STONE
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June 21, 2021

Mr. Adam Teitzman
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Docket No. 20210015-EI – In re: Petition for rate increase by Florida Power & Light Company

Dear Mr. Teitzman:

Please find enclosed for filing in the above-referenced docket the Direct Testimony and Exhibits of Tony Georgis on behalf of the Florida Retail Federation. This filing is being made via the Florida Public Service Commission's Web Based Electronic Filing portal.

If you have any questions or concerns, please do not hesitate to contact me. Thank you for your assistance in this matter.

Sincerely,

/s/ James W. Brew

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Direct Testimony and Exhibits of Tony Georgis has been furnished by electronic mail to the following parties on this 21st day of June, 2021:

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/s/ Laura Wynn Baker
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company	**)))**	**DOCKET NO. 20210015-EI**

DIRECT TESTIMONY OF TONY GEORGIS

ON BEHALF OF THE FLORIDA RETAIL FEDERATION

JUNE 21, 2021

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EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT EMPLOYMENT POSITION.

A. My name is Tony M. Georgis. I am the Managing Director of the Energy Practice of NewGen Strategies and Solutions, LLC ("NewGen"). My business address is 225 Union Blvd, Suite 305, Lakewood, Colorado 80228. NewGen is a consulting firm that specializes in utility rates, engineering economics, financial accounting, asset valuation, appraisals, and business strategy for electric, natural gas, water, and wastewater utilities.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Florida Retail Federation.

Q. PLEASE OUTLINE YOUR FORMAL EDUCATION.

A. I have a Master of Business Administration degree from Texas A&M University, with specialization in finance. Also, I earned a Bachelor of Science in Mechanical Engineering from Texas A&M University. In addition to my undergraduate and graduate degrees, I am a registered Professional Engineer in the states of Colorado and Louisiana.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I am the Managing Director of NewGen's Energy Practice. I have more than 20 years of experience in engineering and economic analyses for the energy, water, and waste resources industries. My work includes various assignments for private industry, local governments, and utilities, including sustainability strategy, strategic planning, financial and economic analyses, cost of service and rate studies, energy efficiency, and market research. I have been extensively involved in the development of unbundled cost of service ("COS") and pricing models during my career. A summary of my qualifications is provided within Exhibit TMG-1 to this testimony.

Q. HAVE YOU TESTIFIED BEFORE ANY REGULATORY COMMISSIONS?

A. Yes. I have submitted testimony to the Public Utility Commission of Texas and the Indiana Utility Regulatory Commission, as shown in my resume and record of testimony included as Exhibit TMG-1.

Q. WAS YOUR TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes, it was.

II. PURPOSE AND SCOPE

Q. WHAT IS THE PURPOSE AND SCOPE OF YOUR DIRECT TESTIMONY?

A. Florida Power & Light Company ("FPL") has proposed a four-year program to increase its base electric rates by $1,995 million over the years 2022–2025, with the cumulative effect being an increase in customer bills of more than $6.5 billion over that period. FPL expressly ties that multi-year rate plan to a variety of special rate treatments and conditions, specifically including an unusual "Reserve Surplus Amortization Mechanism" proposal through which FPL will create a significant apparent excess depreciation reserve that FPL would then be authorized to use throughout the term of the rate plan to manage its regulated earnings to a target level set by FPL management (presumably at the top end of its allowed range).

The base rate revenue increases that FPL seeks in 2022 and 2023 amount to more than a 20% increase overall from current base rates. Significantly, FPL proposes to direct a disproportionate amount of the proposed increases in those years to its commercial service classes, some of whom would see base rate increases approaching or exceeding 40%. Rate increases of this level are incompatible with the concept of implementing gradual changes in rates to the extent practicable.

My testimony explains that FPL's cost of service study in this case systematically over-allocates utility production and transmission costs to non-firm interruptible service commercial and industrial customers. Also, the current and proposed Commercial Demand Reduction ("CDR") credit offset that FPL incorporates in its cost of service study is not valued correctly. The net result of this distorts FPL's cost of service results and the utility's proposed allocation of revenue increases among customer classes.

My testimony also explains why FPL should allocate distribution related costs using the Minimum Distribution System ("MDS") approach that the utility filed in this case but does not propose to employ. Overall, I recommend that the Commission resolve these issues collectively by directing FPL to adopt an equal percentage increase for all customer service classes for the 2022 and 2023 rate increases, if any, just as FPL proposes to apply its base rate increases for the years 2024 and 2025 for its proposed solar base rate adjustment ("SOBRA") investments.

Next, many commercial class customers receive service under interruptible tariff provisions that for decades have provided significant system reliability benefits to FPL and its firm service customers. In addition to the credits being undervalued within the cost of service study, FPL proposes to slash the credits provided for that interruptible service by one-third. Reducing the credits both exacerbates the rate and customer bill impacts for those interruptible customers and diminishes their incentive to continue to participate in the programs. I demonstrate that FPL has significantly understated the value of its Commercial/Industrial Load Control ("CILC") and successor CDR credit programs as well as why the credits associated with those programs should be increased.

My testimony does not propose specific adjustments to FPL's proposed 2022 and 2023 revenue requirement or the SOBRA increases proposed for 2024 and 2025. This should not be interpreted as endorsing in any sense the level of revenue increases that FPL proposes, which appear to be excessive in several significant respects. I do, however, explain why FPL's proposed Reserve Surplus Amortization Mechanism ("RSAM") misapplies basic depreciation concepts, is not in the public interest, and should not be adopted by the Commission.

Q. WHAT EXHIBITS ARE YOU SPONSORING?

A. I am sponsoring the following Exhibits:

- TMG-1 Resume and Record of Testimony of Tony Georgis
- TMG-2 CILC/CDR Credit Rider Embedded Valuation
- TMG-3 Select FPL Responses to FRF Interrogatories (Nos. 7 & 11)

III. SUMMARY AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A. My recommendations are as follows:

- **<u>Interruptible Service Credits:</u>**

  FPL's proposed reduction to the CDR and CILC credit should be rejected because the credit is undervalued today. FPL underestimates the reliability value provided by customers taking service under the terms of FPL's CILC tariff and participating in the CDR rider credit. The prevailing credits should be increased to $10.07 per kW-month and not reduced as FPL proposes.

- **<u>Cost of Service and Revenue Allocation:</u>**

  FPL's cost of service study incorrectly allocates generation and transmission costs to its interruptible non-firm commercial and industrial loads. This is inconsistent with the way in which FPL actually designs and constructs its system and incurs costs. FPL also does not adequately account for the value of CILC and CDR credit offsets in Schedule E-5 in the cost of service study. These errors distort the cost of service results and FPL's proposed allocation of revenue increases among customer classes.

  Due to the structural corrections necessary in FPL's cost of service analysis concerning FPL's allocation of fixed production and transmission costs to non-firm loads in addition to adjustments required to incorporate the MDS for allocating distribution-related costs, I recommend that any base rate revenue increase adopted by the Commission should be implemented through an equal percentage increase to all customer classes for each of the years of an approved base rate plan.

- **<u>Minimum Distribution System:</u>**

  The Commission should find that the MDS study and results should be included in the cost of service results because they better reflect the costs that customer classes impose on the system, improving eventual rate design and better aligning cost recovery with cost incurrence.

- **<u>The RSAM proposal should be rejected.</u>**

  The Commission should determine that FPL's RSAM proposal misapplies the purpose in depreciation studies of comparing booked depreciation to a theoretical reserve level. Any material reserve surplus determined after approval of all pertinent depreciation parameters (i.e., service lives, net salvage, and cost of removal) for FPL's regulated assets should be applied for consumer benefit (used to moderate current rates or applied to write down utility assets) rather than diverted to ensure earnings levels for FPL investors.

Q. WHAT ARE THE RESULTS OF YOUR RECOMMENDATIONS WHEN IMPLEMENTED?

A. The results of my recommendations are as follows:

- The CILC base bill percentage reduction is increased to 25% and the CDR credit increased to $10.07 per kW-month.
- An equal percentage increase approach is applied to revenue allocation to any revenue requirement increase approved in this proceeding.

IV. CILC/CDR VALUATION

Q. PLEASE DESCRIBE FPL'S CURRENT CILC/CDR PROGRAMS

A. The Commercial/Industrial Load Control ("CILC") rate and its successor Commercial Industrial Demand Reduction ("CDR") rider are the largest and most successful FPL demand side management ("DSM") programs for its commercial and industrial customers. Historically, these programs have been among the most cost-effective of all DSM programs implemented by FPL. Combined, they currently provide approximately 814 MWs of interruptible load controlled by FPL, which provides exceptionally reliable capacity value to FPL and all of its other customers.

The CILC rate incorporates an interruptible credit into the design of the rate and was the operative large customer interruptible rate for many years. This rate was closed to new customers in the year 2000. Customers participating in the commercial/industrial interruptible service program in subsequent years take service under an otherwise applicable rate schedule, typically GSLD or GSLDT, and receive the CDR credit to their demand charge.

Operationally, the CILC and CDR are identical in that both are interruptible by FPL on one hour notice for reliability purposes for up to six hours when needed to forestall a system emergency; capacity shortages (generation or transmission); or whenever, in FPL's sole judgement, actual or projected system load could require FPL to operate its generating units above their rated output (i.e., "peaking operation").[1] Moreover, in the event of an actual system emergency, the tariffs allow FPL to interrupt service to CILC/CDR participants on shorter notice (as little as 15 minutes, or even less if service to firm customers is threatened), and the interruption period may be longer than 6 hours.[2] Service interruptions under the programs by FPL can occur at any time of the year. FPL has complete control over the service interruption to participating customers and there is no opportunity for a participating customer to avoid, or "buy through," any service interruption that FPL elects to implement. In fact, there are significant penalties under the tariff and CDR rider for energy consumption above a customer's contracted level of firm demand during an interruption event, and FPL can terminate a customer's participation for such noncompliance.

The result of these rigorously defined tariff conditions is an extremely reliable emergency resource that may be available faster than any FPL peaking black-start supply resource. This resource is also dispersed throughout the FPL territory, so its availability is not limited by transmission constraints or other physical impediments.

In contrast, for peaking assets like the four combustion turbines being added to the Gulf service area, FPL needs to acquire or encumber land, construct and operate the generation facilities, recover a return on and of the assets, pay property taxes on the land and assets, pay salaries and benefits to the staff required for those facilities, build

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[1] *See* the Control Conditions listed in the tariff.

[2] *See* the Duration Conditions listed in the tariff.

or upgrade substations and other equipment to interconnect with the grid, maintain spare parts inventory, make regulatory filings for air permits and other licenses, incur fuel and other operating costs, and contend with all issues affecting unit start up and delivery of output to load centers (e.g., generator availability, location, and transmission limits). For the interruptible resources participating in the CILC and CDR programs, FPL incurs none of those costs, emissions, or system impediments.

For resource planning purposes, FPL has not in the past and does not currently treat the full metered or measured loads of CILC and CDR customers as firm loads. This is routinely reflected in the FPL Ten Year Site Plan filings, which deduct commercial/industrial load management capacity values from the determination of Net Firm Demand upon which FPL calculates its capacity reserve margins and generation need determinations.[3] In short, CILC/CDR participants have, over several decades, provided a continuous source of system reliability benefits and cost savings to FPL and all firm service customers.

The participating customers receive a reduction in their monthly bills through a direct percent reduction of the base CILC bill (currently 22%), or a bill credit of $8.71 per kW-month for the portion of their CILC or CDR that is interruptible.[4]

Q. FPL PROPOSES TO REDUCE THE INTERRUPTIBLE SERVICE CREDIT APPLICABLE TO NON-FIRM CUSTOMERS TAKING SERVICE UNDER THE COMMERCIAL INDUSTRIAL LOAD CONTROL ("CILC") RATES

[3] See Schedules 3.1 and 7.1 of the FPL Ten Year Site Plans.

[4] Direct Testimony of Steven R. Sim at 17 (Sim Direct).

AND THE COMMERCIAL/INDUSTRIAL DEMAND REDUCTION RIDER ("CDR") BY ROUGHLY 33%. DO YOU AGREE WITH THE FPL PROPOSAL?

A. No. The credits applied for this interruptible service should be increased. FPL fully recognizes the continuing reliability value provided by its CILC/CDR interruptible customers and wants to retain all of the 814 MWs of capacity value that current participants provide, but argues incorrectly that the value of that service is declining. Capacity costs actually are not declining, and the reliability value of this interruptible load will only increase as FPL begins to place greater reliance on intermittent supply resources.

Q. PLEASE CONTINUE.

A. The CILC and CDR programs have allowed FPL to avoid or defer additional transmission and generation investments over the decades in which the programs have been in place and customers have been participating. FPL's generation and transmission systems are designed and constructed to meet expected net firm peak demands on the utility system, plus a reserve margin.

In Florida, the accepted capacity reserve margin is 20%.[5] Thus, the capacity benefit that CILC and CDR participants provide includes the dedicated customer load reduction plus the applicable reduction in reserve margin. For example, if 100MW were available for CILC and CDR, the actual benefit to FPL would be 120MW in their resource plan.

[5] The convention to apply a 20% reserve margin is not a rule requirement but has been implemented under a long-standing approach endorsed by the Commission. *See* the calculations on Schedule 7.1 of the FPL Ten Year Site Plan.

Q. PLEASE EXPLAIN THE PROPOSED CHANGES TO THE CURRENT CILC AND CDR VALUATION PROPOSED BY FPL?

A. FPL does not propose any changes to how the CILC/CDR programs work that would make them less valuable to the network as a resource. It simply proposes to pay participants less for providing those benefits. Mr. Sim proposes to reduce the CDR incentive credit from $8.71 per kW-month to $5.80 per kW-month, a reduction of 33%, and to reflect a corresponding reduction in the credit incorporated in the CILC rate. He maintains that the benefits of the interruptible service programs, as well as all other DSM programs, has declined, as measured by FPL's AURORA resource modeling tool.

Q. COULD YOU FURTHER DESCRIBE FPL'S STATED REASONS FOR REDUCING THE CDR CREDIT?

A. Mr. Sim equates the historical CDR and CILC capacity value and customer participation to the cost-effectiveness of "open" DSM programs, or those DSM programs open to new participants and marginal new demand response capacity to FPL.[6] He describes how the AURORA optimization model used by FPL for integrated resource planning was used to estimate resource planning costs with and without the CILC/CDR resources available. FPL used the calculated difference in costs between an option with CILC and CDR and one without CICL and CDR interruptible capacity to quantify the ostensible economic benefit of the interruptible service demand reductions.

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[6] Sim Direct at 19.

FPL did not, however, propose to reset the CDR credit based on the basic RIM cost-effectiveness measure (a RIM measurement of 1.0 indicates that program benefits match costs). Instead, FPL arbitrarily proposes to reduce the CILC/CDR credit to a level that is expected to result in a RIM test of 1.45, which is higher than all but one of the currently approved FPL DSM measures.[7] This produced the FPL proposed reduced CDR incentive credit of $5.80 per kW. I describe the flaws in FPL's assessment below.

A. COST OF SERVICE AND CILC RATE AND CDR CREDIT VALUE MISALIGNMENT

Q. HOW DOES FPL ALLOCATE GENERATION AND TRANSMISSION COSTS TO THE CILC AND CDR CUSTOMER-RELATED CLASSES?

A. FPL allocates demand costs associated with generation and transmission plant to the CILC and CDR-eligible customer classes based on their metered demand coincident with the 12 monthly peaks on the FPL system. In effect, all metered load is considered firm load.

Q. IS THERE ANY REDUCTION OR ADJUSTMENT IN THIS DEMAND ALLOCATOR AT THE SYSTEM COINCIDENT PEAKS TO RECOGNIZE INTERRUPTIBLE (NON-FIRM) CUSTOMER LOAD?

A. No, FPL does not adjust the customer class demand allocations to account for non-firm demand.[8] CILC and CDR customers and related customer classes are treated as firm

[7] Residential Load Management (on call) program has a RIM of 1.82 but yields a small fraction of the demand reduction benefits provided by the CILC/CDR programs. Docket No. 20200054, *Petition for Approval of Florida Power & Light Company's Demand-Side Management Plan*, 2020-2024 Demand-Side Management Plan at 7 (Feb. 24, 2020).

[8] *See* Exh. TMG-3 (FPL Response to FRF's Second Set of Interrogatories No. 11).

capacity customers, even though more than 814 MW of that coincident peak demand included in the cost allocations is interruptible and FPL does not design or construct firm capacity to serve that load.[9] This systematically over-allocates production costs to FPL's non-firm, interruptible customer classes.

Q. WHAT IS THE EFFECT OF FPL'S ALLOCATION OF CAPACITY COSTS TO CILC AND CDR CUSTOMER CLASSES ON THE ACTUAL METERED DEMAND, INCLUDING THE INTERRUPTIBLE CAPACITY, RATHER THAN THE FIRM CAPACITY AMOUNTS THAT ARE LOWER?

A. FPL's approach violates an essential purpose of a cost of service study, which is to assign and allocate a utility's embedded costs to customer classes based on how those customer classes impose costs on the system. For example, customers served at transmission voltages are not allocated distribution costs because they do not use the distribution system and do not cause distribution plant to be constructed. By the same token, the need for FPL's production plant is tied to net firm demand and excludes non-firm load, which receives a lesser quality of service. By allocating its production costs based on customer class metered demand, and not the lower firm capacity amount reduced for interruptible capacity, FPL over-allocates costs to the interruptible customer classes.

Q. PLEASE EXPLAIN FURTHER.

A. By allocating the full embedded generation costs to the CILC and CDR customer classes at the measured demand and failing to adjust for the non-firm amount of that peak demand in the allocation of costs, FPL's cost of service analysis misaligns cost

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9 *See* Exh. TMG-3 (FPL Response to FRF's First Set of Interrogatories No. 7).

causation with cost recovery. It should correct the analysis by crediting the full embedded cost value of the interruptible capacity back to the participating CDR and CILC customer classes, but FPL does not attempt this.

Embedded costs evaluated in the FPL cost of service study represent the accumulated historical and recent costs for FPL's generation and transmission system. FPL did not design its system or construct production assets to serve CDR and CILC customer interruptible loads. To properly match FPL embedded costs to those classes, such production costs should only be allocated to CILC and CDR firm loads, and not the interruptible component. This would properly align cost allocation with cost causation.

Q. WHAT ARE THE EMBEDDED COSTS FPL HAS INCURRED FOR GENERATION AND TRANSMISSION SERVICE AND THE RELATED UNIT COSTS FOR THOSE SERVICES?

A. Exhibit TMG-2 details the system-level total costs for generation and transmission services and translates those total costs to unit costs (i.e., per kW) based on the FPL system coincident peak billing determinants. I used FPL's coincident peak demand billing units to reflect the unit cost values during peak demand periods on the system because that best aligns with periods when the CILC and CDR services would most likely be activated by FPL.

Generation unit costs, based on the coincident peaks, are $14.49 per kW, and the transmission costs are $4.17per kW for the 2023 Test Year. Thus, the total unit cost for generation and transmission for the FPL system based on coincident peak demands is $18.66 per kW. When the 20% reserve margin is applied to this total it becomes $22.39 per kW. This amount fully reflects FPL's embedded cost of firm capacity and the on-going value to the system of the existing CILC/CDR interruptible load.

Q. IS THIS EMBEDDED UNIT COST MORE REFLECTIVE OF THE BENEFIT AND VALUE THE CILC AND CDR CUSTOMERS HAVE PROVIDED AND CONTINUE TO PROVIDE FPL THAN THE PROPOSED INCENTIVE BY MR. SIM?

A. Yes. If the forward-looking, marginal new resource basis proposed by Mr. Sim is used to value the CDR incentive, it will not match the historical and recent benefits FPL has realized with these customers for more than two decades. Adopting FPL's proposed reduced incentive for the CILC and CDR interruptible customer loads substantially under-states the value provided by those customers to FPL and firm service.

Q. DO YOU RECOMMEND THAT THE CDR CREDIT BE INCREASED?

A. Yes. As I explain below, looking at the expected change in capacity costs in the next four years, the CDR credit value should be increased to $10.07 per kW-month.

B. FUTURE COSTS OF FIRM CAPACITY

Q. MR. SIM STATES THAT A NUMBER OF UTILITY COSTS THAT COULD BE AVOIDED BY DSM BENEFITS HAVE BEEN TRENDING STEADILY

DOWNWARD FOR MORE THAN A DECADE AND WILL CONTINUE.[10] DO YOU AGREE?

A. No. While some DSM-related avoided costs may be declining as referenced in his testimony, the value of firm and dispatchable capacity resources has and is not. As seen in the following figures, the near-term projected costs for firm capacity are not steadily declining across the Eastern and Southern United States.

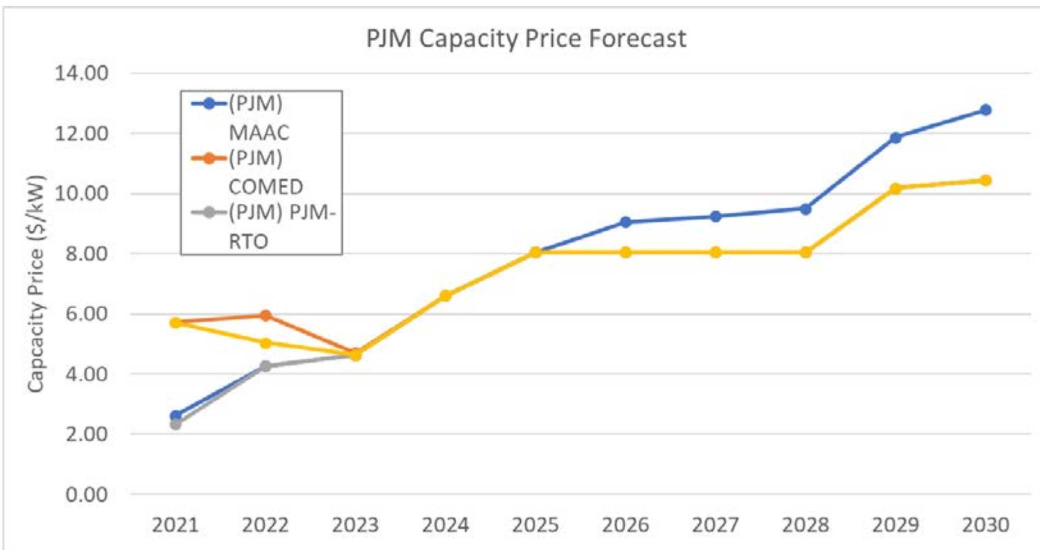

Figure 1: PJM Capacity Price Forecast [11]

[10] Sim Direct at 30.

[11] S&P Global Market Intelligence Power Forecast.

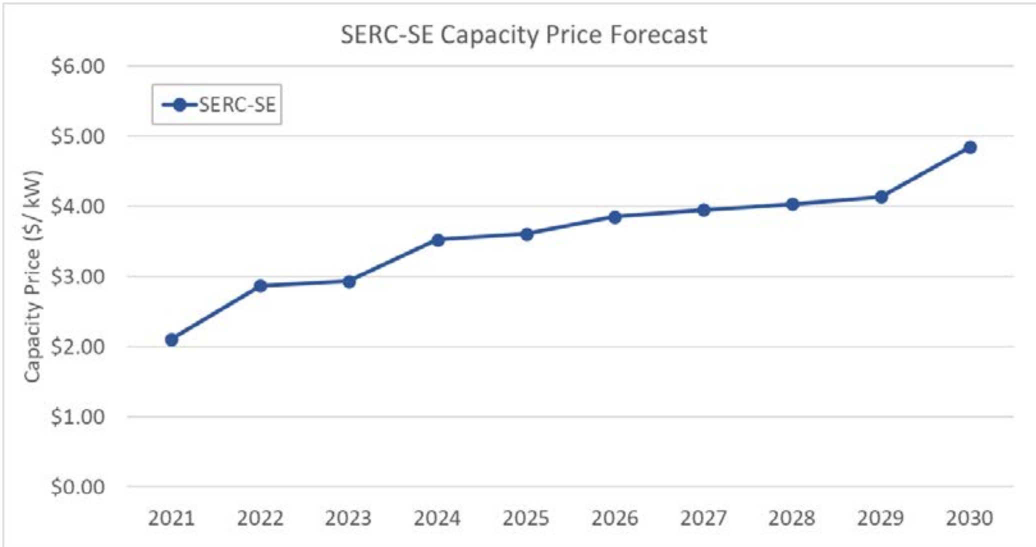

Figure 2: SERC-SE Capacity Price Forecast[12]

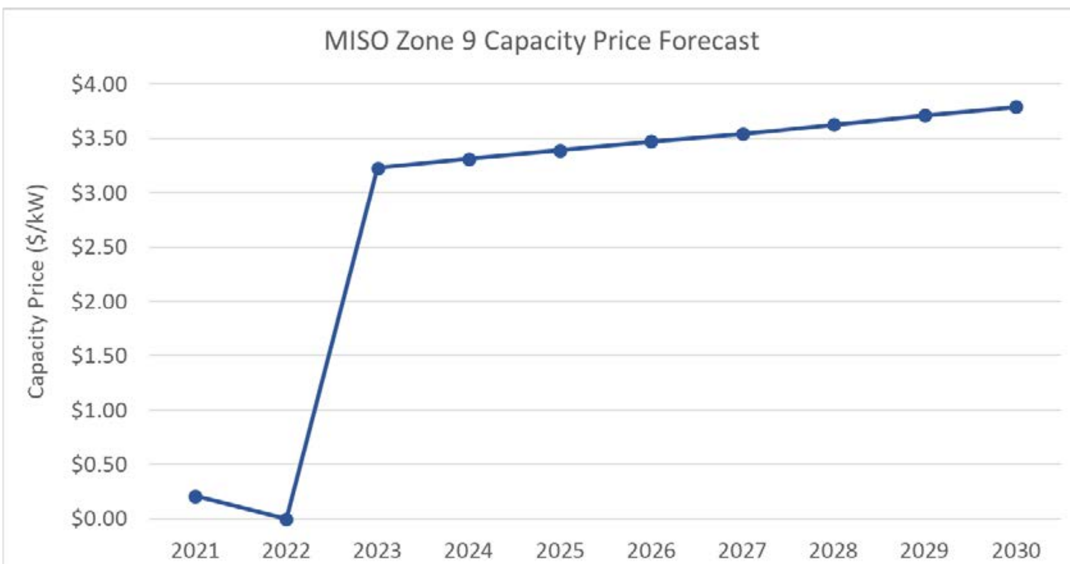

Figure 3: MISO Zone 9 Capacity Price Forecast[13]

[12] S&P Global Market Intelligence Power Forecast.

[13] S&P Global Market Intelligence Power Forecast.

Q. WHAT ARE THE PROJECTED COMPOUNDED ANNUAL GROWTH RATES FOR 2022 THROUGH 2025 IN EACH OF THESE THREE MARKET PROJECTIONS?

A. The compounded average annual growth rates are 17.2% for PJM, 5.9% for SERC-SE, and 1.6% for MISO zone 9. In each case, these projected costs for firm capacity are not decreasing, but increasing substantially. In SERC-SE, the SERC reliability subregion that includes Florida, the capacity costs are projected to increase by 5.9% per year from 2022 through 2025.

Q. WHY DID YOU CALCULATE THE AVERAGE ANNUAL GROWTH FOR YEARS 2022 THROUGH 2025?

A. I selected 2022 through 2025 for SERC-SE because that is a four year period that aligns with the FPL rate plan and Mr. Sim's methodology for calculating the proposed CILC/CDR incentive levels. Mr. Sim noted the setting of incentive levels for DSM programs should ensure the programs remain cost-effective for a minimum of four years.[14]

Q. USING MR. SIM'S METHODOLOGY, COULD THESE PROJECTIONS BE APPLIED TO CALCULATE THE CILC/CDR CREDIT VALUES IN FPL'S CALCULATION METHODOLOGY?

A. Yes. Following Mr. Sim's methodology of a forecasted trend in capacity values, the escalation rates seen in the above examples could be applied to the current CILC/CDR credit value to calculate a new value applicable during the period covered by the proposed FPL rate plan.

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[14] Sim Direct at 31.

Q. WHICH OF THE ANNUAL GROWTH RATES DID YOU APPLY TO THE CURRENT CILC/CDR CREDIT VALUE?

A. As Florida is located in the SERC-SE reliability subregion, the firm capacity price forecast and subsequent escalation rates for that region were applied to the current CILC/CDR credit value.

Q. WHAT IS THE RESULT OF APPLYING THE ESCALATION RATES FOR CAPACITY TO THE CILC/CDR CREDIT?

A. Table 1 shows the annual CDR credit value when the average annual growth rate in SERC-SE is applied for 2022 through 2025.

Current	**2022**	**2023**	**2024**	**2025**	**Average (2022-2025)**
$8.71	$9.22	$9.77	$10.34	$10.95	$10.07

Q. WHAT IS YOUR RECOMMENDATION FOR THE VALUE OF THE CILC/CDR CREDIT?

A. Applying FPL's methodology of projected changes in costs and value for capacity, the CDR credit should be increased to $10.07 per kW-month to reflect the average change in value over the four year proposed rate plan.

C. <u>FPL RATE IMPACT MEASURE TEST VALUATION AND APPLICATION TO CILC AND CDR CREDIT</u>

Q. FPL PROPOSES TO RE-SET THE CILC/CDR CREDIT TO A REDUCED LEVEL THAT WOULD PRODUCE A RIM OF 1.45. DO YOU AGREE WITH THAT APPROACH?

A. No. Even if the embedded benefits of interruptible service discussed above were disregarded, there is no rational basis for reducing the credit below a level that would yield a RIM measurement of 1.0. As stated previously, firm capacity costs are not expected to decline, but increase. Reducing the credits to achieve a RIM of 1.45 is inconsistent with expected market conditions for firm capacity costs.

D. <u>CILC AND CDR CONCLUSIONS AND RECOMMENDATIONS</u>

Q. PLEASE SUMMARIZE YOUR CILC AND CDR VALUATION CONCLUSIONS.

Lowering the value of the CILC and CDR capacity as FPL proposes is inconsistent with the avoided embedded costs provided by the programs and current projections of firm capacity costs, as well as their on-going benefits provided to the FPL and its firm service customers. No credit reduction is warranted, and the credit should be increased.

It is not easier or cheaper to construct firm dispatchable capacity across the Eastern and Southern United States. Those costs are projected to increase, not decrease. At a minimum, FPL's proposal to exaggerate the reduction in the interruptible service credit by re-setting the credit using a RIM of 1.45 is arbitrary and completely unwarranted.

Considering further the heightened importance of reliable capacity resources as weather sensitive intermittent resources on the FPL system increase, FPL's proposal goes in exactly the wrong direction. The credit should not be reduced below the current level of $8.71 per kW-month but should in fact be increased to $10.07 per kW-month.

V. <u>FPL'S COST OF SERVICE AND REVENUE ALLOCATION ERRORS</u>

Q. PLEASE SUMMARIZE YOUR FINDINGS CONCERNING FPL'S COST OF SERVICE STUDY AND PROPOSED REVENUE ALLOCATION FOR ANY BASE RATE INCREASE?

A. As noted above, FPL's cost of service study allocates generation and transmission production costs among service classes based on the metered 12 monthly coincident peaks for the study period without regard for interruptible load on its system. This systematically allocates costs to those classes with interruptible load that FPL does not build generation to serve. FPL's tariff could not be clearer on that point. FPL has not and does not propose to account for service to its interruptible non-firm loads in its generation planning and construction (see the CILC tariff "Continuity of Service Provision"), and its Ten Year Site Plans exclude commercial and industrial load management when determining the Net Firm Demand upon which its capacity reserve margin and generation need determinations are based. FPL's cost of service study simply is inconsistent with these facts.

That basic mis-match distorts the results of the cost of service study, and, by extension FPL's proposed allocation of revenue increases among the service classes that is based on the cost of service study, including in particular the service classes for which it proposes to apply an above system average (1.5 times) increase.

Q. ON SCHEDULE E-5 OF ITS MFRS, FPL ADDS INTERRUPTIBLE REBATES BACK TO THE INTERRUPTIBLE CLASSES IN THE FORM OF A "CILC INCENTIVE OFFSET" TO THE CLASS SALES REVENUES. DOES THIS CORRECT THE BASIC ERROR IN THE COST OF SERVICE STUDY?

A. No. The cost of service study allocates FPL's embedded costs, and the CILC/CDR credit, while a negotiated level in recent years, is based on FPL's avoided costs. The CILC incentive offset on Schedule E-5 reflects the rebate level and not the embedded cost benefits of the interruptible service. From a rate-setting standpoint, it is always hazardous to mix embedded and avoided costs concepts. This misaligns embedded costs and marginal avoided costs concepts in an embedded cost of service by FPL.

Q. PLEASE EXPLAIN.

A. Because it is an embedded cost of service study, to correctly apply the value of the interruptible service programs, the credit offset approach that FPL employs in its study would need to reflect FPL's embedded production and transmission plant costs. As I explained above, that embedded value is approximately $22.39/kW-month, or well more than double the current rebate level that FPL applied on Schedule E-5. Consequently, the study still significantly over-allocates production costs to the service classes with interruptible service participants. This materially under-states the interruptible customer class rates of return shown in the cost of service study.

A. MINIMUM DISTRIBUTION SYSTEM METHODOLOGY AND APPLICATION

Q. PLEASE DESCRIBE THE MDS METHODOLOGY?

A. Distribution costs are driven by the utility's requirement to connect customers to the system no matter where they are located within its service area and the demand requirements those customers place on the system. The MDS method classifies costs as either customer-related or demand-related based on the concept of a minimum system. A minimum system simply represents that infrastructure cost required to connect a customer to the grid without further consideration of the customer's demand and energy requirements. This involves determining the minimum size of pole, conductor, transformer, and service drops required to simply connect to a customer premises. Once the minimum sizes of the distribution system components are determined, the value of the MDS plant is determined. This MDS portion of the total distribution plant is classified as customer-related and allocated to customer classes based on the number of customers. The remaining portion of the distribution plant is classified as demand-related and allocated to customers based on non-coincident peak demand allocation factors.

For example, if the total distribution plant value was $500 million and the MDS study calculated that $100 million was related to the minimum system, then 20% of the distribution plant would be classified as customer-related and allocated accordingly. The remaining 80% would remain classified as demand-related and allocated accordingly. Use of MDS represents a fair classification of distribution costs to customers because it recognizes that the physical location of the customer is an important driver of costs and these costs should be properly classified as customer-related.

Q. IS THE MDS METHODOLOGY FOR CLASSIFYING COSTS AN ACCEPTED INDUSTRY PRACTICE AND CLASSIFICATION METHODOLOGY?

A. Yes. The National Association of Regulatory Utility Commissioners recognizes and details the use and application of the MDS methodology.

Q. WHY SHOULD THE MDS BE APPLIED AND INCLUDED IN THE FPL COST OF SERVICE?

A. The MDS more accurately reflects the costs incurred by the utility to simply connect to customers. It calculates the minimum distribution component sizes for poles, transformers, and conductors to simply connect a customer's meter to the distribution substations to receive power. These distribution assets and infrastructure are required if the customer's peak demand is 10 kW or 0kW. As there is a certain level or amount of distribution assets and infrastructure required whether or not the customer is using any power, a portion of the distribution system costs should be classified as customer related. This customer portion of the distribution costs does not vary with the demand levels, it varies with the number of customers; thus, it should be classified as customer-related.

Q. SHOULD THE MINIMUM DISTRIBUTION SYSTEM (MDS) METHODOLOGY BE APPLIED AND ADOPTED WITH THE FPL RATE PROCEEDING?

A. Yes, it should be included in this and subsequent FPL rate proceedings. It should be included to better reflect the costs imposed on the system by each customer class. The MDS is a long-standing accepted methodology for classifying distribution costs as both customer and demand related. These costs are then allocated on customer and demand allocation factors to the customer classes.

Q. HOW HAS FPL APPLIED THE MDS TO THE PROCEEDING?

A. FPL included an MDS assessment for informational purposes but does not propose to apply the MDS approach in its cost of service analysis. The FPL-prepared MDS cost of service and MFRs are summarized in FPL witness Tara Dubose's Exhibit TBD-7 and TBD-8.

B. RECOMMENDATIONS

Q. WHAT ARE YOUR RECOMMENDATIONS FOR CORRECTING FPL'S COST OF SERVICE STUDY AND PROPOSED REVENUE ALLOCATION?

A. From a bottom line perspective, the erroneous allocation of production costs to non-firm load and FPL's failure to incorporate the MDS approach both indicate that FPL's proposed allocation of above system average increases to its commercial and industrial service classes is not supportable. For the purposes of this case, rather than attempting to re-build the cost of service study from the ground up, I recommend that FPL apply an equal percentage increase to all customer classes for any base rate revenue increase that the Commission may authorize. This approach is appropriate under the circumstances and consistent with the revenue allocation that FPL proposes to apply in the years 2024 and 2025 for its SOBRA-related base rate increases.

VI. RESERVE SURPLUS AMORTIZATION MECHANISM (RSAM)

Q. FPL'S PROPOSED MULTI-YEAR RATE PLAN IS TIED TO ADOPTION, WITH MODIFICATIONS, OF THE RESERVE SURPLUS AMORTIZATION MECHANISM ("RSAM") APPROVED AS PART OF FPL'S 2016 RATE SETTLEMENT. DO YOU SUPPORT APPROVAL OF THE PROPOSED RSAM IN THIS CASE?

A. No. The proposed RSAM is not in the public interest and should not be approved.

Q. PLEASE EXPLAIN.

A. First, the dollars at issue with this mechanism involve the timing of recovery of utility assets from ratepayers through depreciation expense. The proposed RSAM permits FPL to manipulate the timing of charges to depreciation to manage its regulated earnings, and not to benefit consumers. In very brief terms, if FPL's earnings are below its selected target, the utility would implement adjustments to lessen depreciation expense (enhancing reported earnings) and increase its perceived excess depreciation reserve. This is not a zero sum game since this action would create a corresponding increase in rate base that would add to FPL's current return on investment while consumers will be charged higher depreciation in the future to ensure full recovery of the asset costs over time.

If, on the other hand, FPL's earnings looked to exceed its target, the process is reversed: FPL would book increased depreciation expense and lower the perceived reserve. This protects FPL and its shareholders against an excess profit-based rate reduction, but provides no consumer benefit at all.

Q. PLEASE CONTINUE.

A. The reserve surplus refers to a calculated excess in the theoretical depreciation reserve. The theoretical reserve is the calculated balance that would be in the reserve if the service life and net salvage estimates now considered appropriate had always been applied. The book reserve is the amount actually recovered to date. When the actual reserve exceeds the theoretical reserve, it is considered a surplus. When the actual reserve is less than the theoretical reserve, it is considered a deficiency. Comparing the theoretical reserve to the booked amounts provides a general check upon completion of a depreciation analysis to ascertain that the timing of asset cost recovery remains basically on track. Lesser deviations are generally captured in subsequent filings where, as in Florida, the remaining life method is employed. When either a surplus or a deficiency is significant, a ratemaking correction is made to utility rates to keep asset recovery on track with expected service lives. In any event, over time utility ratepayers pay for the full prudently incurred cost of the assets eventually, and correcting a material reserve surplus or deficiency can best be seen as an adjustment in the timing of that recovery.

In its 2016 base rate case, FPL apparently had a substantial reserve surplus. Correcting this excess normally should produce a credit for current consumers in determining a base rate revenue requirement or additional debits to write-down other assets. Instead, the rate settlement produced the RSAM as one of its key features. The RSAM allowed FPL to debit or credit the reserve surplus as needed, in FPL's judgement, to maintain reported earned return on equity within its accepted range (i.e., within 100 basis points of its ROE midpoint range of 10.6%, or 11.6%).[15] Given the expanding level of FPL's rate base, that 100 basis points equates to an additional $360 million in revenue to FPL in 2022 for which there is no underlying cost justification.[16]

The existence of a material reserve surplus is evidence of a depreciation timing mis-match that should be corrected for consumer benefit, RSAM effectively converts the surplus into an earnings maximization mechanism benefitting shareholders. While the mechanism may have been justified in 2016 as part of the compromises and trade-offs inherent in a comprehensive rate settlement, there is no justification for it on its own merits.

Q. DO YOU HAVE OTHER OBSERVATIONS CONCERNING FPL'S PROPOSED RSAM IN THIS DOCKET?

A. Yes. The most obvious is that the RSAM mechanism requires funding through the presence of a large surplus reserve and in this case there is no reserve surplus of any kind. FPL's 2021 depreciation study, sponsored by FPL witness Ned Allis, does not show a reserve surplus, but instead shows a reserve deficiency of $437 million. Thus,

[15] In practice, the reserve amount is adjusted by manipulating the cost of the removal element of the depreciation reserve.

[16] Barrett deposition at p.86.

based on FPL's 2021 depreciation study and Mr. Allis' testimony, there is no foundational predicate for an RSAM at all.

Undaunted, FPL witness Keith Ferguson, proposes a series of plant service life extensions (Exh. KF-3 (B) that are at odds with Mr. Allis' recommendations and are designed to lower depreciation expense by $239 million in 2022 and $249 million in 2023. With these adjustments, when added to an expected 2021 reserve ending balance of $340 million, FPL manages to manufacture a reserve surplus of $1.48 billion that could be used for RSAM purposes.[17] Mr. Ferguson's proposed adjustments are intended solely to create an opportunity to employ the proposed RSAM and are withdrawn if that mechanism is not adopted.

This proposal raises serious issues. Deciding what reasonable service lives should be employed for key FPL production assets in the development of depreciation rates should clearly stand on its own merits. The presence of a depreciation reserve surplus or deficiency should be a fall-out of a sound depreciation analysis and not a designed target. As noted above, comparisons of the actual and theoretical reserves are a check on that process and not something to target as an outcome.

Mr. Allis and Mr. Ferguson each claim they have a reasoned basis for their proposals, but FPL clearly cannot have it both ways. The Commission should reject any effort to manufacture a reserve disparity not grounded in a sound analytical assessment.

[17] This adjustment correspondingly increases the rate base on which FPL earns a return compared to what would otherwise occur.

Q. PLEASE CONTINUE.

A. Regardless of the earnings level achieved, no benefits accrue to ratepayers under FPL's proposed RSAM. This is a fundamental flaw in the mechanism. FPL can debit depreciation expense (and credit the reserve) to hold reported earnings to the permitted high end of its range up to the maximum proposed level of $1.48 billion. If FPL's earnings position remained strong, it could then, other factors being equal, transition to an excess earnings position. In that circumstance, however, the FPL RSAM proposal would permit the utility to begin adjusting the amortization expense of other assets recorded on its Capital Recovery Schedule (Exhibit KF-4) sufficient to cover the full $512 million planned for the period 2022–2025, except the amortization schedule for those assets is already built into the proposed revenue requirements for 2022 and 2023.[18] The RSAM effectively prevents such earnings from being applied to further write down those assets to a period beyond the proposed term of the rate plan. Applying what would otherwise be considered excess earnings to asset write-downs should be among the first uses of a large reserve surplus, so the proposed RSAM treatment conflicts with accepted regulatory practice. In any circumstance in which the RSAM is applied to keep FPL reported earnings in the accepted range, some tangible consumer benefit is required as well by writing down a commensurate level of FPL's regulatory assets.

Finally, FPL proposes that the RSAM remain in effect after the proposed four year rate plan until base rates are re-set by the Commission. This more or less ensures that FPL

[18] *See* FPL Exhibit KF-4.

could not, at least in the foreseeable future, be found to be in an excess earnings situation.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO FPL'S RSAM PROPOSAL?

A. It is essential to recognize at the outset that consumers will eventually be charged in rates for the full prudently incurred costs of FPL's assets. Depreciation rates and corrections associated with a depreciation reserve surplus merely affect the timing of that recovery. The accounting treatments proposed through the RSAM manage utility earnings in the short term but can also skew the appropriate timing of asset recovery from consumers and create other rate issues down the line. With that in mind, I recommend that:

1. The Commission reject the RSAM proposal as unwarranted and not in the public interest.
2. If the final approved depreciation rates demonstrate that a substantial reserve surplus exists, I recommend that 50% of the excess be applied to reducing the base rate revenue requirement and 50% be applied to amortizing FPL assets listed on the Capital Recovery Schedule. This approach would be fair to rate payers and FPL.
3. If an RSAM is approved by the Commission, at least two adjustments are required to benefit consumers.
    a. Any RSAM credits to the reserve should be matched by an equal supplemental credit to assets on the Capital Recovery Schedule, reducing the amounts to be amortized in the future.

b. The Commission should direct that the RSAM expire at the end of proposed term of the rate plan (i.e., yearend 2025 under FPL’s proposal or whatever term the Commission may lawfully fix).

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

NewGen Strategies & Solutions

Tony Georgis
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Tony Georgis brings 20 years of experience in the consulting/utilities industry focusing on the energy, water, and waste resources industries. He is the Managing Director of NewGen Strategy and Solutions, LLC's Energy Practice. His work includes various assignments for utilities, local governments, and private industry, including sustainability strategy, strategic planning studies, expert witness testimony, financial and economic analyses, cost of service and rate studies, energy efficiency, and market research.

In support of sustainability strategy projects, Tony has developed frameworks, optimization, and decision models for sustainability program prioritization and monetization of climate change regulatory, market, and physical impacts. He has also been published in trade journals such as Resource Recycling, Utility Automation and Engineering T&D and has spoken on this topic at several industry conferences.

EDUCATION

- Master of Business Administration, Finance Specialization, Texas A&M University
- Bachelor of Science in Mechanical Engineering, Texas A&M University

PROFESSIONAL REGISTRATIONS / CERTIFICATIONS

- Registered Professional Engineer (PE) Mechanical, Colorado
- Registered Professional Engineer (PE) Mechanical, Louisiana

KEY EXPERTISE

- Sustainability
- Strategic Planning
- Expert Witness and Litigation Support
- Financial / Economic Analysis
- Cost of Service and Rate Design

RELEVANT EXPERIENCE

Sustainability, Energy Strategy, and Strategic Planning

Mr. Georgis has led and managed the development of strategic plans and Roadmaps for utilities, energy agencies and municipal governments to guide decision making in increasing complex business environments. His strategic planning experience includes energy, water, wastewater, and solid waste utilities in addition to local government entities. In support of strategic planning engagements, Mr. Georgis often facilitates internal planning teams and external stakeholder engagement activities to facilitate broad and/or targeted stakeholder input to the plans. Strategic plan or Roadmap development typically include overarching strategic elements such as the organization's vision/mission; tactical components such as projects and activities supporting and ensuring implementation; and tracking/reporting tools for the organization's measurement of progress to the plan.

Mr. Georgis has also led the development of clean energy and sustainability (or CSR) plans for cities, counties and utilities to improve triple bottom line (economic, environmental, and social) and energy performance. Mr. Georgis utilizes an enterprise-wide approach to sustainability in order to manage regulatory, customer, and financial demands while improving the triple bottom line. He has facilitated the development of city-wide sustainability plans, serving as a sustainability subject matter expert while forging collaboration among internal and external stakeholders including city/utility staff, key department managers, community representatives, utility customers, and non-profit or non-governmental organizations (NGOs). In support of sustainability planning efforts, Mr. Georgis has developed optimization models to prioritize and identify the "next best dollar spent" in pursuit of sustainability goals while estimating total costs to implement. He has also implemented sustainability auditing/reporting tools such as GHG inventories/reporting and development of a utility-tailored version of the Global Reporting Initiative (GRI).

Mr. Georgis' clients for sustainability, energy strategy, and strategic planning include:

- City of Fort Collins, Colorado
- Fort Collins Utilities, Colorado
- Loudoun County, Virginia
- Tampa Bay Water, Florida
- City of Colorado Springs, Colorado
- City of Longmont, Colorado
- City of El Paso, Texas
- Western Area Power Administration, Colorado
- Lakeland Electric, Florida
- City of Palo Alto Utilities, California

Cost of Service and Rate Design

In his role as senior consultant and project manager, Mr. Georgis leads numerous utility financial planning, cost of service, and rate design projects. Specific tasks typically include the development of the revenue requirement, functionalization of costs, allocation of costs to customer classes, review of existing customer class criteria, evaluation of line extension and facilities charges, rate design, and transitioning of models for the client's future use. He has also led the development of financial forecasting models to support long-term capital, expense, and revenue budgeting and decision making. Mr. Georgis routinely facilitates workshops in support of developing utility rate strategies or rate studies and presents study and financial recommendations to governing bodies, boards, and city councils. Mr. Georgis' clients for cost of service and rate design include:

- American Samoa Power Authority
- U.S. Army; Huntsville, Alabama
- Colorado Springs Utilities, Colorado
- La Plata Electric Association, Colorado
- Vernon Gas and Electric, California
- Alameda Municipal Power, California
- Anaheim Public Utilities, California
- Merced Irrigation District, California
- Alameda Municipal Power, California
- Glendale Water and Power, California
- Imperial Irrigation District, California
- Pasadena Water and Power, California
- Lafayette Utilities System, Louisiana
- City Utilities, Springfield, Missouri
- Lincoln Electric System, Nebraska
- Farmington Electric Utility, New Mexico
- Cleveland Public Power, Ohio
- Lubbock Power and Light, Texas
- City of Weatherford, Texas
- New Braunfels Utilities, Texas
- Austin Energy, Texas
- City of Garland, Texas
- Benton Public Utility District, Washington
- Arizona Public Service, Arizona

Economic, Financial or Market Analyses

Mr. Georgis often provides technical, financial, and advisory support services for various energy and utility related projects. He is an expert in developing financial pro formas, bond financings, performing scenario analyses, and evaluating market conditions to support project financing or feasibility decision making. He has analyzed technical assumptions, optimized project financing, performed scenario/sensitivity analyses, and assisted clients in bidding processes. He has provided economic analyses of utility scale renewable energy projects, power plant fuel conversions, LNG terminals, conventional/renewable distributed energy resources, and DSM/demand response program benefits. Mr. Georgis' clients for economic, financial or market analyses include:

- Terrebonne Parrish, Louisiana
- Hawaii Gas Company, Oahu, Hawai'i
- U.S. Army; Huntsville, Alabama
- Florida Municipal Power Agency, Florida
- Austin Energy, Texas
- CalRecycle, California
- Arizona Power Authority, Arizona
- Water and Power Authority, US Virgin Islands
- Solid Waste Authority of Central Ohio, Ohio
- Freeport Container Port, Grand Bahama
- Maryland Energy Administration, Maryland
- ISO-New England, Massachusetts
- Niobrara Energy Development, Colorado
- Fort Collins Utilities, Colorado

Expert Witness and Litigation Support

Mr. Georgis has provided expert testimony since 2014 regarding electric utility revenue requirement, cost of service, rate design, and ratemaking issues before state and local regulatory bodies and courts. He has national experience providing litigation support regarding ratemaking matters at wholesale and retail levels in California, Florida, Indiana, and Texas.

Mr. Georgis' expert witness and litigation support experience includes:

Public Utility Commission of Texas

- Southwestern Electric Power Company (SWEPCO); SOAH Docket No. 473-21-0538 and PUC Docket No. 51415
- City of Lubbock, Lubbock Power & Light; SOAH Docket No. 473-21-0043 and PUC Docket No. 51100
- Centerpoint Energy Houston Electric, LLC; SOAH Docket No. 473-14-3897 and PUC Docket No. 42560

Indiana Utility Regulatory Commission

- Northern Indiana Public Service Company LLC (NIPSCO); Cause No. 45159

Florida Public Service Commission

- Duke Energy, Florida; Docket No. 20210016-EI

Superior Court of the State of California for the County of Los Angeles

- City of Pasadena – Pasadena Water and Power; No. BC 677632

PRESENTATIONS AND PUBLICATIONS

Mr. Georgis has presented at numerous industry associations and conferences, providing training for utility staff, and published several trade journal articles. These presentations, articles, and training have focused on utility finance, strategic planning, market trends/opportunities, and sustainability. Mr. Georgis' presentations and publications are displayed below.

Industry Presentations

- Tire Industry Association Recycling Conference 2008: *Selling Tire-derived Products to the Architectural and Construction Markets*
- Tire Industry Association Recycling Conference 2009: *Carbon Credits and Recycling Products*
- Platts Energy Markets Webinar 2010: *SEC Guidance on Climate Change Disclosures*
- Association of Climate Change Officers 2010: *SEC Climate Change Disclosure Guidance*
- Harvard University Zofnass Program for Sustainable Infrastructure 2011: *Tools and*

Tony Georgis

Managing Director, Energy Practice

- Energy Utility and Environmental Conference 2010: *Evolution and Optimization of Energy Efficiency and Smart Grid Measures*
- Tire Industry Association Scrap to Profit 2010: *Evolution of the Carbon Markets and Opportunities for the Scrap Tire Industry*
- Inter-American Development Bank 2010: *Transportation Sustainability and Climate Change Seminar*
- University of Colorado Denver Managing for Sustainability 2012: *Regulatory Drivers for Sustainability*
- Global Commerce Conference 2010: *Leadership in Sustainability – Sustainability Decision Making, Implementation and Reporting Frameworks to Drive the Business Case for Sustainability*
- Washington PUD Association Finance Officers 2016: *Balancing Aging Infrastructure, Rates, and Residential Demand*
- APPA National Conference – Preconference Seminars 2017, 2018, 2019: *Distributed Energy Resources: Risks and Opportunities*
- APPA Business and Finance Conference Preconference Seminar 2019: *Distributed Energy Resources: Risks and Opportunities*
- APPA Legislative Rally Preconference Seminar 2020: *Demystifying Distributed Energy Resources*

Industry Publications and Articles

- *Growing Role for Demand Response in ISO Operations*. Utility Automation and Engineering T&D, November 2008
- *Recycling and Climate Change: A Primer*. Resource Recycling, August 2009
- *Recycling and Climate Change: Opportunities for Recycling as a Climate Change Strategy*. Resource Recycling, September 2009

Record of Testimony: Tony Georgis

Utility	Proceeding	Subject	Before	Client	Date
1. Southwestern Electric Power Company (SWEPCO)	SOAH Docket No. 473-21-0538 PUC Docket No. 51415	Application of Southwestern Electric Power Company for Authority to Change Rates	State Office of Administrative Hearings, Public Utility Commission of Texas	Office of Public Utility Counsel	2021
2. City of Pasadena – Pasadena Water and Power	BC 677632	Komesar vs. City of Pasadena; State of California Proposition 218, City General Fund Transfer from Utility	Superior Court of the State of California for the County of Los Angeles	Jarvis, Fay and Gibson, LLP; City of Pasadena	2021
3. City of Lubbock, Lubbock Power & Light	SOAH Docket No. 473-21-0043 PUC Docket No. 51100	Application of the City of Lubbock for Authority to Establish Initial Wholesale Transmission Rates and Tariffs	State Office of Administrative Hearings, Public Utility Commission of Texas	Lloyd Gosselink Rochelle & Townsend, P.C.	2020
4. Northern Indiana Public Service Company LLC (NIPSCO)	Cause No. 45159	Petition of Northern Indiana Public Service Company LLC (NIPSCO) Authority to 1) Modify Electric Utility Rates; 2) Approval of New Schedules of Rates and Changes, General Rules and Regulations and Riders; 3) Approval of Revised Common and Electric Depreciation Rates; 4) Accounting Relief; and 5) Approval of New Service Structure for Industrial Rates	Indiana Utility Regulatory Commission	Bose McKinney & Evans LLP, United States Steel Corporation	2019
5. CenterPoint Energy Houston Electric, LLC	SOAH Docket No. 473-14-3897 PUC Docket No. 42560	Application of CenterPoint Energy Houston Electric, LLC for Approval of an Adjustment to its Energy Efficiency Cost Recovery Factor	State Office of Administrative Hearings, Public Utility Commission of Texas	Lloyd Gosselink Rochelle & Townsend, P.C., Gulf Coast Coalition of Cities	2014

Florida Public Service Commission
Florida Power and Light Company
Docket No. 20210015-EI
CILC and CDR Embedded Cost Basis Value

Line No.			Total System TY 2022 (1)		Total System SYA 2023 (2)	Note, Comment, and Source (3)
1	**Demand**		($000)		($000)	
2	**Revenue Requirements**					
3	Production - Steam		309,358		312,282	FMR-6B Att2 2022 and 2023 Proposed Rates
4	Production - Nuclear		958,066		1,005,869	FMR-6B Att2 2022 and 2023 Proposed Rates
5	Production - Other Production		2,428,535		2,638,166	FMR-6B Att2 2022 and 2023 Proposed Rates
6	Production - Other Power Supply		4,998		5,336	FMR-6B Att2 2022 and 2023 Proposed Rates
7	Production - Curtailment Credit		0		0	Curtailment Credit eliminated
8	Proposed Production Total	$	3,700,957	$	3,961,652	
9						
10	Proposed Transmission	$	970,218	$	1,140,898	FMR-6B Att2 2022 and 2023 Proposed Rates
11						
12	12 CP (MW)		22,422		22,791	MFR E-9 Avg. 12CP
13						
14	Embedded Interruptible Value					
15	Production ($/MW/Mo.)	$	13,755	$	14,485	Row 8 * 1,000 / Row 12 / 12 Months
16	Transmission ($/MW/Mo.)	$	3,606	$	4,172	Row 10 * 1,000 / Row 12 / 12 Months
17	Total	$	17,361	$	18,657	
18						
19	Production ($/kW/Mo.)	$	13.76	$	14.49	Row 15 / 1,000
20	Transmission ($/kW/Mo.)	$	3.61	$	4.17	Row 16 / 1,000
21	Total	$	17.36	$	18.66	
22						
23	Reserve Margin		20%		20%	Schedule 7.1 FPL 10-Year Site Plan
24	Added value of CDR Credit	$	3.47	$	3.73	Row 23 * Row 21
25	Total Value of CDR ($/kW/Mo.)	$	20.83	$	22.39	Row 24 + Row21
26						
27	Current CDR Credit ($/kW/Mo.)	$	8.71	$	8.71	
28	Proposed CDR Credit ($/kW/Mo.)	$	5.80	$	5.80	

QUESTION:
Please provide the total amount (kW) of curtailment and/or interruptible power by customer class for FPL and Gulf separately and combined for the years 2016-2020 and forecast for test years 2022 and 2023.

RESPONSE:
Historical Curtailment/Interruptible Capacity (MW)[1]

FPL	Summer MW		Winter MW	
Year	Residential Load Management	Commercial & Industrial Load Management	Residential Load Management	Commercial & Industrial Load Management
2016	882	856	742	588
2017	910	846	759	596
2018	866	882	750	608
2019	852	896	706	635
2020	845	896	702	630

Gulf	Summer MW		Winter MW	
Year	Residential Load Management	Commercial & Industrial Load Management	Residential Load Management	Commercial & Industrial Load Management
2016	29	0	17	0
2017	32	0	19	0
2018	34	0	21	0
2019	36	0	21	0
2020	36	10	22	10

Combined	Summer MW		Winter MW	
Year	Residential Load Management	Commercial & Industrial Load Management	Residential Load Management	Commercial & Industrial Load Management
2016	911	856	759	588
2017	942	846	778	596
2018	900	882	771	608
2019	888	896	727	635
2020	881	906	724	640

Forecast Curtailment/Interruptible Capacity (MW)[1]
Integrated FPL and Gulf (MW)

	Summer MW		Winter MW	
Year	Residential Load Management	Commercial & Industrial Load Management	Residential Load Management	Commercial & Industrial Load Management
2022	912	957	750	669
2023	923	969	763	676

1. Values for Interruptible and Curtailable capacity are reflected as Load Management in the tables.

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QUESTION:
Please refer to Schedule E-9. Is curtailable or interruptible capacity by customer class integrated in the calculation of the demand allocation factors (e.g., 12CP, 12CP and 1/13th, and Average Demand)? If so, please describe how.

RESPONSE:
No adjustments for curtailable or interruptible capacity were made to the calculation of the demand allocations factors (e.g., 12CP, 12CP and 1/13th,, and Average Demand) shown in MFR E-9.