost of Service Study E101-Transmission: 12CP Demand, December 2022 - Test Year
FPL Jurisdictional Separation Study and Retail Cost of Service Study E201 - Total Sales: Total Annual Energy, December 2022 - Test Year

# FLORIDA POWER & LIGHT COMPANY

## FIPUG Recommended Class Revenue Allocation Using FPL's MDS Study and Test-Year CDR/CILC Incentive Payments

### Projected Year Ending December 31, 2022
### (Dollar Amounts in Thousands)

| Line | Customer Class | Present Base Revenues | Recommended Allocation Amount | Recommended Allocation Percent |
|---|---|---|---|---|
| | | (1) | (2) | (3) |
| 1 | CILC-1D | $73,052 | $4,207 | 5.8% |
| 2 | CILC-1G | $3,867 | $278 | 7.2% |
| 3 | CILC-1T | $29,430 | $6,721 | 22.8% |
| 4 | GS(T)-1 | $571,840 | $106,452 | 18.6% |
| 5 | GSCU-1 | $4,280 | $977 | 22.8% |
| 6 | GSD(T)-1 | $1,388,256 | $147,737 | 10.6% |
| 7 | GSLD(T)-1 | $436,920 | $99,773 | 22.8% |
| 8 | GSLD(T)-2 | $128,741 | $29,399 | 22.8% |
| 9 | GSLD(T)-3 | $24,121 | $5,508 | 22.8% |
| 10 | MET | $4,067 | $155 | 3.8% |
| 11 | OL-1 | $14,463 | $3,303 | 22.8% |
| 12 | OS-2 | $1,055 | $0 | 0.0% |
| 13 | RS(T)-1 | $4,719,188 | $746,100 | 15.8% |
| 14 | SL-1 | $120,893 | $2,775 | 2.3% |
| 15 | SL-1M | $907 | $0 | 0.0% |
| 16 | SL-2 | $1,884 | $0 | 0.0% |
| 17 | SL-2M | $205 | $47 | 22.8% |
| 18 | SST-DST | $1,526 | $0 | 0.0% |
| 19 | SST-TST | $5,897 | $0 | 0.0% |
| 20 | Total Retail | $7,530,593 | $1,153,430 | 15.3% |

## FLORIDA POWER & LIGHT COMPANY

**FIPUG Recommended Class Revenue Allocation**
**Using FPL's MDS Study;**
**Test-Year CDR/CILC Incentive Payments, 4CP Method**

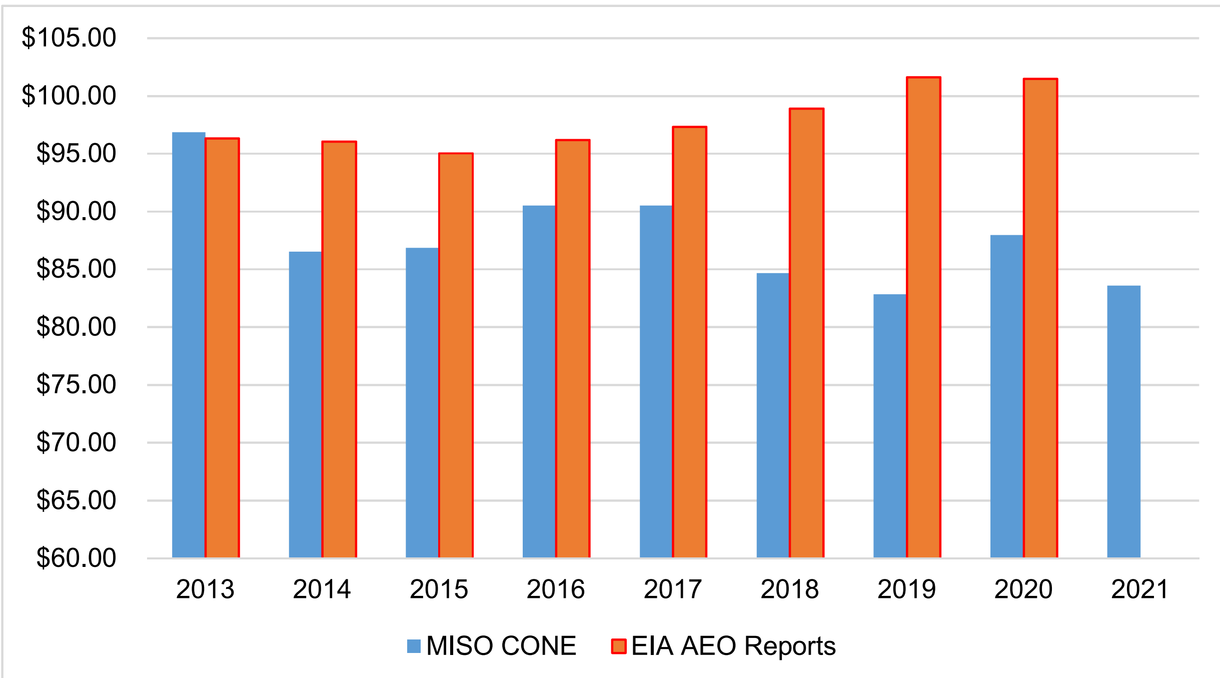
**Projected Year Ending December 31, 2022**
**(Dollar Amounts in Thousands)**

| Line | Customer Class | Present Base Revenues | Recommended Allocation Amount | Recommended Allocation Percent |
|---|---|---|---|---|
| | | (1) | (2) | (3) |
| 1 | CILC-1D | $73,052 | $0 | 0.0% |
| 2 | CILC-1G | $3,867 | $0 | 0.0% |
| 3 | CILC-1T | $29,430 | $4,075 | 13.8% |
| 4 | GS(T)-1 | $571,840 | $98,536 | 17.2% |
| 5 | GSCU-1 | $4,280 | $977 | 22.8% |
| 6 | GSD(T)-1 | $1,388,256 | $104,810 | 7.5% |
| 7 | GSLD(T)-1 | $436,920 | $91,796 | 21.0% |
| 8 | GSLD(T)-2 | $128,741 | $29,399 | 22.8% |
| 9 | GSLD(T)-3 | $24,121 | $5,508 | 22.8% |
| 10 | MET | $4,067 | $0 | 0.0% |
| 11 | OL-1 | $14,463 | $3,303 | 22.8% |
| 12 | OS-2 | $1,055 | $0 | 0.0% |
| 13 | RS(T)-1 | $4,719,188 | $805,847 | 17.1% |
| 14 | SL-1 | $120,893 | $2,132 | 1.8% |
| 15 | SL-1M | $907 | $0 | 0.0% |
| 16 | SL-2 | $1,884 | $0 | 0.0% |
| 17 | SL-2M | $205 | $47 | 22.8% |
| 18 | SST-DST | $1,526 | $0 | 0.0% |
| 19 | SST-TST | $5,897 | $0 | 0.0% |
| 20 | Total Retail | $7,530,593 | $1,146,430 | 15.2% |

# FLORIDA POWER & LIGHT COMPANY

## Trends in Generation Capital Costs

**<u>$ per kW-Year</u>**



## FLORIDA POWER & LIGHT COMPANY
## Installed Cost of Generation Capacity Additions Since 2012

| Line | Plant Name | Year In Service | Investment ($Millions) | Net Capacity (MW) | Installed Cost ($/kW) | Cumulative Installed Cost ($/kW) |
|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) |
| 1 | **Cape Canaveral** | 2013 | $942 | 1,393 | $676 | $676 |
| 2 | **Riviera Beach** | 2014 | $938 | 1,393 | $673 | $675 |
| 3 | **Port Everglades** | 2016 | $1,099 | 1,338 | $821 | $722 |
| 4 | **Ft. Meyers Peaking** | 2016 | $285 | 462 | $618 | $712 |
| 5 | **Lauderdale Jet** | 2016 | $437 | 1,155 | $379 | $645 |
| 6 | **Solar Projects** | 2016 | $379 | 228 | $1,666 | $684 |
| 7 | **Solar Projects** | 2018 | $748 | 599 | $1,249 | $735 |
| 8 | **Okeechobee Unit 1** | 2019 | $1,167 | 1,723 | $677 | $723 |
| 9 | **Solar Projects** | 2019 | $386 | 298 | $1,295 | $743 |
| 10 | **Solar Projects** | 2020 | $1,287 | 1,118 | $1,151 | $790 |
| 11 | **Solar Projects** | 2021 | $1,413 | 894 | $1,580 | $857 |
| 12 | **Dania Beach** | 2022 | $886 | 1,163 | $762 | $847 |
| 13 | **Total Excluding Solar** | | $5,754 | 8,627 | | $667 |

Source: S&P Global Market Intelligence, FPL's 2020 FERC Form 1, Schedule B-11.

# FLORIDA POWER & LIGHT COMPANY

## CDR Monthly Incentive Reflecting Avoided Capital Costs
## Based on FPL's Thermal Capacity Additions Installed Since 2012

| Line | Description | Production Demand | Reference |
|---|---|---|---|
| | | (1) | (2) |
| | **Annual Revenue Requirement ($000)** | | |
| 1 | Steam | $309,358 | MFR E6b 2022 CONS RSAM |
| 2 | Nuclear | $958,066 | |
| 3 | Other | $2,428,535 | |
| 4 | Total | $3,695,960 | |
| | **Plant Investment ($000)** | | |
| 5 | Steam | $1,110,062 | MFR E3b 2022 CONS RSAM |
| 6 | Nuclear | $7,431,698 | |
| 7 | Other | $17,280,159 | |
| 8 | Total | $25,821,920 | |
| 9 | **Annual Carrying Charge Rate** | 14.3% | Line 4 ÷ Line 8 |
| 10 | **Average Cost of New Thermal Capacity Added By FPL Since 2012 ($/kW)** | $667.00 | **Exhibit JP-13** |
| 11 | **Annual Fixed Cost ($/kW)** | $95.47 | Line 10 x Line 9 |
| 12 | **Reserve Margin + Losses at Transmission** | 22.96% | Generator kWh per Part. |
| 13 | **Average Cost of Capacity Avoided ($/kW/Month Load)** | **$9.78** | Line 11 x (1+Line 12) ÷ 12 |
| 14 | **Monthly CDR Incentive ($/KW/Month Load)** | **$8.70** | |

# FLORIDA POWER & LIGHT COMPANY

## CDR Monthly Incentive Reflecting Avoided Capital Costs
## Based on The Capital Cost of New Combustion Turbines

| Line | Description | Amount | Reference |
|---|---|---|---|
| | | (1) | (2) |
| | **CT Annual Revenue Requirement: ($/kW-Year)** | | |
| 1 | 2013-14 | $96.86 | **MISO PRA Filings (Louisiana, Mississippi, Texas)** |
| 2 | 2014-15 | $86.53 | |
| 3 | 2015-16 | $86.87 | |
| 4 | 2016-17 | $90.52 | |
| 5 | 2017-18 | $90.52 | |
| 6 | 2018-19 | $84.68 | |
| 7 | 2019-20 | $82.86 | |
| 8 | 2020-21 | $87.97 | |
| 9 | 2021-22 | $83.59 | |
| 10 | **Average Cost of New Entry ($/kW-Year)** | $87.82 | Average Lines 1-7 |
| 11 | **Reserve Margin + Losses at Transmission** | 22.96% | Generator kWh per Part. |
| 12 | **Average Cost of Capacity Avoided ($/kW/Month Load)** | **$9.00** | Line 9 x (1+Line 10) ÷ 12 |
| 13 | **Current Monthly CDR Incentive ($/KW/Month Load)** | **$8.70** | |