BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20210015-EI

Petition for rate increase by Florida Power & Light Company.
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VOLUME 7
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PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING: CHAIRMAN GARY F. CLARK
COMMISSIONER ART GRAHAM
COMMISSIONER ANDREW GILES FAY
COMMISSIONER MIKE LA ROSA
COMMISSIONER GABRIELLA PASSIDOMO

DATE: Monday, September 20, 2021

TIME: Commenced: 9:30 a.m.
Concluded: 12:00 p.m.

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

REPORTED BY: DEBRA R. KRICK
Court Reporter

APPEARANCES: (As heretofore noted.)

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(Transcript follows in sequence from Volume 6.)

(Whereupon, prefiled direct testimony of Rachel Wilson was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY OF
RACHEL WILSON

ON BEHALF OF
THE CLEO INSTITUTE AND VOTE SOLAR

June 21, 2021

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and position.

A. My name is Rachel Wilson, and I am a Principal Associate with Synapse Energy Economics, Incorporated (Synapse). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q. Please summarize your work experience and educational background.

A. At Synapse, I conduct analysis and write testimony and publications that focus on a variety of issues relating to electric utilities, including: integrated resource planning; power plant economics; federal and state clean air policies; emissions from electricity generation; environmental compliance technologies, strategies, and costs; electrical system dispatch; and valuation of environmental externalities from power plants.

I also perform modeling analyses of electric power systems. I am proficient in the use of spreadsheet analysis tools, as well as optimization and electricity dispatch models to conduct analyses of utility service territories and regional energy markets. I have direct experience running the Strategist, PROMOD IV, PROSYM/Market Analytics, PLEXOS, EnCompass, and PCI Gentrader models, and have reviewed input and output data for several other industry models.

Prior to joining Synapse in 2008, I worked for the Analysis Group, Inc., an economic and business consulting firm, where I provided litigation support in the form of research and quantitative analyses on a variety of issues relating to the electric industry.

I hold a Master of Environmental Management from Yale University and a Bachelor of Arts in Environment, Economics, and Politics from Claremont McKenna College in Claremont, California.

A copy of my current resume is attached as Exhibit RW-1.

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

A. I am testifying on behalf of Vote Solar and The CLEO Institute Inc.

Q. Have you previously testified before the Florida Public Service Commission ("FPSC" or "Commission")?

A. No.

Q. Have you previously testified before other regulatory commissions?

A. Yes. I have submitted expert testimony in electric utility dockets related to integrated resource planning, advance prudence determination, and rate cases in

Minnesota, Kentucky, Indiana, Oklahoma, Missouri, Texas, Virginia, Washington, Georgia, Mississippi, Alabama, North Carolina, South Carolina, and West Virginia.

Q. Are you providing any exhibits with your testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit RW-1: Statement of Qualifications and Experience

Exhibit RW-2: Carbon Reduction Commitments of US Electric Utilities

2. OVERVIEW OF TESTIMONY AND CONCLUSIONS

Q. What is the purpose of your testimony?

A. My testimony reviews the sufficiency of FPL's resource planning process and evaluates the prudence of FPL's recent and proposed gas investments within that context. Specifically, I note the lack of consideration given to demand side management (DSM) measures as a replacement resource in FPL's resource planning process. I describe the deficiencies in FPL's analysis related to both the coal-to-gas conversion project at Crist Units 6 and 7 and the new combustion turbine units added at the Crist site. I also review the stranded asset risk posed to FPL ratepayers through the Company's continued reliance on gas-fired resources, whether by proposing to extend the useful lives of existing assets from 40 to 50 years, or its various additions that are planned or currently under construction.

Q. Please summarize your conclusions.

A. I conclude that FPL's resource planning process contains several flaws that could increase costs to Florida ratepayers. First, it does not allow adequate consideration of DSM measures during its resource planning process, when third-party analysis has shown that Florida leads the other states in the United States in cost-effective energy efficiency potential. Second, FPL's resource planning approach is further flawed in that it locks down the conversion of the coal-fired Crist Units 6 and 7 units to gas without evaluating their retirement and replacement with alternative capacity. Similarly, FPL made the decision to proceed with new gas-fired combustion turbines at the Crist site, locking this decision in place even when updating its modeling analysis with new forecasts and input assumptions could have changed the ultimate resource portfolio selected by the Aurora model. Lastly, I conclude that FPL's continued reliance on gas puts its customers at sizable stranded asset risk, where they must continue to pay for generating assets that are no longer used to produce power. In that case, FPL customers pay twice – once for assets that remain on FPL's books but are no longer used and useful, and once for the replacement capacity that FPL must bring online when retiring assets that no longer provide economic value.

Q. Please provide a brief summary of your recommendations.

A. The Commission has several options that would protect ratepayers from imprudently incurred resource costs and stranded asset risk. Based on my findings, I offer the following recommendations:

1. The Commission should disallow the costs associated with the coal-to-gas conversion of Crist Units 6 and 7 until FPL presents an analysis demonstrating that the cost to convert the units is less than the cost to retire and replace them with an alternative clean energy portfolio.

2. Similarly, the Commission should disallow the costs associated with the addition of four new combustion turbines (CTs) at the Crist site until FPL presents evidence that it was necessary to accelerate their in-service dates from 2023/2024 to the end of 2021/start of 2022. Alternatively, the Commission could disallow the $60 million increase in cumulative present value of revenue requirements (CPVRR) associated with the acceleration of the CTs.
3. The Commission should not approve the requested extension of life at FPL's existing CC units to 50 years. To the extent that FPL is building new gas-fired units, the Commission should condition the determination of prudence for these new gas units with the provision that, in the event the units become stranded assets, FPL's shareholders will bear the risks and costs rather than customers. The Company should be willing to accept this risk if it is confident that these new assets will be used and useful.
4. If FPL is committed to reducing the amount of climate risk unique to Florida utilities, it should join its peer utilities in establishing a zero or net-zero CO_2 target for a date no later than 2050. Decisions around future resource additions should then be made with this goal in mind, and the Company can set interim emissions reduction goals both on a system-wide and individual unit basis to ensure it can meet its long-term goal.

5. The Commission should require FPL to incorporate its currently approved levels of DSM savings into the Company's load forecasts over its long-term planning horizon (rather than assume proposed goals or zero incremental DSM in later years) and should also require FPL to model DSM as an alternative in all future generation resource decisions.

3. FPL'S PLANNING PROCESS IS BIASED TOWARD GAS-FIRED RESOURCES

Q. Witness Sim presents the results of FPL analyses that focus on near-term resource changes and additions for the Gulf generation system. What were the results of that analysis?

A. That analysis identified as economic the following changes and additions to the Gulf system: 1) an upgrade of approximately 80 MW to the Lansing Smith combined cycle (CC) unit, 2) the conversion of the Crist Units 6 and 7 from coal to gas, 3) the addition of four CT units of 235 MW each at the Crist site, and 4) the addition of three 74.5 MW solar facilities.[1]

Q. What evidence does FPL provide in support of the resource decisions for which it is requesting a determination of prudence in this docket?

A. FPL Witness Sim describes the Company's planning process in his direct testimony. FPL performed an "initial" analysis, performed in late 2018/early 2019

[1] FPSC Docket No. 20210015-EI, FPL Witness Sim Direct Testimony (filed March 12, 2021), at page 12, lines 6-11 (hereinafter "Sim Direct").

that led to decisions on near-term unit additions and retirements on Gulf's system.[2] This was done in three steps. Step 1 examined the Gulf system on a standalone basis, while Step 2 examined the economics of the NRFC transmission line linking the Gulf and FPL systems. At that point, it was determined that Gulf would move forward with the four resource additions listed above.[3] FPL then performed its "current" analysis in the second half of 2020/early 2021, assuming that these four changes (Lansing upgrade, Crist 6 and 7 conversion, new Crist CTs, and new solar) were a "given," while also updating "numerous forecasts (load, fuel cost, etc.) and assumptions (cost of capital, discount rate, etc.)."[4]

A. FPL SHOULD CONSIDER INCREMENTAL DSM AS A REPLACEMENT RESOURCE WHEN DOING RESOURCE PLANNING

Q. Did FPL exclude any potential resources from consideration as part of its resource planning analysis?

A. Yes, FPL excluded incremental DSM as a potential resource alternative in its planning analysis. The Company's analysis assumed the amount of DSM approved by the FPSC in its most recent DSM Goals proceeding for both Gulf and FPL.[5] These are five-year goals, and thus the assumed amount of DSM was incorporated for 2020 to 2024. After 2024, Gulf is assumed to have zero

[2] Sim Direct at page 11, lines 4-8.
[3] *Id*. at page 12, lines 6-11.
[4] Sim Direct at page 12, line 18 to page 13, line 1.
[5] *Id*. at page 44, lines 2-4.

incremental energy efficiency, while FPL assumes the numbers it *proposed* in the DSM Goals proceeding, which are equivalent to savings for less than ten residential homes out of the more than ten million people served.[6] Zero incremental DSM was assumed for FPL beyond 2029.

Q. Was FPL correct to exclude incremental DSM as a resource option in its planning analysis?

A. No. Energy efficiency and other DSM measures have historically been the most cost-effective component of a utility's resource portfolio, when considering both supply- and demand-side measures. An analysis from Lawrence Berkeley National Laboratory examined the cost performance of 8,790 electricity efficiency programs between 2009 and 2015 for 116 investor-owned utilities and other program administrators in 41 states, finding that the average cost of kWh saved by energy efficiency (EE) programs funded by electricity customers is 2.5 cents per kilowatt-hour (kWh).[7] In contrast, NextEra (FPL's parent company) projects a range of 3.0 to 4.5 cents per kWh for new combined cycle units.[8]

Florida has been shown to have one of the highest potentials for cost-effective energy efficiency in the United States. According to a 2017 analysis done by the

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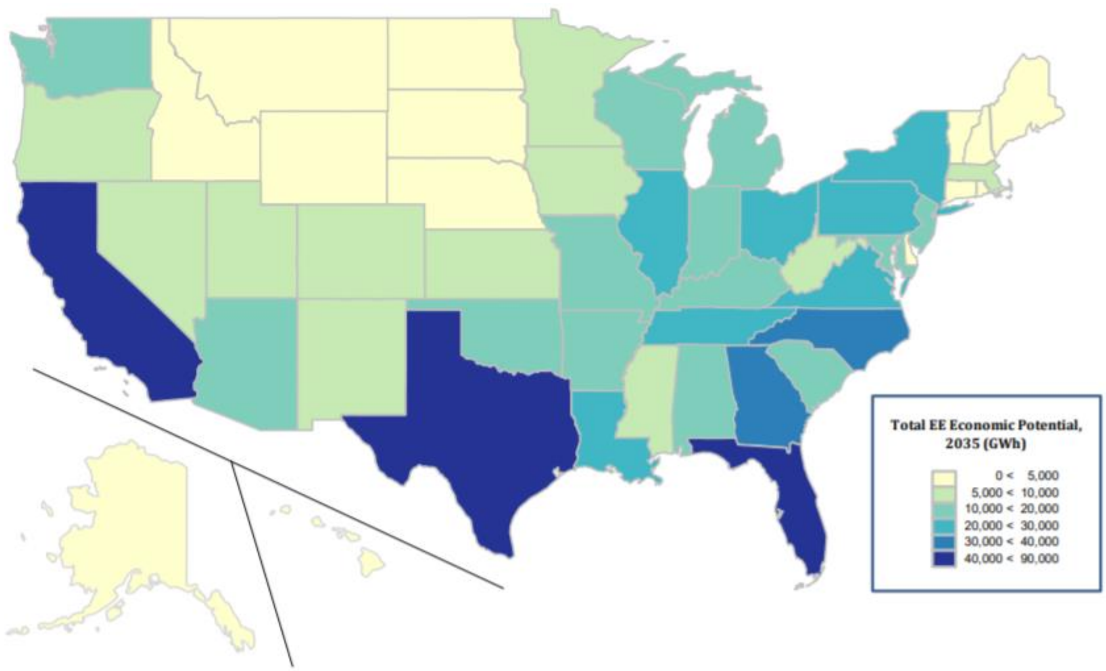
[6] *See* FPSC Docket No. 20190015-EG, Post-Hearing Brief of SACE and LULAC (filed Sept. 20, 2019), at p. 2 (stating that FPL proposed a goal of 1.023 GWh, which is equivalent of less than 10 residential homes, out of more than 10 million people served).

[7] Hoffman, et al. 2018. *The Cost of Saving Electricity Through Energy Efficiency Programs Funded by Utility Customers: 2009-2015.* Lawrence Berkeley National Laboratory. Available at: https://emp.lbl.gov/publications/cost-saving-electricity-through.

[8] NextEra Energy. 2021. *Environmental, Social and Governance.* Available at: https://www.nexteraenergy.com/content/dam/nee/us/en/pdf/2021_NEE_ESG_Report.pdf.

Electric Power Research Institute (EPRI), Florida's state-level EE potential is a whopping 21 percent in 2035 relative to the adjusted baseline sales.[9] A map of Florida's potential relative to other states is shown in Figure 1.

Figure 1. Total energy efficiency economic potential by state (GWh), 2035



Source: Electric Power Research Institute. 2017. State Level Electric Energy Efficiency Potential Estimates. Available at: *https://www.energy.gov/sites/prod/files/2017/05/f34/epri_state_level_electric_energy_efficiency_potential_estimates_0.pdf*.

Energy efficiency programs reduce peak load and annual energy requirements accumulate over time such that more expensive supply-side resources can be

[9] Electric Power Research Institute. 2017. *State Level Electric Energy Efficiency Potential Estimates.* Available at: https://www.energy.gov/sites/prod/files/2017/05/f34/epri_state_level_electric_energy_efficiency_potential_estimates_0.pdf.

displaced, resulting in cost savings to customers. According to FPL, even the Company's minimal efforts through year-end 2018 have eliminated "the need to construct the equivalent of approximately 15 new 400 MW generating units,"[10] and increasing the amount of EE on FPL's system could further avoid construction of costly new supply-side resources.

Q. Are there any examples of other utilities that are leading with respect to the inclusion of DSM as part of their resource planning analyses?

A. Yes, there are several recent examples of utilities increasing their DSM portfolios as part of their resource plans. Xcel Energy's most recent integrated resource plan in Minnesota proposes annual energy efficiency saving levels of approximately 2.5 percent, which equates to annual energy savings of 780 GWh for each year between 2020 and 2034. Xcel's prior resource plan had been approved with 1.5 percent annual savings from EE, but Xcel was able to improve its amount of planned EE based on a 2018 Minnesota Energy Efficiency Technical Potential Study.[11] Annual EE savings of 2.5 percent is a significant number—by contrast, the average annual EE savings in the 2020 ACEEE scorecard was 1.03 percent (by comparison, FPL achieved annual EE savings of **0.06 percent**).[12] In addition

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[10] FPSC Docket No. 20190015-EG, Direct Testimony of FPL witness Thomas R. Koch (filed April 12, 2019), at page 13, lines 3-7.

[11] Xcel Energy. 2019. *Upper Midwest Integrated Resource Plan 2020-2034.* Docket No. E002/RP-19-368. Available at: https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/The-Resource-Plan-No-Appendices.pdf.

[12] ACEEE. 2020. *State Energy Efficiency Scorecard.* Available at: https://www.aceee.org/state-policy/scorecard.

to EE, Xcel also plans for 400 MW of incremental demand response (DR) resources by 2023 in its modeling, based on a Minnesota Public Service Commission order. This DR deployment illustrates both the overall potential of DR and the ability to deploy these resources in the near-term.[13]

In developing its EE projections, Xcel modeled EE as a supply-side resource. This is important because it allows the capacity expansion model to optimize for EE/DR, instead of just manually forecasting an assumed level of EE adoption.[14] To accomplish this, Xcel created EE/DR resource "bundles" that could be selected and optimized by the model. Each bundle represented a portfolio of EE/DR averages at an assumed average cost, and Xcel analyzed multiple capacity optimization runs to create the most cost-effective combination of resources for each bundle. According to Xcel, modeling EE/DR in this way "[allowed] these resources to compete with traditional supply-side resources such as large-scale renewables or gas resources."[15]

Portland General Electric offers a second good example employing a different methodology for optimizing DSM in resource planning. Although they did not model EE on the supply-side in their 2019 IRP, PGE is working with stakeholders to "explore the potential for PGE's portfolio modeling to select incremental

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[13] Xcel Energy. 2019. *Upper Midwest Integrated Resource Plan 2020-2034.* Docket No. E002/RP-19-368. Available at: https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/The-Resource-Plan-No-Appendices.pdf.
[14] *Id.*
[15] *Id.*

energy efficiency that is least cost, least risk, beyond [the] baseline forecast."[16] PGE also intends to explore the addition of an energy efficiency capacity value modifier, which would capture an additional benefit that EE/DR can provide to a portfolio of energy resources. PGE models EE on as a load modifier on the demand-side, but it includes EE/DR contributions in every single IRP scenario. In addition, the EE/DR forecasts that it models as load modifier are developed outside of the utility—PGE tasks the Energy Trust of Oregon, an independent non-profit that is responsible for identifying the state's EE potential and providing funding to EE projects, with developing a 20-year EE forecast that becomes an input into PGE's IRP. The role of the Energy Trust in developing PGE's EE forecast improves transparency and enhances stakeholder engagement.

Q. Can DSM resources be brought online quickly enough to be relevant to the resource selection during the 2020-2024 time period?

A. Yes, absolutely. The Hawaii Public Utilities Commission recently approved an "emergency demand response program" in response to possible resource shortfalls that could occur after a 180 MW coal plant retires in September 2022. The approved program would implement a 50 MW scheduled dispatch program, open to existing and new customers that can add new battery storage charged from their existing PV system, and elevate an existing fast demand response

[16] Portland General Electric Company. 2019. *Integrated Resource Plan: Updated*. Available at: https://assets.ctfassets.net/416ywc1laqmd/1PO8IYJsHee3RCPYsjbuaL/b80c9d6277e678a845451eb89f4ade2e/2019-IRP-update.pdf.

program to full capacity (7 MW) in which customers are financially incentivized to proactively conserve energy.[17]

B. FPL LOCKED IN SPECIFIC GAS RESOURCES RATHER THAN ALLOW ITS MODEL TO SELECT THE OPTIMAL RESOURCE PORTFOLIO

Q. Does FPL present any evidence that the conversion of the Crist Units 6 and 7 from coal to gas was an economic choice for ratepayers?

A. FPL's analysis around the Crist conversion only compares that option to continuing to operate the units on coal. The Company did not examine an option in which the Crist Units were retired and replaced with a portfolio of alternative resources that might include additional DSM, solar, and battery storage.

Q. Why do you suggest that a portfolio of alternative resources might have been more economic for ratepayers than the coal-to-gas conversion?

A. We can compare the lack of analysis around the Crist conversion to the analysis that FPL did do for the Manatee 1 and 2 units. FPL's analysis of the Manatee retirement compared two scenarios: in the first, the Manatee units (800 MW each, for a total of 1,600 MW) operate until 2029, and in the second, they are retired at the end of 2021. FPL examined a number of potential replacement resources, including new gas generation, upgrades to the CT portion of existing CC units, new

[17] Balaraman, Kavya. 2021. *Hawaii Oks emergency demand response to avoid energy shortfalls following AES coal plant closure.* Utility Dive. Available at: https://www.utilitydive.com/news/hawaii-emergency-demand-energy-shortfalls-aes-coal/601573/.

solar, battery storage, and transmission projects in or near the Manatee area.[18] FPL determined that early retirement was the most economic option for ratepayers with a CPVRR savings of $101 million, [19] replacing their capacity with a nominal 400 MW battery storage facility at the site, as well as the acceleration of solar and CC projects. FPL did not even analyze the possibility of retirement and replacement of Crist Units 6 and 7, however, and have provided little analysis that the coal-to-gas conversion was in the best interest of ratepayers.

FPL should have analyzed two scenarios: one in which the Crist conversion is selected, and another in which the units are retired and replaced with an alternative clean energy portfolio. Notably, FPL had to construct a 39-mile gas pipeline to supply gas to the converted plant. This additional cost should have also been considered as part of the cost of the units' conversion.

Q. How did FPL determine that four new CTs, totaling approximately 940 MW, were needed at the Crist site?

A. FPL's Initial Step 2 modeling analysis determined that there was a need for 469 MW of new CTs in Gulf territory in 2023 and again in 2024.[20] Witness Sim's direct testimony states that the decision was made to accelerate the units to an in-service date of late 2021/early 2022, which was then the earliest projected in-service date for the North Florida Resiliency Connection (NFRC) line, to provide

[18] Sim Direct at page 37, lines 3-7.
[19] *Id*. at page 10, lines 1-5.
[20] Sim Direct, Exhibit SRS-7, page 2 of 2.

fast-start/fast ramp capability if either the NRFC line or the upgraded Lansing Smith CC unit was lost.[21] This acceleration was estimated by FPL to result in a cost of $60 million in CPVRR.[22]

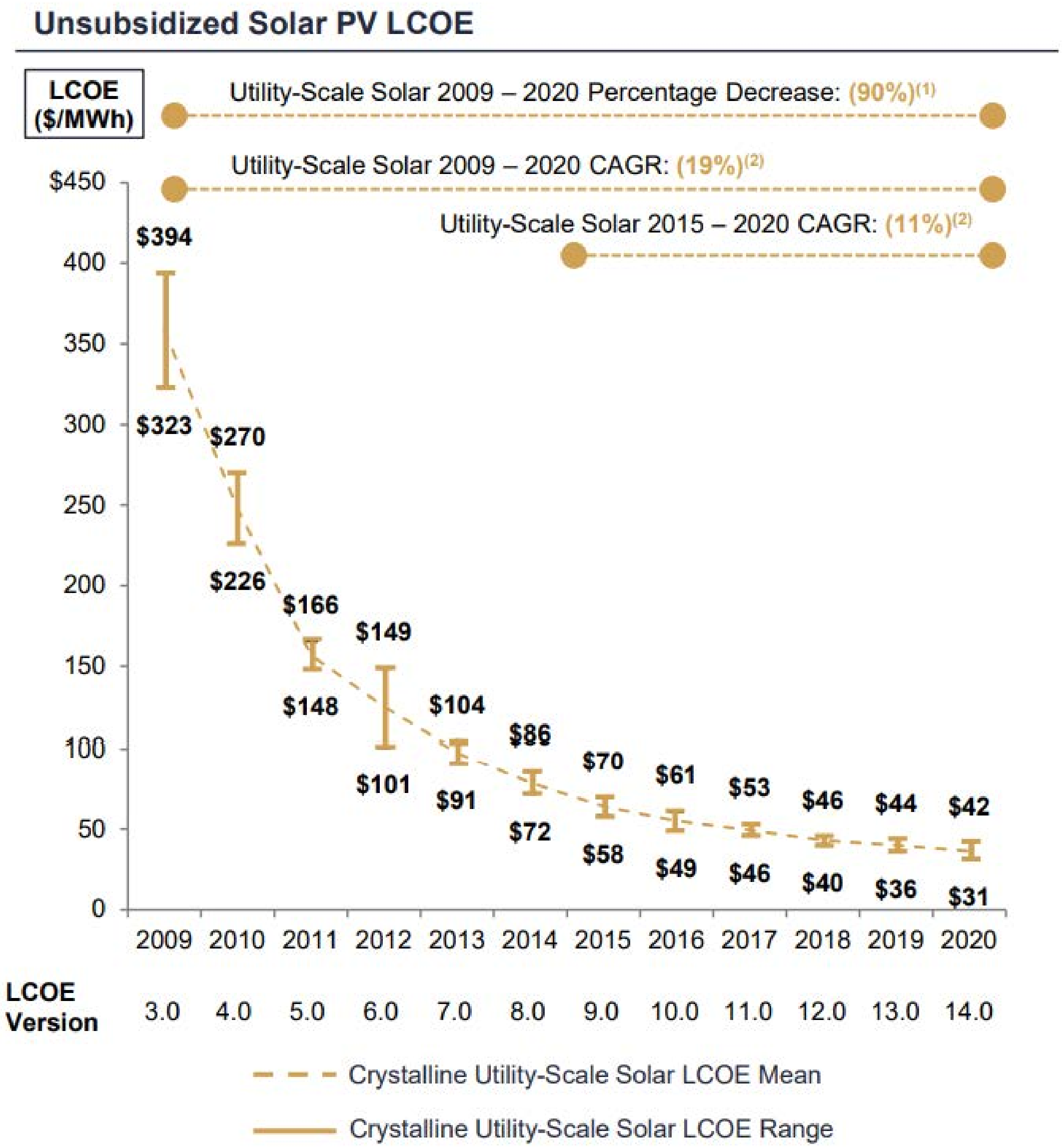
Q. Are there any flaws in this analysis?

A. Yes. The Initial Step 1/Step 2 analyses were done in late 2018/early 2019. FPL then updated its analysis in late 2020/early 2021, referred to as the "Current Analysis," updating various forecasts and assumptions. It did not, however, reevaluate the decision to add the new CTs, instead locking those resources down as common amongst all cases analyzed. Solar prices declined over that time period, making them a more cost-competitive resource addition.

Historical solar prices are shown in Figure 2, below, and the levelized cost of energy declines from $4-$9/MWh from 2018 to 2020.

[21] Sim Direct at page 57, lines 1-6.
[22] *Id*.

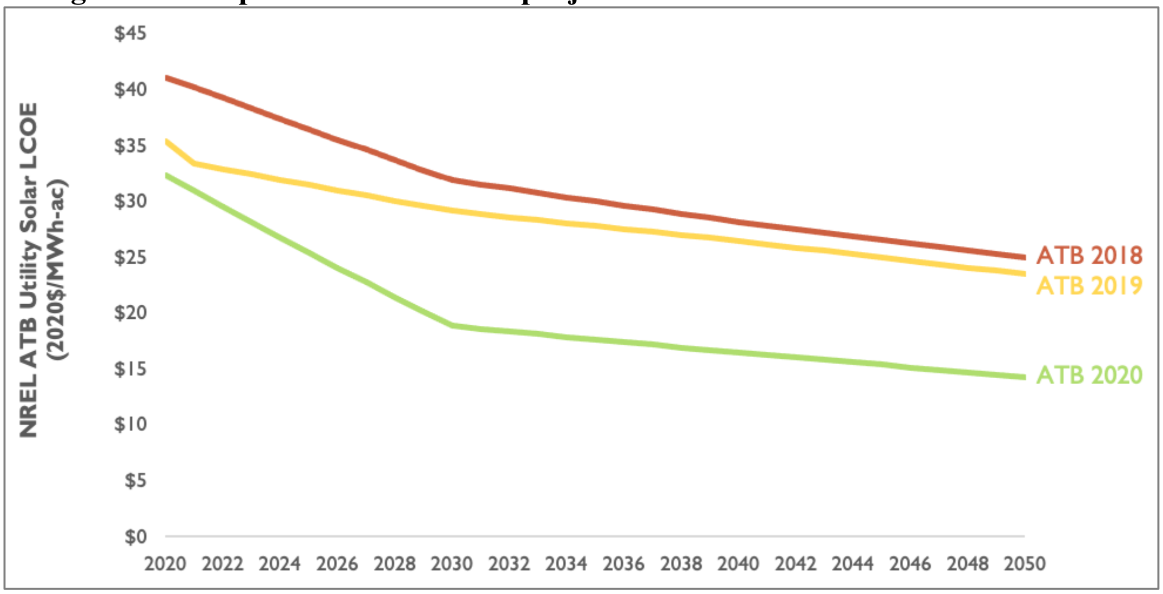
Figure 2. Historical levelized cost of solar declines



Source: Lazard. 2020. Levelized Cost of Energy Analysis—Version 14.0, available at: [*https://www.lazard.com/media/451419/lazards-levelizedcost-of-energy-version-140.pdf*](https://www.lazard.com/media/451419/lazards-levelizedcost-of-energy-version-140.pdf).

Projections from the National Renewable Energy Laboratory's Advanced Technology Baseline (NREL ATB) publications show that projections of storage costs also decrease.

Figure 3. Comparison of solar cost projections from NREL ATB



Source: National Renewable Energy Laboratory. 2018/2019/2021 Annual Technology Baseline.

Battery storage costs have dropped dramatically over the past decade and continue to decline each year.[23] Updating these particular assumptions dictates a reassessment of the decision to add almost 940 MW of new gas-fired capacity, but FPL chose not to update its analysis.

Q. Could battery storage also have been a cost-effective replacement for the Crist units?

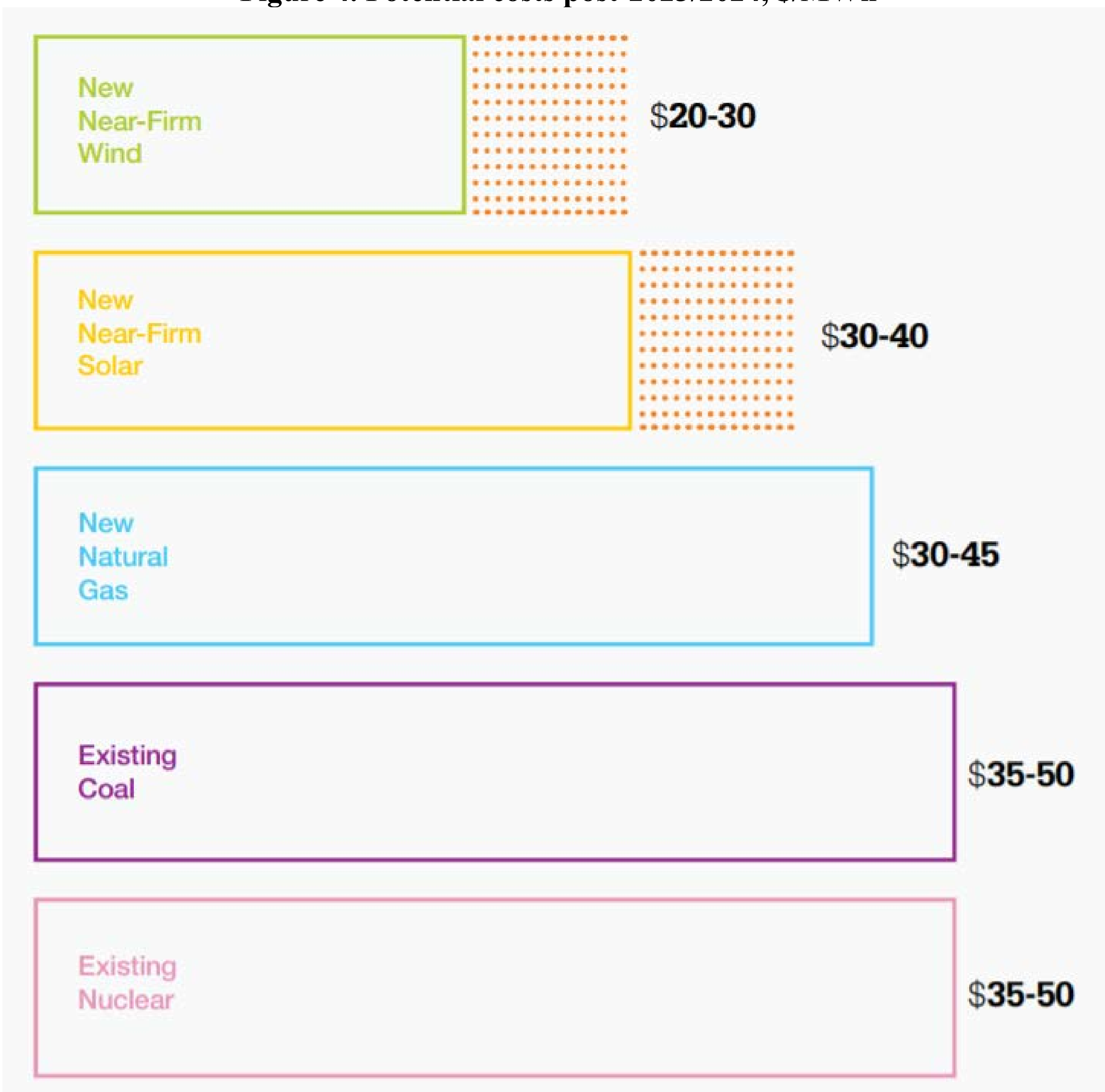
A. Yes, it is very likely that storage could have been a cost-effective replacement. In addition to its cost competitiveness, it can provide the same fast start/fast ramp

[23] Bloomberg New Energy Finance. December 16, 2020. *Battery Pack Prices Cited Below $100/kWh for the First Time in 2020, while Market Average Sits at $137/kWh.* Available at: https://about.bnef.com/blog/battery-pack-prices-cited-below-100-kwh-for-the-first-time-in-2020-while-market-average-sits-at-137-kwh/.

capability cited as the reason for the acceleration of the CT units. According to Witness Sim, the CTs at the Crist run at very low capacity factors, at a high point of five percent in only one or two years, but otherwise at approximately two percent per year, with the primary purpose of providing capacity and fast start capability for the Gulf system either as a standalone or in the event that the NFRC line were to be lost. Standalone battery storage, or storage paired with solar, could have provided the same capacity, and likely more energy, than the new CTs.

NextEra's own projections of costs indicate that solar and storage are more cost-effective resources than new gas-fired generation, as shown in Figure 4. New near-firm solar represents solar paired with battery storage, which is priced in the range of $30-40/MWh, compared to new gas generation at $30-45/MWh.

Figure 4. Potential costs post-2023/2024, $/MWh



Source: NextEra. 2021. Environmental, Social, and Governance. Available at: *https://www.nexteraenergy.com/content/dam/nee/us/en/pdf/2021_NEE_ESG_Report.pdf*

Q. FPL is proposing to add solar during the period from 2022 to 2025. Does this not refute your argument about its bias toward gas-fired resources?

A. No. FPL models all of its potential solar projects at 74.5 MW. If you assume that solar projects require between five and 10 acres of land per MW,[24] FPL needs to acquire 372 to 745 acres of land for each of its projects. One of the benefits of solar is that it is modular in nature and can be sized to meet the space available to it. By focusing on only large projects, and purchasing the land needed for these projects rather than leasing it, FPL is missing a large opportunity to integrate more solar onto the grid using smaller-sized projects.

Q. Are FPL's solar costs competitive with the market?

A. It is difficult to confirm that FPL's solar costs are the lowest that could be achieved, as FPL chooses to self-build its solar projects, and so we do not have data on possible power purchase agreements for solar to which we can compare. Previous experience from several different utilities has shown, however, that competitive market solicitations, in the form of all-source resource procurements, have resulted in lower costs for replacement resources. In the experience of Public Service Company of Colorado, its 2017 all-source procurement resulted in 417 total bids, a low bid price for solar of $22.53/MWh, and the ability to replace

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[24] Solar Energy Industries Association. *Siting, Permitting & Land Use for Utility-Scale Solar.* Available at: https://www.seia.org/initiatives/siting-permitting-land-use-utility-scale-solar.

retiring coal with wind, solar, large-scale battery storage, and existing gas generators.[25]

Monopoly utilities have incentives for over-procurement and self-building of new resources, and all-source, technology neutral, bidding processes can result in better outcomes for utility ratepayers.[26]

Q. Does FPL's modeling further bias the results toward the addition of gas-fired resources?

A. Yes. FPL modeled a useful life of gas assets of 40 years in its analysis. This is a longer useful life than is modeled by many utilities. Engineering firm Sargent & Lundy expects that the useful life of a new combined cycle unit is approximately 30 years,[27] and I often see utilities model useful lives consistent with this expectation. The effect of modeling a useful life of 40 years rather than 30 is that the costs to build a new unit are then spread out over a longer period of time, and the cost stream is then discounted to present dollars. The same costs, spread out over a longer useful life, will then be less expensive from a CPVRR perspective, the Company's metric for making resource decisions. This will be further

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[25] MI Power Grid Phase II: Advanced Planning Evaluator and All-Source Meeting. Michigan Public Service Commission. Available at: https://www.michigan.gov/documents/mpsc/Feb_18_Competative_Procurement_Presentation__716684_7.pdf.

[26] *Id.*

[27] Sargent & Lundy, LLC. *Combined Cycle Plant Life Assessments.* Available at: https://sargentlundy.com/wp-content/uploads/2017/05/Combined-Cycle-PowerPlant-LifeAssessment.pdf.

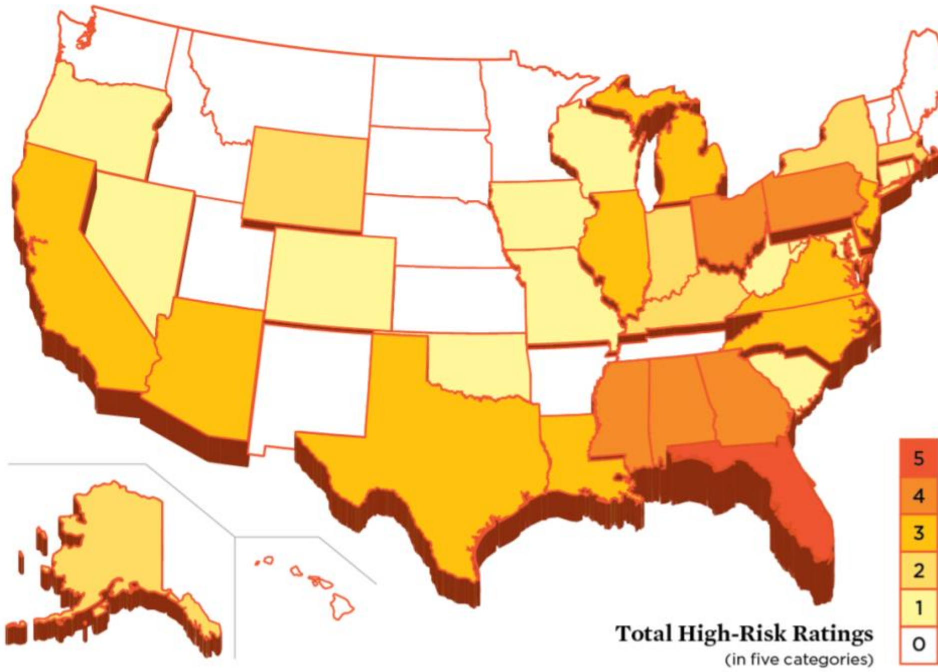
exacerbated by FPL's proposal to increase useful lives of assets to 50 years, if this assumption is also applied to new resources.

<u>4.</u> <u>POTENTIAL FOR NEW GAS UNITS TO BECOME STRANDED ASSETS</u>

Q. Does FPL's continued reliance on gas-fired generation put its customers at risk?

A. Yes. A 2015 report from the Union of Concerned Scientists examined states' risks of overreliance on gas in five categories, rating each on a scale of low, moderate, or high. According to this report, Florida is already over reliant on gas and is subjecting its customers to risks associated with gas price volatility, potential supply shortages during winter events, and costs associated with the cost of CO_2 emissions allowances or controls. Indeed, Florida was the only state to earn a "high" rating in all five categories of risk and is the state at the highest risk for gas overreliance, as shown in Figure 5, below.

Figure 5. States at Highest Risk of Natural Gas Overreliance



Source: Union of Concerned Scientists. 2015. Rating the States on their Risk of Natural Gas Overreliance. Available at: https://www.ucsusa.org/sites/default/files/attach/2015/12/natural-gas-overreliance-analysis-document.pdf.

Q. Do the assets for which FPL is requesting a prudence determination in this docket mitigate any over reliance on gas?

A. No, while FPL does add some solar, it also exacerbates its reliance on gas via conversions of generators from coal to gas, upgrades at an existing combined cycle generator, and the addition of 940 MW of new combustion turbines.

Q. Can we expect that FPL's use of gas for generation will continue in both the short and long-term?

A. Yes. Not only is FPL adding additional gas-fired generators to its system, but the Company is also requesting an increase in the useful life for its combined cycle units from 40 to 50 years as part of its request to adjust depreciation rates and continue the use of the Reserve Surplus Amortization Mechanism (RSAM).[28] With this request, FPL assumes that its combined cycle units will operate for an additional ten years and spreads the depreciation over a longer period of time.

Q. Are there any risks associated with a longer useful life for these gas assets?

A. Yes. The cost of generation from gas assets is tied directly to both the capital cost to build the unit as well as the fuel cost for gas, which rises and falls. Generation from renewable energy has zero fuel cost, and the technology costs have been declining over time and will continue to do so. Recent trends show that it can be cheaper today to build new renewable-plus-storage units than to build ***new*** gas plants. Forecasts suggest that in the future, it will be cheaper to build new renewable-plus-storage units than to continue operating ***existing*** gas plants.[29] This means that new and existing gas plants are likely to become stranded assets.

Q. What is a stranded asset?

A. A stranded asset is one that no longer has value or produces income. It is important to consider the stranded asset risk for power plants because the costs to construct these assets are recovered by utilities at ratepayer expense over many decades. If conditions in the electric sector cause this plant to no longer be "used and useful,"

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[28] FPSC Docket No. 20210015-EI, Direct Testimony of FPL Witness Ferguson (filed March 12, 2021) at page 5, lines 5-18.

[29] Rocky Mountain Institute. 2019. *The Growing Market for Clean Energy Portfolios.* Available at: https://rmi.org/insight/clean-energy-portfolios-pipelines-and-plants/.

ratepayers will be burdened with the costs of a non-performing unit for the remainder of its depreciable life.

Q. Can any of FPL's current generating assets be considered stranded, under this definition?

A. Yes. FPL has several steam generating assets that it either has or plans to retire that still have undepreciated plant balances. Those generators are shown in Table 1.

Table 1. Unrecovered generating investments

Unit	Retirement Date	Fuel Type	Undepreciated Plant Balance
Martin 1/2	Dec-18	Gas/Oil	$365 million
Lauderdale 4/5	Dec-18	Gas	$328 million
Crist 4-7	Oct-20	Coal	$462 million
Manatee 1/2	Jan-22	Gas	$231 million
Scherer 4	Jan-22	Coal	$831 million
Daniel 1/2	2024	Coal	$136 million

Source: Ferguson Direct at page 18, line11 to page 20, line 9.

These generators have been or will be converted to regulatory assets in order for FPL to recover these undepreciated plant balances.

Q. Is FPL aware of the stranded asset risk to its existing generators?

A. Yes. FPL's *Form 10-K*, filed with the Securities and Exchange Commission in 2020, states that its business could be negatively affected by laws or regulations that mandate new or addition limits on the production of greenhouse gases, which could make its electric generation units uneconomical to operate in the long term, require substantial capital investments to comply with new regulations, or create increased costs in the form of taxes or emissions allowances.[30] The Company also states that it can provide no assurance that "…FPL would be able to completely recover any such costs or investments, which could have a material adverse effect on (its) business, financial condition, results of operations and prospects."

Q. Is there anything the Florida Public Service Commission could do to reduce the stranded asset risk to customers with respect to new gas-fired generators?

A. Yes. First, the Commission can deny FPL's request to extend the lives of existing assets from 40 to 50 years. Second, the Commission could condition the determination of prudence for any new gas units with the provision that, in the event the units become stranded assets, FPL's shareholders will bear the risks and costs rather than customers. While not yet a common practice, precedent for such action has occurred in the past. For example, Alabama Power requested a predetermination of prudence via a certificate of convenience and necessity for combined-cycle units Barry 7 and 8 in docket 26115. Citing concerns about stranded asset risk, Witness John A. Putnam of Alabama Power submitted Direct Testimony stating that the Company was willing offer additional assurance that its proposed new capacity was both a cost-effective and competitive means of meeting

[30] Florida Power & Light Company. Form 10-K. *Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.* For the fiscal year ended December 31, 2020. Available at: https://sec.report/Document/0000753308-21-000014/.

identified need by committing that any stranded costs resulting from these units would be borne by Alabama Power's shareholders rather than its customers.[31]

Q. Is there anything that FPL could do to reduce both the stranded asset risk to customers and CO_2 risk with respect to new gas-fired generators?

A. Yes. The majority of electric utilities in the United States have a CO_2 emissions reduction goal, and many of these reduce emissions to either zero or net-zero by 2050 at the latest. A list of utilities and their current carbon reduction commitments is attached as Exhibit RW-2. NextEra, FPL's parent company, has a company-wide carbon reduction goal based on CO_2 emissions rate, which is related to improving the amount of CO_2 generated per MWh across the generating fleet, but is not a mass-based reduction goal.[32] FPL Witness Silagy stated that this goal does not influence FPL's planning decisions in this proceeding, however. If FPL is committed to reducing the amount of climate risk unique to Florida utilities, it should join its peer utilities in committing to a zero or net-zero CO_2 target by no later than 2050. Decisions around future resource additions should then be made with this goal in mind, and the Company can set interim emissions reduction goals both on a system-wide and individual unit basis in order to ensure it can meet its long-term goal.

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[31] Direct Testimony of John A. Putnam before the Alabama Public Service Commission. Docket No. 26115. Page 13, line 7.

[32] NextEra Energy 2021 Environmental, Social and Governance Report, at page 6, available at https://www.nexteraenergy.com/content/dam/nee/us/en/pdf/2021_NEE_ESG_Report.pdf.

5. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your conclusions.

A. My testimony reviews the sufficiency of FPL's resource planning process and evaluates the prudence of FPL's recent and proposed gas investments within that context. Specifically, I note the lack of consideration given to demand side management (DSM) measures as a replacement resource in FPL's resource planning process. I describe the deficiencies in FPL's analysis related to both the coal-to-gas conversion project at Crist Units 6 and 7 and the new combustion turbine units added at the Crist site. I also review the stranded asset risk posed to FPL ratepayers through the Company's continued reliance on gas-fired resources, whether by proposing to extend the useful lives of existing assets from 40 to 50 years, or its various additions that are planned or currently under construction.

Q. Please summarize your recommendations.

A. The Commission has several options that would protect ratepayers from imprudently incurred resource costs and stranded asset risk. Based on my findings, I offer the following recommendations:

1. The Commission should disallow the costs associated with the coal-to-gas conversion of Crist Units 6 and 7 until FPL presents an analysis demonstrating that the cost to convert the units is less than the cost to retire and replace them with an alternative clean energy portfolio.
2. Similarly, the Commission should disallow the costs associated with the addition of four new combustion turbines (CTs) at the Crist site until FPL presents evidence that it was necessary to accelerate their in-service dates

from 2023/2024 to the end of 2021/start of 2022. Alternatively, the Commission could disallow the $60 million increase in cumulative present value of revenue requirements (CPVRR) associated with the acceleration of the CTs.

3. The Commission should not approve the requested extension of life at FPL's existing CC units to 50 years. To the extent that FPL is building new gas-fired units, the Commission should condition the determination of prudence for these new gas units with the provision that, in the event the units become stranded assets, FPL's shareholders will bear the risks and costs rather than customers. The Company should be willing to accept this risk if it is confident that these new assets will be used and useful.

4. If FPL is committed to reducing the amount of climate risk unique to Florida utilities, it should join its peer utilities in establishing a zero or net-zero CO_2 target for a date no later than 2050. Decisions around future resource additions should then be made with this goal in mind, and the Company can set interim emissions reduction goals both on a system-wide and individual unit basis to ensure it can meet its long-term goal.

5. The Commission should require FPL to incorporate its currently approved levels of DSM savings into the Company's load forecasts over its long-term planning horizon (rather than assume proposed goals or zero incremental DSM in later years) and should also require FPL to model DSM as an alternative in all future generation resource decisions.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Curt Volkmann was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY OF
CURT VOLKMANN

ON BEHALF OF

THE CLEO INSTITUTE
AND
VOTE SOLAR

June 21, 2021

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I. INTRODUCTION AND WITNESS QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Curt Volkmann. My business address is 132 Lake Vista Circle, Fontana, Wisconsin, 53125.

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

A. I am testifying on behalf of Vote Solar and The CLEO Institute Inc. (collectively "VS-CLEO").

Q. By whom are you employed and in what capacity?

A. I am President and founder of New Energy Advisors, LLC, an independent consulting firm. I work with clients in a variety of general rate case, grid modernization, and distribution planning regulatory proceedings.

Q. Please summarize your education and professional experience.

A. I have a BS in Electrical Engineering from the University of Illinois with a concentration in Electrical Power Systems. I also have an MBA from the University of California at Berkeley with a concentration in Finance. I have 36 years of experience in the utilities industry, primarily in electric transmission and distribution. My work experience includes nine years at Pacific Gas & Electric in various transmission and distribution ("T&D") engineering roles and eighteen years at Accenture with several positions including Executive Director in the North American Utilities practice. Since 2015, I have worked independently and supported clients in T&D-related regulatory proceedings in several states. Exhibit CV-1 provides a statement of my qualifications and experience.

Q. Have you previously testified before the Florida Public Service Commission ("FPSC" or "Commission")?

A. No.

Q. Have you previously testified before other regulatory commissions?

A. Yes. In the past six years, I have testified and commented before regulatory commissions in Arizona, Arkansas, California, Iowa, Illinois, Massachusetts, Michigan, Minnesota, New York, Ohio, Utah, and Virginia. Exhibit CV-2 provides a summary of my prior testimony and contributions to comments.

Q. Are you providing any exhibits with your testimony?

A. Yes. I am sponsoring the following exhibits:

- Exhibit CV-1: Curt Volkmann's Statement of Qualifications and Experience
- Exhibit CV-2: Prior Testimony and Contributions to Comments by Curt Volkmann
- Exhibit CV-3: Compiled responses to Interrogatories and Production of Documents requests
- Exhibit CV-4: Potential Metrics for T&D Capital Performance Management
- Exhibit CV-5: ICE Calculator screenshots
- Exhibit CV-6: Grid Modernization Playbook
- Exhibit CV-7: Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations
- Exhibit CV-8: Cited Portions of FPL Witness Michael Spoor's deposition dated June 16, 2021

II. PURPOSE OF TESTIMONY AND SUMMARY OF RECOMMENDATIONS

Q. What is the purpose of your testimony?

A. My testimony summarizes my assessment of a subset of the proposed T&D capital expenditures by Florida Power & Light Company ("FPL") and Gulf Power ("Gulf", collectively "FPL-Gulf" or "Company") as described in the Company's direct testimony of witness Michael Spoor. Specifically, I focus on the proposed T&D capital expenditures for Reliability/Grid Modernization and Growth.

Q. Please summarize your conclusions.

A. I conclude that the Company's proposed $11.5 billion of Reliability/Grid Modernization and Growth capital expenditures in 2019-2023 are unsupported with evidence in the record.

Q. Did VS-CLEO attempt to collect evidence in support of the Company's proposed $11.5 billion T&D Reliability/Grid Modernization and Growth capital expenditures?

A. Yes. On May 3, 2021, VS-CLEO submitted 77 T&D-related interrogatories ("INT") and 22 T&D-related requests for production of documents ("RPOD"). On May 24, 2021, the Company objected to most of the T&D-related INT and RPOD. Subsequently, FPL/Gulf has provided limited responses to many of the T&D-related requests. VS-CLEO received the last set of limited T&D-related responses one week ago, on June 14, 2021.

Q. What is your experience with the discovery process and the type of information utilities typically provide in T&D-related proceedings?

A. In other T&D general rate case ("GRC") and grid modernization proceedings I've participated in (involving requests for significantly less capital than what FPL-Gulf is proposing), there have been detailed utility filings, a robust discovery process with detailed utility responses, and ample opportunity for Commissions, staff, and stakeholders to understand the underlying data/analyses supporting a utility's request for approval of capital expenditures.

Q. Please provide examples of other utilities providing sufficient information to support their requested T&D or grid modernization expenditures.

A. In the 2019 Virginia State Corporation Commission ("SCC") proceeding reviewing Dominion Energy Virginia's petition for approval of its Grid Transformation Plan ("GTP", SCC Docket PUR-2019-00154), I was an expert witness for the SCC Staff ("Staff"). Dominion was proposing $2.9 billion of customer costs, as measured by the present value of revenue requirements. Dominion's initial filing had over 1,200 pages of testimony and exhibits, including a detailed benefit/cost analysis for its proposed GTP expenditures. Through discovery, we were able to compel Dominion to provide additional information, such as non-confidential, circuit-level reliability data and unit costs, and to correct errors in its analyses. Staff was able to make specific recommendations based on this detailed information, and the SCC ultimately adopted most of Staff's recommendations.[1]

[1] In its March 26, 2020 Final Order, the SCC agreed with Staff's recommendations by approving a new customer information platform, development of a Hosting Capacity Analysis, Cybersecurity, and costs for stakeholder engagement and communication. The SCC also agreed with Staff's recommendation by rejecting the proposed self-healing grid project and associated telecommunications, and the Enterprise Asset Management System.

In the Southern California Edison ("SCE") 2021 GRC proceeding (California Public Utilities Commission Docket A.19-08-013), I was an expert witness for Vote Solar and the Solar Energy Industries Association. SCE's GRC request included $913 million of grid modernization and $1.5 billion of load growth capital expenditures from 2019-2023. SCE provided over 1,500 pages of growth- and grid modernization-related testimony and workpapers with extensive detail in its initial filing. SCE was very responsive throughout the discovery process, providing non-confidential circuit-level information, including historical reliability, peak loads, minimum loads, and installed/forecasted generation capacity.

In the 2019 Xcel Energy request for certification for its Advanced Grid Intelligence and Security ("AGIS") initiative (Minnesota Public Utilities Commission Docket No. E002/M-19-666), I supported Fresh Energy[2] as a technical advisor. Xcel was requesting $234 million of capital from 2020-2024 for its AGIS grid modernization initiative, and its initial AGIS filing included over 1,500 pages of testimony and exhibits. In response to our discovery requests, Xcel Energy provided specific answers to our questions including spreadsheets with details supporting its AGIS benefit/cost analysis.

Q. How does this compare to the T&D-related information provided by FPL-Gulf in this proceeding?

A. In support of the Company's proposed $15.69 billion of T&D expenditures from 2019-2023, witness Spoor's testimony and exhibits are 50 pages, including the cover pages

[2] https://fresh-energy.org/

and table of contents. He also sponsored or co-sponsored 36 pages of documents as Minimum Filing Requirements, none of which help explain the justification for the proposed capital expenditures. As I previously described, the Company's responses to T&D-related discovery requests were very limited.

Q. Please provide a brief summary of your recommendations.

A. I understand that the Company must spend capital for day-to-day reliability improvements and growth. However, it is unclear from the record that the amounts proposed by FPL-Gulf are justified, reasonable, and based on actual needs. I recommend that the Commission make approval of the Company's proposed Reliability/Grid Modernization and Growth capital expenditures contingent upon:

- FPL-Gulf developing a comprehensive benefit/cost analysis for its proposed Reliability/Grid Modernization expenditures demonstrating cost effectiveness and reasonableness.
- FPL-Gulf establishing a T&D capital performance management framework to track and report metrics of Reliability/Grid Modernization and Growth capital spending and achievement of expected outcomes.

III. THE COMPANY'S PROPOSED T&D CAPITAL EXPENDITURES ARE SIGNIFICANT

Q. What are the Company's proposed base T&D capital expenditures?

As shown in Figure 1 below, FPL-Gulf is proposing $2.9-3.5 billion per year for T&D capital expenditures and a total of $15.69 billion from 2019-2023 to be recovered in base rates. 73% of the expenditures, or $11.5 billion from 2019-2023, are for the categories of Reliability/Grid Modernization and Growth. The 2019 values in Figure 1 reflect the Company's actual expenditures and the 2020-2023 values are FPL-Gulf's projected expenditures.[3]

Category	2019	2020	2021	2022	2023	2019-2023 ($)	2019-2023 (%)
Reliability/Grid Modernization	$ 0.94	$ 1.15	$ 1.36	$ 1.12	$ 1.06	$ 5.64	36%
Growth	$ 0.87	$ 0.99	$ 1.40	$ 1.26	$ 1.35	$ 5.86	37%
FPSC Storm Hardening/SPP	$ 0.85	$ 0.96	$ 0.14	$ 0.15	$ 0.15	$ 2.24	14%
Grid Servicing/Support	$ 0.31	$ 0.29	$ 0.34	$ 0.31	$ 0.35	$ 1.61	10%
Regulatory Compliance	$ 0.06	$ 0.06	$ 0.07	$ 0.08	$ 0.07	$ 0.35	2%
Total	$ 3.03	$ 3.45	$ 3.31	$ 2.92	$ 2.98	$ 15.69	100%

Figure 1 – FPL's Proposed T&D Capital Expenditures ($ in billions)[4]

IV. FPL-GULF'S PROPOSED CAPITAL FOR RELIABILITY/GRID MODERNIZATION IS UNSUPPORTED

Q. What initiatives are included in the Company's Reliability category of capital expenditures?

A. As witness Spoor explains, the focus of FPL-Gulf's T&D Reliability initiatives is to reduce day-to-day outages and restoration times.[5] These initiatives are in addition to, but separate from, the Company's planned Storm Protection Plan expenditures. For the Company's distribution system, reliability initiatives include targeted improvement of infrastructure/devices experiencing high numbers of outages, and targeted rehabilitation or replacement of underground cable.[6] For the Company's transmission

[3] According to FPL's supplemental response to OPC's First Request for Production of Documents No. 44, file 'Rate Case Backup - Spoor Testimony.xlsm', attached in Exhibit CV-3.
[4] FPSC Docket No. 20210015-EI, Direct testimony of Michael Spoor on behalf of FPL, filed March 12, 2021, at page 37, line 17 (hereinafter "Spoor Direct").
[5] Spoor Direct at page 16, lines 13-14.
[6] Spoor Direct at page 19, lines 1-20.

system, reliability initiatives include assessments of transmission line and substation equipment, predictive replacement of major equipment, root cause analysis to prevent recurrence of outage events, and targeted maintenance.[7]

Q. How is the Company's reliability compared to other utilities?

A. FPL-Gulf's day-to-day reliability is very good compared to other utilities. In 2019, FPL and Gulf had their best-ever performance results for FPSC T&D System Average Interruption Duration Index ("SAIDI")[8]. FPL's 2019 Distribution SAIDI performance ranked 58% better than the national average, and Gulf's 2019 Distribution SAIDI Performance ranked 41% better than the national average.[9]

In 2020, both FPL and Gulf once again had best-ever performance results for FPSC SAIDI and both had their best-ever FPSC Distribution Momentary Average Interruption Frequency Event Index ("MAIFIe"). Additionally, for the 15th consecutive year, FPL's 2020 FPSC T&D SAIDI was the best among the Florida IOUs, becoming the first investor-owned utility in Florida to achieve FPSC T&D SAIDI of less than 50 minutes.[10]

Q. Are the Company's customers satisfied with this level of reliability?

A. One measure of satisfaction is the number of reliability-related customer complaints. Witness Spoor states that FPL has reduced FPSC reliability-related logged complaints per 10,000 customers by 32% since 2016.[11]

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[7] Spoor Direct at page 20, line 1 through page 21 line 11.
[8] SAIDI = the total number of minutes of service interruption the average customer experiences in a year.
[9] Spoor Direct at page 17, lines 20-22.
[10] *Id*. at page 17, lines 5-22.
[11] *Id*. at page 36, lines 15-16

Q. Why is the Company proposing to invest an additional $3.54[12] billion in 2021-2023 to further improve day-to-day (non-storm) reliability?

A. I'm unclear. There is no explanation in witness Spoor's testimony why further day-to-day reliability improvement is imperative, other than his statement that customers "require, and increasingly expect, improved reliability"[13].

VS-CLEO submitted a request for production of documents ("RPOD") to the Company on May 3, 2021 seeking support for this statement. On June 14, 2021, the Company provided some heavily redacted pages showing results from various marketing surveys.[14] The survey results show that some of FPL-Gulf's customers care about reliability during storms and day-to-day reliability. However, the provided documents do not clearly demonstrate that FPL-Gulf's customers "require, and increasingly expect, improved reliability".

Q. Ideally, how would you evaluate the Company's request for day-to-day reliability-related capital expenditures in this proceeding?

A. The vast majority of customer outages for an electric utility are caused by problems on the distribution system.[15] Ideally, I would first examine distribution circuit information including the number of customers served, circuit length, and historical reliability performance. I would then attempt to understand how proposed capital expenditures are targeted to address specific problematic circuits.

[12] From Figure 1, the Company is projecting $1.36 billion in 2021, $1.12 billion in 2022, and $1.06 billion in 2023 for Reliability/Grid Modernization.
[13] Spoor Direct at page 8, line 7.
[14] FPL-Gulf Confidential response to VS-CLEO RPOD No. 37.
[15] For example, FPL's 2020 Distribution SAIDI was 47.3 minutes per customer and Transmission SAIDI was 1.2 minutes per customer, according to the 2020 FPL Distribution Reliability Report, p. 4.

Q. Does the Company have this circuit-level information?

A. Yes. The Company publishes much of this information in its annual FPSC Distribution Reliability Report[16] in an appendix titled "Feeder Specific Data and Attached Laterals". The report is in PDF format and VS-CLEO, in a May 3, 2021 interrogatory, requested circuit-level information in a spreadsheet to allow for analysis.

Q. Did the Company provide this circuit-level information?

A. No. On May 24, 2021, the Company objected to the interrogatory in its entirety as "irrelevant, immaterial, overly broad, unduly burdensome, and not reasonably calculated to lead to the discovery of relevant admissible evidence."[17]

On June 9, 2021, following discussion and agreement between counsel for FPL and VS-CLEO, the Company provided some system-level information.[18] This, however, is not helpful for assessing circuit-level reliability.

Q. How else would you ideally evaluate the Company's request for reliability-related capital expenditures?

A. For initiatives that involve discrete units of activity, I would like to understand historical volumes of activity, planned volumes of activity, and unit costs per activity. For example, one of the Company's reliability initiatives is the replacement of substation transformer relays. I would like to know how many relays FPL-Gulf has historically replaced each year, the planned number of relay replacements in 2021-2023, and the actual and forecasted unit costs per relay replacement.

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[16] Available at http://www.psc.state.fl.us/ElectricNaturalGas/ElectricDistributionReliability.
[17] Company 5/24/21 Objection to VS-CLEO Interrogatory No. 93, attached in Exhibit CV-3.
[18] Company 6/9/21 Response to VS-CLEO Interrogatory No. 93, attached in Exhibit CV-3.

Q. Has the Company provided this type of information to VS-CLEO?

A. Not completely. In addition to similar requests for volumes and unit costs, VS-CLEO requested this information for substation relays in spreadsheet format on May 3, 2021. The Company objected on May 24, 2021, stating, “FPL objects to this request calling for information to be provided in a specified format. FPL will provide any responsive information in the form that it is kept in FPL’s normal course of business.”[19]

On June 14, 2021, the company provided the estimated number of relay replacements in 2021-2023. In a specific response to the request for unit costs, the Company stated that it is “designated as Highly Sensitive Information, as that term are [*sic*] used in the Confidentiality Agreements in use in this proceeding. The answer to this interrogatory will be made available for inspection at The Radey Law Firm … (in) Tallahassee, Florida.”[20] I’m unable to review the information in Tallahassee on such short notice.

Q. How else would you ideally evaluate the Company’s request for day-to-day reliability-related capital expenditures?

A. I would ideally examine the Company’s projected reliability improvements from the proposed capital expenditures, the reasonableness of the reliability improvement projections, and the cost-effectiveness of the proposed capital spending.

Q. What day-to-day reliability improvements is the Company projecting from the $3.54 billion Reliability/Grid Modernization expenditures in 2021-2023?

A. VS-CLEO submitted multiple interrogatories and RPODs to the Company on May 3, 2021, seeking details on the expected reliability improvements in SAIDI, SAIFI, and

[19] Company 5/24/21 Objection to VS-CLEO Interrogatory No. 87, attached in Exhibit CV-3.
[20] Company 6/14/21 Response to VS-CLEO Interrogatory No. 87, attached in Exhibit CV-3.

MAIFIe[21] in 2021-2023 from FPL-Gulf's proposed T&D reliability and grid modernization initiatives.[22] On June 9, 2021, the Company responded:

> "T&D reliability initiatives, and the associated investments, are necessary to maintain the current reliability standards and performance as well as the continued improvement in overall system reliability. FPL measures reliability performance at the system level. Power Delivery strives for continual reliability improvement and these initiatives, along with others, have the potential to deliver approximately 2 - 4% annual improvement in SAIDI on top of the current reliability performance, with similar type improvements in the other metrics."[23]

Q. What would a 2-4% annual improvement in day-to-day (non-storm) SAIDI mean for the Company's customers?

A. 2020 T&D SAIDI values for FPL and Gulf were 48.54 and 50.26 minutes respectively.[24] Figure 2 below shows the results of a 3% annual improvement in SAIDI from 2020-2023.

SAIDI
(minutes)

	FPL	Gulf
2020	48.540	50.260
2021	47.084	48.752
2022	45.671	47.290
2023	44.301	45.871

[21] System Average Interruption Frequency Index (SAIFI) = the total number of sustained (> 60 seconds for FPL -Gulf) service interruptions the average customer experiences in a year. Momentary interruptions are those lasting less than 60 seconds, and their frequency is measured by the Momentary Average Interruption Frequency Event Index (MAIFIe).
[22] VS-CLEO Interrogatories Nos. 84, 86(g), 90(a) and RPODs 39, 41, attached in Exhibit CV-3.
[23] Company 6/9/21 Response to VS-CLEO Int. No. 84, attached in Exhibit CV-3.
[24] Company 6/9/21 Response to VS-CLEO Int. No. 93q, attached in Exhibit CV-3.

Figure 2 – Impact of an annual 3% improvement in SAIDI

Q. From Figure 2, how much improvement in outage minutes is the Company projecting by 2023?

A. The Company is projecting approximately 4 minutes improvement for both FPL and Gulf by 2023.

Q. What is the improvement in outage minutes if you assume a 4% annual improvement in SAIDI?

A. Approximately 6 minutes improvement for both FPL and Gulf by 2023.

Q. So the Company is proposing to spend $3.54 billion of capital from 2021-2013 to improve annual day-to-day (non-storm) customer outage time by approximately 4-6 minutes?

A. Yes. That's approximately $600-$900 million of capital per minute of reduced day-to-day (non-storm) customer outage time.

Q. Have the Company's customers indicated a willingness to pay for $600-$900 million of capital (plus associated O&M, financing costs and taxes) for a minute of reduced day-to-day (non-storm) outages?

A. Not that I am aware of. On May 3, 2021, VS-CLEO submitted a Request for Production of Documents requesting data, analyses, studies or reports quantifying the Company's customers' willingness to pay for improved reliability.[25] As I previously explained, on June 14, 2021, the Company provided some heavily redacted pages showing results

[25] VS-CLEO First Request for Production of Documents No. 37(b).

from various marketing surveys.[26] One survey asks if customers would be willing to pay "slightly more" on their monthly bill, and another survey asks customers if they support a "modest increase" in rates for "high quality, safe, and reliable electricity services." During his June 16, 2021 deposition, Mr. Spoor was asked: "In developing your testimony, are you aware of any conversations that took place with customers describing the actual expenditures you're proposing and the actual benefits you're proposing?" Witness Spoor acknowledged that he is not aware of any specific discussions with customers about the magnitude of the Company's proposed Reliability/Grid Modernization capital expenditures.[27]

Q. Can you quantify the economic value to the Company's customers of this expected improvement in reliability?

A. Many utilities use Lawrence Berkeley National Lab's Interruption Cost Estimate ("ICE") Calculator[28] to estimate the economic value to customers from improved reliability. The ICE Calculator is an imperfect tool[29], but can provide indicative values that inform commissions and stakeholders in general rate case and grid modernization proceedings.

[26] *See* FPL's Confidential 6/14/21 Response to VS-CLEO RPOD 37. The quoted portions have been cleared with FPL counsel as non-confidential.
[27] Witness Spoor deposition transcript (dated June 16, 2021), page 26, lines 21-25, attached as Exhibit CV-8.
[28] The ICE Calculator is an electric reliability planning tool developed by Lawrence Berkeley National Laboratory and Nexant, Inc. The tool is designed for electric reliability planners at utilities, government organizations, and other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements in the US. https://www.icecalculator.com/home
[29] The economic benefits from improved reliability are not directly measurable. Also, the ICE Calculator is dated, as some of the surveys are 20+ years old; it is not statistically-representative for all regions of the U.S.; and it is not appropriate for estimating costs of widespread, long-duration (> 24 hour) interruptions. See https://www.icecalculator.com/recent-updates. Additionally, it is difficult to model the impact of momentary interruptions in the ICE Calculator.

Q. What does the ICE Calculator quantify as the economic value to FPL-Gulf's customers of a 2-4% annual improvement in day-to-day reliability from 2020-2023?

A. I ran the ICE Calculator using an annual 3% reduction in non-storm SAIDI and SAIFI from 2020-2023 for FPL and Gulf.[30] According to the ICE Calculator, the value from this day-to-day reliability improvement to FPL's customers is $1.2 billion and the value to Gulf's customers is $0.1 billion. See Exhibit CV-5 for screenshots of these results from the ICE Calculator.

Q. What do you conclude?

A. It appears that the Company's proposed $3.54 billion Reliability/Grid Modernization expenditures in 2021-2023 for day-to-day reliability improvements may significantly exceed the economic benefits to its customers. I recommend that the Commission require the Company to develop a comprehensive benefit/cost analysis for its proposed Reliability/Grid Modernization expenditures to demonstrate cost effectiveness and reasonableness. A benefit/cost analysis is standard practice for assessing grid modernization plans, and it is particularly important for expenditures of the magnitude proposed by the Company. I will further explain this later in my testimony.

Q. Turning to Grid Modernization, what is included in this category of the Company's proposed capital expenditures?

A. For FPL-Gulf's distribution system, this category includes the deployment of smart devices (automated feeder/lateral/transformer switches and fault current indicators)

[30] Other assumptions: 40 year asset life, 2% inflation, 6% discount rate, 2020 customer counts from FPL's response to OPC's First Production of Documents Supplemental No. 35, 2020 SAIFI = 0.87 for FPL, 0.81 for Gulf.

that automatically identify and/or isolate problematic line sections and/or clear temporary faults, avoiding and/or mitigating interruptions and reducing restoration times and costs.[31] For the Company's transmission system, this category includes rebuilding of the Company's 500kV system (replacing transmission structures with galvanized steel poles), the upgrading/digitizing of substation transformer relays, and installing substation fault information capabilities.[32]

Q. How do you typically evaluate a utility's request for Grid Modernization capital expenditures?

A. In a paper I co-authored in 2020[33] ("Grid Mod Playbook", provided as Exhibit CV-6), we explain that regulators should expect to see, among other information, the following when reviewing a utility's proposed grid modernization plan:

- Specific, measurable goals and objectives.
- A benefit/cost analysis ("BCA") to demonstrate cost effectiveness or cost reasonableness.
- Detailed metrics to track progress of the plan's implementation and to hold the utility accountable for achieving planned outcomes.
- A demonstrated need for the proposed expenditures.

Q. Has the Company provided specific, measurable goals and objectives for its proposed reliability and grid modernization expenditures?

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[31] Spoor Direct at page 18, lines 14-18.
[32] *Id*. at page 40 lines 2-4.
[33] Sara Baldwin, Ric O'Connell, Curt Volkmann. *A Playbook for Modernizing the Distribution Grid; Volume I: Grid Modernization Goals, Principles and Plan Evaluation Checklist.* IREC and GridLab. May 2020. https://irecusa.org/publications/a-playbook-for-modernizing-the-distribution-grid-volume-1/ and https://gridlab.org/works/grid-modernization-playbook-report/.

A. No. Witness Spoor states, "With FPL and Gulf's continued commitment and the necessary investments to employ these initiatives, we expect our superior reliability performance will continue to improve."[34] I previously explained that, in response to multiple VS-CLEO interrogatories and RPODs, the Company stated that its reliability and grid modernization initiatives "have the potential to deliver approximately 2 - 4% annual improvement in SAIDI on top of the current reliability performance, with similar type improvements in the other metrics."[35] In his deposition, witness Spoor explained a "two pronged" approach of maintaining existing reliability with continuous improvement.[36] I do not consider this to be a specific goal or objective for the Company's proposed Reliability/Grid Modernization expenditures. A specific goal or objective would be, for example, "achieve a T&D FPL-Gulf SAIDI of 45 minutes by 2023".

Q. Has the Company provided a BCA to demonstrate cost effectiveness or cost reasonableness?

A. No. VS-CLEO submitted several interrogatories on May 3, 2021 requesting benefit/cost analyses demonstrating that the benefits of the Company's various reliability and grid modernization initiatives exceed the costs.[37] FPL-Gulf objected to each of the interrogatories on May 24, 2021.[38]

On June 14, 2021, the Company updated its response and directed VS-CLEO to the FPSC website containing the utilities' Annual Reliability Reports. The Company stated

[34] Spoor Direct at page 18, lines 6-8.
[35] Company 6/9/21 Response to VS-CLEO Int. No. 84, attached in Exhibit CV-3.
[36] Spoor deposition transcript, pages 27, 38, attached in Exhibit CV-8.
[37] VS-CLEO Interrogatories Nos. 86(a), 90(b), 91(a), and 91(b), attached in Exhibit CV-3.
[38] Company 5/24/21 Objections to VS-CLEO's Interrogatories Nos. 86, 90, and 91, attached in Exhibit CV-3.

that these reports include "costs and benefits of FPL's various reliability and hardening initiatives".[39] During his deposition, witness Spoor admitted that the Annual Reliability Reports do not include a full benefit/cost analysis.[40]

In the same June 14, 2021 response, the Company also directed VS-CLEO to the SPP rebuttal testimony of Michael Jarro in FPSC Docket No. 20200071- EI, stating that it contains "a generally applicable description of how cost benefit analyses relate to reliability programs". In his deposition, witness Spoor acknowledged that Jarro's testimony is not relevant for capital expenditures to improve day-to-day reliability.[41] Witness Spoor also admitted that the Company has, in fact, not developed a Benefit Cost Analysis for its proposed Reliability/Grid Modernization expenditures.[42]

Q. Has the Company provided detailed metrics to track progress of its capital expenditures and to track achievement of planned outcomes?

A. No.

Q. Has the Company demonstrated a need for the proposed investments?

A. No. As explained earlier, the Company's day-to-day reliability performance is already very good compared to other utilities, and the Company's reliability-related customer complaints are down significantly since 2016. Company witness Reed's testimony further supports this, stating, "My benchmarking analysis shows that FPL has consistently and substantially out-performed similarly sized companies across a wide

[39] Company 6/14/21 Response to VS-CLEO INT 86(a), attached in Exhibit CV-3.
[40] Spoor deposition transcript, pages 45-51, attached in Exhibit CV-8.
[41] *Id.*
[42] *Id.*

array of financial and operational metrics including … service quality and system reliability."[43]

Q. What do you recommend?

A. I recommend that the Commission, prior to approval of the Company's proposed Reliability/Grid Modernization expenditures, require FPL-Gulf to develop a comprehensive BCA demonstrating cost effectiveness and reasonableness.

Q. What should be included in a comprehensive benefit/cost analysis or BCA?

A. As we explain in the Grid Mod Playbook, a comprehensive BCA includes:

- An appropriate BCA methodology (e.g., least-cost/best-fit, benefit/cost ratio, etc.) for each category of expenditures.
- Disclosure of all planned Grid Mod expenditures including those beyond the initial period of the request.
- Costs reflecting the full revenue requirements and customer bill impacts over the life of the assets.[44]
- Cost contingencies and a corresponding range of potential BCA results.[45]
- Reasonable and credible benefits from improved reliability.[46]

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[43] FPSC Docket No. 20210015-EI, FPL Direct testimony of John J. Reed, filed March 12, 2021, at page 7, lines 6-10.

[44] In addition to capital and O&M costs, the BCA should include full financing costs and taxes over the life of the assets, as measured by the present value of revenue requirements.

[45] Cost contingencies are amounts added to base costs in a spending plan to account for risks and uncertainty. Cost contingencies effectively provide a range of expected costs and best- and worst-case benefit/cost ratios. As with all BCA assumptions and calculations, it is important that the utility's inclusion of cost contingencies be explicit and transparent.

[46] Although the determination of reasonable and credible benefits is subjective, the Grid Mod plan should include clear, understandable, and verifiable data/analysis in support of claimed benefits. The ranges of benefits should be consistent with what the utility has demonstrated in pilots, prior deployments, or with what other utilities have realized deploying similar technologies.

- Use of an appropriate discount rate in the BCA calculations.
- Transparency of and support for key BCA assumptions, and a sensitivity analysis of those assumptions.[47]

Q. Are there other resources the Company can use to help evaluate the cost effectiveness of its Reliability/Grid Modernization expenditures?

A. Yes. The Department of Energy ("DOE") published its 4-volume Modern Distribution Grid Report in 2020, which includes a Strategy and Implementation Guidebook.[48] This Guidebook contains a chapter on a Methodology to Evaluate the Cost-Effectiveness of Investments.

The DOE, together with Synapse, also published a report in February 2021, titled *Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations*.[49] The report reflects a review of 21 recent utility grid modernization plans, and is provided as Exhibit CV-7.

Q. What else do you recommend?

A. To increase transparency into the Company's capital expenditures and to hold the Company accountable for achieving expected outcomes, I recommend that the Commission require the Company to work with stakeholders to establish a T&D capital performance management framework ("Framework") for its largest categories of

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[47] A typical Grid Mod plan BCA includes multiple assumptions such as future reliability improvements, equipment failure rates, customer participation in DSM programs, EV adoption rates, etc. Most, if not all, of these assumptions are uncertain. A sensitivity analysis determines how much the overall costs or benefits change from a change in one or more key assumptions. A sensitivity analysis also identifies the assumptions that have the most impact on the overall costs and benefits of the Grid Mod plan, thus highlighting the key assumptions that the utility should further validate, monitor, and report on throughout the Grid Mod plan implementation.

[48] https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume_IV_v1_0_draft.pdf

[49] https://www.synapse-energy.com/sites/default/files/GMLC-Grid-Mod-BCA-2021-02-02-18-094.pdf

expenditures, including Reliability/Grid Modernization. The Framework should include:

- Metrics to track progress and achievement of expected outcomes for each major capital category.
- Baselines, targets, and actuals for each metric.
- A process for ongoing tracking and reporting of metrics including costs and benefits.

I provide examples of potential metrics in Exhibit CV-4.

Q. How is this different from the Annual Reliability Reports that FPL and Gulf already file with the FPSC?

A. The Annual Reliability Reports are voluminous, providing detailed information on the Company's historical reliability performance, and one-year budgets for certain reliability-related programs. The Framework I'm recommending more closely associates capital expenditures with planned and actual outcomes for both Reliability/Grid Modernization and Growth.

V. <u>FPL-GULF'S PROPOSED CAPITAL FOR GROWTH IS UNSUPPORTED</u>

Q. What is included in the Company's proposed $5.86 billion from 2019-2023 for Growth?

A. This category includes the installation of new service lines for 425,000 new service accounts by 2023, expansion and upgrades of T&D facilities/infrastructure, and other large major construction projects and new streetlight systems.[50]

[50] Spoor Direct at page 38, line 19 through page 39, line 2.

Q. How has the Company explained the need for these expenditures?

A. In only two pages of Witness Spoor's testimony, he attributes the need to FPL's fast growing service area and cites three examples of growth-related major capital projects.[51]

Q. What additional information did VS-CLEO seek to obtain to better understand the need for $5.86 billion of Growth capital?

A. On May 3, 2021, VS-CLEO submitted an RPOD seeking all studies, reports, data, analyses, assumptions, and spreadsheets supporting the request for $5.86 billion of Growth capital. On June 9, 2021, the Company responded by referring VS-CLEO to a spreadsheet titled 'Rate Case Backup – Spoor Testimony.xlsm'.[52] The spreadsheet consists of one tab with seven tables containing high-level summaries of proposed costs. There is no explanation of how the Company derived the costs. In his deposition, witness Spoor stated that he is unaware of any additional information supporting FPL's proposed Growth expenditures.[53]

Q. Ideally, how would you evaluate the Company's proposed growth-related capital expenditures?

A. Ideally, I would first seek to understand the state of the Company's distribution system and distribution planning process, including such information as historical and forecasted peak loads across its various planning areas, its approach to load forecasting, and how it accounts for the impact of demand side management and distributed energy resources.

[51] Spoor Direct at pages 25-26.
[52] Company 6/9/21 Response to VS-CLEO RPOD 44, attached in Exhibit CV-3.
[53] Spoor deposition transcript at pages 52-55, attached in Exhibit CV-8.

Q. Has the Company provided this information?

A. No. VS-CLEO submitted an interrogatory on May 3, 2021 requesting details on the Company's distribution planning process. On May 24, 2021, the Company objected to much of the interrogatory as "irrelevant, immaterial, and not reasonably calculated to lead to the discovery of relevant admissible evidence in this base rate proceeding".[54]

Subsequently, on June 7, 2021, the Company provided a few high-level responses to the same interrogatory.[55] This is, however, insufficient to provide a detailed understanding of the Company's distribution system, approach to distribution planning, and the justification for $5.86 billion of Growth capital expenditures.

Q. What do you recommend?

A. As I previously explained, to increase transparency and to hold the Company accountable for achieving expected outcomes, I recommend that the Commission require the Company to establish a T&D capital performance management framework. This Framework should include Growth capital expenditures. I provide examples of potential growth-related metrics in Exhibit CV-4.

VI. SUMMARY OF RECOMMENDATIONS

Q. Please summarize your recommendations.

A. I recommend that the Commission, before approving the Company's proposed Reliability/Grid Modernization and Growth capital expenditures, require the Company to:

[54] Company 5/24/21 Objection to VS-CLEO Interrogatory No. 92, attached in Exhibit CV-2.
[55] Company 6/7/21 Response to VS-CLEO Interrogatory No. 92, attached in Exhibit CV-2.

- Develop a comprehensive benefit/cost analysis for its proposed Reliability/Grid Modernization expenditures demonstrating cost effectiveness and reasonableness. Pages 21-22 of my testimony and Exhibit CV-7 describe some important attributes of a comprehensive benefit/cost analysis.
- Work with stakeholders to establish a T&D capital performance management Framework for the Company's Reliability/Grid Modernization and Growth capital expenditures. The Framework should include:
    - Metrics to track progress and achievement of expected outcomes (see VS-CLEO Exhibit CV-4 for potential metrics).
    - Baselines, targets, and actuals for each metric.
    - A process for ongoing tracking and reporting of metrics including costs and benefits.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Yoca Arditi-Rocha was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

THE CLEO INSTITUTE, INC.

DIRECT TESTIMONY OF YOCA ARDITI-ROCHA

DOCKET NO. 20210015-EI

JUNE 21, 2021

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I. INTRODUCTION OF THE WITNESS

Q. Please state your name and business address.

A. My name is Yoca Arditi-Rocha, and my non-profit's address is 2103 Coral Way, 2nd Floor, Miami, Florida, 33145.

Q. By whom are you employed and what is your position?

A. I am employed by The CLEO Institute, Inc. ("CLEO" or "Institute"), and I am its Executive Director.

Q. Please describe your duties and responsibilities in that position?

A. As the Executive Director of a small non-profit, I wear many hats. From grant seeking, to Public Relations, to educator, to administrator…. I make sure CLEO's purpose, Mission and Vision are at the center of the organization's activities and educational programs.

Q. In that role, do you manage and oversee CLEO's day-to-day activities?

A. Yes.

II. CLEO'S MEMBERS ARE SUBSTANTIALLY AFFECTED

Q. How many persons are members of The CLEO Institute, Inc.?

A. As of June 17, 2021, the Institute had approximately 10,314 individual members.

Q. How many of those individual members reside in Florida Power & Light Company's ("FPL") service territory?

A. At least 3,784 of our members have provided addresses that are within FPL service territory, however, we have reason to believe that a significantly higher number of them live within the service area since we believe we lost some members on our data base when we migrated CRM systems 2 year ago.

Q. Why do you say that significantly more than 3,748 CLEO Institute members live in FPL's service territory?

A. Our membership database contains physical address information for only 5,231 of our 10,314 individual members. Our staff, using the information available for those 5,231 members, identified 5,231 addresses for them in cities that are fully within FPL service territory. Based on this review of our records, it is reasonable to conclude that, not only do approximately 5,231 CLEO Institute members reside in FPL's service territory, but that a significantly higher number than that does as well, considering CLEO has been established for over a decade in Southeast Florida and only expanded to North/Central Florida at the end of 2019. The discrepancy lacks in switching data base technology and poor zip code tracking.

Q. In its petition seeking to intervene in this case, the Institute stated that at least 10,000 of its members reside in Florida, with approximately 6,500 residing in FPL service territory. Why are those numbers different than the ones you are providing today?

A. The petition seeking intervention was prepared on relatively short notice, and we made rough estimates of our membership numbers at that time. After reviewing our records and counting our members, I still believe the estimates, although high, were sufficiently accurate to illustrate that a substantial number of the CLEO Institute's members reside within FPL service territory, and thus directly impacted by this rate case. Considering that approximately half of the members have provided a physical address, and that the half sample yields 3,784 members with an address inside FPL service territory, it is certainly reasonable to conclude that as many as 7,568 members, or twice 3,784 may live within FPL's service territory. Regardless, 3,784 members is a substantial presence within FPL's service territory, and they are all impacted by the cost of electricity produced by FPL as well as the constrained resource planning decisions that FPL is making and which are being approved for prudence and cost recovery in this case. These CLEO members are directly impacted as ratepaying FPL account holders or as residents who live, work, and conduct commerce within FPL service territory. Additionally, they are affected by the increasingly severe impacts of climate change contributed to by FPL's emissions of greenhouse gases from fossil fueled power plant pollution.

III. CLEO'S SCOPE OF INTERESTS AND ACTIVITIES

Q. Please describe The CLEO Institute, Inc., and what the organization does.

A. The CLEO Institute, which stands for Climate Leadership Engagement Opportunities, is a non-profit, non-partisan organization exclusively dedicated to climate crisis education and advocacy. Our purpose is to educate and empower communities to demand climate action, ensuring a safe, just, and healthy environment for all. The Institute's climate trainings vary in length and are tailored to our audience. CLEO consults with a world-class Expert Advisory Council that ranges from local to national climate scientists, energy experts, to local-municipal policymaking officials. We offer vetted information to enhance climate-oriented environmental literacy which focuses on language that is easy to understand for the general public with the opportunity for topic-focused presentations, such as food, health, climate justice, and energy. We cover the latest scientific data, how it is impacting peoples' daily lives, and what solutions we can take as individuals, as well as a community, to mitigate the climate crisis. A large part of our education work revolves around how electricity, from its sources, generation, distribution and cost, impact our daily lives.

In order to advance environmental literacy and civic engagement, The CLEO Institute has developed transformative initiatives such as certification courses to educate residents on the impacts of extreme weather caused by a changing climate and the intersectionality between energy, food security, extreme heat, and resilience. These certificate programs such as The CLEO Speakers Network, Climate Action Lab, and Climate and Food Policy courses have been scaled and replicated to educate hundreds of Florida residents. Additionally, The CLEO Institute works to ensure that residents across Florida are informed, engaged, and taking action on critical climate issues. This includes actively participating in energy, electricity delivery, and electricity cost related policy matters, in order to advocate for lowering greenhouse gas (heat-trapping global warming gases) emissions, while also ensuring equitable access to clean renewable energy.

Q. You stated that part of the Institute's work includes ensuring that residents across Florida are informed, engaged, and take action on critical climate issues, and that the work includes participation by the Institute in matters having to do with energy and with electricity delivery and cost. Can you provide examples of that kind of work?

A. Yes. The CLEO Institute includes in our educational programs information on how energy choices are vital to combatting climate change. In order to make our communities more resilient in the face of sea level rise and extreme weather events Florida must lower its greenhouse gas emissions coming from carbon pollution. In addition to work securing approval of the Solar Together program, The CLEO Institute also collaborated with Vote Solar to express the concerns and interests of our membership in central and north Florida to Duke Energy Florida and came to a settlement agreement during 2021. During the 2020 Florida legislative session, CLEO advocated against clean energy preemption bills.

Additionally, The CLEO Institute helped write and introduce a resolution urging the state to define long-term climate resilience as "a reduction of pollution and the development of clean energy systems, clean transportation options, flood protections, and other improvements in neighborhood livability, etc." The definition enables communities to take a holistic view of what "resilience" is and what they need to achieve it. It empowers Floridians to make a case for additional investments in clean energy and transportation and neighborhood livability, in addition to the green infrastructure and risk mitigation measures required to respond to the climate crisis. The CLEO Institute policy team also works with local municipalities in Miami Dade, Tampa Bay, Orlando, and Tallahassee to support clean, renewable energy goals. CLEO has also joined national partners to submit letters to the Federal Energy Regulatory Commission advocating for robust investments in clean energy infrastructure. Finally, CLEO Institute has co-published the Florida Future Fund regarding infrastructure investments for clean energy and the importance of necessary partnerships with utility companies.

Q. Does The CLEO Institute's participation in this rate case advance the organization's charitable purpose?

A. Yes. The Institute's Articles of Incorporation state that it was organized for religious, charitable, scientific, testing for public safety, literary or educational purposes, among others. More specifically, the Institute's By-Laws state that the purpose of the Institute shall be to advance environmental literacy and civic engagement. The activities of the Institute, as described above, clearly advance these purposes. Participation in this rate case also furthers the Institute's purposes of advancing civic engagement on the specific environmental concerns of the Institute and its members, notably climate change and its impacts on those most vulnerable to it. The Institute's participation in this rate case on their behalf provides meaningful engagement on the issues to be decided that they otherwise would not have due to the complexity and expense of the undertaking.

Q. How do the issues to be decided in this case relate to the interests of the Institute and its members and the to the Institute's activities?

A. As I previously stated, the interests of the Institute and its members include reduction in greenhouse gas emissions due to their role in exacerbating climate change and its impacts on people, particularly vulnerable populations. As one of the nation's largest electricity generating utilities heavily reliant on fossil fuel combustion, FPL contributes significantly to the heat-trapping pollution produced by greenhouse gas emissions. The amount of those emissions by FPL are tied directly to the electricity generating resources it selects to provide electricity to its customers, and how long they use them. In this rate case, FPL is seeking the Commission's determination that certain of its fossil-fueled electricity generation choices are prudent, its approval of cost recovery mechanisms that assume longer than customary useful lives of combined cycle natural gas generating units, the acceptance of resource planning methodologies that fail to adequately consider solar, battery storage and demand side management programs as alternatives, among other matters. How the Commission addresses each of these issues will impact not only the Institute's and its members' pocketbooks, but will also impact the Institute's and its members' interests in reducing the greenhouse gas emissions that contribute to climate change while exacerbating economic disparities particularly to customers both on the frontlines of a changing warming climate, the pandemic, and economic inequality.

IV. CLEO SEEKS APPROPRIATE RELIEF FOR ITS MEMBERS

Q. What relief is The CLEO Institute seeking on behalf of its members?

A. It is my understanding that we will not have a full picture of the potential relief available until later in the case when all of the discovery responses have been reviewed, all of the experts have fully testified, and all of the issues to be resolved in the case are finally established. However, several expert witnesses sponsored jointly by CLEO and Vote Solar have proposed recommendations to the Commission on a variety of issues in the case. For example, CLEO/Vote Solar witness Wilson addresses costs related to FPL's resource planning and proposes several recommendations to address imprudently incurred costs and stranded asset risk. CLEO/Vote Solar witness Volkmann assesses FPL's proposed transmission and distribution capital expenditures for reliability/grid modernization and growth and recommends contingencies for the approval of the proposed expenditures. Finally, CLEO/Vote Solar witness Whited addresses the inequities of FPL's proposal to its low-income customers and proposes several possible solutions to help protect FPL's most vulnerable customers, improve affordability, and enhance resiliency. For a detailed explanation of the relief they propose at this stage, please refer to their pre-filed testimony filed concurrently with my testimony.

Each of the CLEO/Vote Solar witness proposals are proposals that could have been proposed by any one of CLEO's individual members if they had the financial means and sophistication to undertake intervention in this case. Further, the Commission's acceptance or not of any of the CLEO/Vote Solar witness recommendations, is not dependent upon CLEO's individual interests or its status as an organization. The relief would be appropriate for any one of CLEO's members to receive.

V. CLARIFICATION OF CLEO'S CUSTOMER STATUS

Q. In CLEO's petition to intervene in this case, did CLEO state that its principal place of business is in FPL service territory, making CLEO a rate-paying FPL customer whose operational costs are directly affected by the outcome of this proceeding?

A. Yes.

Q. Did you wish to clarify that statement?

A. Yes. The CLEO Institute's principal place of business is inside FPL service territory. Our address is 2103 Coral Way, 2nd Floor, Miami, FL 33145. Therefore, we do undertake our organization's operations within FPL service territory, and our operational costs are affected by the price FPL charges for electricity. However, CLEO's landlord, maintains an account with FPL, not the Institute, and our landlord passes its electricity costs through to us as part of our negotiated rent payment. So, while our future rent payments may be substantially affected by a change in rates FPL is allowed to charge, we do not receive a bill from FPL each month, and make payments directly to FPL.

Q. When CLEO stated in its petition to intervene that it was a rate-paying FPL customer, did it intend to mislead the Commission?

A. Absolutely not. From a layperson's perspective I believe the statement is accurate. An increase in FPL's rates increases our landlord's costs, and we can expect to see that in increased rent payments in the future. Our landlord reminds us of saving electricity as tenants and thus as users. In the sense that CLEO is situated in FPL service territory and consumes FPL electricity, we understood our organization to be a customer. However, after filing CLEO's petition and after issuance of the Commission's order on CLEO's status as an intervenor, our counsel learned that the Institute's cost of electricity is included in its monthly rent payments, and advised us that it is a material fact that could have a bearing on the Commission's decision to grant CLEO status as an individual intervenor. We immediately made the decision to alert the Commission to that fact.

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Michael P. Gorman was inserted.)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY	)))))	**DOCKET NO. 20210015-EI**

Direct Testimony and Exhibits of

Michael P. Gorman

On behalf of

Federal Executive Agencies

June 21, 2021

BRUBAKER & ASSOCIATES, INC.

Project 11121

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY	)))))	**DOCKET NO. 20210015-EI**

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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 Michael P. Gorman

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

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

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

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

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing in this proceeding on behalf of the Federal Executive Agencies ("FEA").

Q **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A My testimony will address Florida Power & Light Company's ("FPL" or "Company") overall rate of return including return on equity, embedded debt cost, and ratemaking capital structure.

Q **DOES THE FACT THAT YOU DID NOT ADDRESS EVERY ISSUE RAISED IN FPL'S TESTIMONY MEAN THAT YOU AGREE WITH FPL'S TESTIMONY ON THOSE ISSUES?**

A No. It merely reflects that I chose not to address all those issues in my testimony. It should not be read as an endorsement of, or agreement with, FPL's position on such issues.

I. SUMMARY

Q **PLEASE SUMMARIZE THE PURPOSE OF YOUR TESTIMONY.**

A In my testimony, I will make several adjustment to FPL's claimed revenue deficiency. These adjustments are summarized as follows:

1. I respond to FPL's proposal to recover a $100 million payment to the Jacksonville Electric Authority ("JEA") to retire the Scherer Unit 4 early.
2. I will comment on the recovery methodology of several abandoned plant cost capital recovery amounts the Company seeks in this proceeding.
3. I will comment on the Company's proposal for a four-year rate plan including an adjustment to accelerate excess accumulated deferred income taxes in 2024 and 2025 in lieu of a rate change, and its proposal for a new solar rate capital cost recovery to be in effect in 2024 and 2025.
4. I will address an overall rate of return, return on equity, and ratemaking capital structure for FPL. I comment on FPL's proposal and propose an overall rate of return that provides FPL fair compensation, maintains its credit rating and financial integrity, and preserves its access to capital, but accomplishes these utility compensation objectives while preserving just and reasonable and lowest possible prices to customers.

Q PLEASE SUMMARIZE YOUR RECOMMENDATION CONCERNING FPL'S PROPOSAL TO RECOVER A $100 MILLION RETIREMENT PAYMENT TO JEA TO SUPPORT ITS EFFORT TO RETIRE SCHERER UNIT 4 EARLIER THAN THE EXPECTED OPERATING LIFE OF THIS FACILITY.

A FPL is proposing to recover a $100 million payment to JEA as a coordination condition for JEA to agree to retire Scherer Unit 4. FPL proposes to recover this payment to JEA as a regulatory asset and amortize it over ten years.

I recommend the Commission reject FPL's proposal to recover this $100 million payment to JEA from its retail customers. Under the terms of retiring Scherer Unit 4, FPL's retail customers in Florida will be burdened by the unrecovered sunk costs of Scherer Unit 4 based on its decision to retire early. Even with these sunk costs, FPL claims FPL's customers will be economically better off. Similarly, FPL's contractual relationship with JEA would leave JEA customers saddled with unrecovered costs associated with the retirement of Scherer Unit 4, but JEA's economics indicate that its customers would be economically better off even with these sunk investments. It is reasonable to treat FPL's retail customers and JEA on a comparable basis.

FPL's agreement with JEA to retire Scherer Unit 4 also included a 20-year new Power Purchase Agreement ("PPA") where JEA would purchase gas-fired generating resources from FPL at stated capacity prices, fixed gas costs, and later potentially converting to a solar resource backed PPA. The contractual relationship between FPL and JEA will continue beyond the retirement of Scherer Unit 4, and the $100 million payment from FPL to JEA was part of this ongoing contractual relationship. As such, I recommend the Commission reject permitting FPL to recover the $100 million payment to JEA from its retail customers' cost of service in this case, and instead direct FPL to recover its $100 million payment to JEA as part of the contractual agreement between FPL and JEA to retire Scherer Unit 4, and enter a 20-year PPA.

Also noteworthy, the decision to retire Scherer Unit 4 will create economic benefits both to FPL on a stand-alone basis, and to JEA on a stand-alone basis, without regard to the $100 million payment from FPL to JEA. As such, there is no direct tie between FPL's infrastructure investments or operating costs needed to provide service to its retail customers in this case, and its separate contractual arrangements with JEA based on wholesale contract sales for Scherer Unit 4 and/or the new 20-year PPA that would justify shifting this wholesale contractual payment to JEA to its retail operations. For these reasons, I recommend the Commission reject allowing FPL to recover this $100 million payment to JEA from its retail customers.

Q PLEASE DESCRIBE YOUR PROPOSED MODIFIED RECOVERY METHODOLOGY RELATED TO SEVERAL ABANDONED PLANT CAPITAL INVESTMENTS WHICH FPL SEEKS RECOVERY OF IN THIS PROCEEDING.

A I modified recovery for certain coal-fired investments which will be retired early or are already abandoned. The Company's proposal is to recover these in a regulatory asset using a declining balance methodology. Because the assets are retired, the Company will not be adding to these regulatory assets, but rather will simply amortize the cost of these over time.

A more balanced and equitable method of recovering these costs from FPL's customers would be to use a levelized cost recovery instead of a declining balance cost recovery methodology. This will lower costs to customers initially, but will increase costs to customers toward the end of the amortization period. The actual cost to customers over time would be more equitable, and mitigate the impact on customers at the initial outset of beginning to recover the regulatory asset balance. FPL should be economically indifferent to a declining balance cost recovery methodology versus a levelized methodology, because it will continue to earn its Commission-approved weighted average cost of capital on the unrecovered balance as long as it is outstanding.

I also request the Commission to require FPL to consider the potential benefits to customers by the use of a lower financing mechanism for these non-recurring abandoned plant regulatory assets. For example, use of securitization bonds, in lieu of the utility's weighted average cost of capital may provide the Company full recovery of these abandoned plant costs, while reducing the charges to customers to compensate the Company for these regulatory assets.

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS AND CONCLUSIONS ON RETURN ON EQUITY.

A I recommend the Florida Public Service Commission ("Commission") award a return on common equity in the range of 9.10% to 9.70%, with a midpoint of 9.40%. This return on equity reflects FPL's current market cost of equity. I recommend the Commission approve a return on equity that reflects FPL's investment risk, and charges customers tariff prices that are no more than necessary to fairly compensate FPL and maintain its financial integrity and credit standing.

I also respond to FPL witness Mr. James C. Coyne's return on equity recommendation. Mr. Coyne recommends an equity return in the range of 10.50% to 11.50%, and return on equity of 11.00%.[1] Mr. Coyne' recommended return on equity

[1]Coyne Direct Testimony at 5-6.

for FPL substantially exceeds a fair return on equity and unjustifiably inflates rates to customers above a just and reasonable level.

Q PLEASE SUMMARIZE YOUR PROPOSED ADJUSTMENTS TO THE COMPANY'S PROPOSED RATEMAKING CAPITAL STRUCTURE.

A The Company's proposed ratemaking capital structure includes a common equity ratio of total investor capital of approximately 59.6%. This common equity ratio is unreasonable because it represents a capital structure that is far more expensive than necessary to support FPL's current bond rating and access to capital. As such, FPL's proposed ratemaking capital structure does not reflect economic and efficient management and produces an excessive rate of return and unnecessarily inflated retail rates. A more reasonable and balanced ratemaking capital structure, and one more reasonably aligned with capital structures approved for ratemaking purposes for other Florida utilities, will support FPL's investment grade bond rating and access to capital, but at significantly lower tariff rate prices to its retail customers, which supports rates that are just and reasonable.

I recommend a ratemaking capital structure that consists of 53.5% common equity of total investor capital, and when adjusted for other capital components, including customer deposits, accumulated deferred income taxes and investor tax credits, this produces a total ratemaking common equity ratio of 43.12% in 2022.

As shown on my Exhibit MPG-1, my recommended overall rate of return for FPL is 5.52% for 2022 and 5.58% for 2023, which reflects my recommended return on equity of 9.40% and my recommended ratemaking capital structure.

Q PLEASE SUMMARIZE YOUR PROPOSED ADJUSTMENTS TO FPL'S CLAIMED REVENUE DEFICIENCY IN TEST YEARS 2022 AND 2023.

A My recommended adjustments to the Company's claimed revenue deficiencies in its 2022 and 2023 test years are presented in Table 1 below. As shown in this table, the Company's claimed revenue deficiency under the RSM scenario for 2022 and 2023 is overstated by $1.051 billion and $104.1 million, respectively.

TABLE 1

Revenue Requirement Issues
Consolidated Company
($ Millions)

Description	2022	2023
Claimed Deficiency:	$1,108.4	$606.5
Issues:		
Return on Equity	$685.0	$50.9
Cost of Debt	$0.0	$17.8
Capital Structure	$327.9	$24.0
Rate of Return	$1,012.9	$92.7
Capital Recovery Schedules	$24.0	$1.9
Scherer JEA Payment	$14.5	$9.5
Total	$1,051.4	$104.1
Adjusted Deficiency	$57.0	$502.4

Q DO YOU HAVE ANY COMMENTS CONCERNING THE COMPANY'S PROPOSAL FOR A FOUR-YEAR RATE PLAN?

A Yes. I recommend the Commission reject the Company's proposal for a four-year rate plan. In fact, the Company has not presented any quantification of its cost of service relative to the rate revenue expected to be collected in 2022 and 2023.

The Company has not provided a complete revenue requirement in relationship to the projected rate revenue under current rates for 2024 and 2025. Hence, I reject the Company's proposal for a four-year rate plan because its filing only supports its claimed cost of service and rate revenue relationships under a two-year rate plan – 2022 and 2023.

Q PLEASE SUMMARIZE YOUR RESPONSE TO THE COMPANY'S REQUEST TO ACCELERATE AMORTIZATION OF EXCESS ACCUMULATED DEFERRED INCOME TAXES ("EADIT") IN 2024 AND 2025.

A The Company's proposal to accelerate remaining balances of EADIT in 2024 and 2025 should be denied. FPL witness Scott Bores states that accelerating the excess tax benefits will reduce unprotected excess deferred taxes in 2024 and 2025 of around $81.3 million.[2] The revenue requirement net value would be approximately $109 million for tax gross-up of this operating income excess ADIT credit. The Company simply has not demonstrated that it has $218 million (2 times $109 million) of revenue requirement offset that justifies accelerating these excess tax deferred credits in 2024 and 2025 in the amount it is requesting. For these reasons, the Company's proposal should be rejected. The Company has not presented a cost of service analysis that shows allowing for accelerated write-down of these customer regulatory liabilities in 2024 and 2025. Allowing the Company to accelerate amortization of these costs, without determining whether or not a rate decrease to customers is appropriate, will prejudice customers' rights to full value of these regulatory liabilities, and as such, customers would be harmed under this proposal.

[2]Bores Direct Testimony at 41.

Q PLEASE SUMMARIZE YOUR PROPOSAL FOR THE COMMISSION TO APPROVE A SOLAR RATE CAPITAL COST RECOVERY FOR FACILITIES EXPECTED TO BE PLACED IN-SERVICE IN 2024 AND 2025.

A The Commission should not approve FPL's proposal for a 2024 and 2025 Solar Base Rate Adjustment ("SoBRA") mechanism. FPL witness Liz Fuentes proposes a separate mechanism to charge customers for revenue requirement for 2024 and 2025 SoBRAs following the test year. The revenue requirement for these facilities will be based on estimated capital expenditures for each solar project, including depreciation expense and accumulated depreciation, and related operating expenses. She states the revenue requirement will reflect FPL's approved midpoint return on equity and incremental capital structure that is adjusted to reflect the inclusion of investment tax credit on a normalized basis. She states that the estimated capital expenditures will eventually be trued up if the actual capital costs are different than those forecasted.[3]

The Company's proposal for a SoBRA mechanism should be denied. It reflects incremental cost of new Solar Resource capital investments in 2024 and 2025, but does not capture the reduction in capital costs for solar investments that are in-service in 2022 and 2023, which will further depreciate into 2024 and 2025. That is, the incremental capital investments for 2024 and 2025 do not accurately track the change in total FPL Solar Resource "net" plant in-service for all of its solar resources, including those in-service in 2022/2023.

Allowing for an incremental mechanism charge for new investments in 2024/2025 without tracking a decline in the net plant or rate base values of the solar facilities that are in-service before 2024, will have the effect of overcharging

[3]Fuentes Direct Testimony at 25-26.

customers for FPL total Solar Resource "net" plant in-service investments. For these reasons, FPL's proposed solar base rate adjustments for investments made in 2024 and 2025 should be rejected.

II. SCHERER UNIT 4 EARLY RETIREMENT PAYMENT TO JACKSONVILLE ELECTRIC AUTHORITY ("JEA")

Q IS FPL REQUESTING TO SEEK RECOVERY OF A PAYMENT IT MADE TO JEA AS PART OF ITS AGREEMENT TO RETIRE SCHERER UNIT 4?

A Yes. FPL witness Scott Bores states that FPL owns an 76% interest in Scherer Unit 4 and the remaining 24% was owned by JEA.[4] He explains that in order to retire Scherer Unit 4, FPL needed an agreement that JEA would also agree to retire this unit.

FPL witness Sam Forrest at page 20 of his testimony states that under its agreement with JEA, FPL would not have been relieved of its obligation to operate the Scherer Unit unless JEA also agreed to retire its percent ownership share of Unit 4. He explained that JEA had an interest in retiring the unit, but was concerned about ongoing JEA revenue bond obligations related to its Scherer investments. If retired early, JEA would still need to fully meet its debt service obligations for the revenue bonds supporting its investment in Scherer Unit 4, and incur other asset retirement costs.[5]

As part of its agreement to retire Scherer Unit 4 early, FPL agreed to a payment to JEA of $100 million. FPL asserts that it could not have retired Scherer Unit 4 early without agreement from JEA, and retirement of this unit early produces significant economic benefits to its retail customers. FPL proposes to record the

[4]Bores Direct Testimony at 42.
[5]Forrest Direct Testimony at 21.

$100 million payment to JEA as a regulatory asset and amortize it to its retail cost of service over a ten-year period.[6]

Q DID JEA MAKE STATEMENTS CONCERNING THE ECONOMICS OF EARLY RETIREMENT OF SCHERER UNIT 4, IN RECEIPT OF A $100 MILLION PAYMENT FROM FPL?

A Yes. However, JEA's presentation to the public discusses the Scherer Unit 4 early retirement, including a cooperation agreement, which requires FPL to make the $100 million payment to JEA, but also includes an agreement between FPL and JEA to enter into a 20-year Power Purchase Agreement ("PPA") to replace JEA's capacity from Scherer Unit 4. As outlined on my Exhibit MPG-2, a summary of JEA's statements includes the following:

> **DISCUSSION**:
> JEA has held an ownership interest in Scherer since its opening in 1989. JEA holds a 23.64 percent ownership position (approximately 198 MW), while FPL owns the remaining 76.36 percent. The Robert W. Scherer Generating Facility is operated by Georgia Power. Owners of the other three Scherer units are Georgia Power, Municipal Electric Authority of Georgia, Oglethorpe Power, Gulf Power (now owned by NextEra, FPL's parent company) and the City of Dalton. While the Scherer units have long been low-cost generating units, changes in the natural gas market now make Scherer the highest cost dispatch unit in JEA's fleet. <u>Closing Scherer Unit 4 at this time provides benefits to JEA in several key areas, described below:</u>
>
> **Financial**
>
> Comparing current and projected market pricing for natural gas combined cycle electric generation to current and projected Scherer Unit 4 operating costs, results in saving approximately $10/MWh or a cost reduction of approximately 33%. <u>Assuming a plant closure and executing a replacement capacity and energy, 20 year slice-of-system Power Purchase Agreement with FPL</u>, as well as the ongoing future contract and decommissioning costs for Scherer Unit 4, <u>the proposed transaction generates approximately $191 million in NPV savings</u>. In consideration of jointly closing Scherer Unit 4, FPL has offered a cooperation agreement, including some compensation for remaining Scherer future costs. The

[6] Bores Direct Testimony at 42 and Fuentes Direct Testimony at 22.

natural gas price for the initial ten years of the PPA will be fixed, with the option to switch to solar for the last ten years.[7]

JEA's filing included a summary of the Scherer Unit 4 retirement economic study, which demonstrated that from JEA's standpoint, retiring Scherer Unit 4 would produce approximately $91.1 million of savings to JEA. JEA's economic study reflects the remaining JEA debt service costs, operation and maintenance ("O&M") expense, and capital costs associated with Scherer Unit 4. Further, the JEA study also reflects the benefits of the replacement PPA with FPL. FPL's proposed payment of $100 million to JEA increases this economic savings benefit of retiring Scherer Unit 4 from $91.1 million up to $191.1 million, and leaves FPL with a 20-year PPA sales agreement to supply JEA from its gas-fired generation resources.

Q IS IT APPROPRIATE TO ALLOW FPL TO RECOVER THE $100 MILLION PAYMENT TO JEA IN AGREEMENT TO RETIRE SCHERER UNIT 4?

A No. Retiring Scherer Unit 4 was an economic decision to both FPL and to JEA. As outlined by JEA, absent a $100 million payment from FPL, retiring Scherer Unit 4 along with the projected cost of replacement capacity and energy from this unit under a new PPA, would have resulted in over $91 million of savings to JEA.

Also of significance is FPL's agreement with JEA to provide replacement power through a new 20-year PPA agreement with JEA, as another factor in the cooperation agreement to retire Scherer Unit 4. The proposed PPA agreement includes capacity purchases, a slice-of-the-system combined cycle unit agreement, agreement for a fixed gas cost component over the first ten years, and agreement for an option to JEA to switch to a solar resource after year 10. The cooperation agreement between JEA and FPL also includes transaction support which specifically

[7] JEA 2020.06.26 Special Board Meeting Agenda and Package at 3, Inter-Office Memorandum from Paul McElroy, Interim Managing Director/CEO to JEA Board of Directors, emphasis added.

referenced the PPA agreement as a component of JEA's decision to retire Scherer Unit 4.

Q SHOULD FPL'S RETAIL CUSTOMERS AND JEA BE TREATED IN AN ECONOMICALLY SIMILAR MANNER CONCERNING THE COSTS ASSOCIATED WITH THE EARLY RETIREMENT OF SCHERER UNIT 4?

A Yes, particularly since the retirement of this unit results in savings to both FPL customers and JEA based on FPL's projections. Under FPL's proposal, the costs associated with Scherer Unit 4 that would otherwise have been allocated to FPL retail customers and recovered over the remaining life of this unit had it not been retired early, would instead be paid for by FPL customers by the creation of a regulatory asset. In a similar manner, JEA should be placed in a position where its customers will be obligated to pay costs associated with retirement of Scherer Unit 4 in a manner similar to those costs that would have been paid had Scherer Unit 4 not been retired. From FPL's perspective, the investments it made to provide service to its retail customers will be included in the regulatory asset and recovered. Similarly, FPL's investment costs by its contractual relationships with JEA should be recovered through payments JEA makes to FPL. This would include the $100 million payment FPL made to JEA as part of an agreement to both retire Scherer Unit 4 and JEA's agreement to enter into a 20-year PPA agreement with FPL.

Q SHOULD THE $100 MILLION COOPERATION PAYMENT FROM FPL TO JEA BE REFLECTED AS A COST OF SERVICE INVESTMENT FOR RETAIL CUSTOMERS SERVED UNDER FPL'S TARIFFS?

A No. FPL has a separate contractual relationship with JEA concerning providing capacity and energy to JEA which it needs to meet its own retail customer load requirements. The new PPA agreement between FPL and JEA covers a 20-year period and provides FPL margin in the form of both capacity payments and potentially energy pricing that may also produce FPL margin. FPL will earn margin under the proposed PPA agreement with JEA. For these reasons, FPL should recover its $100 million cooperation agreement payment to JEA under the new terms and margin of its new PPA agreement with JEA.

The $100 million payment had no relationship to FPL's investment in Scherer Unit 4 that was used to provide service to retail customers under FPL's own tariffs, but rather deals exclusively with its contractual agreement with JEA.

The $100 million payment to JEA therefore should be removed from FPL's retail cost of service, and should be recovered by FPL under the new PPA pricing terms and conditions with JEA. The PPA will have a margin component which FPL should rely on to recover its costs of the separate contractual wholesale agreement with JEA. For these reasons, I recommend the Commission reject allowing FPL to recover the $100 million cooperation agreement payment with JEA for agreement to retire Scherer Unit 4 and include it as a regulatory asset and amortize it over a ten-year period. This lowers the Company's claimed revenue deficiency by approximately $14.5 million in 2022, as shown on Exhibit MPG-3.

III. PROPOSAL TO CREATE A REGULATORY ASSET

Q PLEASE DESCRIBE FPL'S PROPOSAL TO CREATE A REGULATORY ASSET RELATED TO ASSET RETIREMENTS.

A FPL's proposal for a regulatory asset for asset retirement costs is described in the direct testimony of Keith Ferguson. FPL retired certain assets that are not yet fully depreciated. As a result, Mr. Ferguson developed a series of capital recovery schedules that seek to recover the remaining investment for those assets over a ten-year period. The base rate impact of the capital recovery schedules is identified on the Company's Exhibit LF-4, sponsored by Liz Fuentes. As discussed at pages 18-20 of his testimony, Mr. Ferguson breaks out the 2022 and 2023 regulatory assets for the retired assets and the significant capital assets retiring in periods beyond 2023.

For the 2022-2023 period, Mr. Ferguson describes the following assets to be recorded as a regulatory asset:

1. $365 million investments related to Martin Units 1 and 2 that were retired in 2018.
2. $328 million investments in Lauderdale Units 4 and 5 also retired in 2018.
3. $462 million investments in Gulf Clean Energy Center Units 4-7 retired in October 2020.
4. $231 million remaining investment at Manatee Units 1 & 2 expected to be retired in January 2022.
5. $112 million of investments in FPL's 500 kV Transmission System and related Cost of Removal ("COR") beginning in January 2022, and another $92 million investment in COR beginning in January 2023.
6. Finally, the Company is including $831 million remaining investment at Scherer Unit 4, expected to be retired in January 2022.[8]

[8]Ferguson Direct at 18-19.

The Company also identifies additional asset retirements it proposes to include in a regulatory asset including the following for periods past 2023:

1. $67 million in 2024 and $82 million in 2025 for remaining investment in COR related to FPL's 500 kV Transmission System; and

2. $136 million retirement in 2024 of estimated net book value of Daniel Units 1 and 2, expected to be retired in 2024.

Q HOW DOES THE COMPANY PROPOSE TO RECOVER THESE UNRECOVERED ASSET RETIREMENT COSTS?

A The Company is proposing to create a regulatory asset and include in its cost of service a rate of return on the unamortized balance, and amortization expense on a straight line basis that will recover this regulatory asset over a ten-year period.[9] The Company proposes to recover this abandoned plant regulatory asset in both base rates and certain rider mechanisms. Mr. Ferguson's capital recovery schedules show the Company proposes to recover $1.3 billion in base rates and $1.1 billion through riders. A summary of the unrecovered assets is provided as Exhibit MPG-4. The resulting increase to base rates as a result of the regulatory assets amortization expense is approximately $117 million in the 2022 Test Year and $130 million in the 2023 Subsequent Year.[10] The Company's August 2021 clause projection filing will address the $1.1 billion regulatory assets recovered through riders.

Q ARE YOU OPPOSING THE COMPANY'S REQUEST TO RECOVER THE UNRECOVERED COST ASSOCIATED WITH THE RETIRED ASSETS?

A No. However, I am recommending that the Commission recognize the extraordinary proposal to significantly increase base rates as a result of the Company's capital

[9] Exhibit LF-4.
[10] Ferguson Direct at 21.

recovery schedules. I recommend the Commission modify FPL's proposed recovery mechanism in order to mitigate the test year and subsequent year cost of these abandoned assets, and more economically distribute these costs of these facilities over generations of FPL customers.

To be clear, however, I am not recommending a disallowance or adjustments to recovery of abandoned plant costs, but rather simply a modification to the method upon which these costs will be recovered in FPL's cost of service. The adjustment mitigates the impact on cost of service in this case and is fair to the generations of customers over the next ten years. Specifically, these abandoned costs will not provide service to any generation of customers, and levelizing the costs to all generations of customers places an equivalent burden in the rate structure of customers over the next ten years.

Q PLEASE DESCRIBE YOUR PROPOSED REGULATORY TREATMENT THAT WILL CREATE A MORE ECONOMIC DISTRIBUTION OF THESE ABANDONED ASSET COSTS ON FPL CUSTOMERS.

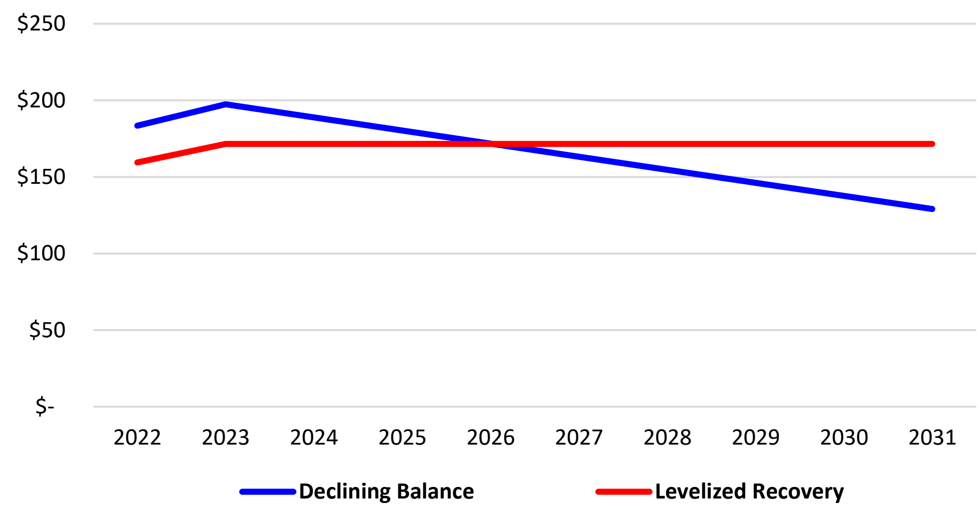
A I recommend a levelized cost recovery over the same ten year recovery period used by the Company. This will have the effect of decreasing FPL's base rate revenue requirement by approximately $24.0 million in the 2022 Test Year and $25.9 million in the 2023 Subsequent Year, as summarized on my Exhibit MPG-5, page 1. Again, it is important to note that this recovery method will still fully compensate FPL for its unrecovered investments, or obsolete plant investments, but the recovery on a levelized basis will reduce its costs in the test year and subsequent year, but increase costs later on. A graphical depiction of the difference between FPL's declining balance basis and a levelized cost basis is shown in Figure 1 below.

Q CAN YOU ILLUSTRATE YOUR PROPOSED RECOVERY STREAM UNDER A LEVELIZED BASIS VERSUS A DECLINING BALANCE BASIS?

A Yes, this is illustrated in Figure 1 below.

FIGURE 1

Declining Balance vs. Levelized Recovery



Source:
Exhibit MPG-5, pages 2-4.

As shown in the graph above, under both instances, FPL will fully recover its unrecovered plant investment for all the retired assets that were or will be retired between 2018 and 2022. The difference is that FPL will recover a levelized annual amount for these facilities each year through 2031. After that time period, the regulatory assets created in 2022 will have been fully recovered. The cost recovery under both scenarios increases in 2023 as a result of the 2023 transmissions assets being turned into a regulatory asset and being recover over 10 years, or 2023 to 2032.

The figure above only reflects the costs FPL proposes to recovery in base rates. As noted above, approximately 50% of the of capital recovery costs will be recovered through riders and addressed by FPL is filing later this year.

Q IF THE COMMISSION ACCEPTS THIS ALTERNATIVE COST RECOVERY MECHANISM YOU PROPOSE, IS THERE POTENTIAL OF ADDITIONAL SAVINGS OTHER THAN THAT YOU HAVE ESTIMATED ON YOUR EXHIBIT MPG-5?

A Yes. In the event that FPL were permitted access to use securitization bonds to finance prudently incurred abandoned plant costs, and if these regulatory assets (including the portion included in the riders) would qualify for the use of securitization bonds, and allowed by statute, a levelized cost recovery of the abandoned coal costs could further reduce cost to customers, while still providing FPL full recovery of abandoned plant costs.

Q PLEASE DESCRIBE HOW YOU DEVELOPED A LEVELIZED ANNUAL REVENUE REQUIREMENT FOR RECOVERING THESE REGULATORY ASSETS.

A This is developed on my Exhibit MPG-5. On page 2 of this exhibit, I first recreate the Company's proposal using the data provided by Mr. Ferguson on his capital recovery schedules (FPL Exhibit KF-4) and Ms. Fuentes on her schedules and workpapers supporting the Company's adjustment (FPL Exhibit LF-4). This is summarized on my Exhibit MPG-5, page 2. I developed the annual cost recovery using the Company's proposed annual amortization expense and a return on the unamortized balance at the Company's weighted average cost of capital, after my proposed adjustments. On page 3, I developed a levelized revenue requirement for each regulatory asset that allows the Company to fully recover the costs of the retired assets using the same 10 year period as the Company (2022-2031 for the regulatory assets and 2023-2032 for the 2023 transmission assets).

This will have the effect of decreasing FPL's base rate revenue requirement by approximately $24.0 million in the 2022 Test Year and $25.9 million in the 2023 Subsequent Year, as shown on page 1 of my exhibit. As mentioned above, this adjustment includes all of unrecovered costs the Company proposes to recover in base rates.

IV. RATE OF RETURN

Q PLEASE DESCRIBE THIS SECTION OF YOUR TESTIMONY.

A I will provide observable market evidence and a detailed analysis to demonstrate that my recommended rate of return represents a fair return for investing in utility infrastructure plant, and equipment, and will support FPL's financial integrity and access to capital. I will use market-based models to estimate the current market-required rate of return investors demand to assume the risk of an investment similar to that of FPL's investment risk. Together, I use this information to demonstrate that my recommended overall rate of return, ratemaking capital structure and return on equity meet the *Hope* and *Bluefield*[11] standards of awarding FPL a rate of return that represents fair compensation while maintaining financial integrity and investment grade credit rating, but at just and reasonable rates to retail customers.

[11] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*") *and Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923) ("*Bluefield*").

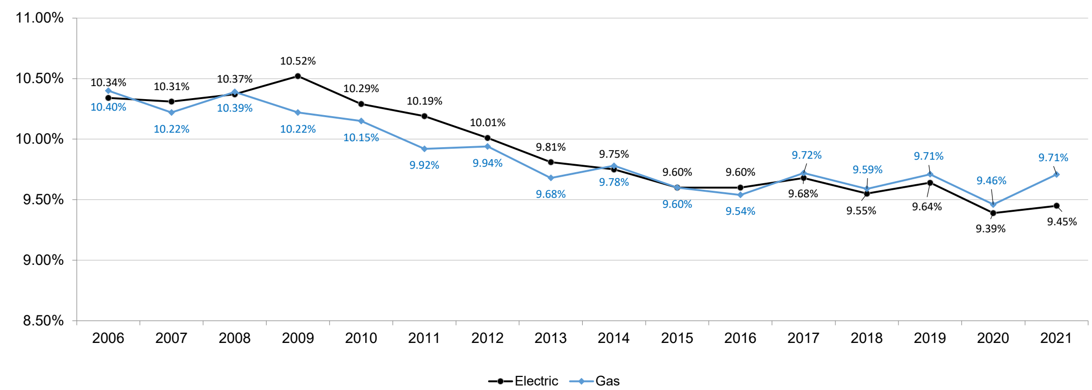
IV.A. Utility Industry Authorized Returns on Equity, Access to Capital, and Credit Strength

Q PLEASE DESCRIBE THE OBSERVABLE EVIDENCE ON TRENDS IN AUTHORIZED RETURNS ON EQUITY FOR REGULATED UTILITIES.

A As illustrated in Figure 2 below, national average authorized returns on equity for both electric and gas utilities have declined over the last several years and have been reasonably stable well below 10.0% for many years.

FIGURE 2

Authorized Returns on Equity*
(Exclude Limited Issue Riders)



ROE Distributions[2]

Electric Utilities	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
<= Average	56.0%	59.5%	51.4%	59.0%	51.7%	55.0%	51.9%	52.4%	57.6%	60.0%	53.1%	60.5%	47.4%	45.5%	33.3%	20.0%
> Average	44.0%	40.5%	48.6%	41.0%	48.3%	45.0%	48.1%	47.6%	42.4%	40.0%	46.9%	39.5%	52.6%	54.5%	66.7%	80.0%
Gas Utilities																
<= Average	46.7%	51.4%	50.0%	50.0%	56.4%	31.3%	45.7%	47.6%	50.0%	50.0%	53.8%	70.8%	47.5%	53.1%	52.9%	64.3%
> Average	53.3%	48.6%	50.0%	50.0%	43.6%	68.8%	54.3%	52.4%	50.0%	50.0%	46.2%	29.2%	52.5%	46.9%	47.1%	35.7%

Source and Notes:
[1] *S&P Global Market Intelligenc* e, RRA Regulatory Focus, Major Rate Case Decisions -- January - March 2021, April 28, 2021, p. 1.
[2] Download from S&P Global Market Intelligence, June 11, 2021.
* Electric Returns exclude Limited Issue Rider Decisions.
* RRA excludes the 2017 Alaska ENSTAR decision from its Industry Average.

Q HAVE UTILITIES BEEN ABLE TO ACCESS EXTERNAL CAPITAL TO SUPPORT CAPITAL EXPENDITURE PROGRAMS?

A Yes. In its April 8, 2021 Utility Capital Expenditures Update report, *RRA Financial Focus*, a division of S&P Global Market Intelligence, made several relevant comments about utility investments generally:

> - Projected 2020 capital expenditures for the 47 energy utilities in the Regulatory Research Associates, a group within S&P Global Market Intelligence, universe currently stands at roughly $141.3 billion, well above 2019's $120.7 billion in capital investment.
>
> - 2020 energy utility capital expenditures marked a record high and were more than 7.75% above the $120.7 billion that the energy utility industry invested in 2019, despite that the coronavirus pandemic interrupted certain supply chains for a period of months in some instances.
>
> - 2021 appears on track to be another record year for energy infrastructure investments. Assuming current projections hold, investment across the RRA covered energy utility industry may rise by 9% or more this year.
>
> * * *
>
> The nation's electric and gas utilities are investing in infrastructure to upgrade aging transmission and distribution systems, build new natural gas, solar and wind generation, and implement new technologies, including smart meter deployment, smart grid systems, cybersecurity measures and battery storage. We expect considerable levels of spending to serve as the basis for solid profit expansion in the sector for the foreseeable future.
>
> * * *
>
> From a natural gas perspective, the momentum in replacement of mature gas distribution infrastructure continues and is likely to maintain at material levels for many years, considering state and federal mandates to address safety. In addition, despite headwinds in many regions of the country regarding the future of gas, it is expected to remain a critical energy source for some time. In addition, natural gas midstream pipelines and downstream distribution networks are likely to be central to aims by many midstream and utility enterprises to extend the life of their infrastructure through transportation of renewable natural gas and hydrogen blends.[12]

As shown in Figure 3 below, capital expenditures for electric and natural gas utilities have increased considerably over the period 2020 into 2021, and the forecasted capital expenditures remain elevated through 2023, albeit falling below current levels in 2023.

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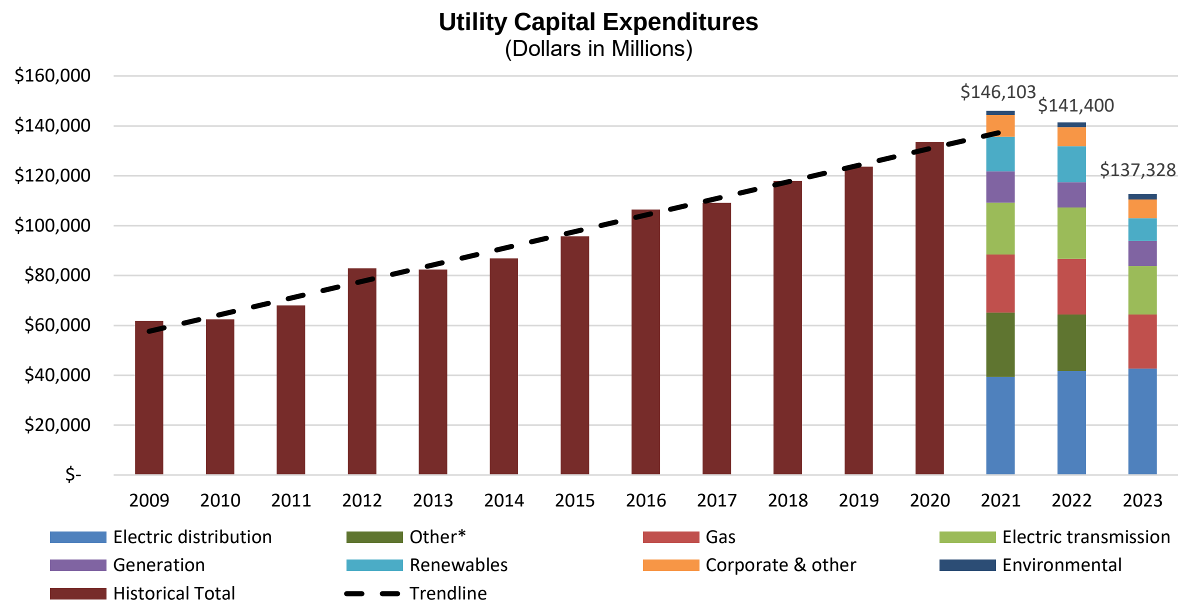
[12] *S&P Global Market Intelligence, RRA Financial Focus*: "Utility Capital Expenditures Update," April 8, 2021, at 1-2.

FIGURE 3



*Other category consists of utilities that do not report capital expenditures by category: Avangrid, Hawaiian Electric, PG&E and Portland General Electric.
Source: *S&P Global Market Intelligence, RRA Financial Focus*, Utility Capital Expenditures Update, April 8, 2021, Tables 1 and 3.

As outlined in Figure 3 above, and in the comments made by *RRA S&P Global Market Intelligence*, capital investments for the utility industry continue to stay at elevated levels, and fuel utilities' profit expansion into the foreseeable future. This is clear evidence that the capital investments are enhancing shareholder value, and are attracting both equity and debt capital to the utility industry in a manner that allows for these accelerated capital investment levels. While capital markets embrace these profit-driven capital investments, regulatory commissions also must be careful to maintain reasonable prices, and tariff terms and conditions to protect customers' need for reliable service at competitive prices.

Q **IS THERE EVIDENCE OF ROBUST VALUATIONS OF REGULATED UTILITY EQUITY SECURITIES?**

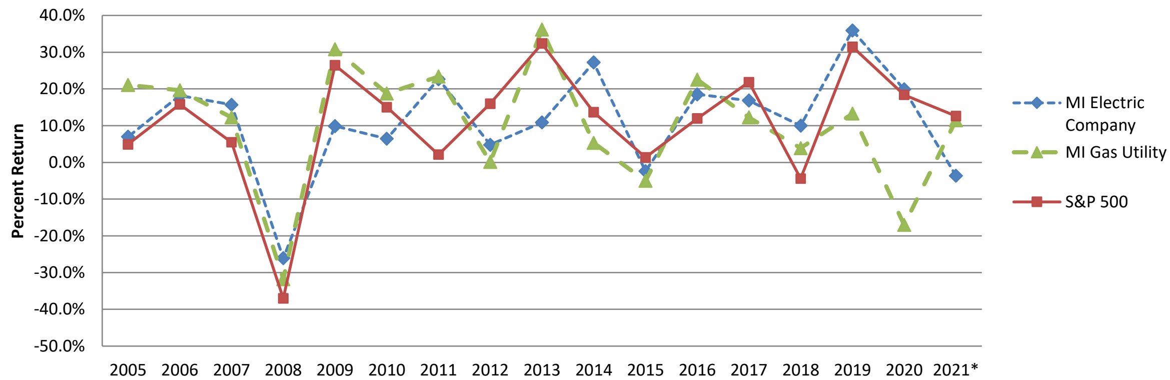
A Yes. Robust valuations are an indication that utilities can sell securities at high prices, which is a strong indication that they can access equity capital under reasonable terms and conditions, and at relatively low cost. As shown on Exhibit MPG-6, the historical valuation of electric and gas utilities followed by *The Value Line Investment Survey* ("*Value Line*"), based on their price-to-earnings ("P/E") ratios, price-to-cash flow ("P/CF") ratios, and market price-to-book value ("M/B") ratios, indicates that utility security valuations today are very strong and robust relative to the last several years. These strong valuations of utility stocks indicate that utilities have access to equity capital under reasonable terms at relatively low cost.

Q PLEASE DESCRIBE UTILITY STOCK PRICE PERFORMANCE OVER THE LAST SEVERAL YEARS.

A As shown in Figure 4 below, S&P Global Market Intelligence ("MI") has recorded utility stock price performance compared to the market. The industry's stock performance data from 2005 through 2020 shows that the MI Electric Company and MI Gas Utility Indexes have followed the market through downturns and recoveries. However, utility investments have been less volatile during extreme market downturns. This more stable price performance for utilities supports my conclusion that market participants regard utility stock sectors as a moderate- to low-risk investment option.

FIGURE 4

Index Comparison



Source: S&P Global Market Intelligence.
***Data through May 2021**

While utility stocks have not exhibited the same volatility as the S&P 500, stock prices have remained strong, relative to the market in general, and support the utilities' access to equity capital markets under reasonable terms and prices.

Q HOW SHOULD THE COMMISSION USE THIS MARKET INFORMATION IN ASSESSING A FAIR RETURN FOR FPL?

A Observable market evidence demonstrates that capital market costs are near historically low levels. While authorized returns on equity have fallen below the mid-9% range, utilities continue to have access to large amounts of external capital, even as they are funding large capital expenditure programs. Furthermore, utilities' investment-grade credit ratings are stable and have improved, due in part to supportive regulatory treatment. The Commission should carefully weigh all this important observable market evidence in assessing a fair return on equity for FPL.

IV.B. Federal Reserve's Impact on Cost of Capital

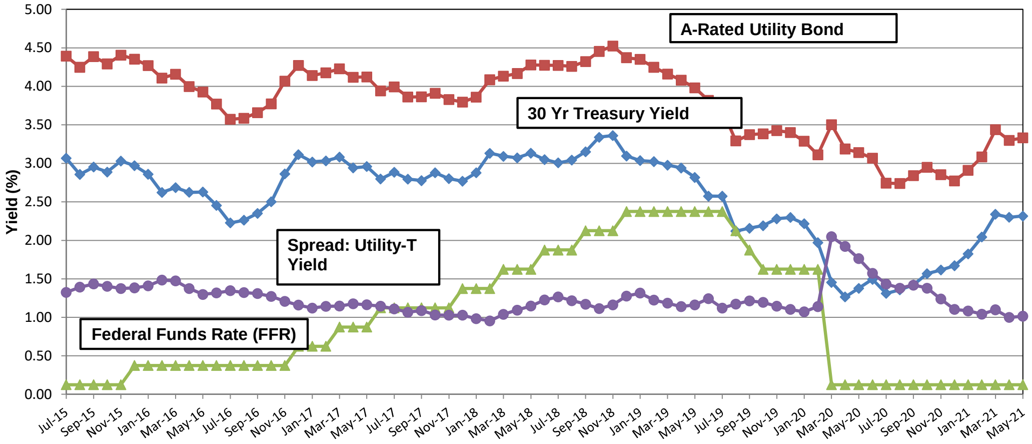
Q DO YOU BELIEVE THAT THE FEDERAL RESERVE'S ACTIONS ARE FULLY KNOWN BY MARKET PARTICIPANTS AND FULLY REFLECTED IN THE VALUATION OF MARKET SECURITIES, BOTH DEBT AND EQUITY?

A Yes, I do. The Federal Reserve's previous actions on Quantitative Easing and more recent reentry into the Treasury, mortgage-backed security, and now, to a limited extent, corporate bond markets were done in order to preserve stability and liquidity in the market and to calm the marketplace. The effects of these measures, and the outlooks by independent economists, continue to support the notion that capital market costs will stay low for an extended period of time. Indeed, this can be seen through observing independent economists' projections, as well as the observable effects of the Federal Reserve's actions on short-term market costs and long-term security costs.

An assessment of the market's reaction to the Federal Reserve's actions on the Federal Funds Rate is shown below in Figure 5.

FIGURE 5

Timeline of Federal Funds Rate Changes Since 2015



Fed FFR Actions:

1	December 2015	0.25	→	0.50	8	September 2018	2.00	→	2.25
2	December 2016	0.50	→	0.75	9	December 2018	2.25	→	2.50
3	March 2017	0.75	→	1.00	10	August 2019	2.00	→	2.25
4	June 2017	1.00	→	1.25	11	September 2019	1.75	→	2.00
5	December 2017	1.25	→	1.50	12	October 2019	1.50	→	1.75
6	March 2018	1.50	→	1.75	13	March 2020	1.00	→	1.25
7	June 2018	1.75	→	2.00	14	March 2020	0.00	→	0.25

Sources:
Federal Reserve Bank of New York, https://apps.newyorkfed.org/markets/autorates/fed-funds-search-page
Board of Governors of the Federal Reserve System, https://www.federalreserve.gov/datadownload/
Moody's Credit Trends, https://credittrends.moodys.com/

As shown in Figure 5 above, while the Federal Reserve has reduced short-term interest rates currently, as it did back in the period prior to 2015, the market's valuation of long-term securities remains relatively stable, and at very low costs. The Federal Reserve's interaction in short-term securities is specifically stated to manage inflation and support employment in the economy. The Federal Reserve's interaction in these marketplaces is not to manipulate utility valuation or security valuations, or drive capital market costs in one direction or the other. Rather, it is strictly for the purpose of supporting the U.S. economy.

Q WHAT DO INDEPENDENT ECONOMISTS' OUTLOOKS FOR FUTURE INTEREST RATES INDICATE?

A Independent economists expect the current low capital costs to prevail over at least the intermediate term. This is illustrated in projections for both short- and long-term changes in interest rates. Further, there is a clear trend in forecasted changes in interest rates over time, indicating that capital market participants are becoming more comfortable with today's low-cost capital market environment and expect it to prevail over at least the intermediate future.

For example, short-term projections suggest that the market expects capital market costs to remain relatively low. Table 2 below shows capital cost projections over the next two years, and demonstrates that projected Treasury bond yields are not expected to increase significantly over the next two years.

TABLE 2

Blue Chip Financial Forecasts
Projected Federal Funds Rate, 30-Year Treasury Bond Yields, and GDP Price Index

Publication Date	4Q 2020	1Q 2021	2Q 2021	3Q 2021	4Q 2021	1Q 2022	2Q 2022	3Q 2022
Federal Funds Rate								
Jan-21	0.1	0.1	0.1	0.1	0.1	0.1	0.1	
Feb-21	0.1	0.1	0.1	0.1	0.1	0.1	0.1	
Mar-21	0.1	0.1	0.1	0.1	0.1	0.1	0.1	
Apr-21		0.1	0.1	0.1	0.1	0.1	0.1	0.1
May-21		0.1	0.1	0.1	0.1	0.1	0.1	0.1
Jun-21		0.1	0.1	0.1	0.1	0.1	0.1	0.1
T-Bond, 30 yr.								
Jan-21	1.6	1.7	1.8	1.9	2.0	2.1	2.1	
Feb-21	**1.6**	1.8	1.9	2.0	2.1	2.1	2.2	
Mar-21	**1.6**	2.0	2.1	2.2	2.3	2.4	2.4	
Apr-21		2.1	2.4	2.5	2.5	2.6	2.7	2.7
May-21		**2.1**	2.4	2.5	2.6	2.7	2.7	2.8
Jun-21		**2.1**	2.4	2.5	2.6	2.6	2.7	2.8
GDP Price Index								
Jan-21	1.6	1.8	1.8	1.8	1.8	1.9	1.9	
Feb-21	2.0	1.8	1.7	1.9	1.9	1.9	2.0	
Mar-21	2.1	2.2	1.8	1.9	1.9	1.9	2.0	
Apr-21		2.2	2.1	2.1	2.0	1.9	2.1	2.2
May-21		4.1	2.4	2.2	2.1	2.2	2.2	2.2
Jun-21		4.3	3.3	2.5	2.1	2.2	2.2	2.3

Source and Note:
Blue Chip Financial Forecasts, January 2021 through June 2021.
Actual Yields in Bold

Further, the outlook for long-term interest rates in the intermediate to longer term is also impacted by the current Federal Reserve actions and the expectation that eventually the Federal Reserve's monetary actions will return to more normal levels. Long-term interest rate projections are illustrated in Table 3 below.

TABLE 3

30-Year Treasury Bond Yield Actual Vs. Projection

Description	Actual	2-Year Projected*	5- to 10-Year Projected
2015			
Q1	2.55%	3.80%	
Q2	2.89%	3.70%	4.8% - 5.0%
Q3	2.84%	3.90%	
Q4	2.96%	3.80%	4.5% - 4.8%
2016			
Q1	2.72%	3.67%	
Q2	2.64%	3.50%	4.3% - 4.6%
Q3	2.28%	3.20%	
Q4	2.82%	3.20%	4.2% - 4.5%
2017			
Q1	3.04%	3.70%	
Q2	2.91%	3.73%	4.3% - 4.5%
Q3	2.82%	3.66%	
Q4	2.82%	3.60%	4.1% - 4.3%
2018			
Q1	3.02%	3.63%	
Q2	3.09%	3.80%	4.2% - 4.4%
Q3	3.07%	3.73%	
Q4	3.27%	3.67%	3.9% - 4.2%
2019			
Q1	3.01%	3.50%	
Q2	2.78%	3.17%	3.6% - 3.8%
Q3	2.30%	2.70%	
Q4	2.30%	2.50%	3.2% - 3.7%
2020			
Q1	1.88%	2.57%	
Q2	1.38%	1.90%	3.0% - 3.8%
Q3	1.36%	1.87%	
Q4	1.62%	1.97%	2.8% - 3.6%
2021			
Q1	2.07%	2.23%	
Q2		2.77%	3.5% - 3.9%

Source and Note:
Blue Chip Financial Forecasts, January 2015 through June 2021.
*Average of all 3 reports in Quarter.

As shown in Table 3 above, independent economists' projections of changes in long-term Treasury rates are very different today than they were over the last five to six years. Specifically, in 2015 economists were expecting that Treasury bond yields, which fell below 3%, would eventually return to the high 4-5% area. That outlook largely remained through 2016, but the outlook for future capital market costs started to decline in 2017. More recently, Treasury bond yields have dropped to historically low levels but are expected to stay low for the next five to ten years.

Again, the market is fully aware of the Federal Reserve's actions, and these actions are not expected to have significant changes in capital market costs over the next five to ten years. Further, the Federal Reserve's actions are expected to maintain relatively stable capital market costs over the next two years.

Q HAVE THE RECENT FEDERAL GOVERNMENT STIMULUS EFFORTS IMPACTED CAPITAL MARKETS?

A The Federal Reserve's most recent projections indicate that its long-term inflation outlook of around 2% is expected to hold, but is expecting relative increases in short-term inflation outlooks through 2021, likely to moderate in 2022.[13]

This outlook is generally shared by consensus economists in the most recent *Blue Chip Financial Forecasts*. In the most recent *Blue Chip*, economists are recognizing economic activity picking up at an accelerated pace due to the unwinding economic negative impact caused by the COVID pandemic and the success of vaccinations. More specifically, *Blue Chip* reports economists' outlooks concerning short-term and long-term inflation, and expected Treasury and Federal Reserve activities to include the following:

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[13]Federal Open Market Committee, FOMC Projections materials accessible version, March 17, 2021.

Some Economic Fallout after the Pandemic Eases. The availability of COVID vaccines and their widespread use is not only helping to shield the population from the disease, but also commensurately reviving business and other activities of society, such as school attendance. We can rejoice in this, but it does not cure all of society's ills. Indeed, perhaps the most prominent of these at the present time is inflation. For many months, we have experienced inflation that was actually too low – or at least well below the Federal Reserve's "target" of 2%. The Fed applies this target specifically to the personal consumption expenditure price index and to its ex-food-and-energy core.

Base Effects Raise Inflation Rates, but Current Months Strong Too. Across 2019, the PCE price index and the core both rose just 1.6% (December over December) and in 2020, the total index was up 1.2%, with that core only 1.4%. Clearly, the monetary policymakers were concerned about the apparent lack of price flexibility in the economy generally.

* * *

All this said, the forecast tabulation shows that the panel estimates that inflation rates will moderate during the second half of this year, reaching the Fed's desired 2% pace by the fourth quarter.

* * *

Going forward, the Blue Chip panel looks for the Federal Reserve to hold the federal funds rate steady throughout the current near-term forecast period, to the end of 2022. They do believe the Fed will moderate the pace of its purchases of Treasury notes and bonds and mortgage-backed securities. So from the latest (May 26) $7.9 trillion, the Fed's balance sheet total assets would rise to $8.6 trillion at the end of this year and $9.3 trillion at the end of 2022. They were $4.17 trillion at the end of 2019.[14]

[14] *Blue Chip Financial Forecasts*, "Growth & Inflation Increase as Pandemic Impact Moderates," June 1, 2021.

IV.C. COVID-19 Pandemic

Q HAVE REGULATORY COMMISSIONS TAKEN SPECIFIC MEASURES TO HELP PROTECT UTILITIES' ABILITY TO FULLY RECOVER THEIR COST OF SERVICE DURING THE ECONOMIC DISTRESS CAUSED BY THE COVID-19 PANDEMIC?

A Yes. Regulatory commissions around the country have implemented measures that prohibit utilities from disconnecting service for customers that are not paying their bill. While this is an extraordinary measure, and exposes utility companies to increases in uncollectible accounts expense, and waiver of certain utility fees, commissions have also approved regulatory mechanisms that allow utilities to defer uncollectible accounts.

These regulatory mechanisms to protect customers' ability to receive essential utility services were done in concert with the implementation of regulatory mechanisms that preserved utilities' ability to recover their cost of service. Accordingly, commissions have mitigated utilities' risks associated with the economic turmoil caused by the COVID-19 pandemic considerably.

IV.D. Market Sentiments and Utility Industry Outlook

Q PLEASE DESCRIBE THE CREDIT RATING OUTLOOK FOR REGULATED UTILITIES.

A The global economy has faced the extraordinary challenges of the novel Coronavirus, which led to nearly a complete shutdown of the global economy. This unprecedented event has impacted all sectors and capital markets. With regard to regulated utilities, S&P made the following statement:

> **Key Takeaways**
>
> - Credit quality for the North American regulated utility industry weakened in 2020. At the beginning of the year about 18% of the

> industry had a negative outlook or ratings on CreditWatch with negative implications. By the end of the year that percentage had doubled, to about 36%.
>
> - For the first time in a decade downgrades outpaced upgrades for the predominately investment-grade industry.
>
> - The industry generally performed well throughout the pandemic and we expect it will continue to mostly manage through the remaining COVID-19-related risks.
>
> - The main causes of weakening credit quality reflected environment, social, and governance (ESG) risks, regulatory issues, and companies' practice of strategically managing financial measures close to their downgrade threshold with little or no cushion.
>
> - Despite our negative 2021 industry outlook, we expect a modest improvement to credit quality over the next 12 months. We believe Congress is more likely to raise the corporate tax rate, which would improve the industry's financial measures, offset in part by a continued focus on ESG risks.
>
> * * *
>
> **COVID-19 Was Not The Culprit For Weaker Credit Quality**
>
> In March 2020, we identified five COVID-19-related risks that could lead to a weakening of the industry's credit quality.
>
> * * *
>
> Encouragingly, the industry has generally performed well throughout the pandemic. Lower electric and gas deliveries to C&I customers were mostly offset by higher residential deliveries, the industry generally worked well with regulators to defer COVID-19-related costs for future recovery, market returns improved, and the industry generally had consistent access to the capital markets.[15]

Moody’s opines that there may be delays in rate case decisions due to COVID-19, but views regulated utilities as resilient to withstand the current economic situation. Specifically, Moody’s states:

> We are maintaining a stable outlook for the US regulated utilities industry, reflecting our expectation for continued strong regulatory support, robust residential demand and a recovering economy in 2021. As a critical infrastructure sector with a regulated business model that

[15] *S&P Global Ratings*: “North American Regulated Utilities’ Negative Outlook Could See Modest Improvement,” January 20, 2021, at 1 and 3. (emphasis added).

> provides good cost recovery, regulated utilities have remained relatively resilient in the face of the uncertain economic environment caused by the coronavirus pandemic.
>
> » **Following a decline in 2020 from last year's level, FFO-to-debt will increase slightly on improving economic conditions.** We project an aggregate industry funds from operations to debt ratio of around 15% over the next 12 to 18 months, a slight improvement from an expected decline to between 14% and 15% in 2020 from 15.8% in 2019. Our expectation considers Moody's global macro outlook forecast of a 4.5% growth in US GDP in 2021, although this will be closely tied to the containment of the coronavirus. We expect continued strength in residential demand, improving commercial and industrial load and disciplined O&M cost management to maintain financial stability. However, greater than usual use of debt financing will constrain FFO-to-debt.
>
> » **Regulatory support to remain strong, although ROEs will be under pressure.** We expect continued supportive regulatory frameworks to underpin the sector's ability to recover costs in a timely manner and earn a fair return even as allowed returns on equity (ROEs) remain under pressure amid low interest rates. We expect most regulators to be supportive of the recovery of coronavirus-related costs and investments, as well as costs associated with the increasing frequency and severity of climate hazards.[16]

Q HOW IS THIS OBSERVABLE MARKET DATA USED IN FORMING YOUR RECOMMENDED RETURN ON EQUITY AND OVERALL RATE OF RETURN FOR FPL?

A Generally, authorized returns on equity, credit standing, and access to capital have been quite robust for utilities over the last several years. The COVID-19 pandemic has created challenges for the U.S. economy as a whole, including utility companies. However, like the U.S. economy, utilities are expected to weather the economic downturn caused by the pandemic, and their financial strength will be restored as the economy recovers. In the meantime, it is critical that the Commission ensure that rates are increased no more than necessary to provide fair compensation and

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[16] *Moody's Investors Service Sector Comment*: "2021 Outlook Stable On Strong Regulatory Support and Robust Residential Demand," October 29, 2020 (emphasis added).

maintain financial integrity, and be especially concerned about rate impacts on the service area economies that are severely constrained due to current economic conditions.

IV.E. FPL Investment Risk

Q PLEASE DESCRIBE THE MARKET'S ASSESSMENT OF FPL'S INVESTMENT RISK.

A The market's assessment of FPL's investment risk is described by credit rating analysts' reports. FPL witness Mr. Coyne testified that FPL's current credit ratings from S&P and Moody's are A, and A1, respectively. The Company has a stable outlook from both rating agencies.[17]

Specifically, S&P states:

> **Outlook**
> S&P Global Ratings' stable outlook on FPL is consistent with its stable outlook on parent NEE and its expectation that FPL's stand-alone financial measures will not materially weaken. The stable outlook on NEE incorporates our view that NEE will remain focused on expanding its regulated utility businesses and will continue to reduce risk at its competitive businesses by strategically growing through contracted assets. We expect NEE's regulated utility business will consistently reflect about 70% of consolidated EBITDA. We expect that NEE's consolidated financial measures will marginally weaken, reflecting FFO to debt at 21%-24%. We also expect that FPL's FFO to debt will continue to reflect the middle of the range for its financial risk profile category at 29%-31%.
>
> **Business Risk: Excellent**
> FPL's business risk profile is further supported by its largely residential customer base, which accounts for about 55% of its operating revenue; its effective management of regulatory risk; and its above-average economic and customer growth, demonstrated by Florida outperforming the national GDP growth rate in the past six consecutive years and, consequently, strong energy demand. At the same time, Florida's economy continues to recover from the impacts of the ongoing COVID-19 pandemic, demonstrated by improvements in the unemployment rate and consumer confidence.

[17] Coyne Direct Testimony at 41.

> The FPSC regulates FPL. We view the regulatory environment in Florida as constructive and supportive of credit quality. FPL benefits from forecast test years, above-average authorized returns on equity (ROEs), multiyear rate settlements, and various regulatory mechanisms that enable the company to reduce its regulatory lag and support earnings without burdening customers, resulting in earned ROEs at the high-end of the authorized range. Further supporting our assessment of the company's business risk profile is the company's ability to consistently recover storm-related costs, protecting it from hurricanes that are common in its service territory and significantly reducing a key risk for the company. As such, our assessment of FPL's business risk is in the higher half of the range compared with peers.[18]

IV.F. FPL Proposed Capital Structure

Q WHAT IS FPL'S PROPOSED CAPITAL STRUCTURE?

A FPL's proposed capital structure is sponsored by FPL witness Robert Barrett and is shown in Table 4 below:

TABLE 4

FPL Proposed Capital Structure

		December 31, 2022		December 31, 2023	
Line	**Description**	**Regulatory Weight (1)**	**Investors Weight (2)**	**Regulatory Weight (3)**	**Investors Weight (4)**
1	Long-Term Debt	31.37%	38.93%	31.43%	38.84%
2	Short-Term Debt	1.18%	1.46%	1.26%	1.56%
3	Common Equity	48.04%	59.61%	48.23%	59.60%
4	Cost Free Capital	16.70%		16.22%	
5	Other Capital	2.71%		2.85%	
6	Total	100.00%	100.00%	100.00%	100.00%

Source: Barrett Direct Testimony at 45 and Schedule D-1a.

[18] S&P Global Ratings, "RatingsDirect®: Florida Power & Light Co.," April 29, 2020, at pages 3-6.

FPL's proposed capital structure is based on projected capital balances as of December 31, 2022.[19]

Q IS THE COMPANY'S PROPOSED RATEMAKING CAPITAL STRUCTURE REASONABLE?

A No. The Company's proposed ratemaking capital structure is unreasonable for the following reasons:

1. It contains far too much common equity to reflect a reasonable cost of capital for setting rates. A more reasonable balance of debt and equity in a ratemaking capital structure will reduce FPL's revenue requirement costs by a lower rate of return, and related income tax expense, and will also provide fair compensation to FPL, maintain its financial integrity and credit rating, but while also maintaining competitive and just and reasonable tariff rates to FPL's retail customers.

2. FPL's recent acquisition of Gulf Power and Florida City Gas illustrates the unreasonableness and expensiveness of FPL's proposed ratemaking capital structure. Specifically, in Gulf Power's last rate case, the Commission approved a ratemaking capital structure common equity ratio of 52.5%, which was later increased to 53.5% to reflect the cash flow impacts associated with the federal tax law change in the Tax Cuts and Jobs Act ("TCJA").

   In a rate case after the TCJA, the Commission accepted a settlement in setting rates for Florida City Gas which included a ratemaking common equity of no more than 49.2%.[20] Ratemaking common equity ratios for these two affiliates when they were owned by Southern Company, represented far more reasonable ratemaking capital structures than FPL's proposal to set rates based on an investor capital equity ratio of 59.6%.

3. Other Florida utilities are also setting rates with more reasonable rates of return. For example, Tampa Electric Company, using a 2022 test year, is proposing a ratemaking capital structure which includes approximately 54.6% common equity as a function of total investor capital.[21]

4. Further, a comparison of regulated utility industry credit rating analysts' equity and debt ratios in support of a bond rating the same as that of FPL,

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[19] Schedule D-1a.

[20] Docket No. 20170179-GU, Order No. PSC-2018-0190-FOF-GU, Attachment A, page 17, April 20, 2018.

[21] Docket 20210034-EI, Direct Testimony of Tampa Electric Company witness Kenneth D. McOnie at 17-18, and MFR Schedule D-1a.

clearly demonstrates that FPL's proposed capital structure contains far more common equity than necessary to support its current bond rating.

5. Also, a comparison of FPL's ratemaking capital structure to the industry range of equity ratios, and the proxy group used to estimate a fair return on equity for FPL in this case, also clearly indicates its common equity component of its ratemaking capital structure is excessive and produces a capital structure cost that simply is unjust and unreasonable.

Q IS FPL'S PROPOSED RATEMAKING CAPITAL STRUCTURE WITH A 59.6% COMMON EQUITY REASONABLY COMPARABLE TO THE PROXY GROUP USED TO ESTIMATE A FAIR RATE OF RETURN ON COMMON EQUITY FOR FPL?

A No. The proxy group, which met FPL witness Mr. Coyne's proxy group selection criteria, includes a common equity ratio of long-term capital on average throughout the proxy group of around 47%, and a median for the proxy group of around 46%. There is one company within the 14-company sample with a common equity ratio of 59%. This company has a common equity ratio of long-term capital and short-term debt of around 49.7%, suggesting that it relies on an inordinately large amount of short-term debt to support its capital investments. FPL's proposal for a long-term common equity ratio of 59.6% exceeds every company within the proxy group, and is substantially higher than the more balanced capital structure mix incorporated by all the publicly traded companies.

Q WHY DO YOU MAINTAIN THAT A RATEMAKING COMMON EQUITY OF 59.6% COMMON EQUITY IS FAR MORE EXPENSIVE THAN NECESSARY TO SUPPORT FPL'S CURRENT "A" BOND RATING?

A I state this in a comparison of distribution of adjusted debt ratios for regulated utility companies across the country with various bond ratings. The distribution of this debt ratio for bond rating purposes based on credit ratings is shown below in Table 5.

TABLE 5

S&P Adjusted Debt Ratio
(Operating Subsidiaries of Value Line Electric, Gas and Water Utilities)

		% Distribution of 9 Year Average		
Rating	**Median**	**<50**	**50 to 55**	**>55**
AA-	45.2%	100%	0%	0%
A+	56.7%	33%	0%	67%
A	48.7%	58%	25%	17%
A-	52.1%	29%	56%	16%
BBB+	50.4%	46%	39%	14%
BBB	54.2%	13%	38%	50%
FPL Proposed*	**39.7%**			
FPL, Gorman*	**45.9%**			

Sources:
S&P Capital IQ, downloaded June 14, 2021.
*Attachment MPG-18.

As shown in the table above, FPL's ratemaking capital structure of 59.6% common equity implies a total adjusted debt ratio of around 39.7%. As shown in the table above, for an "A" rated utility company, the median debt ratio is 48.7%, more than 10 percentage points above FPL's proposed common equity ratio. FPL's S&P adjusted debt ratio at this more leveraged capital structure would be 45.9%, still below the median for "A" rated utility companies.

As also outlined in Table 5 above, the distribution of adjusted debt ratios for utility companies also clearly supports a finding that FPL's capital structure simply is far more expensive than necessary to support its bond rating. Over 50% of the industry have debt ratios of less than 58%, with over 42% having adjusted debt ratios in excess of 50%.

With this as a backdrop, even though it is a significant adjustment from FPL's request, my proposed ratemaking capital structure reflects a relatively moderate debt leverage for a regulated utility company and will support FPL's current "A" rated utility bond rating, but do so at a much lower cost to FPL's customers.

IV.G. Recommended Ratemaking Capital Structure

Q WHAT CAPITAL STRUCTURE DO YOU RECOMMEND BE USED TO SET FPL'S OVERALL RATE OF RETURN AND REVENUE REQUIREMENT IN THIS PROCEEDING?

A I recommend a forecasted test year 2022 and 2023 capital structure reflecting a 53.5% common equity ratio of total investor capital. This is the Commission-approved capital structure for Gulf Power Company after taking in the effects of the TCJA that went into effect January 1, 2018. This ratemaking capital structure is sufficient to maintain FPL's current "A" bond rating, but will do so at considerably lower cost than the capital structure proposed by FPL.

My recommended capital structure is shown below in Table 6.

TABLE 6

Proposed Capital Structure

Line	Description	December 31, 2022 Regulatory Weight (1)	December 31, 2022 Investors Weight (2)	December 31, 2023 Regulatory Weight (3)	December 31, 2023 Investors Weight (4)
1	Long-Term Debt	36.30%	45.04%	36.37%	44.94%
2	Short-Term Debt	1.18%	1.46%	1.26%	1.56%
3	Common Equity	43.12%	53.50%	43.30%	53.50%
4	Cost Free Capital	16.70%		16.22%	
5	Other Capital	2.71%		2.85%	
6	Total	100.00%	100.00%	100.00%	100.00%

Source: Exhibit MPG-1.

Q **WHAT IS THE IMPACT ON FPL'S REVENUE REQUIREMENT IF ITS RATEMAKING CAPITAL STRUCTURE IS ADJUSTED TO INCLUDE A 53.5% COMMON EQUITY RATIO, RATHER THAN ITS 59.6% COMMON EQUITY RATIO WITH NO OTHER ADJUSTMENTS TO FPL'S PROPOSAL?**

A The impact on its revenue requirement in 2022 and 2023 is $0.3 million and $0.3 million, respectively, as developed on my Exhibit MPG-7. These rates of return reflect an adjustment to FPL's ratemaking capital structure by reducing common equity and increasing long-term debt to produce a forecasted ratemaking capital structure composed of 53.5% common equity as a function of total investor capital.

Q WHY DO YOU ASSERT THAT YOUR PROPOSED RATEMAKING CAPITAL STRUCTURE WILL SUPPORT FPL'S CURRENT STRONG "A" BOND RATING?

A As noted above, FPL's proposed ratemaking capital structure contains a debt ratio far lower than that for which other regulated utility companies with the same bond rating are able to manage their capital structure at lower cost to customers, and maintain their bond rating. Again, Gulf Power, Florida City Gas, and Tampa Electric supported a "Stable" credit outlook from S&P at more reasonably balanced and lower cost capital structures relative to that proposed by FPL.

More specifically, an assessment of FPL's actual ratemaking cost of service in this proceeding, along with my recommended capital structure and return on equity, as described in further detail below, demonstrate that FPL will set its revenue requirement and equity ratio at a level that will produce cash flow coverages, and debt balance sheet strength that is more than adequate to support its S&P "A" current investment grade bond rating, at S&P's financial and business ratings for FPL.

All of this supports my recommended overall rate of return as being just and reasonable, and provides fair compensation to FPL in support of more competitive rates that are just and reasonable in providing utility service.

IV.H. Embedded Cost of Debt

Q WHAT EMBEDDED COST OF DEBT IS FPL PROPOSING IN THIS PROCEEDING?

A Mr. Barrett proposes an embedded cost of debt of 3.61% in Schedule D-4a for 2022. The embedded cost of debt for 2023 is 3.77%.

Q DO YOU HAVE ANY COMMENTS CONCERNING THE COMPANY'S PROPOSED EMBEDDED COST OF DEBT FOR FPL IN THIS PROCEEDING?

A Yes. The Company's proposed embedded cost of debt for 2023 includes three projected debt issuances totaling $3.6 billion at a projected interest rate of 4.86%. The interest rate for these projected debt issuances is not reasonable nor supported as a known and measureable costs. First, the 2023 projected interest rates are much higher than actual known cost of issuing new debt . The Company's projected 2023 interest rate of 4.86% is approximately 150 basis points higher than the current 13-week average A rated utility yield of 3.35%, as shown on my Exhibit MPG-21. Second, the projected 2023 interest rates is higher than FPL's projected 2022 interest rate projection for new bond issues of 3.39%, which already reflects an increase relative to current interest rates..

Q DO YOU PROPOSE ANY ADJUSTMENT TO FPL'S EMBEDDED COST OF DEBT FOR 2023 IN THIS PROCEEDING?

A Yes. I repriced the projected 2023 debt issuances to 3.49%, which is the Company's projected cost for new debt issuances in 2022. This coupon yield is slightly higher than FPL actual debt issuance in December 2021 of 3.39% as shown on Schedule D-4a developed by Mr. Barrett. Importantly, in its Energy Annual Outlook for 2021, the EIA, is projecting the Aa utility bond yield to be 3.07% for 2025.[22] The current Aa utility yield as of June 4, which is the end of my study period, is 3.09%. Therefore, the EIA is projecting the utility yields to remain relatively flat after 2022 over the next several years. Hence, an increase in bond yields beyond 2022 is not known and measureable.

I revised the Company's Schedule D-4a to reflect the lower interest rate for the three projected debt issuances, which in turn reduced FPL cost of debt from 3.77% to 3.68% as shown on my Exhibit MPG-8.

V. RETURN ON EQUITY

Q PLEASE DESCRIBE WHAT IS MEANT BY A "UTILITY'S COST OF COMMON EQUITY."

A A utility's cost of common equity is the expected return that investors require on an investment in the utility. Investors expect to earn their required return from receiving dividends and through stock price appreciation.

[22] EIA, Energy Annual Outlook for 2021, Table A20. February 3, 2021.

Q PLEASE DESCRIBE THE FRAMEWORK FOR DETERMINING A REGULATED UTILITY'S COST OF COMMON EQUITY.

A In general, determining a fair cost of common equity for a regulated utility has been framed by two hallmark decisions of the U.S. Supreme Court: Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944). In these decisions, the Supreme Court found that just compensation depends on many circumstances and must be determined by fair and enlightened judgments based on relevant facts. The Court found that a utility is entitled to such rates as were permitted to earn a return on a property devoted to the convenience of the public that is generally consistent with the same returns available in other investments of corresponding risk. The Court continued that the utility has "no constitutional rights to profits" such as those realized or anticipated in highly profitable enterprises or speculative ventures, and defined the ratepayer/investor balance as follows:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[23]

As such, a fair rate of return is based on the expectation that the utility costs reflect efficient and economical management, and the return will support its credit standing and access to capital, but the return will not be in excess of this level. From these standards, rates to customers will be just and reasonable, and compensation to the utility will be fair and support financial integrity and credit standing, under economic management of the utility, and just and reasonable rates.

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[23] *Bluefield,* 262 U.S. 679, 693 (1923).

Q PLEASE DESCRIBE THE METHODS YOU HAVE USED TO ESTIMATE FPL'S COST OF COMMON EQUITY.

A I have used several models based on financial theory to estimate FPL's cost of common equity. These models are: (1) a constant growth Discounted Cash Flow ("DCF") model using consensus analysts' growth rate projections; (2) a constant growth DCF using sustainable growth rate estimates; (3) a multi-stage growth DCF model; (4) a Risk Premium model; and (5) a Capital Asset Pricing Model ("CAPM"). I have applied these models to a group of publicly traded utilities with investment risk similar to FPL.

V.A. Risk Proxy Group

Q PLEASE DESCRIBE HOW YOU IDENTIFIED A PROXY UTILITY GROUP THAT COULD BE USED TO ESTIMATE FPL'S CURRENT MARKET COST OF EQUITY.

A I relied on the same proxy group developed by FPL witness Mr. Coyne, which consists of 14 electric utilities followed by *Value Line*.

Q PLEASE DESCRIBE WHY YOU BELIEVE YOUR PROXY GROUP IS REASONABLY COMPARABLE IN INVESTMENT RISK TO FPL.

A My proxy group shown in Exhibit MPG-9, has an average credit rating from S&P of BBB+, which is a two notches lower than FPL's credit rating from S&P of A. The proxy group has an average credit rating from Moody's of Baa1, which is a four notches higher than FPL's credit rating from Moody's of A1.

My proxy group has an average common equity ratio of 43.4% from S&P and 46.6% (excluding short-term debt) from *Value Line* for 2020, which is significantly lower than the Company's proposed common equity ratio of 59.6% base on investors' capital.

Therefore, my proxy group will produced a very generous return on equity for a low-leveraged utility like FPL.

V.B. DCF Model

Q PLEASE DESCRIBE THE DCF MODEL.

A The DCF model posits that a stock price is valued by summing the present value of expected future cash flows discounted at the investor's required rate of return or cost of capital. This model is expressed mathematically as follows:

$$P_0 = \frac{D_1}{(1+K)^1} + \frac{D_2}{(1+K)^2} \;.\;.\;.\;.\; \frac{D_\infty}{(1+K)^\infty} \qquad \text{(Equation 1)}$$

P_0 = Current stock price
D = Dividends in periods 1 - ∞
K = Investor's required return

This model can be rearranged in order to estimate the discount rate or investor-required return, known as "K." If it is reasonable to assume that earnings and dividends will grow at a constant rate, then Equation 1 can be rearranged as follows:

$$K = D_1/P_0 + G \qquad \text{(Equation 2)}$$

K = Investor's required return
D_1 = Dividend in first year
P_0 = Current stock price
G = Expected constant dividend growth rate

Equation 2 is referred to as the annual "constant growth" DCF model.

Q PLEASE DESCRIBE THE INPUTS TO YOUR CONSTANT GROWTH DCF MODEL.

A As shown in Equation 2 above, the DCF model requires a current stock price, expected dividend, and expected growth rate in dividends.

Q WHAT STOCK PRICE DID YOU USE IN YOUR CONSTANT GROWTH DCF MODEL?

A I relied on the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ending on June 4, 2021. An average stock price is less susceptible to market price variations than a price at a single point in time. Therefore, an average stock price is less susceptible to aberrant market price movements, which may not reflect the stock's long-term value.

A 13-week average stock price reflects a period that is still short enough to contain data that reasonably reflects current market expectations, but the period is not so short as to be susceptible to market price variations that may not reflect the stock's long-term value. In my judgment, a 13-week average stock price is a reasonable balance between the need to reflect current market expectations and the need to capture sufficient data to smooth out aberrant market movements.

Q WHAT DIVIDEND DID YOU USE IN YOUR CONSTANT GROWTH DCF MODEL?

A I used the most recently paid quarterly dividend as reported in *Value Line*.[24] This dividend was annualized (multiplied by 4) and adjusted for next year's growth to produce the D_1 factor for use in Equation 2 above. In other words, I calculate D_1 by multiplying the annualized dividend (D_0) by (1+G).

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[24] *The Value Line Investment Survey*, March 12, April 23, and May 14, 2021.

Q WHAT DIVIDEND GROWTH RATES DID YOU USE IN YOUR CONSTANT GROWTH DCF MODEL?

A There are several methods that can be used to estimate the expected growth in dividends. However, regardless of the method, to determine the market-required return on common equity, one must attempt to estimate investors' consensus about what the dividend, or earnings growth rate, will be and not what an individual investor or analyst may use to make individual investment decisions.

As predictors of future returns, securities analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data.[25] That is, assuming the market generally makes rational investment decisions, analysts' growth projections are more likely to influence investors' decisions, which are captured in observable stock prices, than growth rates derived only from historical data.

For my constant growth DCF analysis, I have relied on a consensus, or mean, of professional securities analysts' earnings growth estimates as a proxy for investor consensus dividend growth rate expectations. I used the average of analysts' growth rate estimates from three sources: Zacks, MI, and Yahoo! Finance. All such projections were available on June 4, 2021, and all were reported online.

Each consensus growth rate projection is based on a survey of securities analysts. There is no clear evidence whether a particular analyst is most influential on general market investors. Therefore, a single analyst's projection does not as reliably predict consensus investor outlooks as does a consensus of market analysts' projections. The consensus estimate is a simple arithmetic average, or mean, of surveyed analysts' earnings growth forecasts. A simple average of the growth

[25] *See, e.g.*, David Gordon, Myron Gordon & Lawrence Gould, "Choice Among Methods of Estimating Share Yield," *The Journal of Portfolio Management*, Spring 1989.

forecasts gives equal weight to all surveyed analysts' projections. Therefore, a simple average, or arithmetic mean, of analyst forecasts is a good proxy for market consensus expectations.

Q WHAT ARE THE GROWTH RATES YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?

A The growth rates I used in my DCF analysis are shown in Exhibit MPG-10. The average growth rate for my proxy group is 5.38%.

Q WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF MODEL?

A As shown in Exhibit MPG-11, the average and median constant growth DCF returns for my proxy group for the 13-week analysis are 9.08% and 9.19%, respectively.

Q DO YOU HAVE ANY COMMENTS ON THE RESULTS OF YOUR CONSTANT GROWTH DCF ANALYSIS?

A Yes. The constant growth DCF analysis for my proxy group is based on an average long-term sustainable growth rate of 5.38%. The three- to five-year growth rate is higher than my estimate of a maximum long-term sustainable growth rate of 4.35%, which I discuss later in this testimony.

Q HOW DID YOU ESTIMATE A MAXIMUM LONG-TERM SUSTAINABLE GROWTH RATE?

A Although there may be short-term peaks, the long-term sustainable growth rate for a utility stock cannot exceed the growth rate of the economy in which it sells its goods and services. The long-term maximum sustainable growth rate for a utility investment is, accordingly, best proxied by the projected long-term Gross Domestic Product ("GDP") growth rate as that reflects the projected long-term growth rate of the economy as a whole. *Blue Chip Financial Forecasts* projects that over the next 5 and 10 years, the U.S. nominal GDP will grow at an annual rate of approximately 4.35%. These GDP growth projections reflect a real growth outlook of around 2.15% and an inflation outlook of around 2.15% going forward. As such, the average nominal growth rate over the next 10 years is around 4.35%, which I believe is a reasonable proxy of long-term sustainable growth.[26]

In my multi-stage growth DCF analysis, I discuss academic and investment practitioner support for using the projected long-term GDP growth outlook as a maximum sustainable growth rate projection. Using the long-term GDP growth rate, however, as a conservative projection for the maximum sustainable growth rate is logical, and is generally consistent with academic and economic practitioner accepted practices.

V.C. Sustainable Growth DCF

Q PLEASE DESCRIBE HOW YOU ESTIMATED A SUSTAINABLE LONG-TERM GROWTH RATE FOR YOUR SUSTAINABLE GROWTH DCF MODEL.

A A sustainable growth rate is based on the percentage of the utility's earnings that is retained and reinvested in utility plant and equipment. These reinvested earnings increase the earnings base (rate base). Earnings grow when plant funded by reinvested earnings is put into service, and the utility is allowed to earn its authorized return on such additional rate base investment.

[26] *Blue Chip Financial Forecasts*, June 1, 2020, at 14.

The internal growth methodology is tied to the percentage of earnings retained in FPL and not paid out as dividends. The earnings retention ratio is 1 minus the dividend payout ratio. As the payout ratio declines, the earnings retention ratio increases. An increased earnings retention ratio will fuel stronger growth because the business funds more investments with retained earnings.

The payout ratios of the proxy group are shown in my Exhibit MPG-12. These dividend payout ratios and earnings retention ratios then can be used to develop a sustainable long-term earnings retention growth rate. A sustainable long-term earnings retention ratio will help gauge whether analysts' current three- to five-year growth rate projections can be sustained over an indefinite period of time.

The data used to estimate the long-term sustainable growth rate is based on FPL's current market-to-book ratio and on *Value Line*'s three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances.

As shown in Exhibit MPG-13, the average sustainable growth rate using this internal growth rate model is 4.66% for the proxy group.

Q WHAT IS THE DCF ESTIMATE USING THESE SUSTAINABLE LONG-TERM GROWTH RATES?

A A DCF estimate based on these sustainable growth rates is developed in Exhibit MPG-14. As shown there, the sustainable growth DCF analysis produces proxy group average and median DCF results for the 13-week period of 8.33% and 8.37%, respectively.

V.D. Multi-Stage Growth DCF Model

Q HAVE YOU CONDUCTED ANY OTHER DCF STUDIES?

A Yes. My first constant growth DCF is based on consensus analysts' growth rate projections so it is a reasonable reflection of rational investment expectations over the next three to five years. The limitation on this constant growth DCF model is that it cannot reflect a rational expectation that a period of high or low short-term growth can be followed by a change in growth to a rate that better reflects long-term sustainable growth. Therefore, I performed a multi-stage growth DCF analysis to reflect this outlook of changing growth expectations.

Q WHY DO YOU BELIEVE GROWTH RATES CAN CHANGE OVER TIME?

A Analyst-projected growth rates over the next three to five years will change as utility earnings growth outlooks change. Utility companies go through cycles in making investments in their systems. When utility companies are making large investments, their rate base grows rapidly, which in turn accelerates earnings growth. Once a major construction cycle is completed or levels off, growth in the utility rate base slows and its earnings growth slows from an abnormally high three- to five-year rate to a lower sustainable growth rate.

As major construction cycles extend over longer periods of time, even with an accelerated construction program, the growth rate of the utility will slow simply because the pace of rate base growth will slow and because the utility has limited human and capital resources available to expand its construction program. Therefore, the three- to five-year growth rate projection should only be used as a long-term sustainable growth rate in concert with a reasonable, informed judgment as to whether it considers the current market environment, the industry, and whether the three- to five-year growth outlook is sustainable.

Q PLEASE DESCRIBE YOUR MULTI-STAGE GROWTH DCF MODEL.

A The multi-stage growth DCF model reflects the possibility of non-constant growth for a company over time. The multi-stage growth DCF model reflects three growth periods: (1) a short-term growth period consisting of the first five years; (2) a transition period, consisting of the next five years (6 through 10); and (3) a long-term growth period starting in year 11 through perpetuity.

For the short-term growth period, I relied on the consensus analysts' growth projections I used above in my constant growth DCF model. For the transition period, the growth rates were reduced or increased by an equal factor reflecting the difference between the analysts' growth rates and the long-term sustainable growth rate. For the long-term growth period, I assumed each company's growth would converge to the maximum sustainable long-term growth rate, which is the projected long-term GDP growth rate.

Q WHY IS THE GDP GROWTH PROJECTION A REASONABLE PROXY FOR THE MAXIMUM SUSTAINABLE LONG-TERM GROWTH RATE?

A Utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services. Utilities' earnings/dividend growth are created by increased utility investment or rate base. Such investment, in turn, is driven by service area economic growth and demand for utility service. In other words, utilities invest in plant to meet sales demand growth. Sales growth, in turn, is tied to economic growth in their service areas.

The U.S. Department of Energy, Energy Information Administration ("EIA") has observed utility sales growth tracks U.S. GDP growth, albeit at a lower level, as shown in Exhibit MPG-15. Utility sales growth has lagged behind GDP growth for more than a decade. As a result, nominal GDP growth is a very conservative proxy for utility sales growth, rate base growth, and earnings growth. Therefore, the U.S. GDP nominal growth rate is a reasonable proxy for the highest sustainable long-term growth rate of a utility.

Q IS THERE RESEARCH THAT SUPPORTS YOUR POSITION THAT, OVER THE LONG TERM, A COMPANY'S EARNINGS AND DIVIDENDS CANNOT GROW AT A RATE GREATER THAN THE GROWTH OF THE U.S. GDP?

A Yes. This concept is supported in published analyst literature and academic work. Specifically, in "Fundamentals of Financial Management," a textbook published by Eugene Brigham and Joel F. Houston, the authors state:

> The constant growth model is most appropriate for mature companies with a stable history of growth and stable future expectations. Expected growth rates vary somewhat among companies, but <u>dividends for mature firms are often expected to grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation)</u>.[27]

The use of the economic growth rate is also supported by investment practitioners as outlined as follows:

> **Estimating Growth Rates**
>
> One of the advantages of a three-stage discounted cash flow model is that it fits with life cycle theories in regards to company growth. In these theories, companies are assumed to have a life cycle with varying growth characteristics. Typically, the potential for extraordinary growth in the near term eases over time and eventually growth slows to a more stable level.

[27] "*Fundamentals of Financial Management*," Eugene F. Brigham & Joel F. Houston, Eleventh Edition 2007, Thomson South-Western, a Division of Thomson Corporation at 298, emphasis added.

* * *

> Another approach to estimating long-term growth rates is to focus on estimating the overall economic growth rate. Again, this is the approach used in the *Ibbotson Cost of Capital Yearbook*. To obtain the economic growth rate, a forecast is made of the growth rate's component parts. Expected growth can be broken into two main parts: expected inflation and expected real growth. By analyzing these components separately, it is easier to see the factors that drive growth.[28]

Q ARE THERE ACTUAL INVESTMENT RESULTS THAT SUPPORT THE THEORY THAT THE GROWTH ON STOCK INVESTMENTS WILL NOT EXCEED THE NOMINAL GROWTH OF THE U.S. GDP?

A Yes. This is evident by a comparison of the compound annual growth of the U.S. GDP to the geometric growth of the U.S. stock market. Duff & Phelps measures the historical geometric growth of the U.S. stock market over the period 1926-2020 to be approximately 6.2%.[29] During this same time period, the U.S. nominal compound annual growth of the U.S. GDP was approximately 6.0%.[30]

As such, over the past 90 years, the geometric average growth of the U.S. nominal GDP has been slightly higher than, but comparable to, the geometric average growth of the U.S. stock market capital appreciation. This historical relationship indicates that the U.S. GDP growth outlook is a reasonable estimate of the long-term sustainable growth of U.S. stock investments.

[28]*Morningstar, Inc., Ibbotson SBBI 2013 Valuation Yearbook* at 51 and 52.
[29]*Duff & Phelps, 2021 SBBI Yearbook* at 6-17.
[30]U.S. Bureau of Economic Analysis, January 28, 2021.

Q WHAT IS THE GEOMETRIC AVERAGE AND WHY IS IT APPROPRIATE TO USE THIS MEASURE TO COMPARE GDP GROWTH TO CAPITAL APPRECIATION IN THE STOCK MARKET?

A The terms geometric average growth rate and compound annual growth rate are used interchangeably. The geometric annual growth rate is the calculated growth rate, or return, that measures the magnitude of growth from start to finish. The geometric average is best, and most often, used as a measurement of performance or growth over a long period of time.[31] Because I am comparing achieved growth in the stock market to achieved growth in U.S. GDP over a long period of time, the geometric average growth rate is most appropriate.

Q HOW DID YOU DETERMINE A LONG-TERM GROWTH RATE THAT REFLECTS THE CURRENT CONSENSUS MARKET PARTICIPANT OUTLOOK?

A I relied on the economic consensus of long-term GDP growth projections. *Blue Chip Financial Forecasts* publishes the consensus for GDP growth projections twice a year. These consensus GDP growth outlooks are the best available measure of the market's assessment of long-term GDP growth because the analysts' projections reflect all current outlooks for GDP. They are therefore likely the most influential on investors' expectations of future growth outlooks. The consensus projections published GDP growth rate outlook is 4.35% over the next 10 years.[32]

I propose to use the consensus for projected five- and ten-year average GDP growth rates of 4.35%, as published by *Blue Chip Financial Forecasts*, as an estimate of long-term sustainable growth. *Blue Chip Financial Forecasts* projections provide

[31] *New Regulatory Finance*, Roger Morin, PhD, at 133-134.
[32] *Blue Chip Financial Forecasts*, June 1, 2020, at 14.

real GDP growth projections of approximately 2.15% and inflation of 2.15%[33] over the five-year and ten-year projection periods, resulting in nominal GDP growth projections of 4.35%. These GDP growth forecasts represent the most likely views of market participants because they are based on published economic consensus projections.

Q DO YOU CONSIDER OTHER SOURCES OF PROJECTED LONG-TERM GDP GROWTH?

A Yes, and these alternative sources corroborate the consensus analysts' projections I relied on. Various commonly relied upon analysts' projections are shown in Table 7 below.

TABLE 7

GDP Forecasts

Source	Term	Real GDP	Inflation	Nominal GDP
Blue Chip Financial Forecasts	5-10 Yrs	2.2%	2.2%	4.3%
EIA - Annual Energy Outlook	28 Yrs	2.0%	2.3%	4.4%
Congressional Budget Office	9 Yrs	1.8%	2.1%	3.9%
Moody's Analytics	28 Yrs	2.1%	1.8%	3.9%
Social Security Administration	73 Yrs			4.1%
The Economist Intelligence Unit	25 Yrs	1.8%	2.0%	3.9%

The EIA in its *Annual Energy Outlook* projects real GDP out until 2050. In its 2020 Annual Report, the EIA projects real GDP through 2050 to be 1.8% and a long-term GDP price inflation projection of 2.2%. The EIA data supports a long-term nominal GDP growth outlook of 4.1%.[34]

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[33] *Id.*

[34] DOE/EIA Annual Energy Outlook 2020 With Projections to 2050, March 2020, Table Macroeconomic Indicators.

Also, the Congressional Budget Office ("CBO") makes long-term economic projections. The CBO is projecting real GDP growth to be 1.8% during the next nine years, with a GDP price inflation outlook of 2.0%. The CBO's nine-year outlook for nominal GDP based on this projection is 3.8%.[35]

Moody's Analytics also makes long-term economic projections. In its recent over 25-year outlook to 2048, Moody's Analytics is projecting real GDP growth of 2.2% with GDP inflation of 1.8%.[36] Based on these projections, Moody's Analytics is projecting nominal GDP growth of 4.1% over the next 25 years.

The Social Security Administration ("SSA") makes long-term economic projections out to 2095. The SSA's nominal GDP projection, under its "intermediate cost" scenario of approximately 50 years, is 4.1%.[37]

The Economist Intelligence Unit, a division of The Economist and a third-party data provider to MI, makes a long-term economic projection out to 2050. The Economist Intelligence Unit is projecting real GDP growth of 1.8% with an inflation rate of 2.0% out to 2050. The real GDP growth projection is in line with the consensus. The long-term nominal GDP projection based on these outlooks is approximately 3.9%.[38]

The real GDP and nominal GDP growth projections made by these independent sources support my use of 4.35% as a reasonable estimate of market participants' expectations for long-term GDP growth.

[35] *CBO: An Update to the Economic Outlook: 2020 to 2030*, July 2020.
[36] www.economy.com, *Moody's Analytics Forecast*, May 11, 2020.
[37] www.ssa.gov, "2020 OASDI Trustees Report," Table VI.G4, April 22, 2020.
[38] *S&P Global Market Intelligence, Economist Intelligence Unit*, downloaded on January 28, 2021.

Q WHAT STOCK PRICE, DIVIDEND, AND GROWTH RATES DID YOU USE IN YOUR MULTI-STAGE GROWTH DCF ANALYSIS?

A I relied on the same 13-week average stock prices and the most recent quarterly dividend payment data discussed above. For stage one growth, I used the consensus analysts' growth rate projections discussed above in my constant growth DCF model. The first stage covers the first five years, consistent with the time horizon of the securities analysts' growth rate projections. The second stage, or transition stage, begins in year 6 and extends through year 10. The second stage growth transitions the growth rate from the first stage to the third stage using a straight linear trend. For the third stage, or long-term sustainable growth stage, starting in year 11, I used a 4.35% long-term sustainable growth rate based on the consensus economists' long-term projected nominal GDP growth rate.

Q WHAT ARE THE RESULTS OF YOUR MULTI-STAGE GROWTH DCF MODEL?

A As shown in Exhibit MPG-16, the average and median DCF returns on equity for my proxy group using the 13-week average stock price are 8.24% and 8.38%, respectively.

Q PLEASE SUMMARIZE THE RESULTS FROM YOUR DCF ANALYSES.

A The results from my DCF analyses are summarized in Table 8 below:

TABLE 8

Summary of DCF Results

Description	Average
Constant Growth DCF Model (Analysts' Growth)	9.08%
Constant Growth DCF Model (Sustainable Growth)	8.33%
Multi-Stage Growth DCF Model	8.24%

I conclude that my DCF studies support a return on equity of 9.10%.

V.E. Risk Premium Model

Q PLEASE DESCRIBE YOUR BOND YIELD PLUS RISK PREMIUM MODEL.

A This model is based on the principle that investors require a higher return to assume greater risk. Common equity investments have greater risk than bonds because bonds have more security of payment in bankruptcy proceedings than common equity and the coupon payments on bonds represent contractual obligations. In contrast, companies are not required to pay dividends or guarantee returns on common equity investments. Therefore, common equity securities are considered to be riskier than bond securities.

This risk premium model is based on two estimates of an equity risk premium. First, I quantify the difference between regulatory commission-authorized returns on common equity and contemporary U.S. Treasury bonds. The difference between the authorized return on common equity and the Treasury bond yield is the risk premium. I estimated the risk premium on an annual basis for each year from 1986 through 2020. The authorized returns on equity were based on regulatory commission-authorized returns for utility companies. Authorized returns are typically based on expert witnesses' estimates of the investor-required return at the time of the proceeding.

The second equity risk premium estimate is based on the difference between regulatory commission-authorized returns on common equity and contemporary "A" rated utility bond yields by Moody's. I selected the period 1986 through 2020 because public utility stocks consistently traded at a premium to book value during that period. This is illustrated in Exhibit MPG-17, which shows the market-to-book ratio since 1986 for the electric utility industry was consistently above a multiple of 1.0x. Over this period, an analyst can infer that authorized returns on equity were sufficient to support market prices that at least exceeded book value. This is an indication that commission authorized returns on common equity supported a utility's ability to issue additional common stock without diluting existing shares. It further demonstrates utilities were able to access equity markets without a detrimental impact on current shareholders.

Based on this analysis, as shown in Exhibit MPG-18, the average indicated equity risk premium over U.S. Treasury bond yields has been 5.70%. Since the risk premium can vary depending upon market conditions and changing investor risk perceptions, I believe using an estimated range of risk premiums provides the best method to measure the current return on common equity for a risk premium methodology.

I incorporated five-year and ten-year rolling average risk premiums over the study period to gauge the variability over time of risk premiums. These rolling average risk premiums mitigate the impact of anomalous market conditions and skewed risk premiums over an entire business cycle. As shown on my Exhibit MPG-18, the five-year rolling average risk premium over Treasury bonds ranged from

4.25% to 7.10%, while the ten-year rolling average risk premium ranged from 4.38% to 6.91%.

As shown on my Exhibit MPG-19, the average indicated equity risk premium over contemporary "A" rated Moody's utility bond yields was 4.34%. The five-year and ten-year rolling average risk premiums ranged from 2.88% to 5.90% and 3.20% to 5.73%, respectively.

Q DO YOU BELIEVE THAT THE TIME PERIOD USED TO DERIVE THESE EQUITY RISK PREMIUM ESTIMATES IS APPROPRIATE TO FORM ACCURATE CONCLUSIONS ABOUT CONTEMPORARY MARKET CONDITIONS?

A Yes. Contemporary market conditions can change during the period that rates determined in this proceeding will be in effect. A relatively long period of time where stock valuations reflect premiums to book value indicates that the authorized returns on equity and the corresponding equity risk premiums were supportive of investors' return expectations and provided utilities access to the equity markets under reasonable terms and conditions. Further, this time period is long enough to smooth abnormal market movement that might distort equity risk premiums. While market conditions and risk premiums do vary over time, this historical time period is a reasonable period to estimate contemporary risk premiums.

Alternatively, some studies, such as Duff & Phelps, have recommended that the use of "actual achieved investment return data" in a risk premium study should be based on long historical time periods. The studies find that achieved returns over short time periods may not reflect investors' expected returns due to unexpected and abnormal stock price performance. Short-term, abnormal actual returns would be smoothed over time and the achieved actual investment returns over long time periods would approximate investors' expected returns. Therefore, it is reasonable to assume that averages of annual achieved returns over long time periods will generally converge on the investors' expected returns.

My risk premium study is based on data that inherently relied on investor expectations, not actual investment returns, and, thus, need not encompass a very long historical time period.

Q WHAT DOES CURRENT OBSERVABLE MARKET DATA SUGGEST ABOUT INVESTOR PERCEPTIONS OF UTILITY INVESTMENTS?

A The equity risk premium should reflect the relative market perception of risk today in the utility industry. I have gauged investor perceptions in utility risk today in Exhibit MPG-20, where I show the yield spread between utility bonds and Treasury bonds over the last 40 years. As shown in this exhibit, the average utility bond yield spreads over Treasury bonds for "A" and "Baa" rated utility bonds for this historical period are 1.48% and 1.92%, respectively. The utility bond yield spreads over Treasury bonds for "A" and "Baa" rated utilities for 2019 were 1.18% and 1.61%, respectively. In 2020, the "A" and "Baa" utility spreads are 1.49% and 1.87%, respectively. More recently in the first quarter of 2021, the "A" and "Baa" utility spreads are 1.08% and 1.36%, respectively. Both the current average "A" rated and "Baa" rated utility bond yield spreads over Treasury bond yields are lower or comparable to the respective 40-year average spreads.

The current 13-week average "A" rated utility bond yield of 3.35% when compared to the current Treasury bond yield of 2.32%, as shown in Exhibit MPG-21, implies a yield spread of 1.03%. This current utility bond yield spread is significantly lower than the 40-year average spread for "A" rated utility bonds of 1.48%. The current spread for the "Baa" rated utility bond yield of 1.30% is also lower than the 40-year average spread of 1.92%.

Q IS THERE OBSERVABLE MARKET EVIDENCE TO HELP GAUGE MARKET RISK PREMIUMS?

A Yes. Market data illustrates how the market is pricing investment risk, and gauging the current demands for returns based on securities of varying levels of investment risk. This market evidence includes bond yield spreads for different bond return ratings as implied by the yield spreads for Treasury, corporate and utility bonds. These spreads provide an indication of the market's return requirement for securities of different levels of investment risk and required risk premiums.

Table 9 below summarizes the utility and corporate bond spreads relative to Treasury bond yields.

TABLE 9

Comparison of Yield Spreads Over Treasury Bond Yields

	Utility		Corporate	
Description	**A**	**Baa**	**Aaa**	**Baa**
Average Historical Spread	1.50%	1.94%	0.84%	1.93%
2019 Spread	1.18%	1.61%	0.81%	1.79%
2020 Spread	1.49%	1.87%	0.96%	2.10%
2021 Spread*	1.08%	1.36%	0.66%	1.40%

Source: Moody's Bond Yields
*2021 data through 3/31/2021

As shown above in Table 9, the average historical utility bond yield spread is greater than the current yield spread based on 2019-2021 data. This is an indication that the market is placing a higher value on utility securities currently, and indicating a preference for lower-risk investment securities. This phenomenon is also evident in spreads for general corporate securities. An Aaa-rated corporate bond 40-year average spread is 0.84%, which is slightly higher than the 2019 spread of 0.81%. In 2020 and the first quarter of 2021, the Aaa and Baa corporate spreads are higher but comparable to the 40-year average corporate spreads. For higher-risk bonds, utility Baa and corporate bonds reflect reasonably consistent yield spreads, suggesting that these higher-risk utility and corporate bond securities are not receiving the same premium valuation as are the lower-risk A-rated and Aaa-rated utility and corporate bond securities.

A relatively low yield for utility and corporate bonds is also reflected in outlooks of real returns on these bond yields compared to the past. Over the period 1926-2020, long-term corporate bond yields have earned around 6.1%, compared to inflation of around 2.9%.[39] This implies a historical real return on long-term corporate bonds of around 2.9%. In 2019-2020, long-term corporate bonds rated Aaa averaged around 3.0%. At that time, future inflation outlooks over the long term were expected to be around 2.0% which implies a current real return outlook on long-term corporate bonds of only 1.0%. Again, the lower current yield in comparison to historical yields indicates that bond yields are being priced at a premium by market participants.

This information supports the finding that higher-risk securities are being valued to produce higher-risk spreads relative to low-risk securities in the current marketplace. As such, I believe this information supports that using an above-average risk premium in the current marketplace accurately estimates the market's required return for an investment in a higher-risk security (common stock) compared

[39] *Duff & Phelps 2021 SBBI Yearbook* at 6-17.

to a lower-risk security (utility and Treasury bond yields). For these reasons, I believe an above-average risk premium is supported by observable market evidence.

Q WHAT IS YOUR RECOMMENDED RETURN FOR FPL BASED ON YOUR RISK PREMIUM STUDY?

A I am recommending more weight be given to the high-end risk premium estimates than the low-end. As outlined above, I believe the current market is reflecting high premiums for investing in securities of greater levels of investment risk. Based on this observation, I propose to be conservative in applying a risk premium analysis. For these reasons, I will recommend my high-end equity risk premium in forming a return on equity in this proceeding.

For Treasury bond yields, I propose a risk premium of 6.75%. This risk premium gives more weight to the high-end estimate than it does to the study period median. Indeed, it represents approximately the third decile in the range of the midpoint of 5.64% up to the high-end of 7.10% based on the five-year rolling average. I relied on the risk premium at approximately the 75th percentile of the range of risk premiums to recognize clear, observable evidence that risk premiums are at abnormally high levels right now, but to also recognize that the projected Treasury bond yield is considerably higher than current observable bond yields, returning to more of a normal level, including that relative to that of other investments. This risk premium still represents an expectation that the current market risk premiums are at elevated levels. This risk premium reflects observable evidence in the market that the market risk premium is at relatively high levels currently, however, risk premiums may be more moderated based on projected increases in Treasury bond yields.

Using a Treasury bond risk premium of 6.75% and a projected Treasury bond yield of 2.80% produces an indicated equity risk premium of 9.55% (6.75% + 2.80%). A risk premium based on utility bond yields was also based on a high-end estimate. However, because current observable yields are employed in this risk premium study, I am relying on the high-end estimate in the study of 5.90% on my Exhibit MPG-19 and the utility yield of 3.35% as developed on my Exhibit MPG-21. Hence, a risk premium based on utility bond yields indicates a return on equity of 9.25% (5.90% + 3.35%).

Based on this methodology, my Treasury bond risk premium and my utility bond risk premium indicate a return in the range of 9.25% to 9.55%, with a midpoint of 9.40%.

V.F. Capital Asset Pricing Model ("CAPM")

Q PLEASE DESCRIBE THE CAPM.

A The CAPM method of analysis is based upon the theory that the market-required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. This relationship between risk and return can be expressed mathematically as follows:

$$R_i = R_f + B_i \times (R_m - R_f) \text{ where:}$$

R_i = Required return for stock i
R_f = Risk-free rate
R_m = Expected return for the market portfolio
B_i = Beta - Measure of the risk for stock

The stock-specific risk term in the above equation is beta. Beta represents the investment risk that cannot be diversified away when the security is held in a diversified portfolio. When stocks are held in a diversified portfolio, stock-specific risks can be eliminated by balancing the portfolio with securities that react in the opposite direction to firm-specific risk factors (e.g., business cycle, competition, product mix, and production limitations).

Risks that cannot be eliminated when held in a diversified portfolio are non-diversifiable risks. Non-diversifiable risks are related to the market and referred to as systematic risks. Risks that can be eliminated by diversification are non-systematic risks. In a broad sense, systematic risks are market risks and non-systematic risks are business risks. The CAPM theory suggests the market will not compensate investors for assuming risks that can be diversified away. Therefore, the only risk investors will be compensated for are systematic, or non-diversifiable, risks. The beta is a measure of the systematic, or non-diversifiable risks.

Q PLEASE DESCRIBE THE INPUTS TO YOUR CAPM.

A The CAPM requires an estimate of the market risk-free rate, FPL's beta, and the market risk premium.

Q WHAT DID YOU USE AS AN ESTIMATE OF THE MARKET RISK-FREE RATE?

A As previously noted, *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield is 2.80%.[40] The current 30-year Treasury bond yield is 2.32%, as shown in Exhibit MPG-21. I used *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield of 2.80% for my CAPM analysis.

[40] *Blue Chip Financial Forecasts*, June 1, 2021 at 2.

Q WHY DID YOU USE LONG-TERM TREASURY BOND YIELDS AS AN ESTIMATE OF THE RISK-FREE RATE?

A Treasury securities are backed by the full faith and credit of the United States government. Therefore, long-term Treasury bonds are considered to have negligible credit risk. Also, long-term Treasury bonds have an investment horizon similar to that of common stock. As a result, investor-anticipated long-run inflation expectations are reflected in both common stock required returns and long-term bond yields. Therefore, the nominal risk-free rate (or expected inflation rate and real risk-free rate) included in a long-term bond yield is a reasonable estimate of the nominal risk-free rate included in common stock returns.

Treasury bond yields, however, do include risk premiums related to unanticipated future inflation and interest rates. In this regard, a Treasury bond yield is not a risk-free rate. Risk premiums related to unanticipated inflation and interest rates reflect systematic market risks. Consequently, for companies with betas less than 1.0, using the Treasury bond yield as a proxy for the risk-free rate in the CAPM analysis can produce an overstated estimate of the CAPM return.

Q WHAT BETA DID YOU USE IN YOUR ANALYSIS?

A As shown on my Exhibit MPG-22, page 1, the average beta of my proxy group is 0.88. This means that my proxy group is less risky than the market as a whole. I also reviewed the long-term trend of *Value Line* betas reported for the proxy group companies. As shown on Exhibit MPG-22, page 2, the proxy group's betas have generally ranged between 0.60 and 0.80, or an average of approximately 0.72. Thus, the current beta estimates of around 0.88 are above the high-end of the historical range. As outlined below, I will consider both current published betas as well as normalized historical beta estimates in deriving a CAPM return estimate that reflects the current market cost of equity, and the likely cost of equity when rates determined in this proceeding are in effect.

Q HOW DID YOU DERIVE YOUR MARKET RISK PREMIUM ESTIMATE?

A I derived two market risk premium estimates: a forward-looking estimate and one based on a long-term historical average.

The forward-looking estimate was derived by estimating the expected return on the market (as represented by the S&P 500) and subtracting the risk-free rate from this estimate. I estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market. The real return on the market represents the achieved return above the rate of inflation.

Duff & Phelps' *2021 SBBI Yearbook* estimates the historical arithmetic average real market return over the period 1926 to 2021 to be 9.1%.[41] A current consensus for projected inflation, as measured by the Consumer Price Index, is 2.2%.[42] Using these estimates, the expected market return is 11.50%.[43] The market risk premium then is the difference between the 11.50% expected market return and my 2.80% risk-free rate estimate, or 8.70%, which I referred to as a normalized market risk premium.

I also developed a current market risk premium based on the difference between the expected return on the market of 11.50% as described above and the current 30-year Treasury yield of 2.32% as shown on my Exhibit MPG-21, which produced a current market risk premium of 9.18%.

[41]Duff & Phelps*, 2021 SBBI Yearbook at 6-18.*
[42]*Blue Chip Financial Forecasts*, February 1, 2021 at 2.
[43]$\{ (1 + 0.090) * (1 + 0.022) - 1 \} * 100$.

A historical estimate of the market risk premium was also calculated by using data provided by Duff & Phelps in its *2021 SBBI Yearbook*. Over the period 1926 through 2020, the Duff & Phelps study estimated that the arithmetic average of the achieved total return on the S&P 500 was 12.2%[44] and the total return on long-term Treasury bonds was 6.1%.[45] The indicated market risk premium is 6.1% (12.2% - 6.1% = 6.1%).

The long-term government bond yield of 6.1% occurred during a period of inflation of approximately 2.9%, thus implying a real return on long-term government bonds of 3.2%.

Q HOW DOES YOUR ESTIMATED MARKET RISK PREMIUM RANGE COMPARE TO THAT ESTIMATED BY DUFF & PHELPS?

A Duff & Phelps makes several estimates of a forward-looking market risk premium based on actual achieved data from the historical period of 1926 through 2020 as well as normalized data. Using this data, Duff & Phelps estimates a market risk premium derived from the total return on the securities that comprise the S&P 500, less the income return on Treasury bonds. The total return includes capital appreciation, dividend or coupon reinvestment returns, and annual yields received from coupons and/or dividend payments. The income return, in contrast, only reflects the income return received from dividend payments or coupon yields.

Duff & Phelps' range is based on several methodologies. First, Duff & Phelps estimates a market risk premium of 7.25% based on the difference between the total

[44]*Duff & Phelps 2020 Yearbook* at 6-17.
[45]*Id.*

market return on common stocks (S&P 500) less the income return on 20-year Treasury bond investments over the 1926-2020 period.[46]

Second, Duff & Phelps used the Ibbotson & Chen supply-side model which produced a market risk premium estimate of 6.0%.[47]

Duff & Phelps explains that the historical market risk premium based on the S&P 500 was influenced by an abnormal expansion of P/E ratios relative to earnings and dividend growth during the period, primarily over the last 30 years. Duff & Phelps believes this abnormal P/E expansion is not sustainable. In order to control for the volatility of extraordinary events and their impacts on P/E ratios, Duff & Phelps takes into consideration the three-year average P/E ratio as the current P/E ratio.[48] Therefore, Duff & Phelps adjusted this market risk premium estimate to normalize the growth in the P/E ratio to be more in line with the growth in dividends and earnings.

Finally, Duff & Phelps develops its own recommended equity, or market risk premium, by employing an analysis that takes into consideration a wide range of economic information, multiple risk premium estimation methodologies, and the current state of the economy by observing measures such as the level of stock indices and corporate spreads as indicators of perceived risk. Based on this methodology, and utilizing a “normalized” risk-free rate of 2.5%, Duff & Phelps concludes the current expected, or forward-looking, market risk premium is 5.5%, implying an expected return on the market of 8.0%.[49]

Importantly, Duff & Phelps’ market risk premiums are measured over a 20-year Treasury bond. Because I am relying on a projected 30-year Treasury bond

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[46] *Duff & Phelps 2021 SBBI Yearbook at 10-21*.
[47] *Id. at 10-29*.
[48] *Id.*
[49] *Duff & Phelps*: “Technical Update: Duff & Phelps Recommended U.S. Equity Risk Premium Decreased from 6.0% to 5.5%,” December 10, 2020.

yield, the results of my CAPM analysis should be considered conservative estimates for the cost of equity.

Q HOW DOES YOUR ESTIMATED MARKET RISK PREMIUM RANGE COMPARE TO THAT ESTIMATED BY DUFF & PHELPS?

A The Duff & Phelps analyses indicate a market risk premium falls somewhere in the range of 5.5% to 7.25%. My market risk premium falls in the range of 6.1% to 9.2%.

Q WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A The evidence outlined above shows that current observable risk-free rates are around 2.32%, but projected risk-free rates increase to around 2.80%. Similarly, current observable beta estimates are around 0.88 but forward-looking more normalized beta estimates have consistently been about 0.72. I will use both of these CAPM factors in deriving a reasonable estimate of the current market cost of equity, and that likely to be reflective as rates determined in this case are in effect. Therefore, I will estimate a CAPM return using a current beta of 0.88, and a normal beta of 0.72, with a current and normalized market risk premium estimate.

As shown on my Exhibit MPG-23, using a current market risk-free rate of 2.32%, a projected market return of 11.50%, a market risk premium of 9.18%, and a current beta of 0.88 indicates a CAPM return estimate of 10.35%. Using a market return of 11.50%, with a projected risk-free rate of 2.8%, produces a market risk premium of 8.7%. This market risk premium and risk-free rate with a normalized utility beta of 0.72, indicates a CAPM return of about 9.10%. The midpoint of the current and normalized CAPM return estimate is 9.73% (midpoint of 10.35% and 9.10%), rounded up to 9.7%.

V.G. Return on Equity Summary

Q BASED ON THE RESULTS OF YOUR RETURN ON COMMON EQUITY ANALYSES DESCRIBED ABOVE, WHAT RETURN ON COMMON EQUITY DO YOU RECOMMEND FOR FPL?

A Based on my analyses, I recommend FPL's current market cost of equity be in the range of 9.10% to 9.70%, with a midpoint of 9.40%.

TABLE 10

Return on Common Equity Summary

Description	Results
DCF	9.10%
Risk Premium	9.40%
CAPM	9.70%

A return on common equity of 9.40%, which is the midpoint of my recommended range of 9.10% to 9.70%, is supported by both my DCF, my risk premium and CAPM studies. The low-end of my range is based on my DCF return and the high-end of my range is based on my risk premium study. The CAPM falls at the high-end of my range. My return on equity estimates reflect observable market evidence, the impact of Federal Reserve policies on current and expected long-term capital market costs, an assessment of the current risk premium built into current market securities, and a general assessment of the current investment risk characteristics of the electric utility industry and the market's demand for utility securities.

V.H. Financial Integrity

Q WILL YOUR RECOMMENDED OVERALL RATE OF RETURN SUPPORT AN INVESTMENT GRADE BOND RATING FOR FPL?

A Yes. I have reached this conclusion by comparing the key credit rating financial ratios for FPL at my proposed return on equity, embedded debt cost, and proposed capital structure to S&P's benchmark financial ratios using S&P's credit metric ranges.

Q PLEASE DESCRIBE THE MOST RECENT S&P FINANCIAL RATIO CREDIT METRIC METHODOLOGY.

A S&P publishes a matrix of financial ratios corresponding to its assessment of the business risk of utility companies and related bond ratings. On May 27, 2009, S&P expanded its matrix criteria by including additional business and financial risk categories.[50]

Based on S&P's most recent credit matrix, the business risk profile categories are "Excellent," "Strong," "Satisfactory," "Fair," "Weak," and "Vulnerable." Most utilities have a business risk profile of "Excellent" or "Strong."

The financial risk profile categories are "Minimal," "Modest," "Intermediate," "Significant," "Aggressive," and "Highly Leveraged." Most of the utilities have a financial risk profile of "Aggressive." FPL has an "Excellent" business risk profile and an "Intermediate" financial risk profile.

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[50] S&P updated its 2008 credit metric guidelines in 2009, and incorporated utility metric benchmarks with the general corporate rating metrics. *Standard & Poor's RatingsDirect®*: "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," May 27, 2009.

Q PLEASE DESCRIBE S&P'S USE OF THE FINANCIAL BENCHMARK RATIOS IN ITS CREDIT RATING REVIEW.

A S&P evaluates a utility's credit rating based on an assessment of its financial and business risks. A combination of financial and business risks equates to the overall assessment of FPL's total credit risk exposure. On November 19, 2013, S&P updated its methodology. In its update, S&P published a matrix of financial ratios that defines the level of financial risk as a function of the level of business risk.

S&P publishes ranges for primary financial ratios that it uses as guidance in its credit review for utility companies. The two core financial ratio benchmarks it relies on in its credit rating process include: (1) Debt to Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA"); and (2) Funds From Operations ("FFO") to Total Debt.[51]

Q HOW DID YOU APPLY S&P'S FINANCIAL RATIOS TO TEST THE REASONABLENESS OF YOUR RATE OF RETURN RECOMMENDATIONS?

A I calculated each of S&P's financial ratios based on FPL's cost of service for its retail utility operations in its Florida service territory. While S&P would normally look at total consolidated FPL financial ratios in its credit review process, my investigation in this proceeding is not the same as S&P's. I am attempting to judge the reasonableness of my proposed cost of capital for rate-setting in FPL's Florida retail utility operations. Hence, I am attempting to determine whether my proposed rate of return will in turn result in cash flow metrics, balance sheet strength, and earnings that will support an investment grade bond rating and FPL's financial integrity.

[51] *Standard & Poor's RatingsDirect®*: "Criteria: Corporate Methodology," November 19, 2013.

Q DID YOU INCLUDE ANY OFF BALANCE SHEET DEBT ("OBS") DEBT EQUIVALENTS?

A Yes, I did. I obtained the off-balance sheet debt for both FPL and Gulf Power from S&P Capital IQ. The latest data available for FPL was as of December 2020 and the latest data available for Gulf Power was as of December 2019. I used S&P last year amortization to estimate the 2022 off-balance sheet debt. In addition, I applied the jurisdictional allocation factor to estimate the FPL OBS debt pertaining to the Company's cost of service.

Q PLEASE DESCRIBE THE RESULTS OF THIS CREDIT METRIC ANALYSIS AS IT RELATES TO FPL'S REGULATED OPERATIONS.

A The S&P financial metric calculations for FPL at a 9.40% return are developed on Exhibit MPG-24, page 1. The credit metrics produced below, with FPL's financial risk profile from S&P of "Intermediate" and business risk profile of "Excellent," will be used to assess the strength of the credit metrics based on FPL's retail operations in the state of Florida.

The adjusted debt ratio for credit metric purposes at my proposed capital structure is 45.9%, which is lower than the debt ratio for the A rated utilities of approximately 48.7%.

Based on an equity return of 9.40% and my proposed common equity ratio of 53.5%, FPL will be provided an opportunity to produce a Debt to Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA") ratio of 3.3x. This is within S&P's "Intermediate" guideline range of 2.5x to 3.5x,[52] which supports FPL's credit rating.

[52] *Standard & Poor's RatingsDirect®*: "Criteria: Corporate Methodology," November 19, 2013.

FPL's retail utility operations FFO to total debt coverage at a 9.40% equity return and 53.5% equity ratio is 23%, which is within S&P's "Intermediate" metric guideline range of 23% to 35%. Again, this FFO/total debt ratio will support a ratio consistent with FPL's "Excellent" business profile from S&P.

Q DOES THIS FINANCIAL INTEGRITY ASSESSMENT SUPPORT YOUR RECOMMENDED OVERALL RATE OF RETURN FOR FPL?

A Yes. As noted above, I believe my return on equity represents fair compensation in today's very low capital market costs, and as outlined above, my overall rate of return will provide FPL an opportunity to earn credit metrics that will support its bond rating.

VI. RESPONSE TO FPL WITNESS MR. COYNE

Q WHAT RETURN ON COMMON EQUITY IS FPL PROPOSING FOR THIS PROCEEDING?

A Mr. Coyne recommends a return on equity reflects return on equity estimates produced by the DCF, CAPM, RP and Expected Earnings models in the range of 9.23% to 14.17%, with an average of 10.89%. Based on his analyses and his consideration of 11 basis points for flotation costs, Mr. Coyne concludes that the return on equity for FPL falls in the range of 10.5% to a 11.5%, with a point estimate of 11.0% for 2020-2025.[53]

FPL proposes to add 50 basis points to Mr. Coyne's estimated market return on equity for FPL as an incentive return on equity. With this incentive, FPL proposes

[53]Coyne Direct Testimony at 5-6.

to set rates based on an 11.5% return on equity, which reflects Mr. Coyne's estimate of 11 basis points plus the 50 basis point return on equity incentive.[54]

Q HOW DOES FPL'S REQUESTED OVERALL RATE OF RETURN AND RETURN ON EQUITY COMPARE TO THAT PREVIOUSLY AWARDED FOR FPL AND GULF POWER, AND TO THOSE RECENTLY APPROVED OR CURRENTLY REQUESTED BY FLORIDA UTILITIES?

A FPL's request in this case completely disconnects from today's very low capital market cost environment, and sets rates of return at substantially above market rates of return, and much higher than those recently awarded to either FPL and/or other Florida utilities, relative to contemporary utility bond yields available during those proceedings. For example, in FPL's last rate decision, Docket No. 160021-EI, award date of November 2016, it was awarded a return on equity of 10.55%. At that time, "A" rated utility bond yields were around 4.16%. Currently, "A" rated utility bond yields are about 3.35%, or roughly 81 basis points lower than the capital market that existed at the time of FPL's last rate case. This suggests that the return on equity appropriate for FPL in this case should be less than that previously awarded, not substantially higher as proposed by FPL in this proceeding.

Similarly, in Gulf Power's last rate case, Docket No. 160186-EI, the Commission awarded it a 10.25% return on equity in March 2017, when contemporary "A" utility bond yields were about 4.16%. Again, this is more than 80 basis points higher than contemporary utility bond yields. As such, this is more observable evidence that FPL's authorized return on equity in this case should be lower than its last case, not greater as proposed by FPL.

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[54]Reed Direct Testimony at 89-90.

Another utility recently acquired by FPL, Florida City Gas, was awarded a return on equity by the Commission of 10.19% in Docket No. 20170179-GU around March of 2018. At the time the Florida City Gas authorized return on equity was approved, contemporary “A” rated utility bond yields were around 4.00%. Again, this is approximately 65 basis points higher than “A” rated bond yields today.

For more recent cases, I would point to FPL witness John Reed’s testimony at page 90. There, he states in Docket No. 20210016-EI, Duke Florida was recently awarded a return of equity of 9.85% with a capital structure of around 53% common equity. Again, this shows FPL’s requested return on equity and ratemaking capital structure are not reasonably priced, and do not reflect a balanced capital structure or fair return on equity.

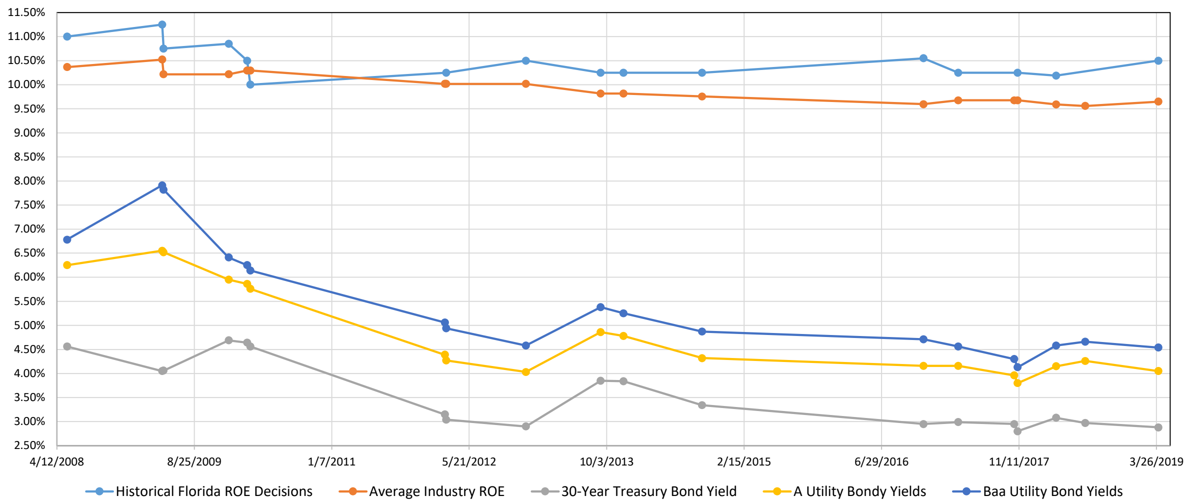
Finally, Tampa Electric Company recently has filed for a rate case, seeking a return on equity of 10.75%,and a ratemaking capital structure with a common equity ratio of 54.6%. Here again, Tampa Electric’s requested rate of return is far more reasonable and much closer to current capital market costs than that proposed by FPL in this proceeding. Tape 1

Q IS FPL’S AUTHORIZED RETURN ON EQUITY REASONABLY ALIGNED WITH INDUSTRY AUTHORIZED EQUITY RETURNS FOR ELECTRIC UTILITIES?

A No. FPL’s authorized return on equity has generally consistently been significantly higher than that of the electric utility industry authorized returns on equity. This relationship is shown below in Figure 6.

FIGURE 6

Florida ROE vs Industry Data



As shown above, because FPL's authorized return on equity has substantially exceeded the industry norms, it is reasonable for the Commission to at a minimum adjust its common equity ratio of capital down to a level that is no greater than necessary to support its current investment grade bond rating. The combination of an above-market rate of return and a common equity ratio more expensive than necessary to support FPL's bond rating, has the effect of substantially increasing FPL's revenue requirement and unjustifiably inflating its retail rates to its Florida customers.

Q ARE MR. COYNE'S RETURN ON EQUITY ESTIMATES REASONABLE?

A No. Mr. Coyne's estimated return on equity is overstated and should be rejected. Mr. Coyne's analyses produce excessive results for various reasons, including the following:

1. His constant growth DCF results are based on unsustainably high growth rates;
2. His CAPM is based on inflated market risk premiums;
3. His Bond Yield Plus Risk Premium studies are based on inflated utility equity risk premiums;

4. Both Mr. Coyne's CAPM and RP studies are based on projected interest rates that are highly uncertain, and
5. His Expected Earnings analysis is unreasonable because it measures the book accounting return, rather than the market required return.

Q PLEASE COMPARE YOUR RECOMMENDED RETURN ON EQUITY WITH MR. COYNE'S RETURN ON EQUITY ESTIMATES.

A Mr. Coyne's return on equity estimates are summarized in Table 11 below. In the "Adjusted" Column 2, I show the results with prudent and sound adjustments to correct the flaws referenced above. With such adjustments to Mr. Coyne's proxy group's DCF, CAPM, and Risk Premium return estimates, Mr. Coyne's studies show that my 9.40% recommended return on equity for FPL is more reasonable and consistent with the current capital market environment.

TABLE 11

Coyne's Adjusted Return on Equity Estimates

Description	Coyne Mean[1] (1)	Gorman Adjusted (2)
Constant Growth DCF		
30-Day Average	9.33%	9.33%
90-Day Average	9.23%	9.23%
180-Day Average	9.30%	9.30%
CAPM DCF-Derived Results		
CAPM (*Value Line* Beta)	14.17%	9.70%
CAPM (Bloomberg Beta)	14.16%	9.70%
Risk Premium		
Current 30-Yr Treasury (1.97%)	9.53%	8.72%
Near-Term Projected 30-Yr Treasury (2.28%)	9.66%	9.03%
Long-Term Projected 30-Yr Treasury (2.80%)	9.88%	Reject
Expected Earnings	10.22%	Reject
Recommended ROE	11.00%	9.40%

Sources: [1]Coyne Direct Testimony at 53, 60, 63, 64.

As shown in Table 11 above, corrections and improvements to the accuracy of Mr. Coyne's return on equity estimates support a return on equity for FPL of 9.40%.

While my adjustments are presented in Adjusted Column 2 of Table 11 above, a description of the bases for my adjustments to Mr. Coyne's return on equity estimates is presented below.

VI.A. Reliability of DCF Return Estimates

Q DOES MR. COYNE COMMENT ON THE RELIABILITY OF MARKET-BASED MODELS TO MEASURE A FAIR RETURN ON EQUITY FOR FPL?

A Yes. Mr. Coyne opines that the traditional DCF analyses are not producing reasonable results at this time due to the current capital market conditions. He goes on to state that the DCF model, which relies on historical averages is likely to understate the cost of equity for FPL.[55] He also opines that it is important now to consider projected market data.[56]

Q HAS MR. COYNE IDENTIFIED ANYTHING DIFFERENT IN THIS CASE TO DISTINGUISH THE PROJECTIONS THAT HAVE BEEN OFFERED OVER THE LAST FIVE TO TEN YEARS, BUT HAVE YET TO PAN OUT?

A No. As explained in more detail later, economists have consistently been projecting increases in interest rates relative to current observable interest rates over approximately the last five years. However, those projections for increased interest rates have turned out to be inaccurate. Instead, interest rates have remained relatively stable and at low levels for approximately the last five to ten years. Also, I show that projections for interest rates over the next five to ten years have been moderated by independent consensus economists. This is clear evidence that today's market is embracing the sustainability of relatively low capital market costs in the current market relative to what independent economists have projected in prior periods. A comparison of the components of the DCF return for utilities generally to other income return investment options and growth investment options shows that the

[55]Coyne Direct Testimony at 28-30.
[56]Coyne Direct Testimony at 57.

results of DCF models are producing reliable and accurate estimates of the current market cost for utility companies.

Q PLEASE EXPLAIN WHY YOU BELIEVE THE DCF MODEL IS PRODUCING RELIABLE RESULTS FOR UTILITY COMPANIES WHEN THE DCF RETURN COMPONENT IS COMPARED TO ALTERNATIVE INVESTMENTS.

A In addition to the discussion above, the DCF model is producing an economically logical estimate of the current market cost of equity and a return that is comparable with observable returns in alternative investments of comparable risk. The DCF model sums the observable dividend yield on utility stocks and then adds to that an estimate of expected growth. These two components yield DCF returns that can be compared to alternative investments to demonstrate their reasonableness.

The current dividend yield of utility stock (3.53%) is higher but comparable to the yield on “A” rated utility bonds (3.02%) as shown my Exhibit MPG-6. Because utility stock dividends can grow over time, and utility bond yield coupons are fixed, historically utility stock dividend yields are lower than observable utility bond yields. The current yield spread of around -51 basis points is negligible, as described later in my testimony. This relatively narrow spread between A-rated utility bonds and utility stock dividend yields is an indication that the yield component, or income component, on a utility stock is competitive with alternative income returns such as A-rated utility bond yields. This is an indication that the yield component of a DCF return is comparable with alternative investments.

Specifically, as shown on Exhibit MPG-6, the historical average yield spread between utility bonds and utility stock dividends has been 0.87%, which is much higher than the current yield spread of -0.51% for utilities. This indicates the DCF income return on utility stocks (dividend yield) is competitive with the income return available on utility bond investments.

The growth component of the DCF return relates to earnings and stock growth over time. The growth outlook for utility stocks is not depressed generally, but rather provides a robust outlook for dividends and stock price growth. The DCF return is not understated due to the DCF growth rate component.

Exhibit MPG-6 also shows the annual growth in earnings for utilities over the last 13 years has been approximately 3.02%. A forward growth rate of 5.38%, as shown in Exhibit MPG-10, is higher than the realized historical growth. Also, utility earnings growth is expected to be considerably higher than the growth of the U.S. GDP, which generally is regarded as the maximum sustainable growth of the market in general. Going forward, long-term sustainable growth for equity investments is around 4.35%, as described above. Based on these factors, the growth rate component of a regulated utility DCF return is quite robust and produces a highly competitive DCF return estimate.

For these reasons, both dividend yield and growth components of a utility DCF indicate an economically logical return estimate that is competitive with comparably risky alternative investments.

VI.B. Coyne's Constant Growth DCF Models

Q PLEASE DESCRIBE MR. COYNE'S CONSTANT GROWTH DCF RETURN ESTIMATES.

A Mr. Coyne's constant growth DCF returns are developed on his Exhibit JMC-4. Mr. Coyne's constant growth DCF models are based on consensus growth rates published by *Yahoo! Finance* and *Zacks* and individual growth rate projections made by *Value Line*.

He relied on dividend yield calculations based on average stock prices over three different time periods: 30-day, 90-day, and 180-day ending February 28, 2021 – all reflecting a half year of dividend growth adjustments.

Q ARE THE CONSTANT GROWTH DCF RESULTS PRODUCED BY MR. COYNE REASONABLE?

A My major concerns with Mr. Coyne's DCF study, as discussed in regard to my own DCF analysis, is that the current consensus analysts' growth rates are substantially higher than the long-term sustainable growth rate of 4.35%. Specifically, Mr. Coyne's constant growth DCF model is based on an average proxy group growth rate of 5.39% for his proxy group. This growth rate is excessive. Therefore, the DCF model produces reasonable high-end return estimates.

VI.C. Coyne's CAPM Studies

Q PLEASE DESCRIBE MR. COYNE'S CAPM ANALYSIS.

A As indicated above, the CAPM analysis is based upon the theory that the market required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. The risk premium associated with the specific security is expressed mathematically as:

Bi x (Rm - Rf) where:

Bi = Beta - Measure of the risk for stock
Rm = Expected return for the market portfolio
Rf = Risk-free rate

Q PLEASE DESCRIBE THE ISSUES YOU HAVE WITH MR. COYNE'S CAPM STUDY.

A I have two primary issues with Mr. Coyne's CAPM study. First, I believe the market risk premium he used in his CAPM studies is overstated because it does not reflect a reasonable estimate of the expected return on the market. Second, Mr. Coyne relies on a projected risk-free rate based on the 30-Year Treasury yield for 2022 to 2026. Mr. Coyne's consistent reliance on projected interest rates is unreasonable and should be rejected.

Q PLEASE DESCRIBE MR. COYNE'S MARKET RISK PREMIUM.

A Mr. Coyne derived his market risk premium by conducting a DCF analysis for the market (S&P 500). Mr. Coyne market risk premium estimate is based on the total return on the market from 1) S&P Earnings and Estimates report of 17.70%, 2) Bloomberg of 15.46%, and 3) Value Line of 14.07%. The average of these market returns is 15.75%, which is utilized in his CAPM study and a five-year projected risk-free rate of 2.80%, produces a market risk premium of 12.95%.[57]

Q WHAT ISSUES DO YOU HAVE WITH MR. COYNE'S MARKET RISK PREMIUM ESTIMATES?

A Mr. Coyne's DCF-derived market risk premium is based on a market returns of 17.70%, 15.46%, 14.07%,[58] which consist of a growth rate component of 16.06%, 13.87% and 12.41% and market-weighted expected dividend yield of 1.52%, 1.49%, and 1.57%, respectively. As discussed above with respect to my own DCF model, the DCF model requires a long-term sustainable growth rate. Mr. Coyne's

[57] Coyne Direct Testimony at 59.
[58] Coyne Direct Testimony at 59 and Exhibit JMC-5.

sustainable market growth rates in the range of 12.41% to 16.06% are far too high to be a rational outlook for sustainable long-term market growth. These growth rates are more than three times the growth rate of the U.S. GDP long-term growth outlook of 4.35% as discussed above.

As a result of these unreasonable long-term market growth rate estimates, Mr. Coyne's market DCF returns used in his CAPM analyses are inflated and not reliable. Consequently, Mr. Coyne's market risk premiums should be given minimal weight in estimating FPL's CAPM-based return on equity.

Q DO HISTORICAL ACTUAL RETURNS ON THE MARKET SUPPORT MR. COYNE'S PROJECTED MARKET RETURNS?

A No. Historical data shows just how unreasonable Mr. Coyne's projected DCF return on the market is on a going-forward basis. Duff & Phelps estimates the actual capital appreciation for the S&P 500 over the period 1926 through 2020 to have been 6.2% to 8.0%.[59] This compares to Mr. Coyne's projected growth rate of the market in the range of 12.41% to 16.06%.

Further, historically the geometric growth of the market of 6.2%[60] has reflected geometric growth of GDP over this same time period of approximately 6.0%.[61]

This review of historical data establishes two facts very clearly. First, historical, actual achieved growth has been substantially less than projected by Mr. Coyne. Second, historical growth of the market has tracked historical growth of the U.S. GDP. Projected growth of the U.S. GDP is now closer to the 4.0% to 4.5% range. All this information strongly supports the conclusion that Mr. Coyne's projected growth rate on the market in the range of 12.41% to 16.06% is substantially

[59] *Duff & Phelps 2021 SBBI Yearbook* at 6-17.
[60] *Id*.
[61] U.S. Bureau of Economic Analysis, January 28, 2021.

overstated. While I do not endorse the use of a historical growth rate to draw assessments of the market's forward-looking growth rate outlooks, this data can be used to show how unreasonable and inflated Mr. Coyne's market return estimate is.

Q DO YOU HAVE ANY FURTHER COMMENTS IN REGARD TO MR. COYNE'S MARKET RETURN?

A Yes. The expected market return of 15.75% developed by Mr. Coyne is rather abnormal. As show in Table 12 below, a market return of 15.75% is rarely sustained. In fact, nearly 65% of the time, the market has achieved a return less than 15.75% over any rolling five-year period dating back to 1926. Expected market returns of this magnitude should be viewed with a large degree of skepticism because it is largely inflated and unreasonable based on historical standards.

TABLE 12

Observed Arithmetic Total Nominal Returns on the Market

	Rolling Period Arithmetic Total Returns - Nominal					Total
	4-Year	**5-Year**	**10-Year**	**20-Year**	**50-Year**	**95-Year**
Rolling periods observed	92	91	86	76	46	1
Rolling periods w/ returns less than 15.75%	60	59	65	64	46	1
Percent of periods less than 15.75%	65.2%	64.8%	75.6%	84.2%	100.0%	100.0%

Source:
Duff & Phelps 2021 SBBI Yearbook Stocks, Bonds, Bills, and Inflation: Appendix C-1.

Q WHY DO YOU BELIEVE MR. COYNE'S RELIANCE ON A PROJECTED LONG-TERM RISK-FREE RATE IS UNREASONABLE?

A Mr. Coyne reliance on long-term projected bond yield of 2.80% does not reflect market participants' outlooks for FPL's cost of capital during the period rates determined in this proceeding will be in effect. This bond yield is based on projections of Treasury bond yields five years out (2022-2026). Those projections are highly uncertain, and in any event, do not reflect the cost of capital in the test period or even the period over the next two to three years, the period in which rates determined in this proceeding will largely be in effect. As such, the market risk premium should be based on observable bond yields in the market today. Alternatively, the market risk premium should at most reflect bond yield projections through the rate-effective period in this case.

Q CAN MR. COYNE'S CAPM ANALYSIS BE REVISED TO REFLECT A MORE REASONABLE MARKET RISK PREMIUM AND RECENT RISK-FREE RATES?

A Yes. Using Mr. Coyne's near-term Treasury yield of 2.28% as a risk-free rate, the average *Value Line* and Bloomberg beta estimates of 0.88,[62], and my calculated high-end market risk premium of 9.18%, Mr. Coyne's CAPM would be no higher than 10.35%. Using the historical beta of 0.72 as discussed in regard to my CAPM study, the projected long-term risk-free rate of 2.80% and my normalized market risk premium of 8.70% will result in a CAPM return of 9.10%. The average of these two CAPM estimates will produce a CAPM return no higher than 9.70%.

VI.D. Risk Premium Analysis

Q PLEASE DESCRIBE MR. COYNE'S RP RISK PREMIUM METHODOLOGY.

A As shown on his Exhibit JMC-6, Mr. Coyne constructs a risk premium return on equity estimate based on the premise that equity risk premiums are inversely related to interest rates. He estimates an average equity risk premium of approximately 6.0% over the period January 1992 through February 26, 2021. He then applies a regression formula to the current, near-term, and long-term projected 30-year

[62]Exhibit JMC-5.2.

Treasury bond yields of 1.97%, 2.28%, and 2.80%, respectively, to produce equity risk premiums of 7.56%, 7.38%, and 7.08%, respectively. Thus, he calculates return on equity estimates of 9.53%, 9.66%, and 9.88%, respectively.[63]

Q IS MR. COYNE'S RISK PREMIUM METHODOLOGY REASONABLE?

A No. Mr. Coyne contends that there is a simplistic inverse relationship between equity risk premiums and interest rates without any regard to differences in investment risk. Academic studies are quite clear that interest rates are a relevant factor in assessing current market equity risk premiums, but the risk premium ties more specifically to the market's perception of investment risk of debt and equity securities, and not simply changes in interest rates.

More specifically, while academic studies have shown that, in the past, there has been an inverse relationship among these variables, researchers have found that the relationship changes over time and is influenced by changes in perception of the risk of bond investments relative to equity investments, and not simply changes to interest rates.[64]

In the 1980s, equity risk premiums were inversely related to interest rates, but that was likely attributable to the interest rate volatility that existed at that time. As such, when interest rates were more volatile, perceptions of bond investment risk increased relative to the investment risk of equities. This changing investment risk perception caused changes in equity risk premiums.

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[63] Coyne Direct Testimony at 61-63.

[64] Robert S. Harris & Felicia C. Marston, "The Market Risk Premium: "Expectational Estimates Using Analysts' Forecasts," *Journal of Applied Finance*, Volume 11, No. 1, 2001 at 10-13; Eugene F. Brigham, Dilip K. Shome, & Steve R. Vinson, "The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Financial Management*, Spring 1985, at 42-43.

In today's marketplace, interest rate volatility is not as extreme as it was during the 1980s.[65] Nevertheless, changes in the perceived risk of bond investments relative to equity investments still drive changes in equity premiums and cannot be measured simply by observing nominal interest rates. Changes in nominal interest rates are heavily influenced by changes to inflation outlooks, which also change equity return expectations. As such, the relevant factor needed to explain changes in equity risk premiums is the relative changes between the risk of equity versus debt investments, and not simply changes in interest rates.

Importantly, Mr. Coyne's analysis simply ignores investment risk differentials. He bases his adjustment to the equity risk premium exclusively on changes in nominal interest rates. This is a flawed methodology that does not produce accurate or reliable risk premium estimates.

Q DO YOU BELIEVE THAT THE REGRESSION STUDY USED BY MR. COYNE IN HIS RP DEMONSTRATES AN ACCURATE CAUSE AND EFFECT BETWEEN INTEREST RATES AND EQUITY RISK PREMIUMS?

A No. Because the returns on equity he uses are authorized by commissions, those returns on equity are not directly adjusted by market forces. While I also use Commission-authorized returns as a proxy for market-required returns, of significance is the simple regression analysis that tries to describe and gauge equity risk premiums based on only changes in interest rates.

Equity risk premiums can move based on changes in market conditions that can impact both equity returns and bond returns in a like manner. This simple

[65]"The Risk Premium Approach to Measuring a Utility's Cost of Equity," *Financial Management*, Spring 1985, at 44.

regression analysis of equity risk premiums and interest rates ignores these relevant market factors in describing the current market-required equity risk premium.

Q DO YOU HAVE ANY OTHER COMMENTS CONCERNING MR. COYNE'S RISK PREMIUM METHODOLOGY?

A Yes. Similar to his CAPM analysis, in his RP risk premium, Mr. Coyne's use of a long-term projected bond yield of 2.80%[66] does not reflect market participants' outlooks for FPL's cost of capital during the period rates determined in this proceeding will be in effect. Therefore, Mr. Coyne's use of projected bond yields five years out should be rejected..

Q CAN MR. COYNE'S RISK PREMIUM ANALYSIS BE REVISED TO REFLECT CURRENT PROJECTIONS OF TREASURY YIELDS?

A Yes. Mr. Coyne's simplistic and incomplete notion that equity risk premiums change only with changes to nominal interest rates should be rejected. Adding my equity risk premium over Treasury bonds of 6.75% to his Treasury yields of 1.97% and 2.28%, produces a RP no higher than 9.0%.

VI.E. Coyne's Expected Earnings Analysis

Q PLEASE DESCRIBE MR. COYNE'S EXPECTED EARNINGS ANALYSIS.

A Mr. Coyne's Expected Earnings analysis is based on the projected returns on book equity for the electric utility companies followed by *Value Line* and included in his proxy group as developed on his Exhibit JMC-7. Based on this analysis, Mr. Coyne

[66]Exhibit JMC-6.

concludes that the average return on equity result for his proxy group is 9.53%, for the projected period 2023-2025.

Q WHAT IS PROBLEMATIC ABOUT MR. COYNE'S EXPECTED EARNINGS ANALYSIS?

A Mr. Coyne's Expected Earnings analysis should be rejected because this approach does not measure the market required return appropriate for the investment risk of FPL. Rather, it measures the book accounting return. The market required return is not the same as the accounting return, and the two can be – and in this instance are – vastly different.

The significant discrepancy between the level and meaning of a market-required return and a book return on equity can have significant implications to both investors and customers, when used to set a fair return on equity for ratemaking purposes. Simply stated, a market return provides a pure measure of fair compensation to investors, and allows for setting rates that provide no more than fair compensation. Conversely, using the earned return on book equity can cause compensation to be either too high or too low, and rates to be set either too low or too high, depending on the specific circumstances when the book return is measured.

For example, if the proxy group's earned return on book equity is lower than the market return, then this could be an indication that the rates for the proxy group are too low and not providing fair compensation. As such, the measured return on book equity would be an indication rates need to be increased. However, if the earned return on book equity was used to estimate a fair return for ratemaking purposes, then this depressed earnings level could result in rates being set below a level that provides fair compensation to investors and may not support the utility's financial integrity. Conversely, if the earned return on book equity for the proxy companies is above a fair market return on equity, then that could be an indication that the rates for the proxy companies produce more earnings than necessary to fairly compensate investors, and using this inflated return on equity would result in rates that are not just and reasonable for customers.

The market-required return is a long-standing practice in setting rates for utility companies. This is because the market sets the required rate of return for assuming the risk of an investment. To the extent the utility's earnings are adequate to allow it to attract investors, then it will be able to sell new equity shares to the market to secure capital needed to fund additional rate base investments. If this long-standing practice of setting authorized returns consistent with market returns is rejected, in favor of Mr. Coyne's proposal to look at returns on book equity, then the balance between estimating a return that is fair to both investors and customers will be turned upside down, and the rate-setting practice could be substantially impaired and rendered unreliable.

The earned return on book equity is simply not an accurate or legitimate basis upon which to determine a fair and reasonable return on equity for both investors and customers. A fair return on equity is a return that provides fair compensation to utility investors, but also results in customer rate impacts that are no more than necessary to produce that fair compensation – except to the extent greater earnings are necessary to maintain financial integrity or credit standing. For these reasons, the Expected Earnings analysis should simply be rejected.

VI.F. Mr. Coyne's Consideration of Additional Risks

Q DID MR. COYNE INJECT CONSIDERATION OF ADDITIONAL BUSINESS RISKS TO JUSTIFY HIS RETURN ON EQUITY?

A It appears so. Mr. Coyne believes that FPL is exposed to additional risks that should be accounted for: (1) FPL's capital expenditure; (2) its nuclear generation fleet; (3) FPL's storm damages and resulting outages; (4) FPL's regulatory risk relative to the proxy group; (5) the Company's risk associated with its proposed 4-year rate plan; (6) the need to recover flotation costs; and (7) superior management performance.[67] Mr. Coyne believes that these additional risks should be considered in determining FPL's return on equity. However, he failed to recognize the fact that these additional risks are already incorporated in FPL credit rating.

Q PLEASE EXPLAIN.

A The major business risks identified by Mr. Coyne are already considered in the assigning of a credit rating by the various credit rating agencies.

As shown on my Exhibit MPG-9, the average S&P credit rating for my proxy group of BBB+ is comparable to FPL's credit rating of A from S&P. The relative risks discussed on pages 66-86 of Mr. Coyne's testimony are already incorporated in the credit ratings of the proxy group companies. Indeed, S&P and other credit rating agencies go to great lengths and detail in assessing a utility's business risk and financial risk in order to evaluate total investment risk. This total investment risk assessment of FPL, in comparison to a proxy group, is fully absorbed into the market's perception of FPL's risk. The use of my proxy group fully captures the

[67]Coyne Direct Testimony at 66-86.

investment risk of FPL and is, in fact, conservative, given that the proxy group has a lower credit rating than FPL.

Q HOW DOES S&P ASSIGN CORPORATE CREDIT RATINGS FOR REGULATED UTILITIES?

A In assigning corporate credit ratings, the credit rating agency considers both business and financial risks. Business risks, among others, include a company's size, competitive position, generation portfolio, and capital expenditure programs, as well as consideration of the regulatory environment, current state of the industry, and the economy as whole. Specifically, S&P states:

> To determine the assessment for a corporate issuer's business risk profile, the criteria combine our assessments of industry risk, country risk, and competitive position. Cash flow/leverage analysis determines a company's financial risk profile assessment. The analysis then combines the corporate issuer's business risk profile assessment and its financial risk profile assessment to determine its anchor. In general, the analysis weighs the business risk profile more heavily for investment-grade anchors, while the financial risk profile carries more weight for speculative-grade anchors.[68]

VI.F.1. Flotation Costs

Q DID MR. COYNE INCLUDE A FLOTATION COST ADJUSTMENT IN HIS RECOMMENDED RETURN FOR FPL?

A Yes. Mr. Coyne calculated an upward adjustment of 11 basis points to his return results to compensate for flotation costs. He developed his flotation cost adjustment by observing the cost incurred by the proxy group companies in issuing equity securities. The costs incurred on these issuances averaged around 2.64% of the issuance amount.

[68] *Standard & Poor's RatingsDirect®:* "Criteria/Corporates/General: Corporate Methodology," November 19, 2013.

Next, Mr. Coyne developed a constant growth DCF model for the proxy group with and without issuance costs to derive his flotation cost adjustment of 11 basis points.[69]

Q IS MR. COYNE'S FLOTATION COST ADDER REASONABLE?

A No. Mr. Coyne's flotation cost adder is not reasonable or justified because it is not based on the recovery of prudent and verifiable actual flotation costs incurred by FPL. NextEra receives dividend payments from its various subsidiaries and can do whatever it wants with that capital, like redistributing it to another subsidiary. Paid-in capital at FPL can also be derived from debt capital issued by NextEra Mr. Coyne has failed to show that the FPL's paid-in capital portion of its common equity balance was derived from common equity issuances at its parent.

Because he does not show that his adjustment is based on FPL's actual and verifiable flotation expenses, there are no means of verifying whether Mr. Coyne's proposal is reasonable or appropriate. Stated differently, Mr. Coyne's flotation cost return on equity adder is not based on known and measurable FPL costs. Therefore, the Commission should reject a flotation cost return on equity adder for FPL.

Q PLEASE SUMMARIZE YOUR CONCLUSIONS IN REGARD TO FPL BUSINESS AND REGULATORY RISK AS DESCRIBED BY MR. COYNE.

A I do not agree that the risk factors discussed in Mr. Coyne's testimony present investment risk that distinguishes FPL from that of the proxy group or the utility industry. As explained previously, flotation costs are a cost (which FPL has not supported), not a risk; FPL's capital expenditures obligations and development risk

[69]Exhibit JMC-10.

are similar to the proxy group and the utility industry; and Florida's regulatory environment is one of the most favorable to utilities in the nation and mitigates FPL's cost recovery risk.

As mention above regulatory risk is a key credit rating consideration by credit analysts in assigning utilities' business risk, which is fully reflected in the utility's bond rating. Mr. Coyne's focus on a limited number of investment risk characteristics, while ignoring many other significant risk factors such as financial risk, and actual financial performance of Florida utilities generally, and FPL specifically, renders his analysis incomplete and his findings inconclusive. Credit analysts would consider all these risk factors, along with all other risk factors in assigning a bond rating. Hence, including companies that have similar investment risk to FPL by reviewing a bond rating of the proxy group companies is a more complete and reliable assessment of total investment risk, including these specific line item risks identified by Mr. Coyne in selecting comparable risk proxy group companies.

Another deficiency in Mr. Coyne's analysis is he is relying on his own assessment of risk, rather than assessments of utility risk made available to the investing public, and likely are risk assessments that are considered by investors in valuing the utilities' securities that are included in the proxy group. In other words, what is at issue here is the investment market's assessment of risk of the utilities' securities, not Mr. Coyne's personal investment outlook.

VI.G. Capital Market Conditions

Q DID MR. COYNE ALSO OFFER AN ASSESSMENT OF CURRENT MARKET CONDITIONS IN SUPPORT OF HIS RECOMMENDED RETURN ON EQUITY RANGE?

A Yes. Mr. Coyne observes a few factors that he believes gauge the capital market environment and investor sentiment, including the Federal Reserve's monetary policy and the impact of the lower interest rate environment on dividend yield and P/E ratios, the current and expected interest rate environment and volatility levels as measured by the Chicago Board of Exchange ("CBOE"), Implied Volatility Index ("VIX'), as well as .[70]

Q DO YOU BELIEVE THAT MR. COYNE'S USE OF THESE MARKET SENTIMENTS SUPPORTS HIS FINDINGS THAT FPL'S MARKET COST OF EQUITY IS CURRENTLY 11.00%?

A No. In many instances, Mr. Coyne's analysis simply ignores market sentiments favorable toward utility companies and instead lumps utility investments in with general corporate investments. A fair analysis of utility securities shows the market generally regards utility securities as low-risk investment instruments and supports the finding that utilities' cost of capital is low in today's marketplace.

Q WHAT IS THE MARKET SENTIMENT FOR UTILITY INVESTMENTS?

A Again, the current market sentiment toward utility investments, rather than just general corporate investments, is that the market is placing high value on utility securities, recognizing their low risk and stable characteristics. This is illustrated by

[70]Coyne Direct Testimony at 15-40.

current utility bond yield spreads as discussed at length previously. The current strong utility bond valuation is an indication of the market's sentiment that utility bonds are lower risk and are generally regarded as a safe haven by the investment industry.

Further, other measures of utility stock valuations also support the conclusion that there is a robust market for utility stocks. As shown on my Exhibit MPG-6, financial valuation measures (*e.g.*, P/E ratio and market price to cash flow ratio) show that utility stock valuation measures are robust.

For all these reasons, direct assessments of valuation measures and market sentiment toward utility securities support the credit rating agencies' findings, as quoted above, that the utility industry is largely regarded as a low-risk investment. All of this supports my finding that utilities' market cost of equity is very low in today's very low-cost capital market environment.

Q DID MR. COYNE ALSO OPINE THAT MARKET VOLATILITY HAS INCREASED, WHICH HAS CAUSED AN INCREASE IN COST OF EQUITY FOR FPL AND OTHER UTILITY COMPANIES?

A Yes. Mr. Coyne also talks about increased volatility as measured by the CBOE Implied Volatility Index ("VIX"). Mr. Coyne states that the VIX index, which generally tracks broader market equity security values, indicates volatility levels not seen since the Great Recession in 2008/2009 in the index.[71]

[71] Coyne Direct Testimony at 16.

Q IS THE VIX INDEX ADEQUATE TO SUPPORT THE NOTION THAT THE MARKET PERCEPTION OF THE INVESTMENT RISK OF FPL OR UTILITIES GENERALLY IS INCREASING?

A No. The VIX is a broader-based market index of stock price volatility, and not that of subgroups within the market generally, and certainly not applicable to the utility subsector. Utility securities are generally regarded as low-risk investments, and the market generally flocks to low-risk sectors during periods of broader economic distress. The VIX index may indicate greater risk in the overall market but that does not indicate a similar change in investment risk for lower-risk regulated utility companies.

Further, the VIX measures investors' expectations of market volatility over the next 30 days and can change significantly over a short period of time. As Mr. Coyne correctly observes recently it has declined. In fact, as of June 7, 2021 the VIX level closed at 16.42, which is very comparable to the levels observed prior to the COVID-19 pandemic. These drastic fluctuations of the VIX index emphasize the fact that the index should not be used to measure investors' perception of utility operating risk.

Q DO YOU HAVE ANY COMMENTS CONCERNING MR. COYNE'S CONTENTION THAT RELYING ON PROJECTED MARKET DATA IS CURRENTLY VERY IMPORTANT?

A Yes. Mr. Coyne develops his CAPM and risk premium studies mainly relying on near-term and long-term projected interest rates. Mr. Coyne's primary reliance on forecasted Treasury bond yields is unreasonable because he is not considering the highly likely outcome that current observable interest rates will prevail during the period in which rates determined in this proceeding will be in effect. This is important because, while current observable interest rates are actual market data that provides a measure of the current cost of capital, the accuracy of forecasted interest rates is highly problematic.

Q WHY DO YOU BELIEVE THAT THE ACCURACY OF FORECASTED INTEREST RATES IS HIGHLY PROBLEMATIC?

A Over the last several years, observable current interest rates have been a more accurate predictor of future interest rates than economists' consensus projections. Exhibit MPG-25 illustrates this point. Specifically, on Exhibit MPG-25, under Columns 1 and 2, I show the actual market yield for Treasury bonds at the time a projection is made, and the corresponding projection for Treasury bond yields two years in the future, respectively.

As shown in Columns 1 and 2 of Exhibit MPG-25, over the last several years, Treasury yields were projected to increase relative to the actual Treasury yields at the time of the projection. In Column 4, I show the actual Treasury yield two years after the forecast. In Column 5, I show the actual yield change at the time of the projections relative to the projected yield change.

As shown in Exhibit MPG-25, economists have consistently projected that interest rates will increase over the near term. However, as shown in Column 5, those yield projections turned out to be overstated in almost every case. Indeed, actual Treasury yields have decreased or remained flat over the last several years rather than increasing as the economists' projections indicated. As such, current observable interest rates are just as likely to accurately predict future interest rates as are economists' projections.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Michael P. Gorman

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

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

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A In 1983 I received a Bachelor of Science Degree in Electrical Engineering from Southern Illinois University, and in 1986, I received a Master's Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield. I have also completed several graduate level economics courses.

In August of 1983, I accepted an analyst position with the Illinois Commerce Commission ("ICC"). In this position, I performed a variety of analyses for both formal and informal investigations before the ICC, including: marginal cost of energy, central dispatch, avoided cost of energy, annual system production costs, and working capital. In October of 1986, I was promoted to the position of Senior Analyst. In this position, I assumed the additional responsibilities of technical leader on projects, and my areas of responsibility were expanded to include utility financial modeling and financial analyses.

In 1987, I was promoted to Director of the Financial Analysis Department. In this position, I was responsible for all financial analyses conducted by the Staff. Among other things, I conducted analyses and sponsored testimony before the ICC on rate of return, financial integrity, financial modeling and related issues. I also supervised the development of all Staff analyses and testimony on these same issues. In addition, I supervised the Staff's review and recommendations to the Commission concerning utility plans to issue debt and equity securities.

In August of 1989, I accepted a position with Merrill-Lynch as a financial consultant. After receiving all required securities licenses, I worked with individual investors and small businesses in evaluating and selecting investments suitable to their requirements.

In September of 1990, I accepted a position with Drazen-Brubaker & Associates, Inc. ("DBA"). In April 1995, the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and Staff. Since 1990, I have performed various analyses and sponsored testimony on cost of capital, cost/benefits of utility mergers and acquisitions, utility reorganizations, level of operating expenses and rate base, cost of service studies, and analyses relating to industrial jobs and economic development. I also participated in a study used to revise the financial policy for the municipal utility in Kansas City, Kansas.

At BAI, I also have extensive experience working with large energy users to distribute and critically evaluate responses to requests for proposals ("RFPs") for electric, steam, and gas energy supply from competitive energy suppliers. These analyses include the evaluation of gas supply and delivery charges, cogeneration and/or combined cycle unit feasibility studies, and the evaluation of third-party asset/supply management agreements. I have participated in rate cases on rate design and class cost of service for electric, natural gas, water and wastewater utilities. I have also analyzed commodity pricing indices and forward pricing methods for third party supply agreements, and have also conducted regional electric market price forecasts.

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

Q HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A Yes. I have sponsored testimony on cost of capital, revenue requirements, cost of service and other issues before the Federal Energy Regulatory Commission and numerous state regulatory commissions including: Alaska, Arkansas, Arizona, California, Colorado, Delaware, the District of Columbia, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oklahoma, Oregon, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin, Wyoming, and before the provincial regulatory boards in Alberta, Nova Scotia, and Quebec, Canada. I have also sponsored testimony before the Board of Public Utilities in Kansas City, Kansas; presented rate setting position reports to the regulatory board of the municipal utility in Austin, Texas, and Salt River Project, Arizona, on behalf of industrial customers; and negotiated rate disputes for industrial customers of the Municipal Electric Authority of Georgia in the LaGrange, Georgia district.

Q PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A I earned the designation of Chartered Financial Analyst ("CFA") from the CFA Institute. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting, economics, fixed income and equity valuation and professional and ethical conduct. I am a member of the CFA Institute's Financial Analyst Society.

(Whereupon, prefiled direct testimony of Brian C. Collins was inserted.)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY	)))))	**DOCKET NO. 20210015-EI**

Direct Testimony and Exhibits of

Brian C. Collins

On behalf of

Federal Executive Agencies

June 21, 2021

Brubaker & Associates, Inc.

Project 11121

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY	)))))	**DOCKET NO. 20210015-EI**

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Exhibit BCC-2: Summary of 2019 FPL System Lambda

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY	)))))	**DOCKET NO. 20210015-EI**

<u>Direct Testimony of Brian C. Collins</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

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

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

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

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing in this proceeding on behalf of the Federal Executive Agencies ("FEA").

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A My testimony addresses FPL's proposed class cost of service, class revenue allocation and rate design proposals.

Q DOES THE FACT THAT YOU DID NOT ADDRESS EVERY ISSUE RAISED IN FPL'S TESTIMONY MEAN THAT YOU AGREE WITH FPL'S TESTIMONY ON THOSE ISSUES?

A No. It merely reflects that I chose not to address all those issues in my testimony. It should not be read as an endorsement of, or agreement with, FPL's position on such issues.

I. INTRODUCTION AND SUMMARY

Q HOW IS YOUR TESTIMONY ORGANIZED?

A First, I present an overview of cost of service principles and concepts. This is followed by a discussion of the typical classification and allocation of distribution related costs. Next, I discuss the results of FPL's cost of service study implementing a Minimum Distribution System ("MDS") that takes into account cost-causation principles. This cost study indicates how individual customer class revenues compare to the costs incurred in providing distribution service to them. This discussion is then followed by recommendations with respect to the class revenue allocation and rate design.

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS AND CONCLUSIONS.

A My specific recommendations and conclusions are as follows:

1. Class cost of service is the starting point and most important guideline for establishing the level and design of rates charged to customers.

2. The primary purpose of the distribution system is to deliver power from the transmission grid to the customer. Certain distribution investments must be made to connect a customer to the system. Therefore, these investments are considered customer-related.

3. The consolidated Class Cost of Service Study ("CCOSS") with an MDS has been provided on an informational basis by FPL. However, this CCOSS best reflects cost causation on the Company's system. The classification and allocation of certain distribution plant accounts in FPL's CCOSS have been modified to classify a portion of those costs as customer-related consistent with the recognition of an MDS.

4. The results of the CCOSS with an MDS, which takes into account actual cost utilization principles, should be used to allocate any distribution revenue increase in this proceeding as well as the design of distribution rates.

5. With respect to Class Revenue Allocation, I recommend that revenues be allocated to classes under FEA's proposed class allocation shown on Exhibit BCC-1. This revenue allocation is guided by FPL's CCOSS with an MDS.

6. With respect to Rate Design, I recommend that FPL should retain the existing Gulf Power ("GP") Real-Time Pricing ("RTP") rate for customers and expand it to be offered for customers in the combined FPL and GP systems.

II. COST OF SERVICE OVERVIEW

Q WHAT INFORMATION IS CONTAINED IN A CCOSS?

A A CCOSS compares the cost that each customer class imposes on the system to the revenues each class contributes. This relationship is generally presented by comparing the rate of return that a class is providing with the utility's overall jurisdictional rate of return.

For example, when a customer class produces the same rate of return as the total jurisdictional utility rate of return, the customer class is paying revenue to the utility just sufficient to cover the costs that the utility incurs to serve that class. If a class produces a below-average rate of return, it may be concluded that the revenue provided by the class is insufficient to cover all relevant costs to serve that class. On the other hand, if a class produces a rate of return above the system average, it is not only paying revenues sufficient to cover the cost attributable to it, but in addition, it is paying part of the cost attributable to other classes who produce below system average rates of return.

Q WHY IS A CCOSS OF IMPORTANCE?

A A CCOSS shows the costs that a utility incurs to serve each customer class. It is a widely held principle that costs should be allocated among customer classes on the basis of cost causation. That principle is perhaps the most universally accepted principle of allocating cost that cannot be directly assigned to a particular customer class. The costs should be allocated to those classes on the basis of cost causation. The results of such studies are used in assigning cost responsibilities to various customer classes in regulatory proceedings.

Q DO YOU SUPPORT THAT PREMISE?

A Yes. Rates that are based on consistently applied cost-causation principles are not only fair and reasonable, but further the cause of stability, conservation and efficiency. When consumers are presented with price signals that convey the consequences of their consumption decisions, i.e., how much energy to consume, at what rate, and when, they tend to take actions which not only minimize their own costs, but those of the utility as well.

Although factors such as simplicity, gradualism, economic development and ease of administration may also be taken into consideration when determining the final spread of the revenue requirement among classes, the fundamental starting point and guideline should be the cost of serving each customer class produced by the CCOSS.

Q HOW IS THE COST OF SERVING EACH CUSTOMER CLASS DETERMINED?

A The appropriate mechanism to determine the cost of serving each customer class is a fully allocated embedded CCOSS. It follows, however, that the objective of cost-based rates cannot be attained unless the CCOSS is developed using cost-causation principles.

Q WHAT ARE THE MAJOR STEPS IN A CCOSS?

A The first step in a CCOSS is known as <u>functionalization</u>. This simply refers to the process by which the utility's investments and expenses are reviewed and put into different categories of cost. The primary functions utilized are production, transmission and distribution. Of course, each broad function may have several subcategories to provide for a more refined determination of cost of service.

The second major step is known as <u>classification</u>. In the classification step, the functionalized costs are separated into the categories of demand-related, energy-related, and customer-related costs in order to facilitate the allocation of costs applying the cost-causation principles.

Demand or capacity-related costs are those costs that are incurred by the utility to serve the amount of demand that each customer class places on the system. A traditional example of capacity-related costs is the investment associated with generating stations, transmission lines, and a portion of the distribution system. Once the utility makes an investment in these facilities, the costs continue to be incurred, irrespective of the number of kilowatthours generated and sold or the number of customers taking service from the utility.

Energy-related costs are those costs that are incurred by the utility to provide the energy required by its customers. Thus, the fuel expense is almost directly proportional to the amount of kilowatthours supplied by the utility system to meet its customers' energy requirements.

Customer-related costs are those costs that are incurred to connect customers to the system and are independent of the customer's demand and energy requirements. Primary examples of customer-related costs are investments in meters, services, and the portion of the distribution system that is necessary to connect customers to the system. In addition, such accounting functions as meter reading, bill preparation, and revenue accounting are considered customer-related costs.

The final step in the CCOSS is the allocation of each category of the functionalized and classified costs to the various customer classes using the cost-causation principles. Demand-related costs are allocated on the basis that gives recognition to each class's responsibility for the Company's need to build plant to serve demands imposed on the system. Energy-related costs are allocated on the basis of energy use by each customer class. Customer-related costs are allocated based upon the number of customers in each class, weighted to account for the complexity of servicing the needs of the different classes of customers.

III. COST OF SERVICE AND REVENUE ALLOCATION/RATE DESIGN PRINCIPLES

Q WHY IS IT IMPORTANT TO ADHERE TO COST OF SERVICE PRINCIPLES IN THE REVENUE ALLOCATION/RATE DESIGN PROCESS?

A The basic reasons for using cost of service as the primary factor in the revenue allocation/rate design process are equity, cost causation, appropriate price signals, conservation and revenue stability.

Q HOW IS THE EQUITY PRINCIPLE ACHIEVED BY BASING RATES ON COSTS?

A To the extent practical, when rates are based on cost, each customer pays what it costs the utility to serve the customer, no more and no less. If rates are not based on cost of service, then some customers contribute disproportionately to the utility's revenue requirement and provide contributions to the cost to serve other customers. This is inherently inequitable.

Q HOW DO COST-BASED RATES PROVIDE APPROPRIATE PRICE SIGNALS TO CUSTOMERS?

A Rate design is the step that follows the allocation of costs to classes, so it is important that the proper amounts and types of costs be allocated to the customer classes so that they may ultimately be reflected in the rates.

When the rates are designed so that the energy costs, demand costs, and customer costs are properly reflected in the energy, demand and customer components of the rate schedules, respectively, customers are provided with the proper incentives to manage their loads appropriately. This, in turn, provides the correct signal to the utility (and other competitive power suppliers) about the need for new investment. When customers impose a certain level of demand on the system, they should pay for the prudent cost that the utility incurs to supply that demand and the energy charge that they pay should reflect the cost of providing that energy.

Q HOW DO COST-BASED RATES FURTHER THE GOAL OF CONSERVATION?

A Conservation occurs when wasteful or inefficient uses of electricity are discouraged or minimized. Only when rates are based on actual costs do customers receive an accurate and appropriate price signal against which to make their consumption decisions. If rates are not based on costs, then customers may be induced to use electricity inefficiently in response to the distorted price signals.

Q PLEASE DISCUSS THE REVENUE STABILITY CONSIDERATION.

A When rates are closely tied to costs, the impact on the utility's earnings due to changes in customer use patterns will be minimized. Rates that are designed to track changes in the level of costs result in revenue changes that mirror cost changes. Thus, cost-based rates provide an important enhancement to a utility's earnings stability, reducing its need to file for rate increases.

From the perspective of the customer, cost-based rates provide a more reliable means of determining future levels of power costs. If rates are based on factors other than the cost to serve, it becomes much more difficult for customers to translate expected utility-wide cost changes, such as expected increases in overall revenue requirements, into changes in the rates charged to particular customer classes and to customers within the class. This situation reduces the attractiveness of expansion, as well as continued operations, in the utility's service territory because of the limited ability to plan and budget for future power cost.

IV. FPL'S CLASS COST OF SERVICE STUDY

Q HAVE YOU REVIEWED THE CONSOLIDATED CCOSS FILED BY FPL THAT UTILIZES AN MDS IN THIS PROCEEDING?

A Yes. In its CCOSS with an MDS, FPL has partially classified and allocated costs on a customer basis for the following Distribution Plant Accounts: 364 (Poles, Towers and Fixtures); 365 (Overhead Conductors and Devices); 366 (Underground Conduit);

367 (Underground Conductors and Devices); and 368 (Line Transformers). The results of FPL's CCOSS with an MDS are shown on Exhibit BCC-1.

Q SHOULD THE CCOSS WITH AN MDS BE USED FOR THE BASIS OF THE CLASS REVENUE ALLOCATION ?

A Yes. Because FPL's CCOSS with an MDS better reflects class cost causation, I recommend that it be used to guide class revenue allocation.

Q WHY SHOULD THE COSTS ASSOCIATED WITH DISTRIBUTION PLANT ACCOUNTS 364 THROUGH 368 BE CLASSIFIED AND ALLOCATED ON BOTH A DEMAND AND CUSTOMER BASIS AS OPPOSED TO JUST A DEMAND BASIS AS PERFORMED IN FPL'S CCOSS WITHOUT AN MDS?

A Classifying and allocating the costs associated with Distribution Plant Accounts 364 through 368 entirely on a demand basis is inconsistent with cost causation and generally accepted costing methodology. The primary purpose of the distribution system is to deliver power from the transmission grid to the customer in various geographical locations with service at different voltage levels. Certain distribution investments must be made just to connect a customer to the system. Also, many equipment manufacturers have only minimum sized equipment available. Safety concerns and construction practices often require minimum sized equipment which is not determined by demand. These investments are properly considered to be customer-related.

Q IS THIS A NEW COST OF SERVICE CONCEPT?

A No. The concept is known as the Minimum Distribution System ("MDS"), and has been accepted for decades as a valid consideration by numerous state public utility commissions. It has also been presented in the National Association of Regulatory Utility Commissioners' Electrical Utility Cost Allocation Manual ("NARUC Manual") and the Gas Distribution Rate Design Manual published by NARUC.

The central idea behind the MDS concept is that there is a minimum cost incurred by any utility when it extends its primary and secondary distribution systems and connects an additional customer to them. By definition, the MDS comprises every distribution component necessary to provide service, i.e., meters, services, secondary and primary wires, poles, substations, etc. The cost of the MDS, however, is only that portion of the total distribution cost the utility must incur to provide service to customers. It does not include costs specifically incurred to meet the peak demand of the customers.

Q PLEASE ELABORATE FURTHER ON THE MDS CONCEPT AND THE DISTINCTION BETWEEN CUSTOMER-RELATED COSTS AND DEMAND-RELATED COSTS IN THE CONTEXT OF A CCOSS.

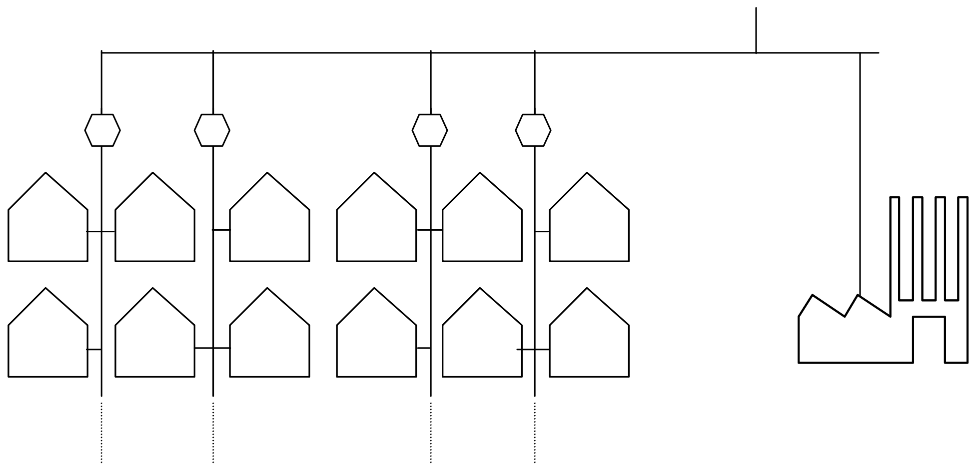
A A certain portion of the cost of the distribution system associated with poles, wires and transformers is required just to attach customers to the system in different geographical locations, regardless of their demand or energy requirements. This minimum or "skeleton" distribution system may also be considered as customer-related cost because it depends primarily on the number of customers, rather than on demand or energy usage.

Figure 1, as an example, shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach Class A is designed to serve 12 customers, each with a 10-kilowatt ("kW") load, having a total demand of 120 kW. This is the same total demand as is imposed by Class B, which consists of a single customer. Clearly, a much more extensive distribution system is required to attach the multitude of small customers (Class A), than to attach the single larger customer (Class B), despite the fact that the total demand of each customer class is the same.

Even though some additional customers can be attached without additional investment in some areas of the system, it is obvious that attaching a large number of customers in different geographical locations requires investment in facilities, not only initially but on a continuing basis as a result of the need for maintenance and repair. Thus, a large part of the distribution system is classified as customer-related in order to recognize this area coverage requirement.

Figure 1

Classification of Distribution Investment



Total Demand = 120 kW
Class A

Total Demand = 120 kW
Class B

Q IN ADDITION TO THE AREA COVERAGE FACTOR YOU NOTED ABOVE, ARE THERE OTHER REASONS FOR CLASSIFYING PART OF THE DISTRIBUTION SYSTEM AS CUSTOMER-RELATED?

A Yes, there are. Safety and reliability are the best examples of these. A properly conducted CCOSS must consider all cost-causing factors.

Q PLEASE EXPLAIN.

A When distribution engineers design the enhancement, upgrade, or extension of an electric system, they must be constantly aware of the operating parameters of the system. It is in the construction of the distribution system, however, that the *true* *cause* of many distribution costs is clearly seen. Surprisingly, that cause is frequently *not* demand.

An illustration helps make this point clear. Consider a customer who intends to build a home on a new lot, one that does not already have electrical service. This customer is cost and energy conscious and, thus, chooses to employ as many energy efficiency and conservation techniques and appliances as the customer can. After considerable research and consultation with experts, the customer calls the utility and advises that service will be required capable of providing a maximum peak demand of 2,000 watts (2 kW).

During the installation of the primary and secondary distribution extension to the customer's home, the customer notices that the linemen are using conductors, poles, cross-arms, and components identical to those serving the much larger, and less efficient, houses down the street. After more investigation, the customer learns that the distribution extension to the home is capable of carrying far greater demand than the home was designed to use. When the customer informs the utility of this "error," the utility explains that because of reliability and safety concerns it cannot install wires smaller than a certain size or hang them below a certain height. In short, there are specified minimum standards that the utility must meet that are wholly unrelated to the new home's reduced demand.

This illustration demonstrates that, although utilities design and install distribution equipment to satisfy their customers' need for electricity, there are factors other than electrical demand that force them to incur costs. Safety and reliability are as critical to every phase of design and construction as demand. Further, many equipment manufacturers have only minimum sized equipment available for installation. As one reviews the cost of the distribution system nearest the customer (i.e., that portion from the primary radial lines through the line transformers and secondary system), the cost incurred to comply with safety and reliability standards, as well as minimum sized equipment available, begins to outweigh the cost of meeting electrical demand.

Q CAN YOU CITE ANY AUTHORITATIVE PUBLICATIONS THAT SUPPORT ALLOCATING PART OR ALL OF DISTRIBUTION PLANT ACCOUNTS 364 THROUGH 368 ON THE BASIS OF A CUSTOMER COMPONENT?

A Yes. In 1992, NARUC published the NARUC Manual which states:

> Distribution Plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system. As shown in Table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities. (NARUC Manual, page 90)

Table 6-1 from the NARUC Manual is included as Figure 2. It shows that Distribution Plant Accounts 364 through 368, which include conductors, support structures and line transformers, have both a demand component and a customer component.

Figure 2

TABLE 6-1

CLASSIFICATION OF DISTRIBUTION PLANT[1]

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

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

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

Q HAVE UTILITY COMMISSIONS ADOPTED ALLOCATION METHODS FOR CLASSIFYING AND ALLOCATING A PORTION OF DISTRIBUTION PLANT AS CUSTOMER-RELATED?

A Yes. For example, the Connecticut, Colorado, Hawaii, Indiana, Kansas, Maine, Missouri, New York, North Carolina, Oregon, Pennsylvania, Texas and Wisconsin commissions have classified a portion of distribution plant on a customer- and demand-related basis for cost of service purposes.

Q HAS ANY UTILITY COMMISSION STAFF OPINED ON THE CLASSIFICATION AND ALLOCATION OF A PORTION OF DISTRIBUTION PLANT AS CUSTOMER-RELATED USING A MINIMUM SYSTEM METHODOLOGY?

A Yes. The Public Staff of the North Carolina Utilities Commission stated the following in a recent report from March 2019:

> After our review, the Public Staff believe that the use of MSM [Minimum System Methodology] by electric utilities for the purpose of classifying and allocating distribution costs is reasonable for establishing the maximum amount to be recovered in the fixed or basic customer charge.[1]

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE CLASSIFICATION AND ALLOCATION OF DISTRIBUTION PLANT COSTS ASSOCIATED WITH ACCOUNTS 364 THROUGH 368?

A I recommend that the Commission use the results of FPL'S CCOSS with an MDS that classifies and allocates a portion of distribution plant costs associated with Accounts 364 through 368 on a customer basis. This approach is consistent with general ratemaking policy objectives, such as customer equity, conservation and revenue stability. The CCOSS with a MDS should be used as a guideline in revenue allocation and rate design in this proceeding.

[1]Report of the Public Staff on the Minimum System Methodology of North Carolina Electric Public Utilities, Docket No. E-100, Sub 162, March 28, 2019, pp. 16-17.

V. CLASS REVENUE ALLOCATION

Q HAS FPL ALLOCATED ITS REQUESTED LEVEL OF DISTRIBUTION INCREASE TO CLASSES IN THIS CASE RECOGNIZING THE RESULTS OF ITS CCOSS WITHOUT AN MDS?

A Yes. I have summarized FPL's proposed class revenue allocation using this study on Exhibit BCC-1.

Q HAVE YOU DEVELOPED A RECOMMENDED SPREAD OF THE INCREASE TO CLASSES, ASSUMING FULL REVENUE RELIEF FOR THE COMPANY, AND USING THE FPL CCOSS WITH MDS?

A Yes. Because the FPL CCOSS with MDS better reflects class cost causation, I recommend the CCOSS with an MDS be used as a guide for class revenue allocation.

Q HAVE YOU PREPARED AN ALTERNATIVE CLASS REVENUE ALLOCATION?

A Yes. FEA's proposed alternative class revenue allocation is also shown on Exhibit BCC-1. Under my class revenue allocation, classes have been limited to an increase no greater than 1.65 times the system average increase of 14.4%. I have also held classes at current rates when the CCOSS indicates those classes should receive a rate decrease.

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO CLASS REVENUE ALLOCATION?

A I recommend that the Commission set rates using FEA's proposed class revenue allocation shown on Exhibit BCC-1. This exhibit assumes the full revenue increase requested by FPL for class revenue allocation. To the extent the Commission approves a revenue requirement that differs from FPL's request, FEA's proposed class revenue allocation would be adjusted.

VI. RATE DESIGN

Q DOES GULF POWER ("GP") CURRENTLY OFFER AN RTP RATE TO ITS CUSTOMERS?

A Yes, it does. Under the current GP tariff, the RTP hourly energy prices are derived using the day ahead projection of Southern System Lambda adjusted to recognize embedded costs.

Q DOES FPL CURRENTLY OFFER AN RTP RATE TO ITS CUSTOMERS?

A No, it does not.

Q PLEASE DESCRIBE RTP TARIFFS IN GENERAL.

A During periods of high electricity use by customers that have the potential to strain a utility's grid, the incentive for electricity customers to conserve energy is reduced when those customers pay a fixed price per kilowatt hour of electricity. Under an RTP tariff, the tariff reflects the cost of electricity that varies throughout the day. As a result, a utility charges customers different prices for electricity through the day typically based on fluctuating wholesale costs. Customers charged according to RTP typically consume less electricity in response to higher prices, primarily due to lower electricity consumption during peak times on the utility's system.

Q DOES FPL PROPOSE TO ELIMINATE THE GP RTP TARIFF?

A Yes, it does. According to the testimony of FPL witness Tiffany C. Cohen at page 38, she indicates that FPL plans to close the RTP rate to new customers and eliminate the rate schedule in the next base rate proceeding.

Q HOW DO YOU RESPOND TO FPL'S PROPOSAL TO ELIMINATE THE RTP RATE?

A The GP RTP rate should not be eliminated until a comparable RTP rate is established for FPL. RTP tariffs offer customers the ability to make energy asset investments or modify operations to alter hourly demands based on the price signals produced in an RTP rate. GP's customers that take service on its RTP rate stand to lose the conservation benefits of these load modifications if the RTP rate is eliminated before FPL develops and offers a comparable RTP rate.

The RTP tariff is another tool available to customers to manage their power costs and consumption during peak periods on the utility's system, provides price incentives to pursue economic renewable and green power investments that reduce carbon emissions and encourage enhanced utilization of the utility's infrastructure investments (e.g., improve load factor). These conservation/clean energy efforts by GP customers benefit both utility customers and the utility.

Q DOES FEA CURRENTLY TAKE SERVICE UNDER THE GP RTP RATE?

A Yes, it does. FEA has considerable load that takes service under the current RTP rate.

Q HAS FPL INDICATED TO FEA WHICH FPL RATE WOULD BE OPTIMAL FOR THE FEA ACCOUNTS CURRENTLY TAKING SERVICE UNDER THE RTP TARIFF?

A No, it has not. This makes it difficult for FEA to forecast its projected electricity costs as well as plan investments for its military installations.

Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE EXISTING GP RTP RATE?

A I recommend that FPL retain the GP RTP rate and investigate expanding the RTP rate into the combined footprint of GP and FPL.

Q DO YOU HAVE SOME COMMENTS ON HOW FPL SHOULD REVISE ITS RATES TO REFLECT REAL-TIME COST DIFFERENTIALS?

A Yes. FPL should either develop a separate RTP rate for eligible customers that reflect real-time cost differentials, or it could possibly add an RTP option to an existing tariff rate that reflects FPL's real-time cost differentials.

Q DOES FPL's SYSTEM LAMBDA VARY BY SEASON AS WELL AS DURING FPL'S TARIFF DEFINED ON-PEAK AND OFF-PEAK PERIODS?

A Yes. I have examined FPL's FERC Form 714 Lambda data. This data is shown in Exhibit BCC-2.

As shown in the exhibit, FPL's system lambda does vary by season and by time period. As a result, an RTP tariff could likely be developed that would provide all eligible customers in the combined GP and FPL footprint a tool to assist them in making investments and/or modifying operations to alter hourly demands based on the price signals produced in an RTP rate tariff.

An FPL RTP tariff rate would provide the opportunity for all eligible customers in the combined GP and FPL footprint to help manage their power costs and consumption during peak periods on the utility's system and provide price incentives for all such customers to pursue economic renewable and green power investments that reduce carbon emissions and encourage enhanced utilization of the utility's infrastructure investments.

Q DO YOU HAVE ANY OTHER RECOMMENDATIONS WITH RESPECT TO AN RTP TARIFF RATE FOR FPL?

A I recommend a workshop be held between the Company and its customers in order to explore an FPL RTP tariff rate option prior to FPL's next rate case.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Brian C. Collins

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

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

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

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A I graduated from Southern Illinois University Carbondale with a Bachelor of Science degree in Electrical Engineering. I also graduated from the University of Illinois at Springfield with a Master of Business Administration degree. Prior to joining BAI, I was employed by the Illinois Commerce Commission and City Water Light & Power ("CWLP") in Springfield, Illinois.

My responsibilities at the Illinois Commerce Commission included the review of the prudence of utilities' fuel costs in fuel adjustment reconciliation cases before the Commission as well as the review of utilities' requests for certificates of public convenience and necessity for new electric transmission lines. My responsibilities at CWLP included generation and transmission system planning. While at CWLP, I completed several thermal and voltage studies in support of CWLP's operating and planning decisions. I also performed duties for CWLP's Operations Department, including calculating CWLP's monthly cost of production. I also determined CWLP's allocation of wholesale purchased power costs to retail and wholesale customers for use in the monthly fuel adjustment.

In June 2001, I joined BAI as a Consultant. Since that time, I have participated in the analysis of various utility rate and other matters in several states and before the Federal Energy Regulatory Commission ("FERC"). I have filed or presented testimony before the Arkansas Public Service Commission, the California Public Utilities Commission, the Delaware Public Service Commission, the Public Service Commission of the District of Columbia, the Florida Public Service Commission, the Georgia Public Service Commission, the Idaho Public Utilities Commission, the Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Kentucky Public Service Commission, the Public Utilities Board of Manitoba, the Minnesota Public Utilities Commission, the Mississippi Public Service Commission, the Missouri Public Service Commission, the Montana Public Service Commission, the North Dakota Public Service Commission, the Public Utilities Commission of Ohio, the Oregon Public Utility Commission, the Rhode Island Public Utilities Commission, the Public Service Commission of Utah, the Virginia State Corporation Commission, the Public Service Commission of Wisconsin, the Washington Utilities and Transportation Commission, and the Wyoming Public Service Commission. I have also assisted in the analysis of transmission line routes proposed in certificate of convenience and necessity proceedings before the Public Utility Commission of Texas.

In 2009, I completed the University of Wisconsin – Madison High Voltage Direct Current ("HVDC") Transmission Course for Planners that was sponsored by the Midwest Independent Transmission System Operator, Inc. ("MISO").

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

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

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

IN RE: PETITION FOR RATE INCREASE BY FLORIDA POWER & LIGHT COMPANY	)))))	**DOCKET NO. 20210015-EI**

STATE OF MISSOURI	)	
	)	**SS**
COUNTY OF ST. LOUIS	)	

Affidavit of Brian C. Collins

Brian C. Collins, being first duly sworn, on his oath states:

1. My name is Brian C. Collins. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by the Federal Executive Agencies in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes are my direct testimony and exhibits which were prepared in written form for introduction into evidence in the Florida Public Service Commission Docket No. 20210015-EI.

3. I hereby swear and affirm that the testimony and exhibits are true and correct and that they show the matters and things that they purport to show.

Brian C. Collins

Brian C. Collins

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

SALLY D. WILHELMS
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis County
My Commission Expires: Aug. 5, 2024
Commission # 20078050

Sally D Wilhelms

Notary Public

(Transcript continues in sequence in Volume 8.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 21st day of September, 2021.

Debbie R Krick

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH31926
EXPIRES AUGUST 13, 2024