BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20240025-EI

Petition for rate increase
by Duke Energy Florida.
___________________________/

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PROCEEDINGS: HEARING

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

DATE: Wednesday, August 21, 2024

TIME: Commenced: 11:00 a.m.
Concluded: 1:30 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.)

PREMIER REPORTING
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I N D E X

P R O C E E D I N G S

(Transcript follows in sequence from Volume 2.)

(Whereupon, prefiled direct testimony of Adrian M. McKenzie was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase, by Duke Energy Florida, LLC	**Docket No. 20240025-EI Submitted: April 2, 2014**

DIRECT TESTIMONY

OF

ADRIEN M. MCKENZIE, CFA

ON BEHALF

OF

DUKE ENERGY FLORIDA, LLC

C14-1338

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EXHIBITS TO DIRECT TESTIMONY

GLOSSARY

CAPM	Capital Asset Pricing Model
CPI	Consumer Price Index
DCF	Discounted Cash Flow
DPS	Dividends Per Share
DEF or the Company	Duke Energy Florida, LLC
Duke Energy	Duke Energy Corporation
ECAPM	Empirical Capital Asset Pricing Model
EPS	Earnings Per Share
FERC	Federal Energy Regulatory Commission
FINCAP, Inc.	Financial Concepts and Applications, Inc.
Fitch	Fitch Ratings, Inc.
FOMC	Federal Open Market Committee
FPL	Florida Power & Light Company
FPSC	Florida Public Service Commission
GWh	Gigawatt-hour
Moody's	Moody's Investors Service
NYSE	New York Stock Exchange
PCE	Personal Consumption Expenditures
ROE	Return On Equity
RRA	S&P Global Market Intelligence, RRA Regulatory Focus
S&P	S&P Global Ratings
Value Line	The Value Line Investment Survey
Zacks	Zacks Investment Research

I. Introduction

Q. Please state your name and business address.

A. Adrien M. McKenzie, 3907 Red River, Austin, Texas, 78751.

Q. In what capacity are you employed?

A. I am President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

Q. Please describe your qualifications and experience.

A. A description of my background and qualifications, including a resume containing the details of my experience, is attached as Exhibit AMM-1.

Q. For whom are you testifying in this case?

A. I am testifying on behalf of Duke Energy Florida ("DEF").

A. Overview

Q. What is the purpose of your direct testimony in this case?

A. The purpose of my Direct Testimony is to present to the FPSC my independent assessment of the just and reasonable ROE for the jurisdictional electric utility operations of DEF. In addition, I also examine the reasonableness of DEF's common equity ratio, considering both the specific risks faced by the Company and other industry guidelines.

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Q. Please summarize the information and materials you rely on to support the opinions and conclusions contained in your testimony.

A. To prepare my testimony, I use information from a variety of sources that would normally be relied upon by a person in my capacity. In connection with the present filing, I consider and rely upon discussions with corporate management, publicly available financial reports, and prior regulatory filings relating to DEF. I also review information relating generally to current capital market conditions and specifically to investor perceptions, requirements, and expectations for DEF's electric utility operations. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of the issues relevant to investors' required return for DEF, and they form the basis of my analyses and conclusions.

Q. How is your testimony organized?

A. I first briefly review DEF's operations and finances. I then explain the development of the proxy group of electric utilities used as the basis for my quantitative analyses. Next, I examine current conditions in the capital markets and their implications in evaluating a just and reasonable return for the Company. With this as a background, I discuss well-accepted quantitative analyses to estimate the current cost of equity for the proxy group of electric utilities. These include the DCF model, the CAPM, the ECAPM, an equity risk premium approach based on allowed equity returns, and reference to expected earned rates of return for electric utilities, which are all methods that are commonly

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relied on in regulatory proceedings.

Based on the results of my analyses, I determine a just and reasonable cost of equity for DEF. My evaluation considers the specific risks for the Company's electric operations in Florida and DEF's requirements for financial strength. Further, consistent with the fact that utilities must compete for capital with firms outside their own industry, I corroborate my utility quantitative analyses by applying the DCF model to a group of low-risk non-utility firms.

B. Summary and Conclusions

Q. What is your recommended ROE for DEF?

A. I apply the DCF, CAPM, ECAPM, risk premium, and expected earnings analyses to a proxy group of electric utilities, with the results being summarized on Exhibit AMM-2. As shown there, based on the results of my analysis, I recommend a cost of equity range for the Company's electric operations of 10.4% to 11.4%, or 10.5% to 11.5% after adjusting for the impact of common equity flotation costs. Considering the risks and exposures specific to DEF, it is my conclusion that an ROE of 11.15% represents a just and reasonable cost of equity that is adequate to compensate the Company's investors, while maintaining the Company's financial integrity and ability to attract capital on reasonable terms.

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Q. Do fundamental financial principles and capital market trends justify an increase to DEF's authorized ROE?

A. Yes. Because investors evaluate investments against available alternatives, the cost of equity and the cost of long-term debt are inextricably linked. As my testimony documents, long-term bond yields climbed dramatically beginning in 2022 and investors anticipate that these increases will be sustained. This provides direct evidence that DEF's cost of equity has also risen significantly. The fact that the 30-year Treasury yield specified as an ROE benchmark in the 2021 Settlement Agreement has almost doubled since the conclusion of the Company's last rate proceeding further supports this conclusion.

II. Return on equity for DEF

Q. What is the purpose of this section?

A. This section presents an overview of the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital under reasonable terms and presents my conclusions regarding the just and reasonable ROE applicable to DEF's utility operations. Finally, I discuss the reasonableness of the Company's capital structure.

A. Importance of Financial Strength

Q. What is the role of the ROE in setting a utility's rates?

A. The ROE is the cost of attracting and retaining common equity investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. Moreover, a just and reasonable ROE is integral in meeting sound regulatory economics and the standards set forth by the U.S. Supreme Court. The Bluefield case set the standard against which just and reasonable rates are measured:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. . . . The return should be reasonable, 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 money necessary for the proper discharge of its public duties.[1]

The *Hope* case expanded on the guidelines as to a reasonable ROE, reemphasizing the findings in *Bluefield* and establishing that the rate-setting process must produce an end-result that allows the utility a reasonable opportunity to cover its capital costs. The Supreme Court stated:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock . . . . By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain credit and attract capital.[2]

[1] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).

[2] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

In summary, the Supreme Court's findings in *Hope* and *Bluefield* established that a just and reasonable ROE must be sufficient to 1) fairly compensate the utility's investors, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity. These standards should allow the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system replacement and expansion, but the Supreme Court's requirements can only be met if the utility has a reasonable opportunity to actually earn its allowed ROE.

The *Hope* and *Bluefield* decisions did not establish a particular method to be followed in fixing rates (or in determining the allowed ROE).[3] Rather, these and subsequent cases enshrined the importance of an end-result that meets the opportunity cost standard of finance. Under this doctrine, the required return is established by investors in the capital markets based on expected returns available from comparable risk investments. Coupled with modern financial theory, which has led to the development of formal risk-return models (e.g., DCF and CAPM), practical application of the *Bluefield* and *Hope* standards involves the independent, case-by-case consideration of capital market data in order to evaluate an ROE that will produce a balanced and fair end result for investors and customers.

[3] *Id.* at 602 (finding, "the Commission was not bound to the use of any single formula or combination of formulae in determining rates." and, "[I]t is not theory but the impact of the rate order which counts.").

Q. Throughout your testimony you refer repeatedly to the concepts of "financial strength," "financial integrity," and "financial flexibility." Would you briefly describe what you mean by these terms?

A. These terms are generally synonymous and refer to the utility's ability to attract and retain the capital that is necessary to provide service at reasonable cost, consistent with the Supreme Court standards. DEF's plans call for a continuation of capital investments to preserve and enhance service reliability for its customers. The Company must generate adequate cash flow from operations to fund these requirements and for repayment of maturing debt, together with access to capital from external sources under reasonable terms, on a sustainable basis.

Rating agencies and potential debt investors tend to place significant emphasis on maintaining strong financial metrics and credit ratings that support access to debt capital markets under reasonable terms. This emphasis on financial metrics and credit ratings is shared by equity investors who also focus on cash flows, capital structure and liquidity, much like debt investors. Investors understand the important role that a supportive regulatory environment plays in establishing a sound financial profile that will permit the utility access to debt and equity capital markets on reasonable terms in both favorable financial markets and during times of potential disruption and crisis.

Q. What part does regulation play in ensuring that DEF has access to capital under reasonable terms and on a sustainable basis?

A. Regulatory signals are a major driver of investors' risk assessment for utilities. Investors

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recognize that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity. Security analysts study commission orders and regulatory policy statements to advise investors about where to put their money. Moody's noted that, "An overarching consideration for regulated utilities is the regulatory environment in which they operate," and concluded that "the regulatory environment and how the utility adapts to that environment are the most important credit considerations."[4] Similarly, S&P observed that, "Regulatory advantage is the most heavily weighted factor when S&P Global Ratings analyzes a regulated utility's business risk profile."[5] Value Line summarizes these sentiments:

> As we often point out, the most important factor in any utility's success, whether it provides electricity, gas, or water, is the regulatory climate in which it operates. Harsh regulatory conditions can make it nearly impossible for the best run utilities to earn a reasonable return on their investment.[6]

In addition, the ROE set by regulators impacts investor confidence in not only the jurisdictional utility, but also in the ultimate parent company that is the entity that actually issues common stock.

Q. Do customers benefit by enhancing the utility's financial flexibility?

A. Yes. Providing an ROE that is sufficient to maintain the Company's ability to attract capital under reasonable terms, even in times of financial and market stress, is consistent

[4] Moody's Investors Service, *Regulated Electric and Gas Utilities*, Rating Methodology (Jun. 23, 2017).

[5] S&P Global Ratings, *Assessing U.S. Investors-Owned Utility Regulatory Environments*, RatingsExpress (Aug. 10, 2016).

[6] Value Line Investment Survey, *Water Utility Industry* (Jan. 13, 2017) at p. 1780.

with the economic requirements embodied in the U.S. Supreme Court's *Hope* and *Bluefield* decisions, as well as customers' best interests. Customers enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure safe and reliable service.

B. Conclusions and Recommendations

Q. What are your findings regarding the just and reasonable ROE for DEF?

A. Considering the economic requirements necessary to support continuous access to capital under reasonable terms and the results of my analysis, I recommend a 11.15% ROE for DEF's electric utility operations, which is consistent with the case-specific evidence presented in my testimony. The bases for my conclusion are summarized below:

- In order to reflect the risks and prospects associated with DEF's utility business, I predicate my analysis on a proxy group of ten electric utilities of comparable risk.
- Because investors' required return on equity is unobservable and no single method should be viewed in isolation, I apply the DCF, CAPM, ECAPM, and risk premium methods to estimate a just and reasonable ROE for DEF, as well as referencing the expected earnings approach.
- Based on the results of these analyses and giving less weight to extremes at the high and low ends of the range, I conclude that the cost of equity for a regulated electric utility is in the 10.4% to 11.4% range.
- My evaluation of a fair ROE also incorporates an upward adjustment of 10 basis points to account for flotation costs, which are a legitimate cost incurred to raise equity capital supporting DEF's investment in utility infrastructure.
- Incorporating this flotation cost adjustment results in my recommended ROE range of 10.5% to 11.5%.

Q. What other evidence do you consider in evaluating a fair ROE for DEF?

A. My conclusion that an ROE of 11.15% is fair and reasonable and should be approved is reinforced by the need to consider the following exposures faced by investors:

- The Company's service area is located in a storm-prone region, which implies a higher risk operating environment and exposes DEF to the additional financial pressures associated with repairing the damage caused by catastrophic weather events.
- DEF is in the midst of a major capital expenditure program to meet customer demand, implement clean energy plans, and increase resiliency against future storm events. As Company witness Karl Newlin discusses, DEF will require significant investor-supplied capital to meet these goals, which heightens the need for supportive regulatory actions.
- DEF must have sufficient financial strength to meet these challenges effectively. Continued support for DEF's financial integrity, including the opportunity to earn a reasonable ROE, is imperative to ensure that the Company has the capability to buttress its credit standing while funding the major investment in utility infrastructure that is necessary to meet the needs of its customers and confront the ongoing risks posed by catastrophic weather events.

Taken together, these findings support an ROE above the midpoint of my 10.5% to 11.5% range and indicate that an 11.15% ROE for DEF is fair and reasonable.

Q. What other evidence supports the reasonableness of your recommended 11.15% ROE for DEF?

A. In December 2021, the FPSC approved a settlement agreement that established an ROE for FPL of 10.6%, with a range of 9.7% to 11.7%.[7] The settlement agreement also provided that if the yield on 30-year Treasury bonds was 2.49% or higher over any consecutive six-month period, the authorized ROE would increase to 10.8%, with a range of 9.8% to 11.8%.[8] The average 30-year Treasury yield reached 2.91% on August 19, 2022,[9] and FPL's ROE was increased to 10.8% effective as of September 1, 2022.[10] As of December, 31, 2023, the six-month average 30-year Treasury bond yield was 4.41%, or a further 150 basis points above the threshold required to justify a 20 basis point increase to FPL's ROE. Under the logic of FPL's settlement, where a 50 basis point increase in the 30-year Treasury bond yield equates to a 20 basis point increase in the cost of equity, this implies a current ROE on the order of 11.4%.[11] Considering that DEF's credit ratings are indicative of greater investment risk than FPL,[12] this reinforces the reasonableness of an 11.15% for the Company.

[7] Florida Public Service Commission, Order No. PSC-2021-0446-S-EI (Dec. 2, 2021) at 4. The Stipulation and Settlement Agreement approved by the FPSC also specifies that the ROE range and midpoint shall increase by 20 basis points if the six-month average yield on 30-year Treasury bonds is at least 50 basis points higher than the yield on the date the Stipulation and Settlement Agreement is filed with the FPSC.

[8] The six-month average yield on 30-year Treasury bonds reached 2.65% in June 2022, was 4.47% during September 2023, or 198 basis points above the 2.49% benchmark referenced in the 2021 settlement agreement.

[9] Florida Public Service Commission, Docket No. 20210015-EI, *Supplement to and Exhibit in Support of Florida Power & Light Company's Notice of Triggering Revised Authorized Return on Equity* (Aug. 31, 2022).

[10] Florida Public Service Commission, Order No. PSC-2022-0358-FOF-EI (Oct. 21, 2022). The higher ROE does not result in a base rate increase but is applied for other regulatory purposes.

[11] (4.41% - 1.99%) = 2.42%. Assuming a 20 basis point increase for each full 50 basis point increment change in the 30-year Treasury yields equates to an 80 basis point increase to the 10.6% ROE established in the settlement.

[12] FPL is rated A1 by Moody's and A by S&P, versus DEF's ratings of BBB+ and A3.

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Q. Your testimony also presents DCF results for a select group of non-utility firms. Does this analysis support your conclusions?

A. Yes. Average DCF estimates for a low-risk group of firms in the competitive sector of the economy range from 10.5% to 10.9%. While I do not base my recommendations on these results, they support my conclusion that an ROE of 11.15% falls in a reasonable range to maintain DEF's financial integrity, provide a return commensurate with investments of comparable risk, and support the Company's ability to attract capital.

III. Fundamental Analyses

Q. What is the purpose of this section?

A. My objective is to evaluate and recommend a just and reasonable ROE for DEF. Much of my work is predicated on a comparison of DEF with the utility industry, and more specifically to a proxy group of publicly traded electric utilities. As a foundation for my opinions and subsequent quantitative analyses, this section briefly reviews the operations and finances of DEF. In addition, I explain the basis for the proxy group I used to estimate the cost of equity and examine alternative objective indicators of investment risk for these firms. I also compare the investment risks of DEF with my reference group and examine specific conditions impacting todays' capital markets. An understanding of the fundamental factors driving the risks and prospects of electric utilities is essential in developing an informed opinion of investors' expectations and requirements, which form the basis of a just and reasonable ROE.

A. <u>Duke Energy Florida, LLC</u>

Q. Briefly describe DEF and its utility operations.

A. DEF is a wholly-owned subsidiary of Progress Energy, Inc., which is ultimately owned by Duke Energy. The Company is principally engaged in the generation, transmission, and distribution of electric power to approximately 1.9 million retail customers across a 20,000-square-mile service area in Florida. During 2022, residential customers accounted for approximately 47% of DEF's total GWh sales, with general service, industrial, and wholesale and others making up 34%, 8%, and 11%, respectively. DEF owns generating facilities with a total capacity of roughly 10,500 MW, approximately 13.4% of which is coal-fired. The Company's transmission and distribution facilities consist of approximately 5,300 miles of transmission, 18,000 miles of overhead distribution lines, and 16,000 miles of underground distribution lines. At December 31, 2022, DEF had total assets of $25.6 billion, with total revenues amounting to approximately $6.4 billion during the 2022 fiscal year.

Q. Where does DEF obtain the capital used to finance its investment in utility plant?

A. DEF is a wholly owned operating subsidiary and obtains its equity capital solely from Duke Energy, whose common stock is publicly traded on the NYSE. DEF issues long-term debt in its own name and has been assigned issuer credit ratings of A3 by Moody's and BBB+ by S&P, as discussed further in the testimony of witness Newlin.

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Q. Does DEF anticipate the need for capital going forward?

A. Yes. The Company must undertake investments to provide necessary maintenance and replacements of its electric utility system as it continues to provide safe and reliable service to its customers. Capital spending has also been augmented in order to harden the system in light of frequent storm activity, and to meet the goals of a clean energy transition plan. DEF's Storm Protection Plan includes approximately $7 billion in capital investment over ten years beginning in 2023 meant to strengthen its infrastructure, reduce outage times associated with extreme weather events, reduce restoration costs, and improve overall service reliability. Moody's reported to investors that, "The company's 2023-2027 capital forecast totaling around $12 billion is approximately $2.6 billion higher than it spent over 2018-2022."[13] Similarly, S&P cited elevated capital spending "averaging about $2.5 billion annually" as a primary contributor to DEF's "significant" financial risk profile.[14] In addition, S&P reported that the Company will be faced with maturing debt obligations of ranging from $65 million to $867 million annually through 2027. Continued support for DEF's financial integrity and flexibility will be instrumental in attracting the capital necessary to fund capital projects and refinance long-term debt in an effective manner.

[13] Moody's Investors Service, *Duke Energy Florida, LLC.*, Credit Opinion (May 22, 2023).
[14] S&P Global Ratings, *Duke Energy Florida LLC*, Ratings Score Snapshot (Jun. 2, 2023).

B. Outlook for Capital Costs

Q. Please summarize current economic and capital market conditions.

A. U.S. real GDP contracted 2.2% during 2020, but with the easing of COVID-19 lockdowns, the economic outlook improved significantly in 2021, with GDP growing at a pace of 5.8%, though growth was more subdued in 2022 at 1.9%.[15] More recently, increases in spending by consumers and the federal government led real GDP to grow by 2.2%, 2.1%, and 4.9% in the first three quarters of 2023, respectively.[16] Meanwhile, indicators of employment remain stable, with the national unemployment rate remaining stable at 3.7% in December 2023.[17]

The underlying risk and price pressures associated with the COVID-19 pandemic were overshadowed by a dramatic increase in geopolitical risks following Russia's invasion of Ukraine in February 2022. These events have also been accompanied by heightened economic uncertainties as inflationary pressures due to COVID-19 supply chain disruptions were further stoked by sharp increases in global commodity prices. The substantial disruption in the energy economy and dramatic rise in inflation led to sharp declines in global equity markets as investors reacted to the related exposures.

Stimulative monetary and fiscal policies, coupled with supply-chain disruptions and rapid price rises in the energy and commodities markets, led to increasing concern that

[15] https://www.bea.gov/sites/default/files/2023-12/gdp3q23_3rd.pdf (last visited Jan. 9, 2024).
[16] *Id.*
[17] https://www.bls.gov/news.release/pdf/empsit.pdf (last visited Jan 9, 2024).

inflation would remain significantly above the Federal Reserve's longer-run benchmark of 2%. In June 2022, CPI inflation peaked at its highest level since November 1981. Since then, CPI inflation has gradually moderated to 3.1% in November 2023.[18] The so-called "core" price index, which excludes more volatile energy and food costs, rose at an annual rate of 4.0% in November 2023.[19] PCE inflation rose 2.6% in November 2023, or 3.2% after excluding more volatile food and energy costs.[20] As Federal Reserve Chair Jerome Powell has noted, "inflation is still too high, ongoing progress in bringing it down is not assured, and the path forward is uncertain."[21]

Investor confidence has also been tested by turmoil in the banking sector, which led to increased volatility in bond and equity markets. The Federal Reserve and U.S. Treasury took quick and dramatic action to shore up banks' liquidity needs and strengthen public confidence in the banking system, but as Moody's noted, "bank stress has added uncertainty to the outlook."[22] More recently, heightened geopolitical tensions in the Middle East have led to concerns over possible disruptions in crude oil supplies and attendant price volatility that could deliver another shock to the world economy.

[18] https://www.bls.gov/news.release/pdf/cpi.pdf (last visited Jan. 9, 2024).

[19] *Id.*

[20] https://www.bea.gov/news/2023/personal-income-and-outlays-november-2023 (last visited Jan. 9, 2024).

[21] Federal Reserve, *Transcript of Chair Powell's Press Conference* (Dec. 13, 2023), https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20231213.pdf.

[22] Moody's Investors Service, *Baseline US macro forecasts unchanged but outlook more uncertain*, Sector Comment (Apr. 12, 2023).

Q. How have these developments impacted the Federal Reserve's monetary policies?

A. Beginning in March 2022, the FOMC responded to concerns over accelerating inflation by steadily raising the benchmark range for the federal funds rate.[23] Chair Powell noted that, "[s]ince early last year, the FOMC has significantly tightened the stance of monetary policy. We have raised our policy interest rate by 5¼ percentage points and have continued to reduce our securities holdings at a brisk pace."[24] Chair Powell has surmised that the significant draw-down of its balance sheet holdings that began in June 2022 could be the equivalent of another one quarter percent rate hike over the course of a year.[25]

Q. What impact do inflation expectations have on the return that equity investors require from electric utilities, including DEF?

A. Implicit in the required rate of return for long-term capital—whether debt or common equity—is compensation for expected inflation. This is highlighted in the textbook, *Financial Management, Theory and Practice*:

> The four most fundamental factors affecting the cost of money are (1) production opportunities, (2) time preferences for consumption, (3) risk, and (4) inflation.[26]

[23] The FOMC is a committee composed of twelve members that serves as the monetary policymaking body of the Federal Reserve System.

[24] Federal Reserve, *Transcript of Chair Powell's Press Conference* (Dec. 13, 2023), https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20231213.pdf.

[25] Federal Reserve, *Transcript of Chair Powell's Press Conference* (May 4, 2022), https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20220504.pdf.

[26] Eugene F. Brigham, Louis C. Gapenski, and Michael C. Ehrhardt, *Financial Management, Theory and Practice*, Ninth Edition (1999) at 126.

In other words, a part of investor's required return is intended to compensate for the erosion of purchasing power due to rising price levels. This inflation premium is added to the real rate of return (pure risk-free rate plus risk premium) to determine the nominal required return. As a result, higher inflation expectations lead to an increase in the cost of equity capital.

Q. Have these developments impacted the risks faced by utilities and their investors?

A. Yes. S&P recently revised its outlook for the utility sector to "negative," noting that:

> Credit quality for North American investor-owned regulated utilities has weakened over the past four years, with downgrades outpacing upgrades by more than three times. We expect downgrades to again surpass upgrades in 2024 for the fifth consecutive year.[27]

S&P cited rising physical risks, as well as weakening financial measures due to rising capital spending and cash flow deficits and observed that "much of the industry operates with minimal financial cushion from their downgrade threshold."[28]

Meanwhile, Fitch Ratings, Inc. noted that its deteriorating outlook for utilities "reflects continuing macroeconomic headwinds and elevated capex that are putting pressure on credit metrics in the high-cost funding environment."[29] Value Line echoed these sentiments for electric utilities, concluding that:

[27] S&P Global Ratings, *Rising Risks: Outlook For North American Investor-Owned Regulated Utilities Weakens*, Comments (Feb. 14, 2024).

[28] *Id.*

[29] Fitch Ratings, Inc., *North American Utilities, Power & Gas Outlook 2024* (Dec. 6, 2023).

> **A Challenging Macroeconomic Backdrop Remains**
> Inflationary pressure, rising interest rates, and high energy and raw material prices will likely remain a significant burden for most utilities. Inflationary headwinds are raising operating and maintenance costs, as well as fuel prices. Meanwhile, the rising interest rate environment is leading income-oriented investors to the bond market, as well as increasing borrowing costs, which is especially significant for utilities as the usually have low returns on total capital and rely heavily on debt borrowings. We think many of these companies will continue to struggle with the higher costs related to the challenging macroeconomic climate in the near term.[30]

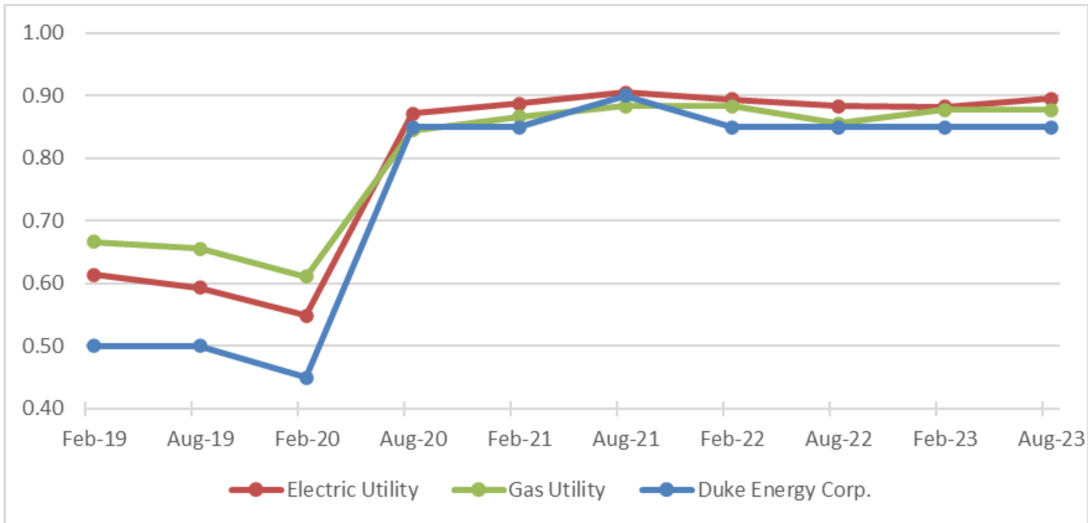
Q. Do changes in utility company beta values corroborate an increase in industry risk?

A. Yes. Beta measures a stock's price volatility relative to the overall market and reflects the tendency of a stock's price to follow changes in the market. The investment community relies on beta as an important guide to investors' risk perceptions. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. Generally, a higher beta means the market perceives the stock to be riskier than a stock with a lower beta.

The significant shift in pre- and post-pandemic beta values for utilities is illustrated in Figure 1 below. As illustrated there, the average beta value for the electric and gas utilities covered by Value Line increased significantly with the beginning of the pandemic in March 2020, continued to increase during 2021, and have remained elevated. This dramatic increase in a primary gauge of investors' risk perceptions is further proof of the higher risk of electric utility common stocks.

[30] The Value Line Investment Survey, *Electric Utility (Central) Industry* (Sep. 8, 2023) (emphasis original).

FIGURE 1
UTILITY BETA VALUES



Q. Do trends in bond yields also indicate that the cost of equity has increased?

A. Yes. While the cost of equity is unobservable, the yields on long-term bonds provide a widely referenced benchmark for the direction of capital costs, including required returns on common stocks. Table 1 below compares the average yields on Treasury securities and Baa-rated public utility bonds during December 2021 with those required in December 2023.

TABLE 1
BOND YIELD TRENDS

Series	Dec. 2023	Dec. 2021	Change (bps)
10-Year Treasury Bonds	4.02%	1.47%	255
30-Year Treasury Bonds	4.14%	1.85%	229
Baa Utility Bonds	5.68%	3.27%	241

Source: https://fred.stlouisfed.org/series/GS30; Moody's Credit Trends.

As shown above, trends in bond yields over the past two years document a substantial increase in the returns on long-term capital demanded by investors. With respect to utility bond yields—which are the most relevant indicator in gauging the implications for the Company's common equity investors—average yields in December 2023 exceed December 2021 levels by approximately 240 basis points.

Q. Have capital costs continued to increase relative to the benchmark established in the settlement agreement approved in DEF's last rate proceeding?

A. Yes. The 2021 Settlement Agreement specified an ROE range of 8.85% to 10.85%, with a midpoint of 9.85%.[31] Paragraph 2(b) of the agreement allowed for a one-time 25 basis point increase in the ROE range and midpoint if the six-month average yield on 30-year Treasury bonds were to exceed the yield on the date the FPSC approved the 2021 Settlement Agreement by 50 basis points or more. Subsequently, in October 2022 the FPSC granted DEF's request to increase its ROE to a midpoint of 10.10%.[32]

The benchmark yield on May 4, 2021, was 2.264%.[33] The six-month average yield on 30-year Treasury bonds at December 31, 2023 was 4.41%, or an increase of approximately 215 basis points. Under the rationale used to calculate the trigger provision of the 2021 Settlement Agreement, where the ROE increases by 50% of the

[31] Florida Public Service Commission, Docket No 20210016-EI, *Petition for Limited Proceeding to Approve 2021 Settlement Agreement, Including General Base Rate Increases* (Jan. 14, 2021).

[32] Florida Public Service Commission, Docket No. 20220143-EI, Order No. PSC-2022-0357-FOF-EI (Oct. 21, 2022).

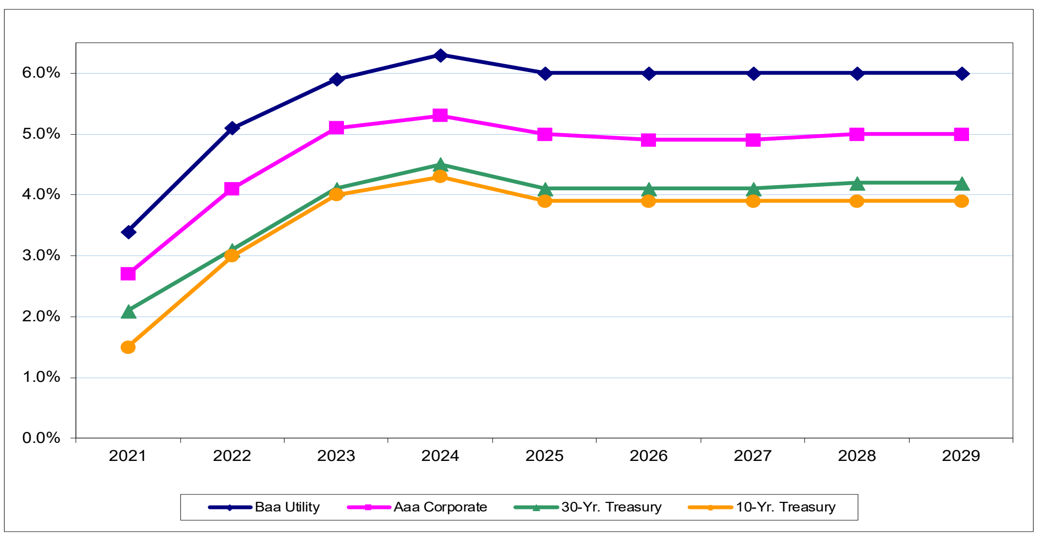
[33] *Id.*

rise in 30-year Treasury bond yields,[34] this implies a current ROE for DEF of 10.93%.[35] Although the 2021 Settlement Agreement does not set a precedent for how to calculate ROEs, there is an undeniable relationship between bond yield rates and ROEs.

Q. Do investors anticipate that these higher bond yields will be sustained?

A. Yes. As illustrated in Figure 2 below, the most recent long-term consensus projections from top economists published by Blue Chip document that long-term bond yields are expected to remain elevated when compared to recent historical levels.

FIGURE 2
PROJECTED INTEREST RATES



Source: Wolters Kluwer, Blue Chip Financial Forecasts (Dec. 1, 2023); Moody's Investors Service; https://fred.stlouisfed.org/.

[34] This relationship is consistent with the findings of empirical research. *See, e.g.,* Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 129 (noting that, "The gist of the empirical research on this subject is that the cost of equity has changed only half as much as interest rates have changed in the past.").

[35] 9.85% + (2.15% / 2) = 10.93%.

This evidence shows that long-term capital costs—including the ROE—have increased substantially, and that investors expect these higher capital costs to be sustained at least through 2029.

Q. Does the prospect for changes in monetary policy alter this conclusion?

A. No. At the conclusion of the FOMC's December 2023 meeting, Federal Reserve Chair Jerome Powell indicated that the participants anticipate that the appropriate level of the Federal funds rate will be 4.6% at the end of 2024, declining to 2.9% by the end of 2026.[36] This easing of monetary policy presumably reflects the FOMC's view that inflation will be sustainably reduced to its target level of 2%. But as Chair Powell has repeatedly noted, "[l]onger-term inflation expectations appear to remain well anchored."[37] In other words, expected inflation rates incorporated into long-term bond and equity costs did not approach the levels reached in recent months, and the impact of any moderation in the Federal Reserve's policy rate would be subdued. This is consistent with the forecasts of leading economists illustrated in Figure 2.

Moreover, while Chair Powell observed that the Federal Funds rate "is likely at or near its peak for this tightening cycle," he also stressed that "the economy has surprised forecasters in many ways" and reiterated that "ongoing progress toward our 2 percent

[36] Federal Reserve, *Transcript of Chair Powell's Press Conference* (Dec. 13, 2023). https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20231213.pdf.

[37] *Id. See also,* Federal Reserve, *Transcript of Chair Powell's Press Conference* (Dec. 14, 2022, Sep. 21, 2022). https://www.federalreserve.gov/monetarypolicy/fomccalendars.htm.

inflation objective is not assured."[38] Reuters reported that Federal Reserve Bank of New York President John Williams has concluded "it's still too soon to call for rate cuts as the central bank still has some distance to go in getting inflation back to its 2% target."[39] Meanwhile, consumer prices rose more than expected in December 2023, pushing the annual rate to 3.4%.[40] As Chair Powell concluded, "[w]e are prepared to tighten policy further if appropriate."[41]

Q, What are the implications of these factors in evaluating a fair ROE for DEF?

A. The upward move in interest rates suggests that long-term capital costs—including the cost of equity—have increased since the Settlement Agreement was approved in Docket No 20210016-EI. Exposure to rising interest rates, inflation, and capital expenditure requirements also reinforce the importance of buttressing DEF's credit standing. Considering the potential for financial market instability, competition with other investment alternatives, and investors' sensitivity to risk exposures in the utility industry, credit strength is a key ingredient in maintaining access to capital at reasonable cost.

[38] Federal Reserve, *Transcript of Chair Powell's Press Conference* (Dec. 13, 2023). https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20231213.pdf.

[39] Michael S. Derby, *Fed's Williams says more work needed to bring inflation back to target*, Reuters (Jan. 10, 2024). https://www.reuters.com/markets/us/feds-williams-says-more-work-needed-bring-inflation-back-target-2024-01-10/ (last visited Jan. 14, 2024).

[40] Jeff Cox, *Consumer prices rose 0.3% in December, higher than expected, pushing the annual rate to 3.4%*, CNBC (Jan. 11, 2024). https://www.cnbc.com/2024/01/11/cpi-inflation-report-december-2023-consumer-prices-rose-0point3percent-in-december-higher-than-expected-pushing-the-annual-rate-to-3point4percent.html (last visited Jan. 14, 2024).

[41] Federal Reserve, *Transcript of Chair Powell's Press Conference* (Dec. 13, 2023). https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20231213.pdf.

Q. Would it be reasonable to disregard the implications of current capital market conditions in evaluating a just and reasonable ROE for DEF?

A. No. Current capital market conditions reflect the reality of the situation in which DEF must attract and retain capital. The standards underlying a fair rate of return require an authorized ROE for the Company that is competitive with other investments of comparable risk and sufficient to preserve its ability to maintain access to capital on reasonable terms. These standards can only be met by considering the requirements of investors over the time period when the rates established in this proceeding will be in effect. If the upward shift in investors' risk perceptions and required rates of return for long-term capital is not incorporated in the allowed ROE, the results will fail to meet the comparable earnings standard that is fundamental in determining the cost of capital. From a more practical perspective, failing to provide investors with the opportunity to earn a rate of return commensurate with DEF's risks will weaken its financial integrity, while hampering the Company's ability to attract the capital necessary to provide safe and reliable service at the lowest reasonable cost.

IV. <u>Comparable Risk Proxy Group</u>

Q. What is the purpose of this section of your testimony?

A. This section explains the basis of the proxy group of publicly traded companies I use to estimate the cost of equity, examines alternative objective indicators of investment risk for these firms, and compares the investment risks applicable to DEF with my reference group.

A. Determination of the Proxy Group

Q. How do you implement quantitative methods to estimate the cost of common equity for DEF?

A. Application of quantitative methods to estimate the cost of common equity requires observable capital market data, such as stock prices and beta values. Even for a firm with publicly traded stock, the cost of common equity can only be estimated. As a result, applying quantitative models using observable market data only produces an estimate that inherently includes some degree of observation error. The accepted approach to increase confidence in the results is to apply quantitative methods to a proxy group of publicly traded companies that investors regard as risk comparable. The results of the analysis on the sample of companies are relied upon to establish a range of reasonableness for the cost of equity for the specific company at issue.

Q. How do you identify the proxy group of electric utilities relied on for your analyses?

A. To reflect the risks and prospects associated with DEF's jurisdictional electric operations, I began with the following criteria to identify a proxy group of utilities:

1. Included in the Electric Utility Industry groups compiled by Value Line.[42]
2. Paid common dividends over the last six months and have not announced a dividend cut since that time.

[42] In addition to the companies included in Value Line's electric utility industry groups, I also considered Algonquin Power & Utilities Company and Emera, Inc., which would both be regarded as comparable utility investment opportunities by investors. Neither of these companies met my required screening criteria.

3. No ongoing involvement in a major merger or acquisition that would distort quantitative results.

In addition, my analysis also considered credit ratings from Moody's and S&P in evaluating relative risk. Specifically, I excluded any companies with ratings more than one "notch" higher or lower than DEF's issuer credit ratings of A3 (Moody's) and BBB+ (S&P). These criteria result in a proxy group composed of ten companies, which I refer to as the "Utility Group."

B. Relative Risks of the Utility Group and DEF

Q. Do you evaluate investors' risk perceptions for the utility group?

A. Yes. My evaluation of relative risk considers five objective, published benchmarks that are widely relied on by investors—credit ratings from Moody's and S&P, along with Value Line's Safety Rank, Financial Strength Rating, and beta values . Credit ratings are assigned by independent rating agencies for the purpose of providing investors with a broad assessment of the creditworthiness of a firm. Ratings generally extend from triple-A (the highest) to D (in default). Other symbols (*e.g.*, "+" or "-") are used to show relative standing within a category. Because the rating agencies' evaluation includes all of the factors considered important in assessing a firm's relative credit standing, corporate credit ratings provide a broad, objective measure of overall investment risk that is readily available to investors. Widely cited in the investment community and referenced by investors, credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of common equity.

While credit ratings provide the most widely referenced benchmark for investment risks, Value Line is one of the most widely available source of investment advisory information and its quality rankings provide an important and objective assessment of investors' risk perceptions for common stocks. Value Line's primary risk indicator is its Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is intended to capture the total risk of a stock and incorporates elements of stock price stability and financial strength. Meanwhile, the Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. These objective, published indicators incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to firm-specific factors.

Finally, beta measures a utility's stock price volatility relative to the market as a whole and reflects the tendency of a stock's price to follow changes in the market. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. Beta is the only relevant measure of investment risk under modern capital market theory and is widely cited in academics and in the investment industry as a guide to investors' risk perceptions. Moreover, in my experience Value Line is the most widely referenced source for beta in regulatory proceedings. As noted in *New Regulatory Finance*:

> Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors . . . . Value Line betas are computed on a theoretically sound basis using a broadly based market index, and they are adjusted for the regression tendency of betas to converge to 1.00.[43]

Q. How do the overall risks of your proxy group compare to DEF?

A. Exhibit AMM-3 compares the Utility Group to the Company across the four key indicia of investment risk discussed above. As shown there, risk measures corresponding to DEF fall within the range for the Utility Group. Considered together, a comparison of these objective measures, which incorporate a broad spectrum of risks, including financial and business position, regulatory recovery mechanisms, and exposure to company specific factors, indicates that investors would likely conclude that the overall investment risks for the firms in the Utility Group are comparable to DEF.

Q. Would investors consider the implications of regulatory mechanisms in evaluating a utility's relative risks?

A. Yes. Decoupling mechanisms, cost trackers, and future test years have been increasingly prevalent in the utility industry in recent years, along with alternatives to traditional ratemaking such as formula rates and multi-year rate plans. RRA concluded in its recent review of adjustment clauses that:

[43] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports (2006) at 71.

> More recently and with greater frequency, commissions have approved mechanisms that permit the costs associated with the construction of new generation or delivery infrastructure to be used, effectively including these items in rate base without the need for a full rate case. In some instances, these mechanisms may even provide the utilities a cash return on construction work in progress.
>
> . . . [C]ertain types of adjustment clauses are more prevalent than others. For example, those that address electric fuel and gas commodity charges are in place in all jurisdictions. Also, about two-thirds of all utilities have riders in place to recover costs related to energy efficiency programs, and roughly half of the utilities have some type of decoupling mechanism in place.[44]

As shown on Exhibit AMM-4, and reflective of this trend, the companies in my Utility Group operate under a wide variety of cost adjustment mechanisms. These encompass revenue decoupling and adjustment clauses designed to address rising capital investment outside of a traditional rate case, increasing costs of environmental compliance measures, as well as riders to address the costs of energy conservation programs, bad debt expenses, certain taxes and fees, post-retirement employee benefit costs and transmission-related charges.

Q. Have similar regulatory mechanisms been approved for DEF?

A. Yes. DEF operates under a multi-year rate plan and the FPSC has established riders related to investment in grid modernization and infrastructure hardening, as well as recovery of certain renewables and environmental compliance costs. Other provisions include establishment of a storm cost reserve, the ability to petition for storm cost

[44] S&P Global Market Intelligence, *Adjustment Clause: A state-by-state overview*, RRA Regulatory Focus (Jul. 18, 2022).

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recovery outside of a base rate case, regulatory asset treatment for storm costs, as well as surcharges related to energy efficiency programs.

Q. Do the regulatory mechanisms approved for DEF set it apart from other firms operating in the utility industry?

A. No. A broad array of adjustment mechanisms is also available to the companies in my proxy group of electric utilities. As documented on Exhibit AMM-4, the majority of firms included in the Electric Group operate under revenue decoupling and in states that allow formula rates or multi-year rate plans for utilities under their jurisdiction.

Thus, while investors would consider DEF's regulatory mechanisms to be supportive of the Company's financial integrity, this does not provide a basis to distinguish the risks of DEF from the Utility Group.

Q. In evaluating a fair ROE, is it appropriate to consider specific risk exposures faced by DEF?

A. Yes. Unlike the majority of firms in the electric utility industry, DEF must regularly contend with the consequences of destructive weather events, most notably, damaging hurricanes. Moody's recently noted that the Company's service territory "is prone to hurricanes . . . the frequency and intensity of which appear to be increasing."[45] Moody's added that, despite supportive regulatory provisions, "Hurricanes have negatively

[45] Moody's Investors Service, *Duke Energy Florida, LLC.*, Credit Opinion (May 22, 2023).

affected Duke Energy Florida's historical credit metrics." Similarly, S&P cited weather as a "key risk" for the Company and pointed out that DEF's service territory "is prone to severe weather events that could disrupt its operations and result in higher costs."[46]

In 2022, for example, storm activity was severe. In addition to feeling the effects of Hurricane Nicole, DEF's service territory was impacted by heavy rainfall, strong winds, and life-threatening storm surge and flooding associated with Hurricane Ian, which was the fifth strongest hurricane on record. Hurricane Ian caused significant damage to the Company's utility system and resulted in more than 1.1 million outages, with DEF incurring storm restoration costs exceeding $380 million. Over the five years ended 2023, DEF's storm costs totaled approximately $741 million.

Q. How does DEF's exposure to the risks of catastrophic storms compare to other Florida utilities, such as FPL?

A. Because the Company's customer base is less concentrated, the impact of hurricanes is magnified for DEF. A review of total incurred storm costs for the years 2016 through 2023 indicates that on a per customer basis, DEF's restoration costs exceeded those of FPL by over 20%. In other words, the nature of the Company's service territory means that storms have an outsized effect.

[46] S&P Global Ratings, *Duke Energy Florida LLC*, Ratings Score Snapshot (Jun. 2, 2023).

Q. Is weather exposure for utilities such as DEF intensifying?

A. Yes. As Moody's recently noted in their review of the utility sector:

> [O]ver the next 10 to 20 years, the risk of severe weather events, such as hurricanes and wildfires, will likely worsen in certain US regions, according to data from Moody's ESG Solutions. Meanwhile, the coastal regions in the Southeast and along the Gulf of Mexico are at the greatest risk of severe hurricanes. Stronger hurricanes, fueled by climate change, pose an ever-greater threat to coastal states' electric grids.[47]

S&P also recently noted that, "Physical risks such as exposure to wildfires, storms, extreme temperature events, and hurricanes, remains a considerable risk for the industry, and concluded that 'over the past three years the U.S. experienced its highest level of damages ever from physical risks.'"[48] As S&P summarized with respect to weather-related risk:

> Not only do the frequency of these disasters appear to be increasing, but their costs are rising. The natural disasters that have occurred over the past decade have wiped out billions of dollars of assets over a relatively short period. Without the appropriate regulatory compact and other risk mitigation, the financial aftermath of these events could be devastating to any individual utility, adding another layer of unpredictability that utilities must effectively manage.[49]

Q. Do these weather-related risks have implications for DEF's financial position?

A. Yes. It is imperative that DEF possess sufficient financial strength so that it can respond effectively to the challenges that this attribute of its business profile may present, as

[47] Moody's Investors Service, *As extreme weather events and net-zero efforts rise, ABS will lower utility credit risk*, Sector In-Depth (Nov. 9, 2022).

[48] S&P Global Ratings, *The Outlook For North American Regulated Utilities Turns Stable*, RatingsDirect (May 18, 2023).

[49] S&P Global Ratings, *Can U.S. Utilities Weather The Storm?*, Comments (Nov. 8, 2018).

described in the direct testimony of Company witness Karl Newlin. These unpredictable events can lead to damages in the hundreds of millions of dollars and require DEF to mount large scale and costly recovery efforts. As a result, DEF must maintain ready access to larger reserves of credit and liquidity than most other utilities and be able to marshal both internal and external resources on a massive scale very quickly. This this leads to an extraordinary need for credit and liquidity.

While the FPSC's regulatory provisions relating to prudently incurred storm costs are generally viewed as supportive,[50] restoration efforts must be funded long before the recovery of prudently incurred costs can be expected. Investors remain exposed to loss of revenues and other impacts during adverse weather conditions, including sometimes prolonged flooding, and restoration periods. This is a risk that is unmitigated by any mechanism for storm cost recovery. As S&P recently noted:

> Without the appropriate regulatory compact and other risk mitigation, the financial aftermath of these events could be devastating to any individual utility, adding another layer of unpredictability that utilities must effectively manage.[51]

DEF nonetheless must continue to maintain the financial strength and liquidity necessary to affect a rapid and far-reaching response in the likely event of a future hurricane strike, as well as upgrading grid infrastructure to mitigate against storm damage. S&P highlighted the associated challenges:

[50] As noted earlier, the FPSC mitigates the impact of storm-related costs through rider recovery and reserve accounts. DEF also benefits from a recovery clause that allows for recovery of new storm hardening investments.

[51] S&P Global Ratings, *Can U.S. Utilities Weather The Storm?* (Nov. 8, 2018).

> Building resilience requires massive investments, both via operating costs and capital investments, with repayment often delayed by several years or decades. The pressure from these expenditures is already contributing to credit deterioration in the sector, and some management teams may find it difficult to achieve all of their priorities while maintaining credit quality. The long design lifetimes, fixed locations, and designs informed by historic weather events, serves only to increase the vulnerability of utilities' assets and the pace and scale of investment required.[52]

S&P noted that, "In Florida, the susceptibility to multiple hurricanes in the same hurricane season can place abnormal strains on liquidity and financial performance."[53]

As Moody's pointed out with respect to electric utilities in Florida, "[a]s we expect extreme weather events to be more severe and more frequent with climate change, credit supportive regulation remains critical going forward."[54]

Q. Has the FPSC recognized that exposure to extreme weather events is a distinguishing factor that should be considered in evaluating relative risk and a fair ROE?

A. Yes. In its recent supplemental final order in Docket No. 20210015-EI, the FPSC explicitly acknowledged that operating an electric utility in a storm prone region entails risks that are not faced by the preponderance of other utilities. As the FPSC concluded with respect to FPL:

[52] S&P Global Ratings, *Keeping The Lights On: U.S. Utilities' Exposure To Physical Climate Risks*, RatingsDirect (Sep. 16, 2021).

[53] S&P Global Ratings, *Can U.S. Utilities Weather The Storm?* (Nov. 8, 2018).

[54] Moody's Investors Service, *Florida Power & Light Company*, Credit Opinion (Aug. 23, 2023).

> Regarding comparable risk, the preponderance of the evidence demonstrates that FPL's infrastructure risk profile is different from most utilities, including those in the various proxy groups. Especially with the acquisition of Gulf, FPL's service territory includes appreciable expanses of low-lying coastline that brings inherent risk. The preponderance of the evidence demonstrates that this risk is likely to continue to increase over time due to storm frequency and severity as well as sea-level rise.[55]

As discussed in the testimony of Company witness Brian Lloyd, DEF's service territory is characterized by the same weather-related risks and challenges associated with low-lying coastal areas, as well as greater potential for vegetation-based destruction.

Q. Do customers benefit by enhancing the utility's financial flexibility?

A. Yes. Given the high value that DEF and its customers place on service availability and reliability, safe and efficient restoration of service after a weather-induced outage is the Company's highest priority. A financially strong utility will be better prepared to deal with these situations when they inevitably arise, ultimately benefiting impacted customers.

By the same token, customers also bear a significant burden when the ability to attract capital for system enhancements and restoration is impaired and service quality is compromised. DEF's customers are predominantly residential and small businesses with few alternatives when power is interrupted and therefore are particularly dependent on the Company's reliability, which creates a particular need for financial resilience.

[55] Supplemental Final Order, Florida Public Service Commission, Docket No. 20210015-EI, Order No. PSC-2024-0078-FOF-EI at 14 (March 25, 2024).

Providing an ROE that is sufficient to compensate investors and maintain DEF's ability to attract capital, even under duress, is consistent with the economic requirements embodied in the Supreme Court's *Hope* and *Bluefield* decisions, but it is also in customers' best interests.

C. Capital Structure

Q. Is an evaluation of the capital structure maintained by a utility relevant in assessing its return on equity?

A. Yes. Other things being equal, a higher debt ratio and lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive their contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow that will remain.

Q. What common equity ratio is implicit in DEF's capital structure?

A. As discussed in the testimony of Company witness Karl Newlin, the common equity ratio applicable to the Company is 53.0%.

Q. How does this compare to the average equity ratios maintained by the utilities in the utility group?

A. As shown on page 1 of Exhibit AMM-5, common equity ratios for the individual firms in the Utility Group ranged between 40.9% and 65.5%. Meanwhile, the three-to-five-year forecasts published by Value Line result in common equity ratios ranging from 40.0% to 59.5% for the Utility Group.

Q. Are there other industry benchmarks that are more relevant in evaluating DEF's capital structure?

A. Yes. Because this proceeding focuses on the ROE for the regulated electric utility operations of DEF, the capital structures maintained by other operating electric utilities provide a direct guide to financing policies that are consistent with industry-specific risks and the need to maintain adequate borrowing capacity and financial flexibility.

Q. What capitalization ratios are maintained by comparable utility operating companies?

A. Page 2 of Exhibit AMM-5 display capital structure data for the most recent fiscal year-end for the group of electric utility operating companies owned by the firms in the Utility Group. As shown there, common equity ratios for these utilities ranged from 43.2% to 60.6% and averaged 53.8%. This benchmark provides a direct guide to financing policies that are consistent with industry-specific risks and the need to maintain adequate borrowing capacity and financial flexibility.

Q. Do ongoing economic and capital market uncertainties also influence the appropriate capital structure for DEF?

A. Yes. Financial flexibility plays a crucial role in ensuring the wherewithal to meet funding needs, and utilities with higher financial leverage may be foreclosed or have limited access to additional borrowing, especially during times of stress. As Moody's observed:

> Utilities are among the largest debt issuers in the corporate universe and typically require consistent access to capital markets to assure adequate sources of funding and to maintain financial flexibility. During times of distress and when capital markets are exceedingly volatile and tight, liquidity becomes critically important because access to capital markets may be difficult.[56]

More recently, Moody's emphasized that the utility sector "is likely to continue to generate negative free cash flow and credit quality is likely to suffer unless utilities fund this negative free cash flow appropriately with a balance of debt and equity financing."[57]

S&P confirmed the financial challenges associated with funding heightened investment in the utility sector, noting that, "[a]bout one-third of the industry is strategically managing their financial performance with only minimal financial cushion," and warning that "when unexpected risks occur or base-case assumptions deviate from expectations, the utility's credit quality can weaken."[58]

[56] Moody's Investors Service, *FAQ on credit implications of the coronavirus outbreak*, Sector Comment (Mar. 26, 2020).

[57] Moody's Investors Service, *Regulate Electric and Gas Utilities – US, Rising capital expenditures will require higher annual equity funding*, Sector In-Depth (Nov. 8, 2023).

[58] S&P Global Ratings, *The Outlook For North American Regulated Utilities Turns Stable* (May 18, 2023).

As a result, the Company's capital structure must maintain adequate equity to preserve the flexibility necessary to maintain continuous access to capital even during times of unfavorable energy or financial market conditions, such as those resulting from catastrophic hurricanes.

Q. What other factors do investors consider in their assessment of a company's capital structure?

A. Utilities, including DEF, are facing significant capital investment plans. Coupled with the potential for turmoil in capital markets, this warrants a stronger balance sheet to deal with an uncertain environment. As S&P noted:

> Under our base case, we expect that by 2024 the industry's capital spending will exceed $180 billion. Because of the industry's continued robust capital spending, we expect that industry will continue to generate negative discretionary cash flow. This requires that the industry has consistent access to the capital markets to finance capital spending and dividends requirements.[59]

More recently, S&P noted that, "[w]ithout a commensurate focus on balance sheet preservation through equity support of discretionary negative cash flow deficits, limited financial cushion could give rise to another round of negative rating actions."[60] Similarly, Moody's higher interest rates and the pressure of maintaining credit metrics

[59] S&P Global Ratings, *For The First Time Ever, The Median Investor-Owned Utility Ratings Falls To The 'BBB' Category*, RatingsDirect (Jan. 20, 2022).

[60] S&P Global Ratings, *Record CapEx Fuels Growth Along With Credit Risk For North American Investor-Owned Utilities*, Comments (Sep. 12, 2023).

while funding capital investments were leading to greater reliance on common equity.[61] Moody's concluded that the utility sector "is likely to continue to generate negative free cash flow and credit quality is likely to suffer unless utilities fund this negative free cash flow appropriately with a balance of debt and equity financing."[62]

Moody's has recognized that DEF's significant capital expenditures, coupled with the potential recurrence of severe storms, place downward pressure on its credit metrics.[63] In addition, the investment community also considers the impact of other considerations, such as leases, purchased power agreements, and postretirement benefit and asset retirement obligations in its evaluation of a utility's financial standing. A conservative financial profile, in the form of a reasonable common equity ratio, is consistent with the need to accommodate these uncertainties and maintain the continuous access to capital under reasonable terms that is required to fund operations and necessary system investment, even during times of adverse capital market conditions.

Q. What does this evidence suggest with respect to DEF's capital structure?

A. DEF's capital structure falls within the range of capital structure ratios maintained by the proxy group and is consistent with industry benchmarks for other electric utility operating companies. While industry averages provide one benchmark for comparison,

[61] Moody's Investors Service, *Regulated Electric and Gas Utilities – US; Rising capital expenditures will require higher annual equity funding*, Sector In-Depth (Nov. 8, 2023).

[62] *Id.*

[63] Moody's Investors Service, *Duke Energy Florida, LLC*, Credit Opinion (May 22, 2023).

each firm must select its capitalization based on the risks and prospects it faces, as well as its specific needs to access the capital markets. DEF's capital structure reflects the Company's ongoing efforts to maintain its credit standing and support access to capital on reasonable terms. The reasonableness of the Company's capital structure is reinforced by DEF's ongoing exposure to catastrophic storms, along with the importance of supporting the enormous system investment required to increase resilience and expand access to renewable generation. Based on this evidence, I conclude that the Company's ratemaking capital structure represents a reasonable mix of capital sources from which to calculate DEF's overall rate of return. Moreover, financial policies to enhance DEF's financial metrics and credit standing by reducing debt leverage would be consistent with the Company's specific risks and the need to ensure access to capital even during times of adverse industry or market conditions.

V. <u>Capital Market Estimates</u>

Q. What is the purpose of this section of your testimony?

A. This section presents capital market estimates of the cost of equity. First, I address the concept of the cost of common equity, along with the risk-return tradeoff principle fundamental to capital markets. I then describe various quantitative analyses conducted to estimate the cost of common equity for the Utility Group.

A. Economic Standards

Q. What fundamental economic principle underlies the cost of equity concept?

A. The fundamental economic principle underlying the cost of equity concept is the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (e.g., U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Because all assets compete for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to invest and hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can generally be expressed as:

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return, and

RP_i = Risk premium required to hold riskier asset i.

Thus, the required rate of return for a particular asset at any time is a function of: (1) the yield on risk-free assets, and (2) the asset's relative risk, with investors demanding correspondingly larger risk premiums for bearing greater risk.

Q. Is there evidence that the risk-return tradeoff principle operates in the capital markets?

A. Yes. The risk-return tradeoff can be readily documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. Comparing the observed yields on government securities, which are considered free of default risk, to the yields on bonds of various rating categories demonstrates that the risk-return tradeoff does, in fact, exist.

Q. Does the risk-return tradeoff observed with fixed income securities extend to common stocks and other assets?

A. It is widely accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets—including common stock—required rates of return cannot be observed. Yet there is every reason to believe that investors demonstrate risk aversion in deciding whether to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q. Is this risk-return tradeoff limited to differences between firms?

A. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility

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vary considerably in risk because they have different characteristics and priorities. As noted earlier, long-term debt is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky. The last investors in line are common shareholders: they receive only the net revenues, if any, remaining after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q. What are the challenges in determining a just and reasonable ROE for a regulated enterprise?

A. The actual return investors require is unobservable. Different methodologies have been developed to estimate investors' expected and required return on capital, but all such methodologies are merely theoretical tools and generally produce a range of estimates, based on different assumptions and inputs. The DCF method, which is frequently referenced and relied on by regulators, is only one theoretical approach to gain insight into the return investors require; there are numerous other methodologies for estimating the cost of capital and the ranges produced by the different approaches can vary widely.

Q. Is it customary to consider the results of multiple approaches when evaluating a just and reasonable ROE?

A. Yes. In my experience, financial analysts and regulators routinely consider the results of alternative approaches in determining allowed ROEs. It is widely recognized that no single method can be regarded as failsafe; with all approaches having advantages and shortcomings. As FERC has noted, "[t]he determination of rate of return on equity starts from the premise that there is no single approach or methodology for determining the correct rate of return."[64] More recently, FERC recognized the potential for any application of the DCF model to produce unreliable results.[65] Similarly, a publication of the Society of Utility and Regulatory Financial Analysts concluded that:

> Each model requires the exercise of judgment as to the reasonableness of the underlying assumptions of the methodology and on the reasonableness of the proxies used to validate the theory. Each model has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises, most of which cannot be validated empirically. Investors clearly do not subscribe to any singular method, nor does the stock price reflect the application of any one single method by investors.[66]

As this treatise succinctly observed, "no single model is so inherently precise that it can be relied on solely to the exclusion of other theoretically sound models."[67] Similarly, *New Regulatory Finance* concluded that:

[64] *Northwest Pipeline Co.*, Opinion No. 396-C, 81 FERC ¶ 61,036 at 4 (1997).

[65] *Coakley v. Bangor Hydro-Elec. Co.*, Opinion No. 531, 147 FERC ¶ 61,234 at P 41 (2014).

[66] David C. Parcell, *The Cost of Capital – A Practitioner's Guide*, Society of Utility and Regulatory Financial Analysts (2010) at 84.

[67] *Id.*

> There is no single model that conclusively determines or estimates the expected return for an individual firm. Each methodology possesses its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises that cannot be validated empirically. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor. There is no monopoly as to which method is used by investors. In the absence of any hard evidence as to which method outdoes the other, all relevant evidence should be used and weighted equally, in order to minimize judgmental error, measurement error, and conceptual infirmities.[68]

Thus, while the DCF model is a recognized approach to estimating the ROE, it is not without shortcomings and does not otherwise eliminate the need to ensure that the "end result" is fair. The Indiana Utility Regulatory Commission has recognized this principle:

> There are three principal reasons for our unwillingness to place a great deal of weight on the results of any DCF analysis. One is . . . the failure of the DCF model to conform to reality. The second is the undeniable fact that rarely if ever do two expert witnesses agree on the terms of a DCF equation for the same utility—for example, as we shall see in more detail below, projections of future dividend cash flow and anticipated price appreciation of the stock can vary widely. And, the third reason is that the unadjusted DCF result is almost always well below what any informed financial analysis would regard as defensible, and therefore require an upward adjustment based largely on the expert witness's judgment. In these circumstances, we find it difficult to regard the results of a DCF computation as any more than suggestive.[69]

Similarly, the FPSC has recognized the controversial nature of estimating a fair ROE and that sometimes the results of a model must be given little or no weight in a case,

[68] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 429.

[69] *Ind. Michigan Power Co.*, Cause No. 38728, 116 PUR4th, 1, 17-18 (IURC 8/24/1990).

even when the application of that model has been accepted to derive a fair ROE in other cases:

> While the legal and economic concepts of a fair rate of return are straight forward, the actual implementation of these concepts is controversial. Unlike the cost rate on debt that is fixed and easily measured due to its contractual terms, the return on equity is a forward-looking concept that must be estimated. Financial models have been developed to estimate the investor-required ROE for a company. Market-based approaches such as the Discounted Cash Flow (DCF) model, the Capital Asset Pricing Model (CAPM), and the ex ante Risk Premium (RP) model are generally recognized as being consistent with the standards for determining a fair rate of return as set forth in the Hope and Bluefield decisions…All three witnesses used variants of generally accepted financial models to derive their respective recommended ROE for Gulf. The dispute among the parties is not about the models themselves, but how the models are applied and the assumptions and inputs used in the models…All three witnesses testified that the results of their respective CAPM analyses underestimate a fair ROE for Gulf at this time, and therefore, recommend that we give little or no weight to their CAPM results…Based on the witnesses' testimony in this proceeding regarding the results obtained using the CAPM, in the interest of efficiency, we will not address the witnesses' arguments and testimony regarding the CAPM in this order. We want to be clear that it is not recommending rejecting the use of the CAPM as a generally accepted method to estimate the ROE, but in this case, the record supports assigning no weight to the witnesses' CAPM results for purposes of determining the appropriate ROE for Gulf.[70]

As this discussion indicates, consideration of the results of alternative approaches reduces the potential for error associated with any single quantitative method. Just as investors inform their decisions using a variety of methodologies, my evaluation of a fair ROE for the Company considered the results of multiple financial models.

[70] *In re: Petition for Increase in Rates by Gulf Power,* Docket No. 110138-EI, Order No. PSC-12-0179-FOF-EI at 84-88 (FPSC, 4/3/2012).

Q. Does the fact that DEF is a subsidiary of Duke Energy in any way alter these fundamental standards underlying a just and reasonable ROE?

A. No. While the Company has no publicly traded common stock and Duke Energy is DEF's only shareholder, this does not change the standards governing the determination of a just and reasonable ROE for the Company. Ultimately, the common equity that is required to support the utility operations of DEF must be raised in the capital markets, where investors consider the Company's ability to offer a rate of return that is competitive with other risk-comparable alternatives. DEF must compete with other investment opportunities and unless there is a reasonable expectation that investors will have the opportunity to earn returns commensurate with the underlying risks, capital will be allocated elsewhere, the Company's financial integrity will be weakened, and investors will demand an even higher rate of return. DEF's ability to offer a reasonable return on investment is a necessary ingredient in ensuring that customers continue to enjoy economical rates and reliable service.

Q. What does the above discussion imply with respect to estimating the ROE for a utility?

A. Although the ROE is unobservable, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is not readily observable, the ROE for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

B. <u>Discounted Cash Flow Analyses</u>

Q. How is the DCF model used to estimate the cost of common equity?

A. DCF models assume that the price of a share of common stock is equal to the present value of the expected cash flows (i.e., future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[71]

$$P_0 = \frac{D_1}{k_e - g}$$

where: P_0 = Current price per share;

D_1 = Expected dividend per share in the coming year;

k_e = Cost of equity; and,

g = Investors' long-term growth expectations.

The cost of common equity (k_e) can be isolated by rearranging terms within the equation:

[71] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve); and all the above extend to infinity. Nevertheless, the DCF method provides a workable and practical approach to estimate investors' required return that is widely referenced in utility ratemaking.

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$$k_e = \frac{D_1}{P_0} + g$$

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0); and 2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q. What steps are required to apply the constant growth DCF model?

A. The first step is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth expectations (g) for the firm. The final step is to add the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of common equity.

Q. How do you determine the dividend yields for the utility group?

A. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend was then divided by a 30-day average stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the Utility Group are presented on Exhibit AMM-6. As shown on the first page of this exhibit, dividend yields for the firms in the Utility Group ranged from 3.3% to 4.8% and averaged 4.0%.

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Q. What is the next step in applying the constant growth DCF model?

A. The next step is to evaluate long-term growth expectations, or "*g*," for the firm in question. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. A wide variety of techniques can be used to derive growth rates, but the only "*g*" that matters in applying the DCF model is the value that investors expect.

Q. What are investors most likely to consider in developing their long-term growth expectations?

A. Implementation of the DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of utilities, dividend growth rates are not likely to provide a meaningful guide to investors' current growth expectations. Utility dividend policies reflect the need to accommodate business risks and investment requirements in the industry, as well as potential uncertainties in the capital markets. As a result, dividend growth in the utility industry has lagged growth in earnings as utilities conserve financial resources.

A measure that plays a pivotal role in determining investors' long-term growth expectations is future trends in EPS, which provide the source for future dividends and ultimately support share prices. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in earnings is far more influential than trends in DPS.

The availability of projected EPS growth rates also is key to investors relying on this measure as compared to future trends in DPS. Apart from Value Line, investment advisory services do not generally publish comprehensive DPS growth projections, and this scarcity of dividend growth rates relative to the abundance of earnings forecasts attests to their relative influence. The fact that securities analysts focus on EPS growth, and that DPS growth rates are not routinely published, indicates that projected EPS growth rates are likely to provide a superior indicator of the future long-term growth expected by investors.

Q. What are security analysts currently projecting in the way of growth for the firms in the proxy group?

A. The EPS growth projections for each of the firms in the Utility Group reported by Value Line, IBES, and Zacks are displayed on page 2 of Exhibit AMM-6.

Q. How else are investors' expectations of future long-term growth prospects often estimated when applying the constant growth DCF model?

A. In constant growth theory, growth in book equity will be equal to the product of the earnings retention ratio (one minus the dividend payout ratio) and the earned rate of return on book equity. Furthermore, if the earned rate of return and the payout ratio are constant over time, growth in earnings and dividends will be equal to growth in book value. Even though these conditions are never met in practice, this "sustainable growth" approach may provide a rough guide for evaluating a firm's growth prospects and is frequently proposed in regulatory proceedings.

The sustainable growth rate is calculated by the formula, g = br+sv, where "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate. Under DCF theory, the "sv" factor is a component of the growth rate designed to capture the impact of issuing new common stock at a price above, or below, book value. The sustainable, "br+sv" growth rates for each firm in the proxy group are summarized on page 2 of Exhibit AMM-6, with the underlying details being presented on Exhibit AMM-7.

The sustainable growth rate analysis shown in Exhibit AMM-7 incorporates an "adjustment factor" because Value Line's reported returns are based on year-end book values. Since earnings is a flow over the year while book value is determined at a given point in time, the measurement of earnings and book value are distinct concepts. It is this fundamental difference between a flow (earnings) and point estimate (book value) that makes it necessary to adjust to mid-year in calculating the ROE. Given that book value will increase or decrease over the year, using year-end book value (as Value Line does) understates or overstates the average investment that corresponds to the flow of earnings. To address this concern, earnings must be matched with a corresponding representative measure of book value, or the resulting ROE will be distorted. The adjustment factor determined in Exhibit AMM-7, is solely a means of converting Value Line's end-of-period values to an average return over the year, and the formula for this adjustment is supported in recognized textbooks and has been adopted by other regulators.[72]

Q. Are there significant shortcomings associated with the "br+sv" growth rate?

A. Yes. First, in order to calculate the sustainable growth rate, it is necessary to develop estimates of investors' expectations for four separate variables; namely, "b," "r," "s," and "v." Given the inherent difficulty in forecasting each parameter and the difficulty of estimating the expectations of investors, the potential for measurement error is significantly increased when using four variables, as opposed to referencing a direct projection for EPS growth. Second, empirical research in the finance literature indicates that sustainable growth rates are not as significantly correlated to measures of value, such as share prices, as are analysts' EPS growth forecasts.[73] The "sustainable growth" approach is included for completeness, but evidence indicates that analysts' forecasts provide a superior and more direct guide to investors' growth expectations. Accordingly, I give less weight to cost of equity estimates based on br+sv growth rates in evaluating the results of the DCF model.

[72] *See,* Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 305-306; *Bangor Hydro-Electric Co. et al*., 122 FERC ¶ 61,265 at n.12 (2008).

[73] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 307.

Q. What cost of common equity estimates were implied for the utility group using the DCF model?

A. After combining the dividend yields and respective growth projections for each utility, the resulting cost of common equity estimates are shown on page 3 of Exhibit AMM-6.

Q. In evaluating the results of the constant growth DCF model, is it appropriate to eliminate illogical estimates?

A. Yes. When applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method.

Q. How do you evaluate DCF estimates at the low end of the range?

A. My evaluation of DCF estimates at the low end of the range is based on the fundamental risk-return tradeoff, which holds that investors will only take on more risk if they expect to earn a higher rate of return to compensate them for the greater uncertainly. Because common stocks lack the protections associated with an investment in long-term bonds, a utility's common stock imposes far greater risks on investors. As a result, the rate of return that investors require from a utility's common stock is considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, DCF results that are not sufficiently higher than the yield available on less risky utility bonds must be eliminated.

Q. Have similar tests been applied by other regulators?

A. Yes. FERC has noted that adjustments are justified where applications of the DCF approach and other methods produce illogical results. FERC evaluates low-end results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold.[74] FERC's current practice is to exclude low-end cost of estimates that fall below the six-month average yield on Baa-rated utility bonds, plus 20% of the CAPM market risk premium.[75] In addition, FERC also excludes estimates that are "irrationally or anomalously high."[76] Similarly, the Staff of the Maryland Public Service Commission has also eliminated DCF values where they do not offer a sufficient premium above the cost of debt to be attractive to an equity investor.[77]

Q. Do you exclude any estimates at the low or high end of the range of DCF results?

A. Yes. As highlighted on page 3 of Exhibit AMM-6, after considering these benchmarks and the distribution of individual estimates, I eliminate five low-end DCF estimates ranging from -7.6% to 7.4%. I also remove a value of 20.8% at the upper end of the range. After removing these illogical values, the lower end of the DCF results for the Utility Group is 8.2% and the upper end is established by a cost of equity estimate of 12.9%. While a 12.9% cost of equity estimate may exceed the other values, low-end

[74] *See, e.g.*, *Southern California Edison Co*., 131 FERC ¶ 61,020 at P 55 (2010).

[75] Based on the six-month average yield at December 2023 of 6.08% and the 7.3% market risk premium shown on Exhibit AMM-8, this implies a current low-end threshold of approximately 7.5%.

[76] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc*., 171 FERC ¶ 61,154 at P 152 (2020).

[77] See, *e.g.*, Maryland Public Service Commission, Case No. 9702, *Direct Testimony, and Exhibits of Anson R. Justi* (Dec. 15, 2023) at 33.

DCF estimates in the 8% range are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the results, the remaining values provide a reasonable basis on which to frame the range of plausible DCF estimates and evaluate investors' required rate of return.

Q. What ROE estimates are implied by your DCF results for the utility group?

A. As shown on page 3 of Exhibit AMM-6 and summarized in Table 2, application of the constant growth DCF model results in the following ROE estimates:

TABLE 2
DCF RESULTS – UTILITY GROUP

Growth Rate	Average	Midpoint
Value Line	10.6%	11.2%
IBES	10.2%	10.7%
Zacks	10.4%	10.5%
br + sv	9.3%	9.3%

C. Capital Asset Pricing Model

Q. Please describe the CAPM.

A. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are fully diversified, the relevant risk of an individual asset (e.g., common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a firm's stock price to follow changes in the market. A stock that tends to respond less to market movements has a beta of less than 1.0, while stocks that tend to move more than the market have betas greater than 1.0. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

where: R_j = required rate of return for stock j;

R_f = risk-free rate;

R_m = expected return on the market portfolio; and,

β_j = beta, or systematic risk, for stock j.

Under the CAPM formula above, a stock's required return is a function of the risk-free rate (R_f), plus a risk premium that is scaled to reflect the relative volatility of a firm's stock price, as measured by beta (β). Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q. Why is the CAPM relevant when evaluating the cost of equity for DEF?

A. The CAPM (which also forms the foundation of the ECAPM) generally is considered the most widely referenced method for estimating the cost of equity among academicians and professional practitioners, with the pioneering researchers of this method receiving the Nobel Prize in 1990. Because this is the dominant model for estimating the cost of equity outside the regulatory sphere, the CAPM (and ECAPM) provides important insight into investors' required rate of return for utility stocks, including the Company.

Q. How do you apply the CAPM to estimate the ROE?

A. Application of the CAPM to the proxy group is based on a forward-looking estimate for investors' required rate of return from common stocks presented in Exhibit AMM-8. To capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500.

The dividend yield for each firm is obtained from Value Line, and the growth rate is equal to the average of the earnings growth projections for each firm from IBES, Value Line, and Zacks, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. After removing growth rates that were negative or greater than 20%, the weighted average of the projections for the individual firms implies an average growth rate over the next five years of 9.7%. Combining this average growth rate with a year-ahead dividend yield of 2.0% results in a current cost of common equity estimate for the market as a whole (R_m) of 11.7%. Subtracting a 4.4% risk-free rate based on the average yield on 30-year Treasury bonds for the six month period ending December 2023 produced a market equity risk premium of 7.3%.

Q. What beta values do you use?

A. As indicated earlier in my discussion of risk measures for the proxy group, I relied on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings.

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Q. What else should be considered in applying the CAPM?

A. Financial research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size. Accordingly, a modification is required to account for this size effect. As explained by Morningstar:

> One of the most remarkable discoveries of modern finance is the finding of a relationship between firm size and return. On average, small companies have higher returns than large ones . . . . The relationship between firm size and return cuts across the entire size spectrum; it is not restricted to the smallest stocks.[78]

According to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, researchers have developed size premiums that need to be added to account for the level of a firm's market capitalization in determining the CAPM cost of equity.[79] Accordingly, my CAPM analyses also incorporated an adjustment to recognize the impact of size distinctions, as measured by the market capitalization for the firms in the Utility Group.

[78] Morningstar, *2015 Ibbotson SBBI Classic Yearbook*, at 99.

[79] Originally compiled by Ibbotson Associates and published in their annual yearbook entitled, *Stocks, Bonds, Bills and Inflation*, these size premia are now developed by Kroll and presented in its *Cost of Capital Navigator.*

Q. What is the basis for the size adjustment?

A. The size adjustment required in applying the CAPM is based on the finding that *after controlling for risk differences reflected in beta*, the CAPM overstates returns to companies with larger market capitalizations and understates returns for relatively smaller firms. The size adjustments utilized in my analysis are sourced from Kroll, who now publish the well-known compilation of capital market series originally developed by Professor Roger G. Ibbotson of the Yale School of Management, and most recently published by Kroll. Calculation of the size adjustments involve the following steps:

1. Divide all stocks traded on the NYSE, NYSE MKT, and NASDAQ indices into deciles based on their market capitalization.
2. Using the average beta value for each decile, calculate the implied excess return over the risk-free rate using the CAPM.
3. Compare the calculated excess returns based on the CAPM to the actual excess returns for each decile, with the difference being the increment of return that is related to firm size, or "size adjustment."

New Regulatory Finance observed that "small market-cap stocks experience higher returns than large market-cap stocks with equivalent betas," and concluded that "the CAPM understates the risk of smaller utilities, and a cost of equity based purely on a CAPM beta will therefore produce too low an estimate."[80] As FERC has recognized, "[t]his type of size adjustment is a generally accepted approach to CAPM analyses."[81]

[80] Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 187.

[81] Opinion No. 531-B at P 117.

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Q. Is this size adjustment related to the relative size of DEF as compared with the proxy group?

A. No. I am not proposing to apply a general size risk premium in evaluating a just and reasonable ROE for the Company and my recommendation does not include any adjustment related to the relative size of DEF. Rather, this size adjustment is specific to the CAPM and merely corrects for an observed inability of the beta measure to fully reflect the risks perceived by investors for the firms in the proxy group.

Q. What is the implied ROE for the utility group using the CAPM approach?

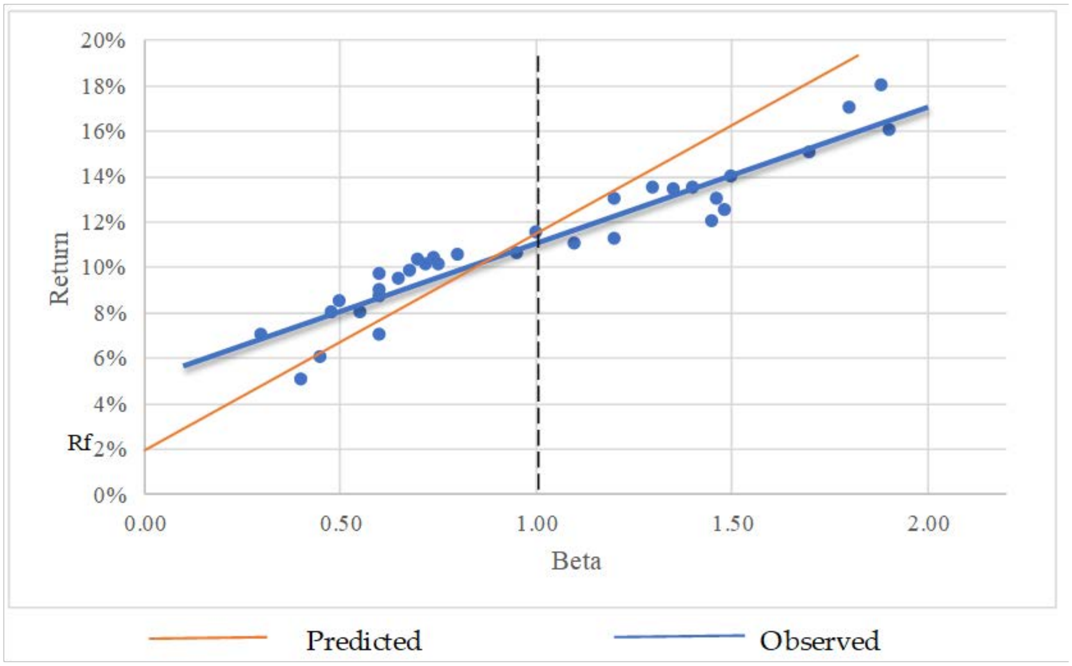
A. As shown on Exhibit AMM-8, after adjusting for the impact of firm size, the CAPM approach implies an average ROE for the Utility Group of 11.6%.

D. <u>Empirical Capital Asset Pricing Model</u>

Q. How does the ECAPM approach differ from traditional applications of the CAPM?

A. Empirical tests of the CAPM have shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta, with low-beta stocks tending to have higher returns and high-beta stocks tending to have lower risk returns than predicted by the CAPM. This is illustrated graphically in Figure 3:

FIGURE 3
CAPM – PREDICTED VS. OBSERVED RETURNS



Because the betas of utility stocks, including those in the proxy group, are generally less than 1.0, this implies that cost of equity estimates based on the traditional CAPM would understate the cost of equity. This empirical finding is widely reported in the finance literature, as summarized in *New Regulatory Finance*:

> As discussed in the previous section, several finance scholars have developed refined and expanded versions of the standard CAPM by relaxing the constraints imposed on the CAPM, such as dividend yield, size, and skewness effects. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the CAPM prediction in keeping with the actual observed risk-return relationship. The ECAPM makes use of these empirical relationships.[82]

[82] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports (2006) at 189.

As discussed in *New Regulatory Finance*, based on a review of the empirical evidence, the expected return on a security is related to its risk by the ECAPM, which is represented by the following formula:

$$R_j = R_f + 0.25(R_m - R_f) + 0.75[\beta_j(R_m - R_f)]$$

Like the CAPM formula presented earlier, the ECAPM represents a stock's required return as a function of the risk-free rate (R_f), plus a risk premium. In the formula above, this risk premium is composed of two parts: (1) the market risk premium (R_m - R_f) weighted by a factor of 25%, and (2) a company-specific risk premium based on the stock's relative volatility [$\beta_j(R_m - R_f)$] weighted by 75%. This ECAPM equation, and its associated weighting factors, recognizes the observed relationship between standard CAPM estimates and the cost of capital documented in the financial research, and corrects for the understated returns that would otherwise be produced for low beta stocks.

Q. Is the use of the ECAPM consistent with the use of value line betas?

A. Yes. Value Line beta values are adjusted for the observed tendency of beta to converge toward the mean value of 1.00 over time.[83] The purpose of this adjustment is to refine beta values determined using historical data to better match forward-looking estimates of beta, which are the relevant parameter in applying the CAPM or ECAPM models. Meanwhile, the ECAPM does not involve any adjustment to beta whatsoever. Rather, it

[83] *See, e.g.,* Marshall E. Blume, *Betas and Their Regression Tendencies*, Journal of Finance (Jun. 1975), pp. 785-95.

represents a formal recognition of findings in the financial literature that the observed risk-return tradeoff illustrated in Figure 3 is flatter than predicted by the CAPM. In other words, even if a firm's beta value were estimated with perfect precision, the CAPM would still understate the return for low-beta stocks and overstate the return for high-beta stocks. The ECAPM and the use of adjusted betas represent two separate and distinct issues in estimating returns.

Q. What cost of equity is indicated by the ECAPM?

A. My application of the ECAPM is based on the same forward-looking market rate of return, risk-free rates, and beta values discussed earlier in connections with the CAPM. As shown on Exhibit AMM-9, applying the forward-looking ECAPM approach to the firms in the Utility Group results in an average cost of equity estimate of 11.7%.

E. <u>Utility Risk Premium</u>

Q. Briefly describe the risk premium method.

A. The risk premium method extends the risk-return tradeoff observed with bonds to estimate investors' required rate of return on common stocks. The cost of equity is estimated by first determining the additional return investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and by then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields.

Q. Is the risk premium approach a widely accepted method for estimating the cost of equity?

A. Yes. The risk premium approach is based on the fundamental risk-return principle that is central to finance, which holds that investors will require a premium in the form of a higher return to assume additional risk. This method is routinely referenced by the investment community and in academia and regulatory proceedings and provides an important tool in estimating a just and reasonable ROE for DEF.

Q. How do you implement the risk premium method?

A. Estimates of equity risk premiums for utilities are based on surveys of previously authorized ROEs. Authorized ROEs presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final order. Such ROEs should represent a balanced and impartial outcome that considers the need to maintain a utility's financial integrity and ability to attract capital. Moreover, allowed returns are an important consideration for investors and have the potential to influence other observable investment parameters, including credit ratings and borrowing costs. Thus, when considered in the context of a complete and rigorous analysis, this data provides a logical and frequently referenced basis for estimating equity risk premiums for regulated utilities.

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Q. How do you calculate equity risk premiums based on allowed returns?

A. The ROEs authorized for electric utilities by regulatory commissions across the U.S. are compiled by S&P Global Market Intelligence and published in its *RRA Regulatory Focus* report. On page 2 of Exhibit AMM-10, the average yield on public utility bonds is subtracted from the average allowed ROE for electric utilities to calculate equity risk premiums for each year between 1974 and 2023.[84] As shown there, over this period these equity risk premiums for electric utilities average 3.89%, and the yields on public utility bonds average 7.78%.

Q. Is there any capital market relationship that must be considered when implementing the risk premium method?

A. Yes. The magnitude of equity risk premiums is not constant and equity risk premiums tend to move inversely with interest rates. In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. The implication of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. Accordingly, for a 1% increase or decrease in interest rates, the cost of equity may only rise or fall some fraction of 1%. Therefore, when implementing the risk premium method, adjustments may be required to incorporate this inverse relationship if current interest rate levels have diverged from the average interest rate level represented in the data set.

[84] My analysis encompasses the entire period for which published data is available.

Current bond yields are lower than those prevailing over the risk premium study periods. Given that equity risk premiums move inversely with interest rates, these lower bond yields also imply an increase in the equity risk premium that investors require to accept the higher uncertainties associated with an investment in utility common stocks versus bonds. In other words, higher required equity risk premiums offset the impact of declining interest rates on the ROE.

Q. Is this inverse relationship confirmed by published financial research?

A. Yes. There is considerable empirical evidence that when interest rates are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums are greater. This inverse relationship between equity risk premiums and interest rates has been widely reported in the financial literature. As summarized by *New Regulatory Finance*:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when rates rose.[85]

[85] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports (2006) at 128.

Other regulators have also recognized that, while the cost of equity trends in the same direction as interest rates, these variables do not move in lockstep.[86] This relationship is illustrated in the figure on page 3 of Exhibit AMM-10.

Q. What ROE is implied by the risk premium method using surveys of allowed returns?

A. Based on the regression output between the interest rates and equity risk premiums displayed on page 3 of Exhibit AMM-10, the equity risk premium for electric utilities increases by approximately 42 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated on page 1 of Exhibit AMM-10 with an average yield on public utility bonds for the six month period ending December 2023 of 5.85%, this implies a current equity risk premium of 4.71% for electric utilities. Adding this equity risk premium to the average yield on Baa utility bonds of 6.08% implies a current ROE of 10.79%.

F. Expected Earnings Approach

Q. What other analyses do you conduct to evaluate a fair ROE for DEF?

A. I also evaluate the ROE using the expected earnings method. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This expected earnings approach is

[86] *See*, *e.g.*, California Public Utilities Commission, Decision 08-05-035 (May 29, 2008); Entergy Mississippi Formula Rate Plan FRP-7, https://cdn.entergy-mississippi.com/userfiles/content/price/tariffs/eml_frp.pdf (last visited Jan. 20, 2024); *Martha Coakley et al.*, 147 FERC ¶ 61,234 at P 147 (2014).

consistent with the economic underpinnings for a just and reasonable rate of return established by the U.S. Supreme Court in *Bluefield* and *Hope*.[87] Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

Q. What economic premise underlies the expected earnings approach?

A. The expected earnings approach is based on the concept that investors compare each investment alternative with the next best opportunity. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital. Such an outcome would violate the *Hope* and *Bluefield* standards and undermine the utility's access to capital on reasonable terms.

Q. How is the expected earnings approach typically implemented?

A. The traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns

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

on book investment, such as those published by recognized investment advisory publications (*e.g.*, Value Line). Because these returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison.

Moreover, regulators do not set the returns that investors earn in the capital markets, which are a function of dividend payments and fluctuations in common stock prices - both of which are outside their control. Regulators can only establish the allowed ROE, which is applied to the book value of a utility's investment in rate base, as determined from its accounting records. This is analogous to the expected earnings approach, which measures the return that investors expect the utility to earn on book value. As a result, the expected earnings approach provides a meaningful guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This expected earnings test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q. What ROE is indicated for DEF based on the expected earnings approach?

A. For the firms in the proxy group, the year-end returns on common equity projected by Value Line over its forecast horizon are shown on Exhibit AMM-11. As I explained

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earlier in my discussion of the br+sv growth rates used in applying the DCF model, Value Line's returns on common equity are calculated using year-end equity balances, which understates the average return earned over the year.[88] Accordingly, these year-end values were converted to average returns using the same adjustment factor discussed earlier and developed on Exhibit AMM-7. As shown on Exhibit AMM-11, Value Line's projections suggest an average ROE of 11.1% for the Utility Group.

G. <u>Flotation Costs</u>

Q. What other consideration is relevant in setting the return on equity for a utility?

A. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds a utility nets when it issues common equity.

[88] For example, to compute the annual return on a passbook savings account with a beginning balance of $1,000 and an ending balance of $5,000, the interest income would be divided by the average balance of $3,000. Using the $5,000 balance at the end of the year would understate the actual return.

Q. DEF does not sell common stock. Why are equity flotation costs relevant to the Company?

A. While DEF does not sell common stock directly to investors, the common equity supporting the Company's investment in utility infrastructure was obtained through the issuance of common stock by DEF's parent, Duke Energy. In order to finance a substantial capital expenditures program and maintain DEF's credit standing, Duke Energy will continue to rely on additional sales of common stock to raise new capital. Because the equity capital supporting DEF is ultimately provided by investors through the flotation of Duke Energy common stock, issuance costs are a relevant consideration in evaluating a fair ROE for the Company.

Q. Is there an established mechanism for a utility to recognize equity issuance costs?

A. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. No rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant investment. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of equity being the most appropriate mechanism.

Q. Is there academic evidence that supports a flotation cost adjustment?

A. Yes. The financial literature and evidence in this case provides a sound theoretical and practical basis to include consideration of flotation costs for DEF. An adjustment for flotation costs associated with past sales of common stock is appropriate, even when the utility is not contemplating any new sales of common stock. The need for a flotation cost adjustment to compensate for past common stock offerings has been recognized in the financial literature. In a *Public Utilities Fortnightly* article, for example, Brigham, Aberwald, and Gapenski demonstrated that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must consider total equity, including retained earnings.[89] Similarly, *New Regulatory Finance* contains the following discussion:

[89] E. F. Brigham, D. A. Aberwald, and L. C. Gapenski, *Common Equity Flotation Costs and Rate Making*, Pub. Util. Fortnightly (May 2, 1985).

> Another controversy is whether the flotation cost allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. … The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.[90]

Q. Can you illustrate why investors will not have the opportunity to earn their required ROE unless a flotation cost adjustment is included?

A. Yes. Assume a utility sells $10 worth of common stock at the beginning of year 1. If the utility incurs flotation costs of $0.48 (5% of the net proceeds), then only $9.52 is available to invest in rate base. Assume that common shareholders' required rate of return is 10.5%, the expected dividend in year 1 is $0.50 (*i.e.*, a dividend yield of 5%), and that growth is expected to be 5.5% annually. As developed in Table 3 below, if the allowed rate of return on common equity is only equal to the utility's 10.5% "bare bones" cost of equity, common stockholders will not earn their required rate of return on their $10 investment, since growth will only be 5.25%, instead of 5.5%:

[90] Roger A. Morin, *New Regulatory Finance*, Pub. Utils. Reports, Inc. (2006) at 335.

TABLE 3
NO FLOTATION COST ADJUSTMENT

Year	**Common Stock**	**Retained Earnings**	**Total Equity**	**Market Price**	**M/B Ratio**	**Allowed ROE**	**EPS**	**DPS**	**Payout Ratio**
1	$ 9.52	$ -	$ 9.52	$10.00	1.050	10.50%	$ 1.00	$ 0.50	50.0%
2	$ 9.52	$ 0.50	$ 10.02	$10.52	1.050	10.50%	$ 1.05	$ 0.53	50.0%
3	$ 9.52	$ 0.53	$ 10.55	$11.08	1.050	10.50%	$ 1.11	$ 0.55	50.0%
Growth			**5.25%**	**5.25%**			**5.25%**	**5.25%**	

The reason that investors never really earn 10.5% on their investment in the above example is that the $0.48 in flotation costs initially incurred to raise the common stock is not treated like debt issuance costs (*i.e.*, amortized into interest expense and therefore increasing the embedded cost of debt), nor is it included as an asset in rate base.

Including a flotation cost adjustment allows investors to be fully compensated for the impact of these costs. One commonly referenced method for calculating the flotation cost adjustment is to multiply the dividend yield by a flotation cost percentage. Thus, with a 5% dividend yield and a 5% flotation cost percentage, the flotation cost adjustment in the above example would be approximately 25 basis points. As shown in Table 4 below, by allowing a rate of return on common equity of 10.75% (a 10.5% cost of equity plus a 25 basis point flotation cost adjustment), investors earn their 10.5% required rate of return, since actual growth is now equal to 5.5%:

TABLE 4
INCLUDING FLOTATION COST ADJUSTMENT

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	EPS	DPS	Payout Ratio
1	$ 9.52	$ -	$ 9.52	$10.00	1.050	10.75%	$ 1.02	$ 0.50	48.9%
2	$ 9.52	$ 0.52	$ 10.04	$10.55	1.050	10.75%	$ 1.08	$ 0.53	48.9%
3	$ 9.52	$ 0.55	$ 10.60	$11.13	1.050	10.75%	$ 1.14	$ 0.56	48.9%
Growth			**5.50%**	**5.50%**			**5.50%**	**5.50%**	

The only way for investors to be fully compensated for issuance costs is to include an ongoing adjustment to account for past flotation costs when setting the return on common equity. This is the case regardless of whether the utility is expected to issue additional shares of common stock in the future.

Q. What is the magnitude of the adjustment to the "bare bones" cost of equity to account for issuance costs?

A. The most common method used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. In Exhibit AMM-12, I present a survey of recent open-market common stock issues for each company in Value Line's electric and gas utility industries. For all companies in the electric utility industry, flotation costs averaged approximately 2.6%. Applying the average 2.6% expense percentage to the Utility Group dividend yield of 4.0% produces a flotation cost adjustment on the order of 10 basis points.

VI. Non-Utility Benchmark

Q. What is the purpose of this section of your testimony?

A. This section presents the results of my DCF analysis applied to a group of low-risk firms in the competitive sector, which I refer to as the "Non-Utility Group." This analysis was not relied on to arrive at my recommended ROE range of reasonableness; however, it is my opinion that this is a relevant consideration in evaluating a just and reasonable ROE for the Company's electric utility operations.

Q. Do utilities have to compete with non-regulated firms for capital?

A. Yes. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives. Clearly, the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment, and there is a plethora of other enterprises available to investors beyond those in the utility industry. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. Indeed, modern portfolio theory is built on the assumption that rational investors will hold a diverse portfolio of stocks, not just companies in a single industry.

Q. Is it consistent with the *Bluefield* and *Hope* cases to consider investors' required ROE for Non-Utility companies?

A. Yes. The cost of equity capital in the competitive sector of the economy forms the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility. The *Bluefield* case refers to "business undertakings attended with comparable risks and uncertainties." It does not restrict consideration to other utilities. Similarly, the *Hope* case states:

> By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.[91]

As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

Q. Does consideration of the results for the Non-Utility group improve the reliability of DCF results?

A. Yes. The estimates of growth from the DCF model depend on analysts' forecasts. It is possible for utility growth rates to be distorted by short-term trends in the industry, or by the industry falling into favor or disfavor by analysts. Such distortions could result in biased DCF estimates for utilities. Because the Non-Utility Group includes low risk companies from more than one industry, it helps to insulate against any possible distortion that may be present in results for a particular sector.

[91] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 391 (1944).

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Q. What criteria do you apply to develop the Non-Utility group?

A. My comparable risk proxy group was composed of those United States companies followed by Value Line that:

1) pay common dividends;

2) have a Safety Rank of "1";

3) have a Financial Strength Rating of "A" or greater;

4) have a beta of 0.95 or less; and,

5) have investment grade credit ratings from Moody's and S&P.

Q. How do the overall risks of this Non-Utility group compare with the Utility group?

A. Table 5 compares the Non-Utility Group with the Utility Group and DEF across the measures of investment risk discussed earlier:

TABLE 5
COMPARISON OF RISK INDICATORS

			Value Line		
	S&P	**Moody's**	**Safety Rank**	**Financial Strength**	**Beta**
Non-Utility Group	A-	A2	1	A+	0.79
Utility Group	BBB+	Baa1	2	A	0.94
Duke Energy	BBB+	A3	2	A	0.90

Note: Duke Energy's Value Line ratings are for its parent company, Duke Energy

As shown above, the risk indicators for the Non-Utility Group consistently suggest less risk than for the Utility Group and DEF.

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The companies that make up the Non-Utility Group are representative of the pinnacle of corporate America. These firms, which include household names such as Coca-Cola, Johnson & Johnson, Procter & Gamble, and Walmart, have long corporate histories, well-established track records, and conservative risk profiles. Many of these companies pay dividends on a par with utilities, with the average dividend yield for the group at 2.2%.[92] Moreover, because of their significance and name recognition, these companies receive intense scrutiny by the investment community, which increases confidence that published growth estimates are representative of the consensus expectations reflected in common stock prices.

Q. What are the results of your DCF analysis for the Non-Utility group?

A. I apply the DCF model to the Non-Utility Group using the same analysts' EPS growth projections described earlier for the Utility Group. The results of my DCF analysis for the Non-Utility Group are presented in Exhibit AMM-13. As summarized in Table 6, after eliminating illogical values, application of the constant growth DCF model results in the following cost of equity estimates:

TABLE 6
DCF RESULTS – NON-UTILITY GROUP

Growth Rate	Average	Midpoint
Value Line	10.5%	10.9%
IBES	10.9%	11.4%
Zacks	10.9%	11.5%

[92] Exhibit AMM-13, page 1.

As discussed earlier, reference to the Non-Utility Group is consistent with established regulatory principles. Required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Because the actual cost of equity is unobservable, and DCF results inherently incorporate a degree of error, cost of equity estimates for the Non-Utility Group provide an important benchmark in evaluating a just and reasonable ROE for DEF.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Karl W. Newlin was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Duke Energy Florida, LLC

Docket No. 20240025-EI

Submitted for filing: April 2, 2024

DIRECT TESTIMONY

OF

KARL W. NEWLIN

On behalf of Duke Energy Florida, LLC

I. Introduction and Summary

Q. Please state your name and business address.

A. My name is Karl W. Newlin. My business address is 525 South Tryon Street, Charlotte, North Carolina, 28202.

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

A. I am employed by Duke Energy Business Services, LLC ("DEBS") as Senior Vice President, Corporate Development and Treasurer. DEBS provides various administrative and other services to Duke Energy Florida, LLC, ("DEF" or the "Company") and other affiliated companies of Duke Energy Corporation ("Duke Energy").

Q. What are the duties and responsibilities of your position as Treasurer with DEF?

A. In my role as Treasurer, I am responsible for treasury-related services to Duke Energy and its subsidiaries, including DEF. I monitor trends in the investment markets and maintain key relationships with debt investors, analysts, and financial institutions. Under my supervision, the Treasury Department arranges and executes all capital raising and liquidity transactions, including credit facilities and commercial paper, debt securities, preferred and hybrid securities, and common stock, as well as daily cash management for Duke Energy and its subsidiaries. My responsibilities include managing Duke Energy and its

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subsidiaries' credit ratings and interactions with the major credit rating agencies, commercial banks, and the capital markets. I am also responsible for liability management and long-term investments.

Q. **Please describe your educational background and professional experience.**

A. I graduated from Southern Methodist University with a Bachelor of Business Administration degree in 1991. I subsequently received a Master in Business Administration degree from UCLA's Anderson School of Management in 1998. I am also a Chartered Financial Analyst.

In November 2018, I assumed the role of Senior Vice President, Corporate Development and Treasurer for Duke Energy. Previously, I served as Senior Vice President and Chief Commercial Officer for Duke Energy's natural gas business. In this role, I was responsible for gas commercial operations, which included supply, wholesale marketing, transportation and pipeline services, field customer service, sales and delivery, and business development. I was named to this position following Duke Energy's acquisition of Piedmont Natural Gas ("Piedmont") in October 2016.

I joined Piedmont in 2010 to manage Piedmont's strategic planning functions, new business development activities and joint venture investments. In November 2011, I was appointed to the position of Chief Financial Officer, assuming responsibility for Piedmont's accounting, controller, finance, treasurer, investor relations, insurance, credit policy, risk management and state regulatory affairs areas. Prior to joining Piedmont, I served as Managing Director of Investment Banking for Merrill Lynch & Co. in its New York and Los Angeles offices.

Q. Have you ever testified before the Florida Public Service Commission?

A. I have not previously testified before this Commission. However, I have testified before the North Carolina Utilities Commission on behalf of Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and Piedmont.

Q. What is the purpose of your direct testimony?

A. My testimony will address DEF's general financial objectives, and its requested capital structure, and cost of capital. I will also discuss the current credit ratings and forecasted capital needs of DEF explained in detail in the testimony of other DEF witnesses in this proceeding. Throughout my testimony, I will emphasize the importance of DEF's continued ability to maintain its financial strength and need for its requested capital structure and cost of capital to continue to provide cost-effective, safe, reliable, and increasingly cleaner electric service to its customers.

Q. Do you have any exhibits to your testimony?

A. No.

Q. Do you sponsor any schedules of the Company's Minimum Filing Requirements ("MFRs")?

A. Yes. I sponsor a portion or all of the following MFRs:

C-23	Interest in Tax Expense
C-24	Parent Debt Information
D-1a	Cost of Capital – 13 Month Average
D-1b	Cost of Capital – Adjustments
D-2	Cost of Capital – 5 Year History
D-3	Short-term Debt
D-4a	Long-Term Debt Outstanding
D-4b	Reacquired Bonds
D-5	Preferred Stock Outstanding
D-7	Common Stock Data
D-8	Financial Plans – Stock and Bond Issues

These MFR Schedules are true and correct, subject to being updated during the course of this proceeding.

Q. Please summarize your testimony.

A. As detailed in my testimony and the testimony of DEF's witnesses in this proceeding, DEF faces substantial capital needs over the next several years. To meet those capital needs, the Company will compete for capital in the open market and must appeal to debt and Duke Energy's equity investors to attract the capital it needs. As Dr. Roger Morin, a leading expert on utility finance, states, "[t]he … prices of debt capital and equity capital are set by supply and demand, and both are influenced by the relationship between the risk and return expected for those securities and the risks expected from the overall menu of available securities." Morin, Roger A., *Modern Regulatory Finance* (PUR

Books LLC 2021), at 27. Investors have a variety of investment opportunities available to them and require a return commensurate with the risk they incur. They will invest elsewhere if they feel the expected return provided by a company is inadequate, and lower credit quality weakens a company's attractiveness as an investment opportunity relative to companies with higher credit quality and similar return profiles. For this reason, it is critically important that the Company maintain strong, investment-grade credit quality to assure its financial strength and flexibility and ensure access to capital on reasonable terms.

The Company is making significant capital investments to provide cost-effective, safe, reliable, and increasingly cleaner electric service to its customers. The Company's proposed rate increase will allow it to recover prudently incurred costs for this investment, compete in the capital markets for needed capital for this investment on reasonable terms for DEF's customers, and preserve its financial standing with both equity and debt investors as well as the credit rating agencies, to the long-term benefit of customers.

II. <u>DEF's Capital Structure and Financial Objectives</u>

Q. What are DEF's financial objectives?

A. Financial strength and access to capital are necessary for DEF to provide cost-effective, safe, and reliable service to its customers. The Company, at all times, seeks to maintain its financial strength and flexibility, including its strong investment-grade credit ratings, ensuring reliable access to capital on reasonable terms. Specific objectives that support financial strength and flexibility include: (a) maintaining an adequate percentage of common equity for DEF on a financial capitalization basis as shown in Schedule D-1a of the MFRs; (b) ensuring timely recovery of prudently incurred costs; (c) maintaining sufficient cash flows to meet obligations; and (d) maintaining a sufficient return on equity to fairly compensate shareholders for their invested capital. The ability to attract capital (both debt and equity) on reasonable terms is vitally important to the Company and its customers, and each of these specific objectives helps the Company both to maintain its investment-grade credit ratings and to meet its overall financial objectives for the benefit of customers.

Q. What ratemaking treatment is being requested in this proceeding and how will the Company's financial objectives be impacted?

A. As explained in the Company's Petition and in the direct testimony of Witness Marcia Olivier, and as shown on MFR A-1, DEF is requesting an overall increase in revenue requirement of approximately $593 million in 2025, and incremental increases of approximately $98 million in 2026, and $129 million in 2027 ($820 million total increase in revenue requirement by 2027). On an FPSC-adjusted basis, the proposed capitalization in this request is comprised of 40.68 percent long-term debt and 45.61 percent equity in 2025, 40.58 percent long-term debt and 45.73 percent equity in 2026, and 39.57 percent long-term debt and 45.83 percent equity in 2027. The requested capital structure is further delineated in MFR Schedule D-1a and, in addition to long-term debt and equity, comprises short-term debt, customer deposits, investment tax credits, and deferred income taxes. The proposed capitalization in this request will help DEF maintain its investment-grade credit ratings and meet its overall financial objectives for the benefit of customers.

The Company's Return on Equity ("ROE") Witness, Adrien McKenzie, indicates that the Company's cost of equity capital is in the risk-adjusted range of 10.5 percent to 11.5 percent. Based on his quantitative and qualitative analyses including the risk profile of the Company, Witness McKenzie's view is that 11.15 percent is a reasonable and appropriate estimate of the Company's cost of equity capital. Approval of the Company's request in this case will support its financial objectives by allowing timely recovery of its investments in plant and equipment, providing sufficient cash flows to fund necessary capital expenditures and service debt, and providing a fair and reasonable return to equity investors.

III. <u>DEF's Credit Quality & Credit Ratings</u>

Q. Please explain credit quality and credit ratings, and how they are determined.

A. Credit quality (or creditworthiness) is a term used to describe a company's overall financial health and its willingness and ability to repay all financial obligations in full and on time. An assessment of DEF's creditworthiness is performed by two major credit rating agencies, Standard & Poor's ("S&P") and Moody's Investors Service ("Moody's"), and results in DEF's credit rating.

Many qualitative and quantitative factors go into this assessment. Qualitative aspects may include DEF's regulatory climate, its track record for delivering on its commitments, the strength of its management team, its operating performance, and the economic vitality and customer profile of its service area. Quantitative measures are primarily based on operating cash flow and focus on the level at which DEF maintains debt leverage in relation to its generation of cash and its ability to meet its fixed obligations (interest expense in particular) based on internally generated cash. The percentage of debt to total capital is another example of a quantitative measure. Creditors and credit rating agencies view both qualitative and quantitative factors in the aggregate when assessing the credit quality of a company.

Q. What is the role of regulation in the determination of the financial strength of a utility company?

A. Investors, investment analysts, and credit rating agencies regard constructive regulation as one of the most important factors in assessing a utility company's financial strength. These stakeholders want to be confident that the Company operates in a stable regulatory environment that will allow the Company to recover prudently incurred costs and earn a reasonable return on investments necessary to meet the demand, reliability, and service requirements of its customers and service area. Important considerations include the allowed rate of return, the cash quality of earnings, the timely recovery of capital investments, the stability of earnings, and the strength of its capital structure. Positive consideration is also given for utilities operating in states where the regulatory process is streamlined, the time lag in capital investment recovery is minimized through cost recovery mechanisms such as riders and trackers, and outcomes are equitably balanced between customers and investors.

Q. How are DEF's outstanding securities currently rated by the credit rating agencies?

A. As of the date of this testimony, DEF's outstanding debt is rated as follows:

Rating Agency	**S&P**	**Moody's**
Issuer / Corporate Credit	BBB+	A3
Senior Secured	A	A1
Outlook	Stable	Stable

Moody's rates Duke Energy and its individual subsidiaries on a standalone basis. Accordingly, there is no reason to believe that a downgrade or negative outlook as to a different Duke Energy subsidiary would have a corresponding negative impact upon DEF's credit ratings. S&P utilizes a family rating methodology, whereby the credit rating and outlook of the parent company, Duke Energy, is applied to each of the parent's subsidiaries. Similar to DEF, S&P's outlook on Duke Energy is "Stable."

Obligations carrying a credit rating in the "A" category are considered strong, investment-grade securities subject to low credit risk for the investor. "A" rated debt is presumed to be somewhat susceptible to changes in circumstances and economic conditions; however, the debt issuer's capacity to meet its financial commitments is considered strong. By contrast, ratings in the "BBB" category are considered adequate and have less assurance of access to the capital markets in challenging market conditions. (AA and Aa category ratings for S&P and Moody's, respectively, are stronger than A ratings.)

S&P may also modify its ratings with the use of a plus or minus sign to further indicate the relative standing within a major rating category. An "A+" credit rating is at the higher end of the "A" credit rating category and an "A-" is at the lower end of the category. Moody's credit rating assignments use the numbers "1," "2," and "3", with the numbers "1" and "3" analogous to a "+" and "-", respectively. For example, Moody's credit ratings of "A2" and "A3" would be analogous to "A" and "A-" credit ratings at S&P, respectively.

The ratings outlook assesses the potential direction of a long-term credit rating over an intermediate term (typically six months to two years). DEF's "Stable" outlook at Moody's and S&P means that those credit ratings are not likely to change at this time; however, a change in outlook or rating could occur if the Company experiences a change in its qualitative or quantitative credit quality.

Q. What strengths and weaknesses have the credit rating agencies identified with respect to DEF?

A. The rating agencies believe DEF operates in a generally constructive regulatory environment that supports long-term credit quality and view the Company's previous history of approved regulatory settlements including multi-year rate plans and certain cost recovery mechanisms as credit supportive. However, the rating agencies have identified several challenges the Company faces in maintaining its credit ratings. In May 2023, Moody's identified several factors that could adversely impact the Company's financial metrics (specifically, cash flow coverage ratios), which, in turn, could affect its ratings.[1]

- Severe Storms: Moody's notes that DEF's service territory is prone to hurricanes and major storms. The frequency and intensity of these storms appear to be increasing and have negatively impacted the Company's financial metrics.
- Capital Expenditures: Moody's also notes elevated capital expenditures due primarily to initiatives to harden its system and to implement the clean energy plans, and while the Company has multiyear rate plans and rider mechanisms in place, there is still some regulatory lag since certain investments will not be recovered until the assets are placed in-service, which will negatively pressure credit metrics.
- Sustaining Weak Credit Metrics: Moody's specifically identifies DEF's weak 2022 credit metrics as a credit challenge. Deferred fuel costs, driven by high gas prices, and storm damage from Hurricane Ian resulted in 2022 credit metrics that were weak for DEF's rating. While Moody's expects

[1] *See* Moody's Investors Service, Credit Opinion, "Duke Energy Florida, LLC. Update to credit analysis," May 22, 2023 ("May 2023 DEF Report").

DEF's metrics to improve, continuing weak metrics present the risk of a downgrade.

- Environmental Considerations: Moody's measures DEF's exposure to environmental risk as highly negative, driven by its high exposure to storm-caused damage to physical assets. The May 2023 DEF Report also notes that DEF's fossil fuel generation fleet presents moderate exposure to carbon transition risk.

Granting the rate relief as requested by the Company in this proceeding would make significant progress in addressing Moody's identified concerns.

S&P identifies similar risks to Duke Energy and DEF in its June 2023 DEF report.[2] As of June 2023, S&P affirmed its credit rating and "Stable" outlook for Duke Energy and its subsidiaries, including DEF. S&P stated in its June 2023 Duke Energy Corporation report[3] as well as its June 2023 DEF report that the current rating and outlook for Duke Energy and its subsidiaries is predicated, in part, on Duke Energy's ability to achieve constructive regulatory and rate case outcomes across its six service territories and manage environmental risks through its clean energy transformation strategy.

Q. Do DEF's customers benefit from the Company's strong credit ratings?

[2] *See* S&P Global Ratings, Research "Duke Energy Florida LLC," June 2, 2023 ("June 2023 DEF Report").
[3] *See* S&P Global Ratings, Research "Duke Energy Corp" June 8, 2023 ("June 2023 Duke Energy Report").

A. Yes. To ensure reliable and cost-effective service, and to fulfill its obligations to serve customers, the Company must continuously plan and execute major capital projects. This is the nature of regulated, capital-intensive industries like electric and gas utilities. The Company must be able to operate and maintain its business without interruption and refinance maturing debt on time, regardless of financial market conditions. The financial markets can experience periods of volatility, and DEF must be able to finance its needs throughout such periods. Strong investment-grade credit ratings provide DEF with greater access to the capital markets on reasonable terms during such periods of volatility.

Q. Can the physical risks of DEF's service territory impact DEF's credit quality?

A. Yes. DEF's service territory is prone to strong storms and hurricanes and its enhanced risk and susceptibility to storms as compared to other utilities around the nation is described further in the testimony of Witness Brian Lloyd. These extreme weather events can be unpredictable and recovery costs can amount to hundreds of millions of dollars. These costs can be partially mitigated due to regulatory mechanisms such as DEF's storm reserve, however readily available access to capital on reasonable terms is critical in times such as these. Even facing the threat of a hurricane, mobilization efforts can be large scale and very costly. Storm recovery and repair require large amounts of capital on very short notice which is why it is even more important for utilities such as DEF to maintain adequate liquidity and access to capital. The Commission has recognized the importance of a utility's overall capital structure and how it may contribute to the utility's "ability to provide customers reliable service at reasonable rates while weathering tropical and financial storms."[4] Moody's and S&P list extreme storms and environmental risks as threats to DEF's credit quality. Therefore, it is important that DEF maintain an appropriate overall capital structure to ensure continued access to the markets on favorable terms for the benefit of its customers.

IV. <u>DEF's Capital Structure and Cost of Capital</u>

Q. What is DEF's proposed capital structure?

A. DEF's proposed capital structure can be found in MFR Schedule D-1a. The proposed equity percentage in 2025, 2026 and 2027 on an FPSC-adjusted basis[5] is 45.61 percent, 45.73 percent, and 45.83 percent, respectively. MFR Schedule D-1a assumes a financial equity percentage of 53% (using common equity, long-term debt, and short-term debt). The Company believes this proposed capital structure is optimal for DEF, as it provides an appropriate amount of risk due to leverage while minimizing the weighted average cost of capital to customers. Approval of the proposed capital structure will help DEF maintain its credit quality, including its strong investment-grade credit ratings.

Q. Does the actual financial capital structure vary over time?

[4] Supplemental Final Order, Florida Public Service Commission, Docket No. 20210015-EI, Order No. PSC-2024-0078-FOF-EI at 14 (March 25, 2024).
[5] Includes investor sources of capital as well as customer deposits, accumulated deferred income taxes and investment tax credits.

A. Yes. It does. The specific debt/equity ratio will vary over time, depending on a variety of factors, including, among other things, the timing and size of capital investments and payments of large invoices, debt issuances, seasonality of earnings, and dividend payments to the parent company. The requested regulatory capital structure is consistent with the Company's financial objectives and overall plan to maintain its ability to finance operations at rates favorable for customers, and DEF will manage its capital structure within reasonable range of this base requested capital structure. As of December 31, 2023, DEF's 13-month average FPSC-adjusted capital structure was 37.73 percent long-term debt and 44.58 percent equity.

Q. What is DEF's cost of equity?

A. Witness McKenzie indicates that a reasonable and appropriate cost of equity for the Company is 11.15 percent. The Company supports Mr. McKenzie's analysis.

Q. What role do equity investors play in the financing of DEF, and how will the outcome of this case impact these investors?

A. Equity investors provide the foundation of a company's capitalization by providing significant amounts of capital, for which an appropriate economic return is required. DEF compensates equity investors for the risk of their investment in Duke Energy by targeting fair and adequate returns, a stable dividend, and earnings growth – these are all necessary to preserve access to equity capital. Returns to equity investors are realized only after all operating expenses and fixed payment obligations (including debt principal and interest) of the business have been paid. Because equity investors are the last to receive surplus earnings and cash flows, their investment involves significantly more risk. For this reason, equity investors require a higher return for their investment. Equity investors expect utilities like DEF to recover their prudently incurred costs and earn a fair and reasonable return for their investors. The Company's proposal in this proceeding supports this investor requirement.

Q. What effect does capital structure and return on equity have on credit quality?

A. Capital structure and return on equity are important components of credit quality. The greater the equity component of capitalization, the safer the returns are to debt investors, which translates into higher credit quality and lower borrowing costs. In addition, the allowed return on equity is important to the generation of earnings and cash flows. An adequate return on equity helps ensure equity investors receive fair compensation for their investment while also helping to protect the interests of debt investors.

A strong capital structure and an adequate return on equity provide balance sheet protection and cash flow generation to support high credit quality. High credit quality creates financial flexibility by providing more readily available access to the capital markets on reasonable terms, and ultimately lower debt financing costs. Conversely, a weak capital structure and an inadequate allowed return on equity produces lower earnings and cash flows, lowers credit quality, and may limit financial flexibility.

Q. Do you believe that DEF's requested capital structure has an adequate equity component to enable DEF to achieve the Company's financial strength and credit quality objectives?

A. Yes. DEF's equity component, as requested in this case, enables it to maintain current credit ratings and financial strength and flexibility. This level of equity enables the Company to tolerate different business cycles while also providing more confidence to the Company's lenders and bondholders. Like many utilities, DEF is in a period of significant capital investment necessary to provide cost-effective, safe, reliable, low-carbon service to its customers in a time of rising costs, load growth, and rapidly evolving state and federal requirements. The magnitude of its capital requirements dictates the need for a strong equity component of the Company's capital structure to ensure access to capital funding at reasonable terms. The capital structure being sought in this case will help enable DEF to maintain its current credit ratings and financial strength and flexibility, to the benefit of its customers.

Q. What is DEF's average cost of long-term debt?

A. DEF's average cost of long-term debt is projected to be 4.49 percent in 2025, 4.52 percent in 2026, and 4.63 percent in 2027, as shown in MFR Schedule D-

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4a. In 2023, the average cost of long-term debt was 4.60 percent. Note that when DEF filed its MFRs with the 2021 Settlement Agreement, MFR Schedule D-1a showed a long-term debt cost rate of 4.02 percent. Therefore, DEF experienced nearly 60 basis points higher cost of long-term debt in 2023 than what was included in rates.

Following the onset of the COVID-19 pandemic in early 2020, the Federal Reserve ("Fed") implemented a zero-interest rate policy, which lasted until the Fed began aggressively hiking interest rates in March 2022 to combat rising inflationary pressures. During this two-year period of zero-interest rate policy, long-term U.S. Treasury ("UST") yields also declined to historically low levels with the 10-year UST rate reaching as low as 0.54 percent and the 30-year UST rate touching just below 1.00 percent. During this period of ultra-low interest rates, the Company continued to fund its capital requirements by locking in historically low interest rates with the issuance of long-dated securities. In doing so, the Company materially reduced its refinancing risk as only 7 percent of DEF's $9 billion long-term debt portfolio (excluding securitizations) will mature over the years of 2024-2027. DEF also entered into pre-issuance interest rate hedges during the period of low UST rates, allowing the Company to lock in low interest rates in anticipation of future debt issuances. With long-term UST rates now north of 4.00 percent, reaching levels not seen since 2007, the Company's long-term debt funding strategy should prove very beneficial to customers in the coming years. In addition to U.S. Treasury rates, it is also worth noting that credit spreads have been extremely volatile since 2022 and could continue to be, which also contributes to refinancing risks.

Q. What is DEF's average cost of short-term debt?

A. DEF's average cost of short-term debt is projected to be 3.25 percent in 2025 and 3.20 percent in 2026 and 2027, as shown in MFR Schedule D-3. In 2023, the average cost of short-term debt was 5.17 percent. The Company's short-term debt rate is comprised of two components: (1) interest expense paid on utility moneypool borrowings, and (2) interest income received from utility moneypool lending. Per MFR Schedule D-3, annual short-term debt interest is calculated as interest on moneypool borrowings less interest income received from DEF's lending into the moneypool. This annual short-term debt interest amount is divided by the 13-month average net moneypool position to calculate the cost of net short-term debt as shown in MFR Schedule D-3.

As previously noted, persistently high inflation following the easing of fiscal and monetary policy during the COVID-19 pandemic has led the Federal Reserve to undertake one of the most aggressive Federal Funds cyclical increases in its history, raising the Fed Funds rate over 500 basis points since March 2022. The 5.25 percent to 5.50 percent Fed Funds target range, at the time of this rate case filing, is the highest level since 2006. The inversion of the yield curve reflects the fact that short-term borrowing rates are currently higher than long-term borrowing rates. Short-term rates are expected to remain high, albeit at lower levels than experienced in 2023, as the Federal Reserve has signaled, they are willing to go to great lengths to curtail the 40-year high inflation the economy has recently experienced. While the Fed has signaled that the Fed Funds rate is likely to remain higher for longer, their most recent dot plot shows that rate cuts are anticipated to begin sometime in 2024 and continue over the 2025-2027 timeframe.

Q. What benefits do DEF customers enjoy by being a part of the broader Duke Energy family?

A. Customers of DEF enjoy several benefits attributed to being a subsidiary of the larger Duke Energy portfolio of utilities. DEF is a participant in Duke Energy's $9.0 billion Master Credit Facility and $6.0 billion commercial paper program, which provide DEF greater access to liquidity from highly reputable financial institutions and in the short-term money markets. The Utility Moneypool Agreement between DEF and the other Duke Energy utilities, as approved by the FERC, allows DEF to borrow short-term funds from participating entities at the 'AA' Industrial Commercial Paper Composite Rate, which is a lower rate than would otherwise be available to DEF as a stand-alone issuer. The Moneypool also grants DEF the ability to lend excess short-term funding to participating Duke Energy affiliates, excluding Duke Energy Corp., and DEF is able to generate interest income on these short-term loans. Under Duke Energy's $9.0 billion Master Credit Facility, DEF is able to borrow up to a maximum sublimit of $1.35 billion. Depending on DEF's cash position on a given day, the Company will either be in a borrowing or lending position with respect to the Utility Moneypool arrangement with the other regulated Duke Energy affiliates; the regulated utilities can never lend to the parent, Duke Energy Corp. Access to deeper pools of liquidity at lower borrowing costs have been particularly beneficial in recent years financing hurricane restoration costs and under-collected fuel balances. DEF also benefits from operational efficiencies as a result of shared corporate services.

V. <u>Funding of DEF's Forecasted Capital Requirements</u>

Q. What are DEF's capital requirements over the three test years?

A. DEF faces substantial capital needs over the next several years to add solar generation and energy storage capacity; make the energy grid even more reliable and resilient; improve the efficiency and flexibility of existing generating plants to help lower fuel costs while proactively managing the changing grid; and satisfy its debt maturities. The Company's total capital requirements for the three-year test period ended 2027 are projected to be approximately $8.8 billion. This amount consists of approximately $8.1 billion in projected capital expenditures and approximately $0.7 billion in debt retirements.

Q. How will DEF's capital requirements be funded?

A. DEF's capital requirements are expected to be funded from internal cash generation and the issuance of debt by the Company.

Q. Is it appropriate to consider Duke Energy Corporation's capital structure and cost of debt when determining the revenue requirement for DEF?

A. No. DEF funds its operations through retained earnings and the issuance of its own debt. The capital structure on its balance sheet is its true capital structure. The assets constructed by DEF to serve customers were financed in a manner consistent with the Company's capital structure as a regulated utility, not that of a parent-level holding company. For this reason alone, deriving a revenue adjustment based on the capital structure and debt costs of DEF's parent is not appropriate. Additionally, Duke Energy's capital structure is significantly influenced by strategic transactions, for example acquiring other companies such as Progress Energy and Piedmont Natural Gas. Transactions such as these have increased Duke Energy's diversity and scale, ultimately providing benefits to the Company and its customers. These strategic transactions have nothing to do with DEF's capital structure; therefore, taking them into account in DEF's capital structure will impact it for reasons unrelated to DEF's capital investments and DEF's capital ratio necessary to meet the need for DEF's investments.

Q. Does the Company understand that the Commission's current Rule 25-14.004, F.A.C. requires the Company to address whether or not a parent debt adjustment should be computed to adjust the Company's revenue

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requirement?

A. Yes. The Company believes, however, that the rule is obsolete because the rule does not reflect the way regulated utilities like DEF now calculate income tax. The existing rule imputes the tax effect of parent interest that may never be deductible by the subsidiary for tax purposes. However, this imputed effect is unnecessary because prior to making the parent debt tax adjustment, the utility is making an interest reconciliation adjustment to recognize the interest that is inherent in the utility's FPSC-adjusted capital structure. This provides a match between capital structure interest and the tax effect considered in cost of service. Assuming the capital structure has been determined properly, the utility's interest has been properly addressed. Because the capital structure of a utility is always an issue in litigated base rate proceedings, it is fair to assume that each utility's capital structure has been properly set. The current rule is one-sided in its application, and results in the utility not being allowed the opportunity to recover its costs and earn its authorized ROE. Debt incurred by the parent is assumed to be that of the utility as a rebuttable presumption under the Commission rule but other capital components of the parent, retained earnings of its subsidiaries for example, are not recognized. The Company forecasts that this adjustment will continue to grow in a material manner over the next several years and believes a more reasonable approach is to compute DEF's tax expense on a stand-alone basis without making this adjustment.

Q. Has any outstanding parent debt been used to make equity contributions to

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DEF?

A. No. In 2009, Progress Energy, Inc. issued $750 million of Senior Notes, in which a portion of the proceeds was used to fund DEF's capital expenditures through a $620 million equity contribution. Over the period of the next three years (2010-2012), DEF sent dividends totaling $730 million back to the parent company, essentially returning the capital that was infused from the parent in 2009. Additionally, the $750 million Progress Energy, Inc. 2009 bond issuance used to partially fund DEF consisted of two tranches which matured in 2014 and 2019. The debt is no longer on the parent company's books, and therefore no tax deduction has been taken on this debt since all tranches have 02now matured. No equity contributions have been made to DEF since 2009 and the parent debt used to make any historical equity contributions has since matured. DEF, therefore, has demonstrated the rebuttable presumption even under the current rule. DEF should not be required to recognize the impacts of its parent company's debt. Duke Energy merged with Progress Energy, Inc. in 2012. Again, since then, Duke Energy has purchased additional businesses such as Piedmont and acquired and sold a number of commercial businesses. The capital structure of the parent is diluted by additional strategic transactions and capital raising activities and it should not be considered in determining DEF's revenue requirement. These investments have nothing to do with DEF's capital structure.

Q. Does this conclude your direct testimony?

A. Yes.

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(Whereupon, prefiled direct testimony of Michael T. O'Hara was inserted.)

C16-1476

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for increase in rates by Duke Energy Florida, LLC	**Docket No. 20240025-EI** **Submitted for filing: April 2, 2024**

DIRECT TESTIMONY

OF

MICHAEL O'HARA

On behalf of Duke Energy Florida, LLC

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Michael T. O'Hara. My business address is 525 South Tryon Street, Charlotte, North Carolina 28202.

Q. What is your position?

A. I am the Regional Forecasting Director for Duke Energy Florida, LLC ("DEF" or the "Company").

Q. What are your duties and responsibilities?

A. My duties and responsibilities include strategic planning, financial planning and forecasting, business planning, budgeting, cost management, management accounting, and key performance management.

Q. Please describe your educational background and professional experience.

A. I hold a Bachelor of Science degree in Accounting from LeMoyne College in Syracuse, New York. I joined Duke Energy in 2004 and have held several positions within the company prior to my current role, including Manager of Wholesale Accounting and Manager of Carolinas Regulatory Accounting. Prior to joining Duke Energy, I held various positions at Wells Fargo & Co., Oneida Limited, and Ernst & Young LLP. I am a licensed CPA in good standing in the state of New York.

Q. What is the purpose of your testimony?

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A. My testimony describes the budget and financial forecast process. This process was used to develop the Company's detailed "per books" income statement and balance sheet information for the test years, which for this proceeding are 2025, 2026 and 2027. I present the key assumptions for, and the key components of, the Company's 2023 to 2027 five-year financial plan, including income statements, balance sheets, and subledgers. I explain how DEF's financial plan was used to develop the Company's Minimum Filing Requirements ("MFRs") and I also describe the procedures the Company uses to monitor and control its operation and maintenance ("O&M") and construction budgets.

Q. Do you have any exhibits to your testimony?

A. Yes, I prepared or supervised the preparation of Exhibit MTO-1, which is a list of the MFRs I sponsor or co-sponsor in this rate proceeding. This exhibit is true and accurate.

Q. Do you sponsor any schedules in the Company's MFRs?

A. Yes. I sponsor or co-sponsor the MFR schedules listed in Exhibit MTO-1. These schedules are true and accurate, subject to being adjusted during the course of this proceeding.

Q. What are the time periods covered by the MFRs in this proceeding?

A. The MFR schedules provide financial data and other information for three time periods: (1) the "test years" are the forecasted calendar years 2025, 2026, and 2027 and are based on the results of DEF's 2022 financial planning process;

(2) the "prior year" is calendar year 2024 and is based on the results of DEF's 2022 financial planning process; and

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(3) the "historic year" is calendar year 2023 and is based on actual data from the Company's books and records.[1]

II. DEF'S FINANCIAL PLANNING AND BUDGET PROCESS

Q. Please explain the Company's financial planning and budgeting process.

A. Developing the Company's financial plan and budget involves the interplay of strategic planning, examination of historical spending levels, updates to energy and sales forecasts, rigorous review of resource needs and operational constraints, cost controls, and ensuring that any additional outlays for capital projects and O&M expenditures are necessary and cost-effective.

DEF produces a five-year financial plan on an annual basis. Included in each five-year financial plan is a one-year budget that is used for financial analysis and reporting purposes, two years of detailed O&M expenditures, as well as three years of forecasted data. For example, the 2022 Financial Plan includes a budget for 2023, detailed O&M expenditures for 2023 and 2024, and forecasted data for 2025 to 2027 to support Duke Energy's financial planning and ratemaking processes. DEF's individual functional business units (which are individual cost centers with clearly established roles and responsibilities such as Transmission, Customer Delivery, or Renewable Energy) develop resource plans that include the labor, infrastructure, and maintenance needed to deliver safe and reliable electric service to DEF customers. Individual business units also produce detailed O&M and capital budgets based on parameters provided by Duke Energy's Budgeting and Business Support Organization.

[1] Because 2023 actuals had not occurred when the 2022 financial planning process was completed, the 2024 beginning balances as represented in the MFRs may not agree to ending 2023 balances.

Once the business unit budgets are prepared, the forecasting team integrates the budgets into the overall corporate financial plan. The corporate five-year financial plan is reviewed and modified as may be appropriate and is approved by senior management and the Board of Directors. Updates to the forecast may occur for material changes that occur which were not known at the time of Board approval, and these changes are reviewed and approved by executive management.

Q. What is the difference between the financial plan and the budget?

A. The "financial plan" refers to the forecasted five-year income statement and balance sheet. The financial plan includes information regarding O&M expenditures and capital for each business unit, as well as assumptions regarding revenues, operating expenses other than O&M (such as depreciation, amortization, property tax, payroll tax, income tax, etc.), plant additions and retirements, financing needs, and regulatory strategies. The financial plan also segregates dollars that are recoverable in cost recovery clauses versus base rates.

The "budget" as referred to in my testimony, represents the first year of the financial plan. The budget includes detailed information such as FERC account numbers and other descriptors and elements that enable analysis and reporting. The budget includes the same components as the overall financial plan but in a more detailed manner and represents the current year metric for measuring DEF's financial results.

Q. How are business unit O&M budgets and forecasted plans developed?

A. Each business unit develops a two-year preliminary detailed O&M budget on a FERC account, resource type (e.g., internal labor, contract labor, materials, etc.) and departmental basis using the guidelines referenced above. The O&M budget process for business units is exclusive of fuel costs recoverable through the fuel adjustment clause. For example, the guidelines include detailed instructions for budgeting employee labor data, non-labor related expenses (such as transportation and information technology expenses), as well as instructions for handling contract labor and supplies. The Company follows internal capitalization guidelines when identifying a capital versus expense item, and budget coordinators are required to use these assumptions and/or instructions when projecting their future departmental expenses.

This "bottom-up" approach is reasonable and has been an effective process for DEF in managing costs. The O&M budgets represent the baseline for which each business unit is held accountable. At the conclusion of the preliminary review and analysis, each department inputs its direct O&M expenditures into the OneStream budget tool, then a series of burdens and allocations are run, including benefit and tax burdens on payroll, inventory burdens, sales and use tax burdens on materials, and the allocation of Duke Energy's service company costs to individual business units.

The detailed two-year O&M budgets for each individual business unit are integrated into the corporate financial plan. The overall O&M expenditures for the remaining three years of the corporate financial plan include adjustments for non-levelized or non-recurring items, and the remaining levelized and recurring items include an inflation factor each year.

Q: What are the key assumptions for DEF's 2025, 2026, and 2027 financial plans?

A. The key assumptions underlying the 2025, 2026, and 2027 financial plans are listed in MFR Schedule F-8.

Q. How are DEF's planned construction programs incorporated into Duke Energy's five-year financial plan?

A. The need for physical facilities required to provide electrical energy to our customers is the foundation of Duke Energy's construction program and, in turn, DEF's construction budget. Examples of these physical facilities are generating units, transmission and distribution lines and substations, and other structures. The need for these facilities is driven by a number of factors, either individually or in combination, such as customer growth projections, age of existing facilities, technological obsolescence of existing plant, availability of alternative energy sources, and system reliability.

Prior to constructing new facilities, the Company evaluates various alternatives, and considers a host of factors such as reliability, cost, and fuel type. Utilizing this information, the Company develops a specific plan for the construction of generating facilities that considers factors such as size and if additional transmission and distribution facilities will be needed. The essential construction requirements data included in this plan are then transmitted to various construction management groups who develop detailed construction budgets. Please refer to the direct testimony of Company witnesses Reginald Anderson, Edward Scott, Brian Lloyd, Vanessa Goff, and Hans Jacob for additional information concerning each business unit. Please also refer to MFR Schedule F-5 for a complete description of DEF's forecasting methodology for construction work in progress, electric plant in service, accumulated depreciation, and depreciation expense.

Q. How does DEF monitor and control operating costs after budgets have been developed for individual business units?

A. The primary means to monitor and control O&M and construction costs is through monthly cost management reports. These reports reflect monthly and year-to-date variances between actual costs and budgeted costs by individual business units and are distributed to senior management as part of DEF's monthly corporate financial report. Cost management reports also include updated projections of O&M and capital spending as compared to the original annual budgets. These projections are the basis for updated corporate income and cash flow projections, which are presented to senior management on a monthly basis.

III. DEVELOPMENT OF THE COMPANY'S MFRs

Q. Please explain how the financial plan supports the Company's MFRs.

A. DEF's 5-year financial planning process for 2023 through 2027 is the starting point for developing the MFRs. The financial plan was prepared in accordance with the procedures and processes used by the Company to prepare its financial plans for normal business purposes and these numbers reasonably represent the actual expected financial results for operating the business for the test years (2025 through 2027).

Q. In developing the MFRs, did the Company make any adjustments to the per books financial information derived from the Company's budget process?

A. Yes, a number of adjustments were made to the "per books" actual and budget data for retail ratemaking purposes, as detailed in the testimony of Company witness Marcia Olivier.

IV. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Marcia J. Olivier was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Duke Energy Florida, LLC

DOCKET NO. 20240025-EI
Submitted for filing: April 2, 2024

DIRECT TESTIMONY

OF

MARCIA J. OLIVIER

On Behalf of Duke Energy Florida, LLC

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Marcia J. Olivier. My business address is 299 1st Avenue North, St. Petersburg, Florida 33701.

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

A. I am employed by Duke Energy Florida, LLC ("DEF" or the "Company") as the Director of Rates and Regulatory Planning.

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

A. I am responsible for the preparation of jurisdictional separation studies and class cost of service studies, overseeing rate case activities, reporting actual and forecasted earnings surveillance results, and supporting various regulatory filings and initiatives.

Q. Please describe your educational background and professional experience.

A. I hold a Bachelor of Science degree in Accounting and a Bachelor of Science degree in Finance from the University of South Florida and have over 25 years of utility experience, primarily in the regulatory area.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to:

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1) Provide the revenue requirements for each of the three projected test periods, 2025, 2026, and 2027, and explain how they were derived;
2) Present the Florida Public Service Commission ("FPSC" or "Commission") and Company-proposed adjustments to rate base, net operating income, and capital structure;
3) Present a jurisdictional separation study for each of the projected test year periods;
4) Present six retail allocated class cost of service studies, two for each of the projected test period years, differing only in the weighting of demand and energy responsibilities in the allocator for fixed production capacity costs;
5) Explain the derivation of the retail revenue forecast by retail rate class;
6) Discuss DEF's proposal for addressing any changes in tax law that might become effective during the test periods; and
7) Discuss DEF's proposal to true-up changes in solar production tax credits.

Q. Have you prepared any exhibits to your testimony?

A. Yes. I have prepared or supervised the preparation of several exhibits, as follows:

- Exhibit MJO-1: Minimum Filing Requirement ("MFR") Schedules Sponsored or Co-sponsored by Marcia Olivier;
- Exhibit MJO-2: Depreciation Study Company Adjustment;
- Exhibit MJO-3: Dismantlement Study Company Adjustment;
- Exhibit MJO-4: Electric Vehicle ("EV") Make Ready Credit Program Company Adjustment;
- Exhibit MJO-5: Clean Energy Connection Cumulative Revenue Requirements;

- Exhibit MJO-6: Clean Energy Connection Subscription Revenue Company Adjustment;
- Exhibit MJO-7: Functionalization, Classification, and Allocation of Plant; and
- Exhibit MJO-8: Delivery Voltage Credit Calculation.

These exhibits are true and accurate.

Q. Which MFR schedules do you sponsor?

A. I sponsor all or portions of the MFR schedules identified in Exhibit MJO-1. I have reviewed these schedules, and they are true and accurate, subject to being updated during the course of this proceeding. The MFRs include historical data for 2023, budgeted data for 2024, and forecasted data for 2025, 2026, and 2027.

Q. Please provide a brief summary of your testimony.

A. DEF is currently operating under the 2021 Settlement Agreement[1] ("2021 Settlement") which provides for annual base rate increases in January of each year for 2022, 2023, and 2024. As the 2021 Settlement is set to expire at the end of 2024, DEF is requesting three test periods in this rate case proceeding: 2025, 2026, and 2027, with incremental revenue requirements of $593 million, $98 million, and $129 million in each year, respectively, for a total increase of $820 million by 2027. To support this request, we are providing MFRs for each of these years based on our five-year forecast for the years 2023-2027, as further explained in the direct testimony of Company witness Mr. Michael O'Hara. We include both FPSC and Company adjustments to rate base, net operating income, and capital

[1] Order No. PSC-2021-0202-AS-EI

structure, and we apply jurisdictional separation factors based on projected retail sales (to ultimate customers) and wholesale sales (to other electric utilities or power marketers for resale), as further explained in the direct testimony of Company witness Mr. Benjamin Borsch, for each applicable year using the same allocation methodologies as approved in previous Commission orders.

Both the required FPSC and proposed Company adjustments are provided on MFR Schedules B-2 and C-3. The Company adjustments include incorporating the depreciation study results as explained in the direct testimony of Company witness Mr. Ned Allis, the dismantlement study results as explained in the direct testimony of Company witness Mr. Jeffrey Kopp, the EV Make Ready Credit program as explained in the direct testimony of Company witness Mr. Timothy Duff, and the following adjustments explained in my testimony: amortization of the cost-of-removal ("COR") regulatory asset, capital recovery schedules, and rate case expenses, as well as the expansion of the Clean Energy Connection program. My testimony will also explain that there are several FPSC adjustments that we have been making consistent with past rate case decisions and settlement agreements that we are proposing to stop making in our 2025-2027 test periods, as we believe they no longer apply and/or the costs are appropriate for inclusion in cost of service. They include the cost of the long-term incentive plan ("LTIP"), the supplemental executive retirement plan ("SERP"), 50 percent of the directors' and officers' ("D&O") insurance premiums, Levy county land held for future use, and the parent debt tax adjustment.

We have completed a jurisdictional separation study for each of the three test periods, and we have completed six class cost of service studies, two for each test period, differing only in the allocation methodology for production demand costs. We are required by Rule 25-

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6.043(1)(a), F.A.C. to file the 12 CP & 1/13 AD methodology. However, paragraph 10 in our 2021 Settlement states that we will rely on the 12 CP & 25% AD methodology. Therefore, we request that the Commission approve the 12 CP & 25% AD methodology. As part of these studies, we have also calculated the projected base revenues under current rates and under the assumption that revenues are equal to cost of service. These cost of service studies support the proposed rate design that is further described in the direct testimony of Company witness Mr. Matt Chatelain.

Further, both federal and state changes in tax laws have been enacted in recent years, impacting income tax expense, and accumulated deferred income tax. DEF proposes a mechanism to recover or flow back the impact of any changes in tax laws that become effective during the 2025, 2026, or 2027 test years.

Finally, DEF has been recognizing the production tax credits under the 2022 Inflation Reduction Act since 2022. However, there is uncertainty in forecasting the amount of credits to be received. To avoid over-recovering and under-recovering these production tax credits, DEF requests a mechanism to true-up the difference between the amount included in base rates and the actual production tax credits received by DEF each year via the Capacity Cost Recovery clause.

II. TEST PERIOD REVENUE REQUIREMENTS

Q. Why is DEF filing three test periods?

A. There was a time when annual increases in sales revenues generally kept up with annual increases in costs and rate base (with the exception of placing large generating units in service), resulting in less frequent rate cases. While the number of customers has increased, the decline in kWh usage per customer has slowed the growth in sales. In addition, there is less of a focus on large new generators and more investments in smaller renewable generation that are spread out over time. There have also been increased investments in transmission and distribution systems to be more resilient and accommodate an increasingly cleaner system. These factors would lead DEF and other utilities to file frequent rate cases. Both of DEFs last two settlements, the 2017 Settlement (term 2018-2021) and the 2021 Settlement (term 2022-2024), have included multiple-year rate increases. Other utilities in Florida have also reached similar multi-year rate agreements. The benefit of setting the rates over three years is greater rate certainty for customers and avoiding the cost of annual litigated rate cases for all parties involved. For these reasons, DEF is requesting approval of three test periods which would allow for a three-year reprieve from filing our next rate case, barring any unforeseen circumstances.

Q. What guidance exists for filing multiple test periods?

A. It is not uncommon for a Florida electric utility to file multi-year test period rate cases. Section 25-6.0425, F.A.C. states: "The Commission may in a full revenue requirements proceeding approve incremental adjustments in rates for periods subsequent to the initial period in which new rates will be in effect." The FPSC last approved a dual test period rate case for DEF in Order No. PSC-1992-1197-FOF-EI. More recently, both Florida Power and Light and Tampa Electric Company filed rate cases in 2021 (Docket Nos. 20210015 and 20210034, respectively) with multiple year rate increases.

Q. Please explain how DEF's revenue requirements were calculated.

A. DEF's revenue requirements of $593 million in 2025, $98 million in 2026, and $129 million in 2027 were calculated on MFR Schedule A-1 as well as in the jurisdictional separation studies. The jurisdictional separation factors derived on MFR Schedule E-10 were applied to the various functional total system per-books costs to arrive at the retail costs. After applying the FPSC and Company adjustments, jurisdictional adjusted rate base calculated on MFR Schedule B-1 was multiplied by the weighted average cost of capital calculated on MFR Schedule D-1a to arrive at DEF's jurisdictional net operating income requested. DEF's jurisdictional net operating income earned was calculated on MFR Schedule C-1. The difference between jurisdictional net operating income requested and jurisdictional net operating income earned equals DEF's revenue requirements. The requested rates of return on rate base calculated on MFR Schedule D-1a include an equity cost rate of 11.15 percent. This cost rate is explained in the direct testimony of Company witness Mr. Adrien McKenzie. Absent the requested rate increase, the earned return on equity ("ROE") would be 6.43 percent in 2025, 5.90 percent in 2026, and 5.15 percent in 2027.

It is important to note that approximately $99 million of the 2025 deficiency is driven by the monetization of the award from the Department of Energy ("DOE") in accordance with paragraph 3 of the 2021 Settlement. In that settlement, DEF's annual rate increases from 2022 through 2024 assumed amortization of the DOE award of approximately $74 million in 2023 and $99 million in 2024, thus reducing the base rate increases by those amounts. All else being equal from 2024 to 2025, DEF would still need to implement a rate increase in 2025 to recover the non-recurring $99 million from 2024.

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Q. What are the primary inputs in calculating DEF's total retail cost of service?

A. The primary inputs to DEF's retail COS calculation are forecasted retail revenues and costs for each of the test periods. Revenues are compared to costs to calculate a net surplus (if revenues are higher than costs) or deficiency (if costs are higher than revenues). The net surplus or deficiency is grossed-up for the effect of state and federal income taxes and bad debt expense to determine the requested revenue requirement in each test year. Costs include both operating expenses and a return on rate base. Revenues are forecasted for the test period based on the Company's sales forecast, as further explained in the direct testimony of Company witness Mr. Borsch. System costs and revenues may be adjusted for a variety of reasons, including, but not limited to: Commission-ordered adjustments, costs associated with Company-proposed programs, and updated depreciation, dismantlement, and storm reserve studies. The MFR schedules filed in this proceeding support the detailed cost, revenue, and adjustments used to calculate DEF's cost of service.

III. FPSC AND PROPOSED COMPANY ADJUSTMENTS

A. <u>Depreciation Study</u>

Q. Did DEF perform a depreciation study for inclusion in this proceeding?

A. Yes. Pursuant to Rule 25-6.0436, F.A.C., DEF must file a depreciation study at least once every four years. DEF's last study was filed in January 2021. Therefore, an updated study is required to be filed no later than January 2025. The study performed for and included in this proceeding ("2023 Depreciation Study") is based on actual plant and reserve balances through December 31, 2022 plus projected additions and retirements in 2023 and 2024 to arrive at projected December 31, 2024 balances. Please refer to the direct testimony of Company witness Mr. Allis for a detailed discussion of the 2023 Depreciation Study process, cost drivers, and results, including Tables 1, 2, and 3, which present proposed depreciation rates by plant account.

Q. What is the impact of the 2023 Depreciation Study on depreciation rates?

A. As a result of the 2023 Depreciation Study, the impact to DEF's depreciation rates is a net increase overall. DEF has included the impact of the proposed change in depreciation rates to depreciation expense in each of the three test years, with corresponding adjustments to accumulated depreciation in Exhibit MJO-2.

Q. How did the Company calculate its proposed adjustment to depreciation expense and accumulated depreciation?

A. DEF performed the following steps, as reflected on Exhibit MJO-2:

1. Calculated monthly depreciation expense during the test periods (for the months of January 2025 through December 2027) based on current depreciation rates multiplied by monthly base rate-recoverable ending plant balances.
2. Calculated monthly depreciation expense during the test periods based on proposed depreciation rates multiplied by the monthly base rate-recoverable ending plant balances. Both current and proposed rates are presented in Table 2 of the 2023 Depreciation Study.
3. Calculated the difference in monthly depreciation expense between the results from steps 1 and 2, and sum to annual totals.

4. Calculated the difference in monthly accumulated depreciation based on the difference in monthly depreciation expense calculated in step 3, sum the monthly accumulated depreciation differences, and then divide by 13.

Q. Why is DEF's proposed adjustment different from the impact in Table 2 of the 2023 Depreciation Study presented in the direct testimony of Company witness Mr. Allis?

A. DEF's proposed adjustment is different for two reasons. First, the impact in Table 2 is calculated based on the projected total gross plant balances as of December 31, 2024, multiplied by the change in depreciation rates; whereas the depreciation expense adjustment included in the MFRs is based on gross plant balances for each month during the three test periods multiplied by the change in depreciation rates. Second, Table 2 includes all plant balances; whereas the depreciation expense adjustments in the MFRs are based only on the plant balances that are recoverable through base rates (i.e., all clause-recoverable depreciation expense impacts have been excluded).

Q. Are there any additional considerations associated with the 2023 Depreciation Study?

A. Yes. In paragraph 21.c. of the 2021 Settlement, DEF agreed to delay the start of amortization of the COR regulatory asset, previously authorized for recovery by the Commission[2] to January 1, 2025. The COR regulatory asset included in this proceeding is $478 million, amortized over the average remaining service life of all assets, 25.5 years, for $18.8 million in annual amortization expense. This proposed Company adjustment is titled "COR Reg Asset" in the MFRs.

[2] Order Nos. PSC-2010-0398-S-EI, PSC-2012-0104-FOF-EI, PSC-2013-0598-FOF-EI, PSC-2017-0451-AS-EU, and PSC-2021-0202-AS-EI.

Q. Are you requesting to recover any capital recovery schedules for retired plant balances shown at the bottom of Tables 1 and 2 attached to the 2023 Depreciation Study in Company witness Mr. Allis' direct testimony?

A. Yes. These tables show a net debit balance of $17.6 million in accumulated depreciation remaining on our books after retiring and dismantling the plants on that list. The only plant on that list that is not entirely dismantled is Crystal River Units 1 and 2. Therefore, that final remaining balance will be proposed for recovery in a future rate case. We are requesting to move the balances for all of the other plants in that Capital Recovery Schedule section of Table 2 to a regulatory asset and amortize that regulatory asset over five years beginning in January 2025, for annual amortization of approximately $3.5 million. This amortization is included for recovery as proposed Company adjustment "Capital Recovery Schedule."

B. Dismantlement Study

Q. Did DEF perform a dismantlement study for inclusion in this proceeding?

A. Yes. Pursuant to Rule 25-6.04364, F.A.C., DEF must file a dismantlement study at least once every four years. Like the 2023 Depreciation Study, DEF's last dismantlement study was filed in January 2021 ("2021 Dismantlement Study"); therefore, an updated study is required to be filed no later than January 2025. The updated dismantlement study included in this case ("2023 Dismantlement Study") was performed by Company witness Mr. Jeffrey Kopp and is provided as Exhibit JTK-2 to his testimony. Please refer to the direct testimony of Company witness Mr. Jeffrey Kopp for a detailed discussion of the 2023 Dismantlement Study process, cost drivers, and results.

Q. Was the current dismantlement accrual established in the 2021 Dismantlement Study?

A. Yes. The current annual dismantlement accrual of approximately $20.6 million ($20.0 million retail) was established in the 2021 Dismantlement Study, an increase of approximately $16.8 million over the prior accrual.[3] As a part of the 2021 Settlement, DEF agreed to defer collection of the retail portion ($14.3 million in 2022 and $15.0 million in 2023 and 2024) in incremental annual expense over the settlement period (2022-2024) to a regulatory asset to be included in this proceeding. DEF estimates this regulatory asset to be approximately $47 million as of December 2024. Paragraph 23.c. of the 2021 Settlement provides that DEF shall offset the dismantlement regulatory asset by the $29 million regulatory liability created by a tax savings surplus under Order No. PSC-2019-0268-PCO-EI. The net of the dismantlement regulatory asset and tax savings regulatory liability of approximately $19 million is being amortized over five years beginning January 1, 2025, with approximately $3.8 million annually included in the cost of service as amortization expense.

Q. Please provide the impact on revenue requirements of DEF's 2023 Dismantlement Study accrual.

A. The 2023 Dismantlement Study projects a total dismantlement cost of $546.0 million in 2025 dollars, or an annual accrual of $34.1 million for plants in service as of December 2024. The total dismantlement cost is approximately $131.5 million higher than the 2021

[3] Order No. PSC-2010-0131-FOF-EI

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Dismantlement Study, and the annual accrual included in this proceeding is an increase of approximately $14.2 million in 2025, $17.3 million in 2026, and $19.3 million in 2027. Please refer to Exhibit MJO-3 "Dismantlement Study Company Adjustment" for the calculation of the adjustment to depreciation expense and the depreciation reserve.

C. Storm Reserve Study

Q. Did DEF perform a Storm Reserve Study for inclusion in this proceeding?

A. No. Pursuant to Rule 25-6.0143(1)(l), F.A.C., DEF must file a Storm Damage Self-Insurance Reserve Study ("Storm Reserve Study") at least once every five years. DEF's current study was filed in January 2021; therefore, an updated study is required to be filed by January 2026. DEF will file an updated study on or before that date.

Q. Has DEF included an adjustment for a storm reserve study accrual?

A. No. DEF has not recorded a storm reserve accrual since it was discontinued in 2010.[4] However, as a part of the 2021 Settlement, the parties agreed that DEF's storm reserve shall remain at $132 million. Since Rule 25-6.0143(1)(l), F.A.C. authorizes electric utilities to petition for recovery of storm restoration costs and replenishment of the storm reserve, in the event of a storm that occurs subsequent to the expiration of the 2021 Settlement, DEF requests approval to implement a storm surcharge 60 days after filing a petition to recover estimated storm costs and replenish the storm reserve to $132 million over a 12-month period. Once actual storm costs are recognized, DEF would then file a petition to true up the difference between the amount collected and the actual costs incurred through

[4] Per Order No. PSC-2010-0131-FOF-EI

the next Capacity Cost Recovery clause filing after the 12-month surcharge ends. With the ability to expeditiously recover storm costs and replenish the storm reserve to $132 million, DEF would not need to increase the storm reserve balance beyond $132 million at this time.

D. Rate Case Expenses

Q. Please provide the rate case expenses and the amortization period that DEF has included in the test year revenue requirements.

A. Total rate case expenses of approximately $2.5 million are reflected in MFR Schedule C-10. DEF proposes a three-year amortization period which covers the three test periods, 2025 through 2027. While the Commission approved a four-year amortization period in DEF's 2009 rate case,[5] and DEF agreed to a four-year amortization period for rate case expenses in the 2021 Settlement, DEF is requesting a three-year amortization period in this case to fully recover the rate case expenses by the end of 2027. DEF believes a three-year amortization is more appropriate now that DEF is filing more frequent rate cases and/or settlement agreements than when the Commission approved the four-year amortization period almost 15 years ago.

E. Regulatory Assessment Fees

Q. Are regulatory assessment fees included in the cost of service?

A. No. DEF proposes to continue the current treatment of removing regulatory assessment fees from both operating revenue and operations and maintenance ("O&M") expense as

[5] Order No. 2010-0131-FOF-EI

they are reflected in a separate line on customer bills. Those amounts are included in the "Revenue Tax" Commission adjustment in MFR Schedules C-2 and C-3.

F. Executive Compensation

Q. Why has DEF removed the FPSC adjustment to O&M expense to eliminate the cost of 50% of the D&O liability insurance premiums and 100% of the LTIP and SERP costs in the test periods?

A. While DEF has agreed to remove these expenses in its 2017 Settlement and 2021 Settlement, those agreements specifically state that they shall not set a precedent, and DEF contends these are legitimate expenses incurred in the normal course of business. The direct testimony of Company witness Ms. Shannon Caldwell further explains the Company's LTIP and SERP. Therefore, DEF has not adjusted O&M in the test periods to eliminate these costs.

G. Levy County Land Held for Future Use

Q. Why has DEF removed the adjustment to remove the land held for future use in Levy county?

A. DEF agreed to make that adjustment in both its 2017 Settlement and 2021 Settlement. However, as explained in the direct testimony of Company witness Mr. Borsch, it is probable that the land in Levy county will be used for a regulated project in the future. Therefore, it is appropriate to include the cost of that land in Plant Held for Future Use.

H. Parent Debt Tax Adjustment

Q. Why has DEF removed the Parent Debt Tax adjustment in the test periods?

A. Please refer to the direct testimony of Company witness Mr. Karl Newlin for an explanation as to why the parent debt tax adjustment is not appropriate and why DEF's income tax expense should be viewed on a stand-alone basis.

I. Tax Proration Adjustment

Q. Has DEF made the tax normalization proration adjustment to accumulated deferred income taxes ("ADIT")?

A. Yes, DEF has made the tax normalization proration adjustment in each of the years 2025 through 2027 as shown on MFR Schedule D-1a. Please refer to the direct testimony of Company witness Mr. John Panizza for a detailed explanation of the proration adjustment.

Q. Has DEF included any additional proposed Company adjustments in its cost of service?

A. Yes. DEF has included costs related to the following three programs:

- EV Make Ready Credit Program
- Expansion of the residential off-peak charging credit
- Clean Energy Connection 2.0 Program ("CEC 2.0 Program"), a continuation of DEF's current Clean Energy Connection program.[6]

J. Proposed Electric Vehicle Make Ready Credit Program

Q. What is the Electric Vehicle Make Ready Credit Program?

[6] Authorized by the Commission in Order No. PSC-2021-0059-S-EI.

A. DEF is proposing the EV Make Ready Credit Program to replace the Commercial and Industrial Rebate program authorized in the 2021 Settlement, as further explained in the direct testimony of Company witness Mr. Duff. This program supports the adoption of EVs by customers through a one-time, upfront credit that defrays a portion of the cost to install EV charging infrastructure. Eligible costs include infrastructure such as wiring or electrical upgrades but not the cost of the equipment and charging station. Residential and non-residential customers may participate in the program.

Exhibit MJO-4 "EV Make Ready Credit Program Company Adjustment" provides the following Company adjustments related to this program:

- Revenues – Additional incremental base revenues based on the expected level of participation.
- Amortization Expense – amortization of the EV Make-Ready regulatory asset, over four years based on four years of estimated monthly revenues (following the CIAC calculation model) for the applicable EV charger segment using the RST-1 rate schedule for residential customers or GSD-1 rate schedule for non-residential customers.
- O&M Expense – to account for administrative costs of the program.
- Working Capital – the EV Make-Ready regulatory asset for the deferral of the upfront payment to customers based on the assumed level of participation, net of amortization.

K. <u>Proposed EV Residential Off-Peak Charging Credit Expansion</u>

Q. Are there any additional adjustments related to EVs?

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A. Yes. DEF is proposing to expand its Residential off-peak charging credit pilot, authorized in the 2021 Settlement, by removing the 1,000 annual customer cap and making the pilot a permanent program. DEF is also proposing to change the amount of the credit from $10 per month to $7.50 per month. Please refer to the direct testimony of Company witnesses Mr. Chatelain and Mr. Duff for more information on this program. DEF has included a Company adjustment to decrease revenues by $0.266 million in 2025, $0.571million in 2026, and $1.247 million in 2027 to reflect the program expansion and revised credit amounts.

L. Proposed Clean Energy Connection Program Expansion

Q. Please briefly describe DEF's existing Clean Energy Connection (CEC) Program.

A. DEF's existing CEC program is a solar program through which participating customers can voluntarily subscribe to a share of solar energy sites. Participating customers pay a subscription fee in exchange for receiving bill credits related to the solar generation produced by the CEC solar sites. The current CEC program is made up of ten solar sites, of which six were placed in service in 2022 and 2023, with the remaining four sites to be placed in service in 2024.

Q. Is DEF proposing to expand its existing CEC program?

A. Yes. DEF is proposing to expand its existing CEC program. DEF's current CEC program was approved by the Commission in Order Nos. PSC-2021-0059-S-EI, dated January 26, 2021, and PSC-2021-0059A-S-EI, dated September 23, 2022. In this current rate proceeding, DEF is proposing to expand its CEC program to add five of the fourteen solar sites projected to go in service during the test years, as discussed in the direct testimony of Company witness Mr. Borsch. DEF currently projects that two sites will be placed in service in March 2025, two additional sites in December 2025 and the fifth site in June 2026. Upon completion, the expanded CEC program would include a total of fifteen solar sites.

Q. Why is DEF proposing to expand its existing CEC program?

A. As further described in the direct testimony of Company witness Mr. Borsch, DEF is proposing the CEC program expansion to meet the substantial demand from DEF customers who are seeking access to solar energy but do not have the ability or the desire to construct it on their property.

Q. Will the capacity associated with the five additional solar sites be allocated among different customer groups?

A. Yes, 8% of the expanded CEC program capacity will be allocated to residential and small business customers, 64% will be allocated to commercial and industrial customers, 18% will be allocated to local governments, and 10% to higher education.

Q. What is the reason for the separate carveout for local government and higher education customers?

A. DEF wants to be responsive to local governments and higher education institutions who wish to use the CEC program to meet their sustainability needs. Therefore, DEF has reserved a portion of the CEC program for these customers. The carveout allows local governments and higher education customers to follow their energy procurement processes without the concern of large commercial and industrial customers taking all the available capacity. This carveout was a suggestion from stakeholders in alignment with DEF's desire to afford customers who had voiced interest in renewables the ability to participate.

Q. Will a portion of the CEC program be available to low-income customers?

A. Yes. Consistent with DEF's existing CEC program, DEF will allocate 3.5% of the expanded CEC program capacity to low-income customers. Also consistent with the existing CEC program, these customers will receive a bill credit rate that ensures that in no year will their subscription charge increase their total bill.

Q. Will DEF be allowed to re-allocate CEC program capacity amongst the customer groups?

A. Yes. DEF proposes to be able to re-allocate capacity from one customer segment to another as needed to encourage full CEC program subscription.

Q. What are the subscription and bill credit rates that DEF is proposing?

A. DEF is proposing the same subscription rates and bill credit rates for the CEC program expansion as in DEF's existing CEC program. In other words, DEF is not proposing any changes to the rates shown in rate schedule CEC-1. DEF is not requesting a separate program for the additional five solar facilities. Therefore, when calculating the bill credits, all fifteen solar facilities will be considered.

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Q. How does DEF propose to recover the bill credits that will be provided to the CEC program participants?

A. Consistent with DEF's existing CEC program, DEF proposes to recover these credits through the Fuel clause, allocated based on kWh sales.

Q. How does DEF propose to recover the cost of the solar plants in the expanded CEC program?

A. DEF has included the investments and associated operating expenses of the five proposed CEC solar sites in its revenue requirements. DEF has also included the subscription fee revenues as a reduction to revenue requirements as a proposed Company adjustment labeled "CEC 2.0" in the MFRs. Even though the expansion is labeled "CEC 2.0" in the MFRs, there will be a single CEC program to include both the existing program and the expansion. The monthly difference between the subscription fees and the revenue requirements associated with the cost of the solar plants will continue to be allocated to the general body of customers.

Q. What are the net revenue requirements for DEF's CEC program expansion?

A. Please refer to Exhibit MJO-5 "Clean Energy Connection Cumulative Revenue Requirements". DEF calculated the total revenue requirements over a 30-year period for each of the five projects. In addition to the traditional capital and operating costs, DEF included certain administrative costs in the revenue requirements. DEF calculated the benefits associated with the five projects from both a fixed and variable perspective. The variable benefits more than offset the fixed revenue requirements and result in a projected

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$310.0 million cumulative present value revenue requirement ("CPVRR") net benefit to customers.

Q. What is the amount of the CPVRR benefit for the general body of customers?

A. The total CPVRR net benefit to the general body of customers is $299.5 million.

Q. What are the annual amounts of the proposed Company adjustments in DEFs MFRs?

A. For 2025, 2026, and 2027, DEF has included a proposed Company adjustment for estimated subscription fee revenues in sales of electricity of $10.0 million, $31.9 million, and $37.5 million, respectively, totaling $79.4 million, as it relates to the expansion of the program. DEF's financial plan already includes $225.1 million in CEC subscription revenue related to its existing CEC program. Again, these subscription fees reduce DEF's revenue requirements, and absent this program, DEF's revenue requirements would be $304.6 million higher. Please see Exhibit MJO-6 "Clean Energy Connection Subscription Revenue Company Adjustment" for the calculation of these subscription fee revenues.

IV. JURISDICTIONAL SEPARATION STUDY

Q. What is the purpose of a jurisdictional separation study?

A. The purpose of a jurisdictional separation study ("JSS") is to allocate rate base and net operating income between a utility's rate-regulated jurisdictions. In the case of DEF, those jurisdictions include the Company's retail jurisdiction (regulated by this Commission) and wholesale jurisdiction (regulated by the Federal Energy Regulatory Commission). Most of the costs incurred by an electric utility to serve its customers are of a joint or common use nature. For example, a generating plant is ordinarily not constructed to serve any one customer or even one class of customers but is part of a total generating system designed to serve the aggregate load requirements of all customers on the system. The JSS allocates those investments and costs to the retail and wholesale jurisdictions for the test periods. The JSS also incorporates FPSC and proposed Company adjustments to arrive at the retail jurisdictional cost of service recoverable through a utility's retail base rates (i.e., excluding cost recovery clauses and other amounts not recoverable in base rates). The resulting JSS retail jurisdictional cost of service is then allocated to the retail rate classes via the retail cost of service study.

The results of the JSS can be found in a more summarized fashion in MFR Schedules A, B, C and D. The revenue requirements in the JSS should tie to MFR Schedule A-1, the FPSC-adjusted retail rate base should tie to MFR Schedule B-1, the FPSC-adjusted retail net operating income should tie to MFR Schedule C-1, and the rate of return should tie to the weighted average cost of capital in MFR Schedule D-1. The JSS is simply a different and more detailed way of looking at the summarized data in the MFR schedules.

Q. What sources of information have you used to prepare the Company's jurisdictional separation study?

A. The Company's forecasted income statement and balance sheet (including supporting details), sponsored by Company witness Mr. O'Hara and presented in MFR Schedules B, C, and D, are the basis for the system-per-books dollars in the JSS. System adjustments are made to the system-per-books dollars for various reasons, including Commission-ordered adjustments and proposed Company adjustments as described in the preceding section (III.

FPSC and Proposed Company Adjustments). The adjusted system rate base and net operating income are then allocated between DEF's retail and wholesale jurisdictions.

Q. How did DEF allocate costs to the retail and wholesale jurisdictions?

A. Functionalization is the first step in a JSS and refers to the assignment of costs into one or more of the major functions of an electric utility (e.g., production, transmission, or distribution). All investments and other costs are recorded on the Company's books and records in accordance with the Uniform System of Accounts ("USOA") as prescribed by the FERC and this Commission. The USOA facilitates the functionalization of costs by requiring utilities to record costs in specific FERC accounts that are grouped by function. After functionalization, costs are classified according to one of three cost drivers: 1) demand (i.e., kW load placed onto the system); 2) energy (i.e., kWh required by the system); or 3) customer (i.e., the number of customers using the system). Once costs have been functionalized and classified, an appropriate jurisdictional separation factor (between zero and one hundred percent) is applied to each functionalized and classified group of costs to arrive at the retail costs. A separation factor of zero indicates no retail responsibility, and a separation factor of 100% indicates 100% retail responsibility. The jurisdictional separation factors for each category of costs are either calculated on MFR Schedule E-10 (along with the retail class allocators), or they are derived from the subtotals in the JSS.

Q. Please explain the calculation of the jurisdictional separation factors on MFR Schedule E-10.

A. MFR Schedule E-10 contains the calculation of certain jurisdictional separation factors (also called "jurisdictional allocators") and retail class allocators for all three test years. For production plant, the jurisdictional energy allocators for 2027, 2026, and 2025 are derived on pages 1, 18 and 35, respectively, and the jurisdictional demand allocators for 2027, 2026, and 2025 are derived on pages 2, 19, and 36, respectively. The energy allocators are based on total projected annual retail and wholesale kWh sales, and the demand allocators are based on the average of the projected 12 monthly retail and wholesale kW coincident peaks ("CP"), which represent each jurisdiction's peak demand at the time of each monthly system peak. The projected kWh sales and kW CPs are from the Company's sales forecast as further explained in the direct testimony of Company witness Mr. Borsch. The transmission and distribution separation factors are calculated at the bottom of pages 2, 19, and 36. All calculated separation factors are compiled at the bottom of JSS Schedule No. 1.

Q. Please explain the different jurisdictional separation factors for production base, intermediate, peaking, and solar?

A. Rather than calculate single jurisdictional energy and demand allocators for production plant, DEF has separate energy and demand allocators for base, intermediate, peaking, and solar generation. These separate jurisdictional allocators are required, because certain wholesale sales contracts are priced or could be priced to provide baseload, intermediate, peaking, or solar generation depending on how that capacity will serve that customer's utility load. DEF refers to these wholesale sales as "stratified sales." DEF's wholesale load has been declining over the years, and the only projected wholesale sales remaining in the test years are stratified intermediate and peaking contracts apart from a very small 14 KW contract priced at average system cost, all with Seminole Electric Cooperative, Inc. The decline in wholesale sales results in higher jurisdictional separation factors, and therefore, higher retail revenue requirements.

The calculation of the stratified energy separation factors on MFR Schedule E-10 pages 1, 18, and 35 starts with projected MWh generated to supply power under the wholesale stratified base, intermediate, peaking, or solar contracts, with the remaining sales delivered under wholesale non-stratified contracts (i.e., wholesale average rate sales) and to all retail customers. Those projected sales are divided by projected total generated and purchased MWh from all resources by stratum, net of MWh generated from solar plants under the Clean Energy Connection program and non-class energy sales (i.e. short term non-separated interchange sales). The result is the percentage assignment to wholesale customers by stratum, and remaining percentage is the responsibility of the retail customers and wholesale average-rate contracts. The final step is to multiply the percentage responsibility of remaining average rate sales by the percentage of retail to total average rate sales to arrive at the base, intermediate, peaking, and solar separation factors.

The calculation of the stratified demand separation factors on MFR Schedule E-10 pages 2, 19, and 36 is similar to the calculation of the stratified energy separation factors. The main difference is that average projected 12 CP is used instead of MWh sales. For the wholesale contracts, the projected contractual wholesale demands are assumed to be the CP, and for the retail sales, the projected monthly peak-hour KW demands are used after removing projected retail curtailable and interruptible loads. Further, the calculation assumes a 20% reserve margin as further explained in the direct testimony of Company witness Mr. Borsch.

Q. Please explain how certain jurisdictional separation factors are derived from the subtotals in the JSS.

A. Outside of the calculated separation factors shown at the bottom on JSS Schedule No. 1, all other separation factors in the JSS are derived from the subtotals within Schedule No. 1 itself. For example, rather than splitting out property tax expense into each function and applying a calculated allocator to each function, property tax is allocated using a derived "Net Total Plant" allocator as calculated in the JSS on Schedule 1, line 193. The type or source of each jurisdictional separation factor applied to each category of cost can also be seen at the top of Schedule Nos. 2 through 11.

Q. Are there any costs that are directly assigned to the retail or wholesale jurisdiction?

A. Yes. Occasionally, it is necessary to connect a group of retail customers to the transmission system. The transmission lines connecting these customers are considered "radial lines" and do not serve DEF's broader transmission network. Therefore, this plant is not included in the calculation of transmission network costs in DEF's open access transmission tariff (OATT) cost-of-service calculation and is recovered directly from DEF's retail jurisdiction. DEF has isolated the cost of transmission radials into a separate functional category on Schedules 2, 3, 9, and 10, and has applied a 100% retail jurisdictional separation factor to those costs.

Q. Please explain how the results of the JSS are used in the cost-of-service study.

A. The results of the JSS are the starting point for the class cost of service study. To recap, the JSS starts with system-per-book rate base and net operating income, incorporates FPSC and Company adjustments, and removes the portion of costs allocated to the wholesale jurisdiction. The FPSC-adjusted retail cost of service in the JSS equals the sum of the retail rate classes in the retail class cost of service study.

V. RETAIL COST OF SERVICE STUDY

Q. What is a retail Cost of Service study?

A. The retail Cost of Service ("COS") study is an extension of the JSS, in which retail jurisdictional adjusted rate base and net operating income are further allocated to the various retail rate classes. Factors for allocating the retail jurisdictional costs to rate classes include the number of customers and kWh sales derived from the Company's sales forecast and class load characteristics derived from the Company's latest load research study. Costs are first functionalized, then classified as either demand-related, energy-related, or customer-related, and finally allocated to the retail rate classes. The COS study provides: (i) class rates of return (i.e., net operating income divided by rate base) at present and proposed rates, (ii) class revenue surpluses or deficiencies, and (iii) functional cost information for rate design considerations.

One thing that is unique in the way DEF presents its COS studies is that it combines the JSS with the COS study for a wholistic view. In other words, while most COS studies start with retail jurisdictional rate base and net operating income (i.e., the results of the JSS), DEF's studies start with total system-per-books, then add system adjustments and remove

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the wholesale amounts to arrive at the total retail-adjusted amounts, which are then allocated or direct-assigned to the various retail rate classes.

Another unique aspect of DEF's COS studies is that they are presented by rate class, by function, and then each rate class is presented by function. This last step is required to facilitate calculating the delivery voltage credits for the customers who take delivery at voltages higher than distribution secondary in the general service demand, interruptible, and curtailable rate classes.

Q. How did you establish the customer rate classes that were used as costing entities in your COS studies?

A. Each regular rate schedule in the Company's present tariff has been established as a rate class in the COS studies, with the exception of a new class that has been added in the current studies, the "EV Solution" class. The rate schedules for general service non-firm service (i.e., the curtailable and interruptible rate schedules) are reported separately in the COS studies, but they are treated as one rate class in the MFR E-Schedules since these customers only differ as to Company or customer control of their non-firm load capability. Each rate schedule serving either (i) optional time of use, (ii) load management service, or (iii) standby service, has been combined with its corresponding or related rate class. The resultant rate classes are described as:

(1) Residential Service (RS)

(2) General Service Non-Demand (GS-1)

(3) General Service 100% Load Factor (GS-2)

(4) General Service Demand (GSD)

(5) Curtailable/Interruptible General Service (CS/IS)

(6) Lighting Service (LS), consisting of sub-groups for the costs of

(a) Lighting Energy

(b) Lighting Facilities (Fixtures and Poles).

(7) EV Solution (EV)

Q. Please explain the new "EV Solution" rate class.

A. At the time DEF completed its financial forecast for this rate case filing, DEF expected to file a request with this Commission for approval of a new EV Solution program. If approved, DEF would install EV chargers in residential and commercial/industrial customers' premises and lease those chargers to those customers. Similar to the Lighting Facilities class, a separate class has been created for the EV Solution program. Within that class are estimated rental revenues as well as the net book value of the chargers, depreciation expense, O&M expense, and property tax expense. DEF has since placed a pause on requesting approval of this program. However, since the revenues and costs are isolated in a separate rate class, regardless of whether DEF decides to pursue or not pursue this program, there is no impact to the other rate classes.

Q. How is the information from the load research study used in allocating costs to the retail rate classes?

A. Load research studies collect data that provide important information on customers' electric load characteristics. As further explained in the direct testimony of Company witness Mr. Chatelain, DEF's load research study from January through December 2022 was used to develop the load factors reported in MFR Schedule E-17. Load factors are a measure of how consistently energy is used over a specified period of time. Load factors are ratios that are calculated by dividing kWh used in a period by the product of peak kW demand and the number of hours in that period. For example, if a customer uses 1,080 kWh in a 30-day month (720 hours) and has a peak demand during that month of 3 kW, then that customer's load factor would be 50% [1,080 kWh / (3 kW x 720 hours)]. Said another way, this customer consumed energy at a 50% efficiency rate. There are three types of load factors that are used in the calculation of class allocation factors in MFR Schedule E-10 as follows:

1) 12 CP: Each class's annual kWh consumed divided by the product of that class's average of the 12 monthly kW demands at the time of the monthly system peaks and the number of hours in that year;
2) Class non-coincident peak ("NCP"): Each class's annual kWh consumed divided by the product of that class's annual peak kW and the number of hours in that year; and
3) Customer maximum demands: Each class's annual kWh consumed divided by the product of the sum of the customer maximum demands and the number of hours in that year.

As shown on MFR Schedule E-10, the 12 CP load factors are used to calculate the production demand allocators as well as the transmission demand allocators, the NCP load factors are used to calculate the distribution-primary allocators, and the customer maximum demand load factors are used to calculate the distribution-secondary allocators.

Q. What is the delivery efficiency factor?

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A. The delivery efficiency factor accounts for line losses, or the amount of energy that is produced but is not sold or used by the Company. The delivery efficiency factor is applied based on delivery voltage level and serves to gross-up delivered sales to source-level sales. Increasing losses occur as electricity is stepped up from the generators and flows through the transmission system, is stepped down to distribution primary voltages, flows through the distribution primary system, is further stepped down to distribution secondary voltages, and finally flows through the distribution secondary lines. Since customers take delivery at varying voltage levels, the delivery efficiency factor adjusts all sales back to the source generation levels, thereby providing an equal measure by which all rate classes can be evaluated.

Q. You indicated that a retail COS study functionalizes, classifies, and allocates costs. What functional components are provided in the COS studies and how are they classified and allocated?

A. The COS for each of the Company's rate classes, which ultimately translates into each class's revenue requirement for rate design purposes, is functionalized, classified, and allocated according to the following table:

Function	Classification	Allocation
Production Capacity	Demand	12 CP & 25% AD
Production Energy	Energy	kWh
Transmission	Demand	12 CP
Distribution – Primary	Demand	Class NCP at Primary
Distribution - Secondary	Demand	Cust. Max Demand at Secondary
Distribution - Services	Customer	# Customers at Secondary
Metering	Customer	Meter cost
Interruptible General Service Equip.	Direct	Direct to CS/IS Class
Lighting Facilities (fixtures & poles)	Direct	Direct to Lighting Class
Customer Billing, Information, etc.	Customer	# Customers

Please also refer to Exhibit MJO-7 "Functionalization, Classification, and Allocation of Plant" for a detailed schedule of function, classification, and allocation by plant primary account.

Q. You mentioned that you prepared six COS studies for this filing, differing only in the weighting of demand and energy responsibilities. Please explain those differences.

A. DEF prepared two COS studies for each of the three test periods, differing only in the weighting of demand and energy responsibilities in the allocator for fixed production capacity costs. Paragraph 10 of the 2021 Settlement states: "…in DEF's next general base rate case, DEF intends to file both the 12 CP and 1/13 AD and the 12 CP and 25 AD methods but rely upon only the 12 CP and 25 AD method to meet its initial burden of proof." Therefore, while DEF is providing COS studies based on the 12 CP and 1/13 AD methodology for informational purposes, the rate design MFR E-Schedules rely on the 12 CP and 25% AD methodology for fixed production capacity costs.

Q. Please describe these two production capacity cost allocation methods.

A. The 12 CP and 1/13 AD methodology calculates allocation factors by rate class based on 12/13 (or about 92%) multiplied by the average of the twelve monthly coincident peaks and 1/13 (or about 8%) multiplied by the class average hourly demands, thus the term "AD." It should be noted that average demand and annual energy usage result mathematically in the same class allocation percentages since average demand is simply total energy use divided by number of hours of use. Under the 12 CP and 25% AD methodology, 75% of the allocator is based on the average 12 CP, and 25% is based on energy. The 12 CP and 25% AD methodology increases the weighting of energy usage from about 8 percent to 25 percent.

Q. Does DEF maintain that a 12 CP and 25% AD methodology is appropriate for allocating production capacity costs?

A. Yes. DEF believes that an energy weighted allocation of only 8 percent under the 12 CP and 1/13 AD method gives too little recognition to the role energy is given in generation facility planning. DEF continues to emphasize providing clean and efficient generation, as well as satisfying reliability criteria. DEF will have 23 utility scale solar plants in service by December 2024 and plans to install fourteen additional solar facilities in the 2025-2027 test periods. These plants will continue to provide clean, low-cost generation and will continue to reduce our dependence on fossil fuel. These investments have a higher up-front capital cost, but the benefits to customers are primarily related to the costs of fuel, which is apportioned on an energy basis. Therefore, a larger portion of the Company's production capacity costs should be apportioned in the same manner as the customer realizes the benefits, i.e., on an energy basis.

Further, DEF's power plants are planned and operated in response to both customer demand and energy needs, and the decision on how much to allocate to each rate class is based on how much of the fixed production plant cost is incurred to meet system peak demand and how much is incurred to reduce variable operating costs, primarily fuel, by running a plant beyond peak demand periods. The higher the weighting on an energy basis, the more cost responsibility is allocated to higher load factor customers, such as General Service Demand and Curtailable/Interruptible customers. DEF has a significant amount of baseload generation, which is more expensive to install than peaking generation but less expensive to operate over time, mainly due to lower fuel costs. Investment in more expensive generating units to provide more efficient fuel conversion for the generation of electricity supports the need to use the 12 CP and 25% AD allocator.

Q. Please explain the functionalization, classification, and allocation of transmission plant.

A. Except for transmission generator step-up transformers, which connect the generating facilities to the transmission network and are functionalized as production plant, and transmission radials that are directly assigned to the retail jurisdiction, transmission plant is functionalized into plant primary accounts 350-359 and O&M accounts 560-574 per the USOA, and is classified as demand and allocated to the individual rate classes based on 12 CP.

Q. Please explain the functionalization, classification, and allocation of distribution plant.

A. The functionalization of distribution plant is somewhat unique as compared to production and transmission plant in that distribution plant is further sub-functionalized into primary, secondary, services, meters, lighting facilities, and interruptible equipment. Distribution costs are driven by both demands placed on the system and the number of customers using the system; therefore, distribution subfunctions are classified as either demand or customer. Several distribution plant accounts must be split between the primary and secondary subfunctions. To accomplish this, DEF has calculated the proportion of primary and secondary line miles or pole counts for various type of assets. For FERC account 362-station equipment, a portion is direct assigned to the CS/IS classes and the remainder is direct assigned to the primary function. For FERC account 364-poles, towers, and fixtures, DEF first direct assigns a portion to the Lighting class, and 73% of the remaining amount is assigned to the primary function and 27% to the secondary function, based on pole counts. For FERC account 365-overhead conductors and devices, a specific amount is direct assigned to the CS/IS classes and 69% of the remaining amount is assigned to the primary function and 31% to the secondary function, based on overhead circuit miles. For FERC account 367-underground conductors and devices, 63% is assigned to the primary function and 37% is assigned to the secondary function, based on underground circuit miles.

Distribution primary costs are allocated based on each rate class's NCP only for customers taking delivery at primary or secondary voltage levels. Distribution secondary costs are allocated based on the sum of customer maximum demands only for customers taking service at secondary voltages. Distribution services costs are allocated based on the average number of customer bills only for customers taking delivery at the distribution secondary voltages. Distribution metering costs are allocated based on meter investment at the class level. Distribution lighting and interruptible equipment costs are directly assigned to the lighting and interruptible rate classes.

Q. How does the COS study account for customers that take delivery at higher voltage levels than the distribution secondary system?

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A. While most of DEF's retail customers take power from the distribution secondary voltages, there is a small subset who take power at one of the transmission or distribution primary voltages. The principle of cost causation suggests that customers taking power at higher voltages should not pay for system costs below the voltage level at which they take service, since they do not cause those costs to be incurred. DEF offers a delivery voltage credit (DVC) as a reduction to the base demand charge, applicable to all rate schedules with a demand charge, for customers taking power at higher voltage levels. The credit is currently offered at three levels at which customers may take power:

1) Distribution primary delivery voltage: Customers taking power at the distribution primary level are credited for the cost of the distribution secondary system.
2) Transmission delivery voltage below 230 kV ("subtransmission"): Customers taking power at the subtransmission level are credited for the cost of the distribution secondary and primary systems.
3) Transmission delivery voltage at or above 230 kV: Customers taking power at or above 230 kV are credited for all three: the subtransmission and the distribution primary and secondary systems.

Q. How are the delivery voltage credits calculated?

A. The DVCs are calculated by dividing the functional cost of service for distribution secondary, distribution primary, and sub-transmission allocated to the rate classes with demand rates by the billed kW for those rate classes for each of the three functions. DVCs are applied on a cumulative basis. For example, a customer taking delivery at a subtransmission voltage will receive a cumulative DVC that includes both the distribution primary and distribution secondary credits.

Please refer to Exhibit MJO-8, Delivery Voltage Credit Calculation for the calculation of DEF's proposed DVCs for each of the three test years. Again, DEF has calculated the credits based upon functional cost of service; however, if the Commission approves a different level of revenue requirements for DEF than what was requested, the DVCs should be recalculated and incorporated in the final rates 1) to reflect DEF's final approved cost of service, and 2) to adjust for any disparity between the final approved cost of service and the final revenues authorized by this Commission for those rate classes to which the DVCs apply, thereby ensuring that the DVCs reflect the proportion of costs being collected from the demand rate classes. The issue of rate disparity is discussed in detail in the results section below.

Q. What costing treatment is utilized in the COS studies for those rate groups that contain non-firm service provisions?

A. DEF's residential service and general service rate groups include optional load management provisions that permit the interruption of certain specified customer equipment, while the interruptible service and curtailable service rate groups require that all, or a significant portion of the customer's load, be subject to interruption or curtailment as a condition for service. However, the development of costs for these rate groups is based on the premise that all the groups' load requirements are firm. This is because the Company's various forms of non-firm service are elements of its demand side management ("DSM") program and, therefore, the value of each rate group's load subject to interruption or curtailment is not a consideration in setting base rates, but instead is recognized separately by the payment of billing credits that are established in and recovered through DEF's Energy Conservation Cost Recovery clause.

Q. What are the results of the COS studies?

A. The results of the COS studies using the 12 CP and 25% AD production demand allocation methodology are presented on MFR Schedule E-1. This MFR shows the rate of return ("ROR") index for each class at both present and proposed rates. The ROR index provides the ratio of each class's ROR (i.e., net operating income divided by rate base) to the total retail ROR. Rate parity exists when the ROR earned from each of the rate classes is equal to the total retail ROR. ROR indexes greater than one indicate a class's ROR is greater than the total retail ROR. Conversely, indexes less than one indicate a class's ROR is less than the total retail ROR. The class revenue requirement index represents the percentage of each class's current or proposed revenue to its COS (i.e., revenue requirement). Indexes greater than one indicate a class's revenues are greater than its COS. Conversely, indexes less than one indicate a class's revenues are less than its COS.

At present rates, DEF's COS study calculates a projected retail jurisdictional ROR of 4.85 percent for the 2025, 4.62 precent for the 2026, and 4.32 percent for the 2027 test periods. The COS study shows that at present rates, certain rate classes, such as RS and GS-1, are above rate parity, while other classes, such as GSD and CS/IS, are below parity. Again, MFR E-1 lists the ROR and associated ROR index for each rate class.

At proposed rates, DEF's COS study calculates a projected retail jurisdictional ROR of 7.01 percent for the 2025, 7.02 percent for the 2026, and 7.07 percent for the 2027 test periods. The GS, CS/IS, and LS rate class revenue increases are limited by the Commission's practice of gradualism, which limits the increase of each rate class to no more than 1.5 times the average system increase, and not allowing any class to receive a decrease when there is an overall increase. As a result of the practice of gradualism, these three rate classes will still be below parity at proposed rates, but they will be moving closer to parity. Company witness Mr. Chatelain's exhibit MJC-2 presents the revenue requirement necessary to achieve full parity in each of the 2025 – 2027 test periods.

Q. What is the next step once you have calculated the COS by rate class?

A. The COS study under present rates is summarized on MFR Schedules E-6a, and the COS study under proposed rates is summarized on MFR Schedule E-6b. Unit costs are developed in MFR Schedules E-6a and E-6b by dividing each class's COS components by the appropriate billing units (i.e., the number of customer bills, energy sales, or billing demands). This type of information is then used as a consideration in rate design when establishing the level of customer charges, demand charges, energy charges, etc. This is further explained by Company witness Mr. Chatelain.

VI. REVENUE FORECAST

Q. How were base revenues forecasted in the test periods?

A. The revenue forecast starts with the sales forecast which includes the forecasted number of customers and kWh sales by revenue class (i.e. residential, commercial, industrial, lighting, and sales to public authorities), as further explained in the direct testimony of Company witness Mr. Borsch. DEF performs a multi-step process to calculate the forecasted revenues by rate class. DEF uses historical billing determinants (i.e., the various units to which tariffed rates are applied as presented on MFR Schedule E-13c) to calculate the forecasted kW and allocate the kWh and number of customers from the sales forecast to retail rate class and rate schedule. Next, currently authorized base rates are applied to the billing determinants to produce the base revenue forecast at present rates by rate class. The results are presented on MFR Schedule E-13c under current and proposed rates as further discussed in the direct testimony of Company witness Mr. Chatelain. The results are also summarized on MFR Schedule E-5.

Q. Are there any other revenues included in forecasted base rate revenues?

A. Yes. There are several additional types of base rate revenues. DEF has included estimates for minimum bill revenues, additional revenues expected from the EV Make Ready Credit program, and subscription fees associated with the current and proposed expansion to the Clean Energy Connection program. DEF has also reduced revenue for expansion of the EV residential off-peak charging credits, as further explained in the direct testimony of Company witness Mr. Chatelain.

It is important to note that for the CEC program, the revenues presented by rate class are not the actual subscription revenues forecasted from each rate class. Rather, DEF has allocated the revenues to the rate classes on the same basis as the associated solar plant costs, which is the production demand 12 CP and 25% AD method. This accurately aligns the revenues with the allocated costs of the solar plants for each rate class, thereby providing a more precise COS calculation by rate class.

Q. What additional adjustments were made to base revenues in the test period?

A. There is one additional adjustment made to base revenues in the test year, "Synchronize Revenue to E-Schedules." The adjustment is required to reconcile forecasted revenues in DEF's regulatory modeling program and the forecasted revenue results produced in MFR E-13C. The process described above produces the results presented in MFR E-13c. Revenues are input into DEF's regulatory modeling program relatively early in the rate case preparation process, and as the revenue forecast is refined, small adjustments are made via the synchronization adjustment.

IMPACT OF POTENTIAL TAX LAW CHANGES

Q. Which tax law changes have impacted DEF in recent years?

A. The 2017 Tax Cuts and Jobs Act ("TCJA") reduced the top corporate income tax rate from 35 percent to 21 percent effective in January 2018.[7] This was followed by a temporary reduction in the Florida corporate income tax rate from 5.5% to 4.458% in 2019 and 2020[8] and a further reduction to 3.535% in 2021.[9] Finally, the 2022 Inflation Reduction Act ("IRA") provided for production tax credits instead of investment tax credits for solar projects placed in service after December 31, 2021, and it imposed a 15% corporate alternative minimum tax for corporations with profits in excess of $1 billion.[10] These tax law changes have all reduced income tax expense, and DEF's 2017 and 2021 settlement agreements have provided a mechanism to expeditiously flow those tax savings back to customers. These settlement agreements have also provided a mechanism to recover any

[7] Docket No. 20180047
[8] Approved in Order No. PSC-2021-0024-FOF-EI
[9] Approved in Order No. PSC-2022-0147-PAA-EI
[10] Approved in Order No. PSC-2022-0425-TRF-EI

increases in income tax expense resulting from tax law changes, but thus far the tax law changes have not resulted in the need to recover costs from customers.

Q. Are there any future changes in tax laws that DEF anticipates?

A. No one can predict with certainty what changes in tax laws might take effect. For that reason, DEF is proposing a mechanism to expeditiously adjust base rates to flow back or recover the impact of any changes in tax laws that become effective in the 2025, 2026, or 2027 test years. This is especially important since DEF is requesting three test periods, thereby mitigating the need to file another rate case for several years.

Q. Please describe DEF's proposed mechanism to address a change in tax law.

A. DEF proposes that if a change in tax law becomes effective for any of the test years 2025, 2026 or 2027, DEF shall submit a petition for approval of DEF's calculation of the impact on base rate revenue requirements along with the tariffs to implement a change in base rates. DEF proposes to use the same methodology to calculate the impact of tax law changes as it has used for previous tax law changes. That is, DEF will quantify the impact on its Florida jurisdictional base rate revenue requirement as projected in DEF's forecasted earnings surveillance report for the calendar year that includes the period in which the tax law change becomes effective.

Further, excess, or deficient accumulated deferred income taxes shall be deferred to a regulatory asset or liability included in the FPSC-adjusted capital structure and flowed back to customers over a term consistent with law. DEF shall follow tax normalization laws with respect to the period over which it flows back or recovers excess or deficient deferred tax balances. For any deferred excess or deficient tax balances that are not subject to tax normalization laws, if the cumulative balance is less than or equal to $200 million, the flow-back or collection period shall be five years, and if the cumulative balance is greater than $200 million, the flow-back or collection period shall be ten years.

Upon approval by this Commission, base rates shall be adjusted through a one-time uniform percentage decrease or increase to customer, demand, and energy base rate charges, excluding delivery voltage credits, for all retail customer classes. Any effects of tax law change on retail revenue requirements from the date the tax law becomes effective through the date of the base rate adjustment shall be flowed back or collected from customers through the Capacity Cost Recovery clause.

VII. SOLAR PRODUCTION TAX CREDIT TRUE-UP PROPOSAL

Q. Why is DEF proposing a true-up mechanism for solar production tax credits?

A. DEF has been flowing back the benefits of the production tax credits ("PTC") under the 2022 Inflation Reduction Act since 2022. However, there is a fair amount of uncertainty in forecasting the credits to be received. For example, as further explained in the direct testimony of Company witness Mr. Panizza, DEF has had to make certain forecast assumptions, i.e., the projects would meet the prevailing wage and apprenticeship guidance and would be transferred at 90 cents on the dollar. DEF also assumed a certain amount of kWh would be generated from the applicable solar plants to achieve those PTCs, which can vary due to weather and other circumstances. Finally, fees and administrative costs, as further explained by witness Mr. Panizza, could vary with each transaction. To avoid over-recovering or under-recovering these PTCs, net of their associated costs, DEF requests to true-up the difference between the actual PTC net amounts received and the amounts in base rates each year.

Q. How much has DEF included in the test years for PTCs?

A. DEF has included $65 million in 2025, $96 million in 2026, and $117 million in 2027, as further explained in the direct testimony of Company witness Mr. Panizza.

Q. DEF does not have a true-up mechanism for any other component of DEF's cost of service, so why is DEF proposing a true-up mechanism solely for PTCs?

A. PTCs are very isolated and measurable amounts. To true-up all costs would be time intensive, as it would require additional submissions to the Commission for review, and essentially result in formula rates. DEF is not proposing to adjust any other costs or revenues. The true-up of PTCs will be a very formulistic calculation, comparing actual PTCs received to the amounts in the MFR schedules by year, allowing for expeditious review and approval.

Q. Please explain DEF's proposed true-up mechanism for PTCs.

A. DEF proposes to calculate the difference between the dollars in DEF's MFR schedule C-22 and the amount actually received from either including the PTCs on a Company tax return or from transferring them. This calculation would take place annually for each year 2025, 2026 and 2027. The difference would be included for recovery or refund in DEF's next Capacity Cost Recovery clause filing.

VIII. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes.

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$310.7 million cumulative present value revenue requirement ("CPVRR") net benefit to customers.

Q. What is the amount of the CPVRR benefit for the general body of customers?

A. The total CPVRR net benefit to the general body of customers is $300.1 million.

Q. What are the annual amounts of the proposed Company adjustments in DEFs MFRs?

A. For 2025, 2026, and 2027, DEF has included a proposed Company adjustment for estimated subscription fee revenues in sales of electricity of $10.0 million, $31.9 million, and $37.5 million, respectively, totaling $79.4 million, as it relates to the expansion of the program. DEF's financial plan already includes $225.1 million in CEC subscription revenue related to its existing CEC program. Again, these subscription fees reduce DEF's revenue requirements, and absent this program, DEF's revenue requirements would be $304.6 million higher. Please see Exhibit MJO-6 "Clean Energy Connection Subscription Revenue Company Adjustment" for the calculation of these subscription fee revenues.

IV. JURISDICTIONAL SEPARATION STUDY

Q. What is the purpose of a jurisdictional separation study?

A. The purpose of a jurisdictional separation study ("JSS") is to allocate rate base and net operating income between a utility's rate-regulated jurisdictions. In the case of DEF, those jurisdictions include the Company's retail jurisdiction (regulated by this Commission) and wholesale jurisdiction (regulated by the Federal Energy Regulatory Commission). Most of the costs incurred by an electric utility to serve its customers are of a joint or common use nature. For example, a generating plant is ordinarily not constructed to serve any one

(Whereupon, prefiled direct testimony of John R. Panizza was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for increase in rates by Duke Energy Florida, LLC

Docket No. 20240025-EI

Submitted for filing: April 2, 2024

DIRECT TESTIMONY

OF

JOHN R. PANIZZA

On behalf of Duke Energy Florida, LLC

C18-1570

I. INTRODUCTION AND SUMMARY.

Q. Please state your name and business address.

A. My name is John R. Panizza, and my business address is 525 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Business Services, LLC ("DEBS") as Director, Tax Operations. DEBS provides various administrative and other services to Duke Energy Florida, LLC ("DEF" or the "Company") and other affiliated companies of Duke Energy Corporation ("Duke Energy").

Q. What are your duties and responsibilities with respect to DEF?

A. As Director, Tax Operations, I have overall responsibility for corporate tax compliance and accounting for Duke Energy and therefore its subsidiary DEF. The Duke Energy Tax Operations Department, which I manage, is staffed by the public accounting firm Ernst & Young to provide efficient and technical tax services, and is responsible for all federal, state, and local income tax returns for Duke Energy, including various joint ventures if Duke Energy is the designated tax matters partner. The Duke Energy Tax Operations Department is also responsible for maintaining and reconciling Duke Energy's tax accounts and for the reporting and disclosure of tax-related matters.

Q. Please describe your educational background and professional experience.

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A. I have a Bachelor of Science degree in Accounting from Montclair State University and a Master's in Taxation from Seton Hall University. I am a Certified Public Accountant in the state of New Jersey. My professional work experience began in 1989 as an auditor with KPMG. From 1993 to 2002, I held several financial positions primarily at two companies, in telecommunications and automotive (AT&T Corp., and Collins & Aikman Inc.). In 2002, I joined Duke Energy and have held several financial positions of increasing responsibilities, including various accounting and tax related positions. In March 2018, after a three-year rotation primarily in Corporate Accounting, I moved back into the role of Director, Tax Operations, a position that I had previously held.

Q. Have you previously testified before this Commission or other State Public Utility Commissions?

A. Yes. I submitted pre-filed direct testimony before this Commission in the Company's previous Petition for a Limited Proceeding to Approve Rate Reductions Associated with the Inflation Reduction Act of 2022 in Florida Public Service Commission ("FPSC") Docket No. 20220172-EI. I have also filed testimony on behalf of Duke Energy operating utilities in proceedings before the North Carolina, South Carolina, Indiana, and Kentucky utility commissions.

Q. What is the purpose of your direct testimony?

A. My testimony addresses DEF's income tax expense presented in this proceeding, including DEF's treatment of excess deferred income taxes ("EDIT") balances arising from the 2017 Tax Cuts and Jobs Act ("Tax Act"), and background on the proration adjustment to the

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capital structure. I also summarize the key tax related components of the Inflation Reduction Act of 2022 ("IRA") most applicable to DEF in this proceeding.

Q. Do you sponsor any schedules of the Company's Minimum Filing Requirements ("MFRs") and Exhibits?

A. Yes, I sponsor or co-sponsor the following MFR schedules and Exhibits, and they are true and accurate, subject to being updated during this proceeding:

B-22 Accumulated Deferred Income Tax
B-23 Investment Tax Credits – Annual Analysis
C-6 Budgeted vs. Actual Operating Revenue & Expense
C-8 Detail of Changes in Expenses
C-9 5 Year Analysis – Change in Cost
C-20 Taxes Other Than Income Taxes
C-21 Revenue Taxes
C-22 State & Federal Income Tax Calculation
C-23 Interest in Tax Expense Calculation
C-25 Deferred Tax Adjustment
C-26 Income Tax Returns
C-27 Consolidated Tax Information
C-28 Miscellaneous Tax Information
C-35 Payroll & Fringe Benefit Increases Compared to CPI
D-1a Cost of Capital

Exhibit JRP-1 – Calculation of PTCs In Test Periods

Exhibit JRP-2 – Calculation of Proration Adjustments

Q. Please summarize your testimony.

A. My testimony addresses DEF's income tax expense presented in this proceeding, DEF's compliance with the 2017 Revised and Restated Stipulation and Settlement Agreement ("2017 Settlement")[1] methodology for amortization of EDIT balances, and the proration

[1] Approved in Order No. PSC-2017-0451-AS-EI.

adjustment to Accumulated Deferred Income Taxes ("ADIT") for calculating the capital structure for the projected test periods. I also summarize the key tax related components of the IRA and provide an overview of the impacts most applicable to DEF in this proceeding.

Based on these facts and others that are discussed more fully in my testimony, the Company's forecasted tax costs are reasonable and should be approved in this proceeding.

II. <u>INCOME TAX EXPENSE</u>

Q. What tax rate did the company use to calculate its historical, prior, and projected test periods federal income tax expenses?

A. The Company used the statutory Federal corporate income tax rate of 21 percent for the historical, prior, and projected test periods.

Q. What tax rate did the Company use to calculate its historical, prior, and projected test periods state income tax expense?

A. The Company used the statutory Florida corporate income tax rate of 5.5 percent for the historical, prior, and projected test periods.

Q. Please discuss the concept of ADIT.

A. Many timing differences exist between when items are recognized in the financial statements and when they are recognized in the tax return. These timing differences are referred to as temporary differences. A temporary difference is a difference between the tax basis of an asset or liability, determined based on recognition and measurement requirements for tax positions, and its reported amount in the financial statements that will result in taxable or deductible amounts in future years when the reported amount of the asset or liability is recovered or settled, respectively.

Deferred tax assets and liabilities represent the future effects on income taxes that result from temporary differences and carryforwards that exist at the end of a period. Deferred tax assets and liabilities are measured using enacted tax rates and provisions of the enacted tax law. All deferred tax balances, whether they are assets or liabilities, reverse over time and converge to zero over the life of the underlying item giving rise to the deferred tax balance.

Q. How has federal EDIT from the Tax Act impacted customer rates in the historical, prior, and projected test periods?

A. The 2017 Settlement methodology provided that EDIT should be flowed back to customers over a term consistent with the law. For protected EDIT, the Company applies the Tax Act-prescribed IRS tax normalization rules. The amortization methodology the Company uses is called the Average Rate Assumption Method ("ARAM"). ARAM is the method under which the excess in the reserve for deferred taxes is reduced over the remaining lives of the property as used in its regulated books of account which gave rise to the reserve for deferred taxes. The total amount of EDIT amortization will fluctuate year to year.

For unprotected EDIT, the amount of EDIT to amortize was less than $200 million and therefore amortized over five years. The amortization began in 2018 and ended in 2022.

Since the amortization ended in 2022 there was no impact to the forecasted test periods of 2025-2027 in this case.

III. PROR<u>ATION ADJUSTMENT.</u>

Q. Has the Company made an adjustment to the amount of ADIT included in its capital structure?

A. Yes, the Company has made a proration adjustment to apply proration to all property, plant & equipment-related ADIT activity including activity related to EDIT. The proration formula treats all activity prior to the test period as historical data; therefore, the beginning balance of the proration formula will not include any prorated amounts even though it is based on a projected balance. Proration takes the place of the averaging convention. The depreciation-related prorated ADIT balance replaces the 13-month average balance in the weighted average cost of capital ("WACC") and therefore is a specific adjustment to ADIT in the WACC calculation. The decrease in ADIT because of the proration formula results in a corresponding pro-rata increase to all other sources of capital in the cap structure. The decrease in ADIT is assumed to be funded with other sources of capital thereby keeping the capital structure equal to rate base.

Q. Why is the proration adjustment being made in this rate case?

A. ADITs are included as a component of zero-cost capital in DEF's capital structure. To comply with the Internal Revenue Code ("IRC") set forth under Treasury Regulation §1.167(l)-1(h)(6), ADIT treated as zero cost capital, or a component of rate base, in determining a utility's cost of service must be determined by reference to the same period as is used in determining the income tax expense utilized for ratemaking purposes. If the amounts are computed using projected data, in whole or in part, and the rates go into effect during the projected period, then the utility must use the proration formula provided in Treasury Regulation §1.167(1)-1(h)(6)(ii) to calculate the amount of ADIT to be included for ratemaking purposes. Because DEF expects the base rate increase(s) to become effective in the first billing cycle of the 2025-2027 projected test periods, DEF is required to comply with Treasury Regulation §1.167(1)-1(h)(6).

Q. Do the Treasury Regulations require the Company to follow a certain formula to adjust ADIT during the test period?

A. Yes. There is a specific "proration formula" that must be applied to project depreciation-related ADIT. The pro rata amount of any increase during the future portion of the period is determined by multiplying the increase by a fraction, the numerator of which is the number of days remaining in the period at the time the increase is to accrue, and the denominator of which is the total number of days in the future portion of the period. The proration formula prorates the projected accruals to the reserve to account for the actual time these amounts are expected to be in the reserve. The impact of the proration adjustment is reflected in MFR Schedule D-1 Cost of Capital which provides the projected proration of depreciation-related ADIT and federal EDIT for years 2025-2027 and Exhibit JRP-2 Calculation of Proration Adjustments which provides the calculation of the projected proration of depreciation-related ADIT and federal EDIT for years 2025-2027.

IV. <u>SUMMARY OF TAX-RELATED CHANGES IN THE IRA</u>

Q. What are the impacts of the IRA to DEF in this proceeding?

A. The key tax-related components of the IRA that impact DEF in this proceeding include modifications made to the production tax credit ("PTC") and the investment tax credit ("ITC") provided under IRC §§ 45 and 48, respectively, and the introduction of a corporate alternative minimum tax ("CAMT") based on adjusted financial statement income. In particular, the IRA expands PTC eligibility to solar generation and ITC eligibility to stand-alone energy storage projects, such as battery storage.

The IRA tax credit for which DEF expects to qualify – and whose impact on the revenue requirement is at this time capable of estimation, is the IRC § 45 PTC related to solar projects. The amount of tax benefits associated with the solar PTCs that customers will ultimately receive will be reduced by costs associated with obtaining and maximizing the value of the tax benefits. Examples of these costs could include, but are not limited to, legal fees, investment banker fees, and costs to cure the prevailing wage requirements. The amounts of the PTCs estimated in the forecasted periods are $64.563 million, $95.934 million, and $117.008 million for 2025, 2026 and 2027, respectively, as reflected in Exhibit JRP-1 Calculation of PTCs in Test Periods. The estimated PTCs do not reflect a reduction for associated costs.

Q. What could impact the actual PTCs for which DEF will qualify?

A. The actual credits could change, given the impacts of bonus credit amounts available under certain prevailing wage and apprenticeship standards, as well as domestic content and qualified facilities located in applicable energy development communities. In addition, the IRA contains provisions that allow both PTC and ITC credits to be transferred. Under new IRC § 6418, an

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eligible taxpayer can elect to transfer all (or any portion specified in the election) of an eligible credit to an unrelated transferee taxpayer. The transfer may have the effect of accelerating monetization of these credits. The transfer, however, must be paid in cash, not be included in the income of the recipient taxpayer, and not be deducted by the paying taxpayer. Further, the transfer must be a one-time transfer (i.e., the transferee cannot make a subsequent election to further transfer any portion of the transferred credit). The taxpayer must elect to transfer the credits no later than the due date (including extensions) for the tax return for the tax year for which the credit is determined, and any election, once made, is irrevocable. Furthermore, the costs associated with each transaction reduce the benefit to be returned to customers and may vary by transaction.

DEF believes that availing itself of the market for transferable credits may ultimately be beneficial to customers in that it would provide DEF with the opportunity to monetize the cash benefit of the credit more rapidly. While a discount on the total credit value is expected upon the sale and transfer of the credit, the economics for these credit transfers is still uncertain as a market will need to develop.

DEF assumed that the PTC projects would meet the prevailing wage and apprenticeship guidance and would be transferred at 90 cents on the dollar. DEF has assumed that no projects eligible for the PTC will be eligible for the bonus credits described in IRC § 45(b)(9) or § 45(b)(11) (domestic content and energy communities). The forecasted PTC credits do not reflect a reduction for associated costs except for the transferability discount at 90%. Given the uncertainty in forecasting the credits, DEF is proposing a solar PTC tax credit true-up which is discussed in greater detail in the testimony of Witness Marcia Olivier.

Q. Has DEF made other assumptions in the forecasted periods with respect to tax credits?

A. DEF projects to amortize $1.012 million, $1.458 million, and $2.497 million of IRC § 48 ITCs related to standalone energy storage projects in 2025, 2026, and 2027, respectively.

In addition, DEF could incur tax liability related to the CAMT provisions during tax years beginning after December 31, 2022. DEF estimated current CAMT of approximately $15.116 million in the 2027 test period, offset by a CAMT deferred tax asset of the same amount. However, the application of the CAMT framework is still uncertain.

V. <u>CONCLUSION</u>

Q. Does this conclude your testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Lesley G. Quick was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Duke Energy Florida, LLC	**Docket No. 2024025-EI Submitted for filing: April 2, 2024**

DIRECT TESTIMONY

OF

LESLEY G. QUICK

On behalf of Duke Energy Florida, LLC

C19-1585

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Lesley G. Quick. My business address is 525 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I am Vice President of Customer Advocacy, Regulatory Engagement and Support within Customer Services for Duke Energy Corporation, including Duke Energy Florida ("DEF" or the "Company"). DEF is a subsidiary of Duke Energy Corporation ("Duke Energy").

Q. Please describe your educational background and professional experience.

A. I have a bachelor's degree in financial management from Clemson University. I started with Duke Energy two weeks after graduation from Clemson in 2002, and I have remained an employee for the past 21 years. Since 2002, I have worked for Duke Energy in a variety of roles, each with increasing responsibility. I have worked in Finance, Rates and Regulatory Compliance, Corporate Strategy, Customer Solutions Products and Services, Revenue Services, and Customer Services. I assumed my current position in Customer Experience and Services in July 2022.

Q. Please describe your duties and responsibilities as Vice President of Customer Advocacy, Regulatory Engagement and Support within Customer Services.

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A. My responsibilities include the oversight, leadership, integration, and implementation of strategic business planning governance, change management, audit and compliance requirements, customer technology support, digital experience transformation, and enhanced customer communications. I provide direction and leadership in the development of organizational business plans to ensure alignment and achievement of objectives, regulatory compliance and reporting, key performance indicators, and operational metrics. Additionally, I lead the Customer Advocacy division. Customer Advocacy is responsible for enhancing support for our customers by expanding outreach with local, state, and federal agency partners to improve access to assistance funding.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to highlight DEF's service to our customers and to describe how we have improved and plan to continue to improve our customer service. I outline some of the steps the Company is taking to continue improving the experience and satisfaction of our customers when they engage with us.

Q. Do you sponsor or co-sponsor any schedules of the Company's minimum filing requirements?

A. Yes. I am a co-sponsor supporting the costs and/or investments related to Customer Operations in the following Minimum Filing Requirements ("MFRs"): B-7, B-8, B-9, B-10, B-11, B-13, C-6, C-8, C-9, C-11, C-12, C-15, C-16, C-35, C-36, C-37, C-41, and D-6. They are true and accurate, subject to being updated during the course of this proceeding.

Q. Do you have any other exhibits to your testimony?

A. No. I do not have any exhibits to my testimony.

Q. Please summarize your testimony.

A. DEF considers customer service a top priority and works to provide a customer experience that is informed by both customer and employee feedback. As I demonstrate in my testimony, DEF accomplishes this by engaging customers across multiple platforms and offering robust customer care centers with dedicated support for residential and commercial customers across the Company's diverse customer base. My testimony describes the digital enhancements underway that provide customers with more information and options than ever to manage their own account and services, and I elaborate on the ways in which DEF utilizes and tracks customer feedback and survey reporting to tailor customer offerings and continuously improve its support.

II. <u>SUPPORTING OUR CUSTOMERS</u>

Q. How does the Company view customer service?

A. DEF strives to exceed customer expectations by building genuine connections with all customers, soliciting customer feedback, taking note of evolving customer expectations, anticipating customer needs, leveraging emerging technologies, and offering dynamic solutions to customer issues. Providing our customers with the service they need drives our policies, programs, and decisions.

Q. Please provide an overview of the Company's customer experience and services functions.

A. DEF's Customer Experience and Services functions are comprised of multiple departments responsible for developing and executing policies, processes, and procedures to successfully engage with our customers across multiple communication channels. The primary channels our customers use to interact with the Company are phone, email, social media (Facebook, Instagram, LinkedIn, and Twitter/X), a mobile application, DEF's website, and face-to-face interactions. Our organization includes customer care operations, large account management, assistance agency support, customer experience, customer technology, metering field services, complaint resolution, billing and payment processes, and credit and collections activities.

Q. Please describe the operation of the customer care centers.

A. Our customer care operations are designed and continuously enhanced to ensure that customer inquiries are answered promptly and accurately. There are several locations and numerous remote agents that handle inbound and outbound calls, as well as emails, web inquiries, mailed letters, faxes, and social media inquiries. Over 1,200 Duke Energy representatives are available and ready to process and support work in response to Florida customer inquiries. The Company also utilizes vendor call centers to supplement internal Duke Energy customer care specialists.

Customer calls are either processed in our Interactive Voice Response ("IVR") system, allowing customers to self-serve, or by a call center specialist. In 2023, DEF received an average of 634,000 phone calls per month to the IVR system, of which approximately 58% were handled completely within the IVR (i.e., successfully self-served), with the remaining callers speaking with a customer care specialist.

Q. Does the Company consider the diverse needs of the DEF customer base when providing service?

A. Yes. The Company understands that its customers have diverse service needs and strives to recognize and accommodate those diverse needs when possible. For example:

- Account managers are assigned to our large, complex customer accounts to answer questions, resolve issues, and manage the customer relationship.
- The Business Service Center ("BSC") is focused on providing a more tailored service model for our SMB customers, customized by business segment. This model allows us to build a virtual account management system to handle requests and ensure customers can leverage all our digital channels for their unique business needs more effectively and efficiently.
- A variety of billing and payment choices are offered to make paying bills simple, secure, and convenient, such as paperless billing, Pick Your Due Date, Fixed Bill, and Budget Billing.
- An award-winning free mobile app for residential and small business customers allows those customers to easily manage their account from anywhere in the United States.
- Important information is shared with customers through monthly bill inserts, text, email, or the Company's website.

- Communication and customer service practices are available to address language, cultural, and disability barriers.
- Customer care specialists are available to provide 24/7 service for emergency and outage-related requests.

Q. Please describe how DEF's social media program has evolved to keep pace with evolving customer expectations.

A. With the rise in the use of social media in recent years, DEF has seen an increased number of customers contacting the Company for account-related questions through social media. The Duke Energy enterprise social media channels continue to grow, with more than 730,000 followers on its Facebook, Twitter/X, Instagram, and LinkedIn pages. The Company uses these channels to inform customers about reliability updates in their area and changes that could impact their bills. Further, in an emergency or major storm, social media is used to communicate important information to customers. This allows DEF to make proactive posts providing warnings and safety information to quickly reach as many customers and stakeholders as possible, engage with customers who have storm- or outage-related questions, and monitor how messages are being received and answered. Moreover, the Company has posted updates, including videos detailing storm restoration progress and photos of significant damage to infrastructure, to show customers the scale of repairs underway.

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III. TRANSFORMING THE CUSTOMER EXPERIENCE

Q. Is the Company continuing to make digital enhancements to better serve its customers?

A. Yes. The Company makes strategic, value-based investments for the benefit of our customers. Some examples of the benefits to customers are discussed below.

Q. How is the Company improving interactions with customers?

A. Examples of improved interactions with customers include: the deployment of Customer Connect, enhancements to our IVR system, and online portal enhancements.

Customer Connect

The Company implemented a new customer information system platform, Customer Connect, in November 2021. Customer Connect helps the Company deliver a customer experience that simplifies, strengthens, and advances our ability to serve customers. It provides a modern, configurable billing engine and is based on a customer-centric data model that provides a more personalized experience for customers. To that end, customers are now taking advantage of more automated processes and enhanced billing and payment options using new or enhanced self-service capabilities.

Interactive Voice Response ("IVR")

Since launching the advanced language IVR system in 2019, the Company has learned that customers want the ability to self-serve while navigating seamlessly through the IVR. Existing self-service functionality, such as requesting a payment arrangement and reporting a power outage, was improved via voice activated prompts, helping to provide a more positive customer experience. From 2021 to 2023, the IVR has increased its containment rate from 54.7% to 58%. This means that a higher percentage of customers that utilized the voice channel were able to self-serve, thus substantiating the effectiveness and efficiency of the IVR's self-service options.

New self-serve options through the IVR include allowing customers to enroll in or withdraw from Budget Billing, securely add their card information for easy access to make a payment, update their phone number, and request their account number. Another added feature is called First-in-Line, which allows customers, during busier-than-normal periods of call volume, to either remain on hold or select a call back number where they can be reached when a service representative becomes available. During 2023, approximately 300,000 DEF customers were offered a call back option through the First-in-Line feature, with over 115,000 accepting the offered call-back thus relieving customers from long wait times.

In addition to the capabilities now available through Customer Connect and the improved IVR, DEF can better connect with customers through texting experiences. Prior to these technology enhancements, the Company was limited to sending web links to static forms that still required manual processing. The new capabilities allow for more dynamic URLs to process requests, thereby reducing the need for manual intervention. For example, when a customer calls into the IVR for a start service request, we can offer to text them a link to the start service page, and if the customer prefers, they can complete their request from their device, allowing them to self-serve. Customers can also receive texts with additional options and links, such as bill reminders and confirmations, tree trimming information, payment locations, street light repair, and others.

In 2022, DEF enabled another new texting feature, two-way texting, which allows customers to respond to certain messages and reminders. For example, if a bill reminder is sent via text message, and a customer responds indicating that they are unable to pay by the due date, the system can recognize that message and provide relevant options or a link to set up an installment plan. These texting capabilities provide yet another avenue for customers to interact with the Company and to self-serve.

Web Portal

As of December 31, 2023, DEF's live chat functionality within the MyAccount portal has handled approximately 12,000 successful live chat sessions, primarily related to billing and payments. The chat icon is visible to customers during customer service business hours when a specialist is available. Upon identifying their account, the customer will be routed to a specialist. Based on activity seen and positive feedback received during the four-month pilot, the Company made live chat a permanent option for customers in February 2024. In addition, the functionality of live chat was recently enhanced to automatically identify account information based on web login credentials and to include frequently asked questions.

Q. How have the Company's digital enhancements made it easier for customers to report concerns with service outages?

A. Outage reporting was enhanced to make it easier for customers to report service interruptions through our website or mobile app. An internet form was launched that allows customers to provide greater detail about their outage, along with an option to enter free form comments to allow for more detail on the situation. The adoption rate of the new outage forms has grown, with the success rate increasing from approximately 55% with the legacy forms to 87% with the new forms. This indicates that more customers are staying on the internet to complete the submission rather than leaving the internet to call in the outage report.

This increased outage reporting information further allows the Company to digitally collect more detailed data about outage tickets, providing important information to our outage management system. For example, a customer can use the form to report downed wires or loud booms from the area, and our distribution control centers and crews see that detail. This provides more direct information of the immediate situation and field conditions at the scene of the outage.

The Company continues to proactively communicate with customers experiencing outages, providing updates to customers, via text or email, and up-to-date information on the new outage maps, without a customer having to call. Improvements were also made to the mobile app to ensure key outage data points were more visible to customers during active outages.

DEF also launched a new Street and Area Light Repair platform on the Company webpage in March 2021. This platform allows both customers and call center specialists to easily report streetlight issues. The tool enables reporting of detail for the exact problem, improving operational efficiencies on repairs. Additionally, customers can select to receive email or text updates on the progress of their requested repair. Chartwell, a company that works with utilities to improve customer experience, satisfaction, and operational efficiency, recently awarded one of its 2022 Best Practices Awards in Outage Restoration to Duke Energy for this tool.

Q. What other efficiencies has the Company gained through digital enhancements?

A. Other examples of digital transformation efficiencies include the expansion of "Ping It." Ping It is a tool that utilizes Advanced Metering Infrastructure ("AMI") to remotely diagnose customer reported issues. This allows the Company to check the status of a smart meter in lieu of sending a technician to the premises, which is especially useful during major storm event restoration. The elimination of field visits reduces overall costs and allows DEF to focus resources on actual outages and improve overall service. Since 2022, the Company has updated the program to enhance its usage by the Customer Care Operations and Customer Delivery teams. The ability to retrieve information such as voltage data or meter communication status helps troubleshoot customer issues more efficiently. In 2022, the utilization of Ping It enabled DEF to close 23,000 outage tickets without a field visit, saving $2.4 million through 52.5% fewer field visits. In 2023, DEF avoided over 8,400 outage tickets and closed approximately 17,000 outage tickets without a field visit, thus saving approximately $2.6 million.

The Ping It program continues to be especially useful during major storms. In fact, during Hurricane Ian in September 2022, Ping It was used approximately 36,000 times to determine a customer's service. In over 6,100 cases, Ping It successfully validated that the customers' service had been returned and closed associated outage tickets, avoiding the need to dispatch technicians. During the most recent storm, Idalia, in September 2023, Ping It was used approximately 36,000 times and resolved more than 2,000 cases without the need to dispatch technicians.

Additionally, the Company has developed the Usage Alert program, which utilizes AMI technology and data to send customers timely, accurate, and easy to understand usage information to provide transparency into their estimated electricity costs and help them stay on budget and in control of their usage. In 2023, Customer Services brought the digital production and distribution of usage alerts in-house rather than utilizing an outside vendor's services. This change generates financial savings, creates an enriched usage experience across platforms, and ultimately provides a more personalized experience to a larger group of customers. This decision will provide $1.4 million in net annual savings to the Duke Energy enterprise and further leverage the functionality of DEF's AMI meters.

Finally, as outlined above and described further below, customer usage of self-service options continues to increase. Since 2021, DEF call volume has dropped by 21%, while the number of website and mobile application customer sessions increased 52%.

Q. Please describe how digital enhancements have made it possible for customers to manage their own accounts and service more easily?

A. The Company's digital enhancements provide customers more information and options than ever to manage their own account and services. For example, Duke's free mobile app allows residential and small business customers to easily manage their account from anywhere in the United States. The app was developed based on customers' most requested features – with it, customers can: view and pay their bill; use the app to manage their profiles; set reminders; schedule automatic payments; enroll in billing and payment programs or view their billing history; report an outage and receive restoration updates; monitor their energy use over time so they can better manage it; and receive personalized offers that help them save. The app uses the same login as the customer's current online account and has an option to use fingerprint or facial recognition for a fast, secure sign-in. The mobile app has been well received by our customers, with user registrations increasing over 200% since the app was originally offered in 2019.

In April 2023, a chatbot feature was added to the mobile app to help customers navigate the site more easily, answer frequently asked questions or navigate to other features outside of the mobile app (e.g., directs customers to the Company's full website for additional information or into the authenticated space for certain account specific features). Since its implementation, approximately 214,000 users have interacted with the chatbot across all Duke Energy utilities. In April 2023, the Company was recognized for the success of the chatbot through winning the gold Chartwell award for the chatbot's functionality.

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In addition, in November 2021, Remote Order Fulfillment ("ROF") enabled same day start service through AMI meters in connection with Customer Connect. Customers can request same-day, Saturday, and digital self-service options. This enhancement has increased efficiency in operations and customer satisfaction. Since the enablement, over 309,000 residential customers have requested same-day service, which is approximately 35% of total start service requests. Additionally, a recent enhancement to the IVR system informs calling customers about same-day self-service and can generate a text message to the customer with a direct link to the online form. During 2023, approximately 30% of all DEF start service orders were submitted online through the digital self-service tools. By coupling ROF with remote meter reading capabilities, DEF has been able to redistribute resources to advance other strategic investments.

Our Company applications, updated website, AMI meters, and Customer Information System allow us to offer various programs and products and better communicate with customers. Many of our products and services are available and communicated through multiple digital channels. For example, Pick Your Due Date, which the Company offers through an online web form and through call center enrollment, enables customers to select the billing date that best aligns with their financial situation. Usage alerts, which include current electricity cost and projected costs, are sent via email or text to customers at the midpoint of their billing cycle, and eligible customers are automatically sent payment confirmations via email or text.

Finally, the Company has improved our customer payment confirmation messaging. Customers will now see the dates their payment was posted. If a customer's balance is paid in full, the customer will see a message stating $0 remaining balance. These messages can provide other account insights to the customer, such as indicating that an account is at risk for disconnection. Also, with the deployment of the new customer information system, a bill reminder message was introduced, which reminds customers three days prior to a bill due date if they had not yet paid. These changes were made to be more informative when communicating with customers who choose to interact digitally with us.

IV. <u>CUSTOMER SATISFACTION AND COMPLAINT RESOLUTION</u>

Q. How does the Company measure customer satisfaction?

A. DEF recognizes that customer expectations continuously evolve and that it is critical to hear and understand the "Voice of the Customer" to improve overall customer satisfaction ("CSAT"). To that end, the Company operates a robust CSAT program, which includes both national benchmarking studies and proprietary relationship and transactional CSAT studies. The Company analyzes results from these studies in monthly data review sessions, with findings driving improvements to processes, technology, and behaviors – all to continuously improve the customer experience.

DEF measures overall customer satisfaction and perceptions about the Company through an ecosystem of measurement tools designed to understand what is working well from a customer perspective and to identify opportunities to improve the customer experience. In 2018, the Company launched the CX Monitor, a randomized, census-based survey that measures overall customer sentiment and the ongoing perceptions of the customer experience. The CX Monitor survey is sent annually via an email with an embedded online survey link to all residential customers; small, and medium business ("SMB") customers; and large business customers for whom we have a valid email address. Customers are asked to give feedback on their overall sentiment and satisfaction with key experiences, such as billing and payment, power quality and reliability, that they have had with us over the past year. Customers can rate overall sentiment and key experience satisfaction on a 0-10 scale and also provide open-ended comments detailing the primary reason(s) for their score.

Since its implementation in 2018, the CX Monitor has collected more than 798,000 residential electric customer surveys and over 8,500 SMB customer surveys for DEF. As of December 2023, DEF has seen an improvement in overall customer sentiment since 2018 as data-driven enhancements continue to improve the customer experience. Further, DEF customers reported some of the highest monthly scores to date during the COVID-19 pandemic, a particularly challenging time that led to significant financial hardship for many of our customers and communities. In response, DEF launched a sweeping series of unprecedented steps to help our customers, including suspending disconnections for nonpayment, suspending late-payment fees and credit card payment fees, offering flexible payment arrangements to customers with past-due balances, and connecting customers to federal funding to help those in need of economic assistance. The Company's ability to pivot and to do so quickly was recognized by our customers and resulted in the highest customer satisfaction ratings the Company has experienced in several years. Customer sentiment remains high today, at or above pre-pandemic levels.

C19-1601

In addition to our CX Monitor survey, the Company uses “Fastrack 2.0,” a proprietary, post-transaction CSAT measurement program. Fastrack 2.0 measures customer satisfaction with recent Company interactions. Fastrack 2.0 was intentionally designed to complement the CX Monitor survey, provide greater insight into experiences that matter to our customers, and offer near-real time feedback to our front line, customer-facing employees. The survey questions cover the customer’s experience regarding completed field work, including requests to start and transfer electric service, repair outdoor lights, and restore outages. Analysis of these ratings helps identify specific service strengths and opportunities that drive overall satisfaction and provides guidance for the implementation of process and performance improvement efforts. In the past year alone, DEF has collected more than 33,000 residential and SMB Fastrack 2.0 surveys, with 60-87% of customers regularly providing the highest satisfaction ratings (9 or 10 on a 10-point scale).

The Company also implemented “Reflect,” a post-contact survey that offers customers the opportunity to provide immediate feedback after they contact the Company by web or phone call (either to the automated system or to a live agent). This tool provides critical feedback to help improve the channel’s customers’ use when interacting with the Company. In 2023, Reflect collected more than 88,000 responses from DEF customers, with 65-80% of customers regularly providing the highest satisfaction ratings (9 or 10 on a 10-point scale).

Q. How does a customer bring an issue to the Company’s attention?

A. DEF customers have numerous avenues to voice an issue, including through our customer care team, social media platforms or website, email, our employees, or our Ethics line. In addition, as I previously mentioned, CX Monitor and Fastrack are two key proprietary surveys DEF uses on an ongoing basis to track customer feedback. At the end of each survey, customers can provide additional comments regarding any outstanding questions that still need to be answered or issues that still need to be resolved. These comments are converted into high priority "Hot Alerts" and forwarded to the Consumer Affairs team to resolve, and a member of our customer service staff directly contacts the customer to ensure satisfactory resolution to the customer's question or issue. Separately, a Hot Alert may be triggered by an automated key word software review of survey statements, which may indicate customer frustration or a poor experience, even if the customer did not directly ask for follow up.

In addition, customers can raise issues and inquiries directly with our employees. Our employees can then use the "I Can Help" tool to report the concern and immediately begin the process of resolving the issue, as well as track the issue's resolution. Thus, while the Company continues to seek feedback from customers through its various survey instruments, we are also making it easier for customers to proactively contact us, receive follow-up, and resolve issues. Most importantly, the Company is using innovative tools to reduce customer complaints and the need for customers to escalate an issue. At the end of 2023, the average number of complaints per 10,000 customers continued to trend downward since 2019.

V. CHANGING FEE-FREE PAYMENT OPTIONS

Q. What changes has the Company implemented to the fee-free payment program for residential customers as approved in its previous rate case?

A. The Company continuously seeks opportunities to lower costs for customers and to meet the growing need for affordable payment options for customers. In 2023, Duke Energy worked with third-party payment processing vendors to amend contract terms to be more favorable to customers. The amended contract will lower the residential transaction fee from $1.50 to $1.25 per transaction. This lowered fee is estimated to yield an average savings of approximately $100,000 per month based on average transaction volume.

Q. Were there other changes to the contract beyond the residential fee noted above?

A. Yes. The amended contract will offer free ACH transactions to non-residential customers who pay their monthly bills via ACH. Based on average transaction volumes, these customers are expected to save $374,000 annually. Additionally, non-residential credit card transaction fees will be 2.75% of the transaction amount rather than the $8.50 per transaction currently charged. The Company anticipates that the majority of small business customers paying via card will experience cost savings from this amendment.

Q. Please describe the Company's efforts to support its low-income customers.

A. There are multiple programs and assistance options designed to support our low-income customers. For example, in 2023, DEF connected approximately 46,000 customers with assistance agencies that administer the Low-Income Energy Assistance Program ("LIEAP") and Elderly Home Energy Assistance Program ("EHEAP") and collected approximately $27 million in pledges towards customer electricity bills. Additionally, Duke Energy's Share the Light Fund assists customers struggling to pay their energy bills. In 2023, Duke Energy employees, customers and shareholders contributed approximately $512,000 to the Share the Light Fund, plus a Company match of $706,000 from the Duke Energy Foundation. Since 2020, Duke Energy and our foundation have funded more than $27.5 million in charitable giving across the state of Florida.[1]

In addition, the Company realized that a more tailored experience was needed to provide more efficient service for those agencies providing customer assistance funding. To streamline and efficiently apply pledges to our customers' accounts, our Centralized Agency Team became the single point of contact for utility assistance agencies. In addition to the Centralized Agency Team, a new digital, self-service portal was developed. The portal provides agencies a confidential and secure way to view customer account details, process agency commitments, and make payments. Agencies can conveniently and more efficiently view pledge history on customer accounts to make more informed pledge decisions and receive notification of pledge expirations to ensure their commitments are satisfied.

VI. CUSTOMER EXPERIENCE AND SERVICES O&M EXPENSE

Q. Please provide an overview of Customer Experience and Services' O&M expenses.

A. Customer Experience and Services' O&M expense is driven by several key activities including billing, payment processing, customer care, credit and collections, and various

[1] Charitable giving from the Duke Energy Foundation is not recovered from customers.

field and support activities to serve DEF customers. While there will always be necessary expenses to serve our customers, the Company continually looks for ways to efficiently use resources. For example, the Company has found cost savings related to digital solutions that customers adopt rapidly, such as IVR self-service, Ping-It, usage alerts, and online self-service options. These examples allowed the Company to manage its overall customer service O&M expenses.

Q. How do the Customer Accounts, Customer Service & Information, and Sales functional areas of O&M expenses for the 2025-2027 test years compare to the Commission's O&M benchmarks (MFR C-41, O&M benchmark variance by function)?

A. The Customer Accounts (FERC Accounts 901 through 905) 2025 through 2027 Test Year O&M expenses are significantly below the Commission's O&M benchmark thresholds for that functional area, by approximately $50 million. The Customer Service & Information (FERC Accounts 908 through 910) 2025 Test Year O&M expenses are only $1 million above the Commission's O&M benchmark threshold in 2025 (due to new and expanded groups that are focused on growth and improving the customer experience) and very slightly over the benchmark for 2026 and 2027. The Sales (FERC Accounts 911-916) 2025 Test Year O&M expenses are slightly above the Commission benchmark thresholds (due to an increase in economic development expense consistent with Rule 25-6.0426, F.A.C.) and below the thresholds for 2026 and 2027.

Q. Are there any specific expense categories that the Company is monitoring?

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A. Yes. One expense category, Uncollectible Expense, has been trending higher since 2022. The higher account write-off trends are primarily a result of the Company's proactive measures to support our customers when they faced a time of uncertainty during and after the COVID-19 pandemic. Together with other Florida investor-owned electric utilities, DEF temporarily suspended disconnections for several months in 2020. When the Company began to return to more normal billing practices, we continued to provide additional flexibility and assistance needed by many customers, particularly vulnerable populations. When setting payment arrangements, the Company offered terms that included no down payments, extended durations of offers (e.g., up to 6 months), and restructured defaulted agreements without penalty. These customer-focused policy changes gave customers the support they needed to ensure every opportunity to maintain their electric service through an unprecedented time; however, these additional support measures resulted in higher uncollectible expenses in the years following when compared to pre-COVID levels.

In the last 12-18 months, the Company has made several changes to gradually move closer to pre-COVID credit policies to help alleviate the impact to uncollectible expenses. However, the effects of such changes will take time to be fully realized. For example, the Company's standard payment plan offer was reduced in early 2023 to only 2 months, the option to restructure after a default was removed, and customer deposits are now evaluated annually to ensure ample account security is held. The Company will continue to monitor, assess, and adjust credit policies as necessary to balance the needs of all customers.

C19-1607

Finally, in addition to COVID-era customer support impacting the Company's uncollectible expenses, increases driven by higher fuel costs (i.e., natural gas) in the past few years spurred higher bills, leading to larger unpaid balances.

VII. <u>CONCLUSION</u>

Q. Does this conclude your direct testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Edward L. Scott was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Duke Energy Florida, LLC

Docket No. 20240025-EI

Submitted for filing: April 2, 2024

DIRECT TESTIMONY

OF

EDWARD L. SCOTT

On behalf of Duke Energy Florida, LLC

I. Introduction and Summary

Q. Please state your name and business address.

A. My name is Edward L. Scott. My business address is 6565 38th Avenue North, St. Petersburg, Florida 33710.

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

A. I am employed by Duke Energy Florida, LLC ("DEF" or "the Company") as General Manager of System Operations, Florida. DEF is a subsidiary of Duke Energy Corporation ("Duke Energy").

Q. What are the duties and responsibilities of your position with DEF?

A. As General Manager of System Operations, I am responsible for the safe, reliable, economic, and regulatory compliant operation of the DEF power system. This is done by overseeing the real time electric system operations of DEF, including generation dispatch, transmission reliability, and transmission service transactions. I also serve as Vice Chair on the Florida Reliability Coordinating Council ("FRCC") Operating Committee.

Q. Please describe your educational background and professional qualifications.

A. I earned Bachelor of Science and Master of Science degrees in electrical engineering from the Florida Institute of Technology in 1998 and 1999, respectively. I also earned a Master of Science in Business Administration from the

University of Florida in 2007. I am a licensed Professional Engineer in Florida and North Carolina. I have been with the Company, and its predecessor companies, since 2001 in positions of increasing responsibility. Before my current role as General Manager of System Operations at the Florida Energy Control Center, I was Director of Transmission Planning for DEF and was responsible for all transmission planning activities. In this role, I was involved in many areas of the DEF's transmission system, including its design, construction, operation, and maintenance to provide reliable transmission service to the Company's retail and wholesale customers. I was also responsible for ensuring that long-range transmission plans, studies, and assessments were performed in accordance with all applicable Federal Energy Regulatory Commission ("FERC"), North American Electric Reliability Corporation ("NERC"), FRCC, and Duke Energy planning standards and requirements. I developed Generation and Transmission Integrated Siting Strategies, supervised the evaluation of Generator Interconnection Requests, and represented DEF on the FRCC Planning Committee. Additionally, I held prior leadership roles for the Company as Manager of System Operations, Manager of Bulk Transmission Planning, and Supervisor of System Operations. I also held several Company engineering positions with increasing responsibilities in Operations Engineering, Operations Planning, and Operations Training. Prior to joining the Company, I was a staff engineer and compliance manager with the FRCC.

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

A. Yes. In 2015, I gave direct transmission testimony in Docket No. 20150043-EI in support of the Company's Generation Base Rate Adjustment ("GBRA"). In 2014, I filed direct testimony in Docket No. 20140110-EI (Citrus County Combined Cycle Power Plant Need Petition) and Docket No. 20140111-EI (Suwannee Project and Hines Chillers Power Uprate Need Petition) describing transmission system impacts.

Q. What is the purpose of your direct testimony?

A. My testimony supports the Company's requested transmission capital and Operations & Maintenance ("O&M") expense for the test years applicable to this proceeding, namely, the projected 12-month periods ending December 31, 2025, 2026, and 2027. The requested transmission capital and O&M expense included in this case is set out in Table 1, below:

Table 1

	2025	**2026**	**2027**	**2025-2027 Total**
Capital	$503.8 M	$416.2 M	$407.3 M	$ 1,327.2 M*
O&M	$31.5 M	$32.7 M	$33.8 M	$98 M

** 2025-2027 Total may not foot due to rounding.*

These investments are necessary so DEF can meet the requirements of customer and load growth in an increasingly stringent regulatory environment, particularly pertaining to system reliability. These are some of the major challenges the Company now faces and will continue to face in the future. DEF must meet these challenges to continue providing safe and reliable electric services to its customers, which is the main goal of its transmission system.

Q. How is your testimony organized?

A. In Section I, in addition to information regarding my background and expertise, I have discussed the purpose of my testimony, including an overview of the Company's requested transmission expense over the test years applicable to this case, the Minimum Filing Requirement ("MFR") schedules I co-sponsor in support of the Company's request, and a summary of my testimony.

In Section II, I describe DEF's transmission system and provide background information regarding the Company's previous base rate case and transmission investment since that case.

In Section III, I discuss the operational performance of DEF's transmission system, and specifically the improvement in reliability metrics experienced by the Company over the last several years, which is evidence of DEF's investment in the system. I also discuss the practices, procedures, and controls utilized by DEF to ensure the cost effectiveness of the Company's transmission investments.

In Section IV of my testimony, I describe DEF's transmission capital and O&M expenditure requests in this case.

Finally, in Section V, I provide some concluding remarks, and note that the Company's transmission expenditure requests are prudent, reasonable, and necessary to provide service to our customers.

Q. **Are you presenting any exhibits with your testimony?**

A. Yes, I have prepared or supervised the preparation of the Exhibit ELS-1, a summary of co-sponsored schedules of the Company's MFRs. This exhibit is true and correct to the best of my knowledge, subject to being updated during the course of this proceeding.

Q. Please provide a summary of your testimony.

A. My testimony presents the Company's requested transmission capital and O&M expense for the test years applicable to this proceeding (2025-2027) and demonstrates that the requested investments are needed to provide safe and reliable transmission service to DEF's customers. These investments are necessary so that DEF can meet the challenges facing the Company, now and in the future – including customer growth, load growth, and increasingly stringent regulatory requirements regarding reliability.

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In outlining the Company's response to these challenges and supporting its transmission funding request, my testimony further demonstrates that DEF's past transmission investments have proven to be effective, as evidenced by the consistent improvement in its reliability metrics under standard industry-wide measures. In addition, my testimony details the extensive long-term strategic planning and cost management practices in which the Company engages. These practices and procedures show the Company's commitment to strengthening the transmission grid and increasing system reliability in a manner that has proven to be cost effective, demonstrating DEF's customer focus and excellent stewardship.

II. <u>Background – A Description of DEF's Transmission System, and Transmission Investment since the 2021 Settlement Agreement</u>

Q. Please generally describe the Company's transmission system.

A. The Company's transmission system includes approximately 5,300 circuit miles of transmission lines, which includes 500 kV, 230 kV, 115 kV and 69 kV lines. The Transmission system has more than 520 transmission substations and over 49,500 towers, poles and other related equipment and material that support a peak load of approximately 13,000 MWs. These assets deliver electric service to almost 2.0 million retail customers located throughout a 20,000 square mile area in densely populated areas around Orlando, St. Petersburg, and Clearwater, as well as rural north Florida, and west central Florida.

DEF's transmission system is part of the Florida interconnected power grid that enables utilities to exchange power. Within Florida, the Company's system is extensively networked and interconnected with other investor-owned utilities, municipal electric utilities, and rural electric cooperatives.

In addition to power lines and substations, the system includes various other equipment and facilities such as control houses, computers, structures, transformers, regulators, capacitors, breakers, communication devices, and protective relays. Together, these assets provide the Company with considerable operational flexibility with its transmission system and allow DEF to provide safe and reliable power to DEF's customers.

Q. How is the Company organized to manage its transmission system?

A. DEF manages its transmission system both locally and regionally with multiple shared support and service organizations. The Company maintains local control over transmission line and substation field, design engineering, project management, work management, construction, maintenance, and restoration activities. This organizational structure allows the Company to provide quick and responsive support in each region and fosters a sense of local ownership while leveraging shared services and support, where appropriate, to provide safe and reliable power to the Company's customers in Florida.

Q. Were transmission system investments addressed in connection with the 2021 Settlement Agreement?

A. Yes. I understand that DEF entered into a comprehensive settlement agreement with key consumer groups, approved by the FPSC in 2021, which I will refer to as the 2021 Settlement Agreement. My understanding is that the settlement facilitated base rate investment in many areas, including transmission investments to maintain reliability and meet the ongoing needs of the transmission system. The settlement also confirmed the transfer of costs previously recovered through base rates to the Storm Protection Plan ("SPP") cost recovery clause. This clause and related items are described in detail in the testimony of Company witness Brian Lloyd.

Q. Are DEF's capital and O&M expenditure requests in this case duplicative of any activities taken or that will be taken in connection with SPP requirements?

A. No. The expenditure requests in this case are entirely separate from any funds requested through the SPP and its cost recovery clause.

Q. With DEF now recovering certain costs through the SPP cost recovery clause, why does the Company need an increase in base rates?

A. The principal purpose of the Company's SPP investments is to systematically harden the system to better withstand the range of extreme weather conditions expected to impact Florida. But even apart from SPP expenditures focused upon weather conditions, Florida is experiencing significant economic development, and the Company is focused on making sure it is appropriately investing in the DEF transmission system and upgrading its infrastructure to meet this ever-growing demand. In addition, the transmission system investments that are the subject of DEF's request in this case are focused upon compliance with increasingly stringent regulatory standards and renewables integration into the grid, separate and apart from the Company's SPP requests. By maintaining and improving its transmission system, the Company reliably delivers power from generation resources to be distributed to customers' homes and businesses.

Q. Has DEF invested in its transmission system since the 2021 Settlement Agreement?

A. Yes, absolutely. Approximately $1.67 billion in capital has been invested from 2021-2023 in the DEF transmission system, and we project an additional investment of $578.4 million will occur during 2024. Since January of 2021, major transmission projects completed/energized during this timeframe include 108 miles of new lines, 97 miles of rebuilt lines, 16 new switching stations/substations, and interconnections of 14 new solar generation sites. The payoff has included significant improvement in the system's reliability, as measured by standard industry reliability metrics, as I discuss in the next section of my testimony. As I also discuss, these improvements have been accompanied by prudent and responsible management of operational and capital expenditures for our customers' benefit.

III. Operational Performance of the DEF Transmission System and Practices, Procedures, and Controls to Ensure Cost Effectiveness of Transmission Investments

Q. How have the transmission investments that the Company has made over the past several years impacted the operational performance of its transmission system?

A. As detailed further below, the trend line of the principal reliability metrics DEF utilizes to measure transmission system reliability has shown consistent improvement over the past six years, with the statistics showing that 2023 reflects the Company's best performance over this period. In addition, the testimony of DEF witness Brian Lloyd demonstrates that the reliability of the Company's Distribution function has also improved over this time period, an improvement that necessarily also reflects improvement in our transmission system reliability metrics.

Moreover, as further detailed below, the Company engages in extensive long-term strategic planning (including processes to identify optimal capital investment) and cost management practices. The procedures DEF has in place indicate not only the Company's commitment to strengthen the transmission grid and enhance the operation of our system, but also to do so in a manner that demonstrates we are being good stewards of the funds entrusted to us. Overall, the Company has seen positive reliability performance, which demonstrates DEF's overall commitment to system reliability and operational excellence in an efficient, safe, and cost-effective manner, ultimately benefiting our customers.

Q. What reliability metrics does the Company use to measure the reliability of its transmission system?

A. The Company utilizes reliability data to assess and track the performance of its transmission system using standard indices generally accepted in the electric utility industry. The principal metrics are:

- *Grid SAIDI – System Average Interruption Duration Index.*

  Grid SAIDI reflects the average number of minutes each customer was without power during a given time period, typically annually. It is determined by taking the sum of Grid CMI (customer-minutes of interruption) during all events[1] and dividing by the total number of grid customers served on DEF's system, as follows:

$$Grid\ SAIDI = \frac{\sum t_i N_i}{N_{total}} = \frac{Grid\ CMI}{\#\ of\ Grid\ Customers\ Served}$$

$Where$:

t_i: $Duration\ of\ Interruption\ in\ Minutes$

N_i: $Number\ of\ Customers\ Impacted$

N_{total}: $Total\ Number\ of\ Customers$

The Company includes DEF's total customer base, both retail and

[1] Standard industry practice excludes certain outages and events from the calculation of Grid SAIDI scores, such as interruptions caused by defined "Major Events." Major Events so defined include but not limited to hurricanes and other tropical cyclones named by the National Weather Service ("NWS"); winds 75 mph or greater confirmed by the NWS; extreme weather events; and icing beyond design parameters.

wholesale customers, in this metric. For Grid SAIDI, a lower number of customer minutes interrupted indicates better performance, and a downwards trend over several years indicates continuous reliability improvement.

- *OHMY-SA – Outages per Hundred Miles per Year – Sustained Automatic.* OHMY-SA measures the number of transmission line sustained outages[2] that are incurred per hundred circuit miles per year, as follows:

$$OHMY - SA\ Rate = \frac{\#\ of\ SA\ Outages\ on\ \geq 100kV\ Lines}{100\ miles}$$

Sustained is defined as any outage of one or more minutes in duration. This is a transmission industry standard performance measure applicable to circuits 100 kV and greater. Just like for Grid SAIDI, for OHMY-SA a lower rate, or lower the number of sustained outages, indicates better performance, and a downwards trend over several years indicates reliability improvement.

Q. How has DEF's transmission system performed against these metrics?

A. As Figures 1 and 2 show, DEF's transmission system performance has demonstrated continuous improvement since 2018 with Grid SAIDI, improving by 50%, and OHMY-SA improving by 14%:

[2] Similar to Grid SAIDI, standard industry practice excludes certain outage events from the calculation.

Figure 1

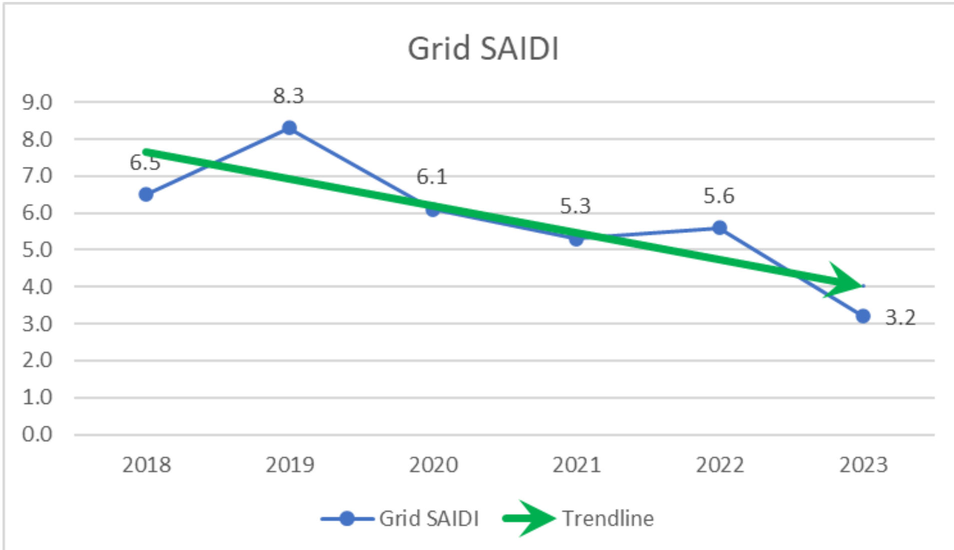
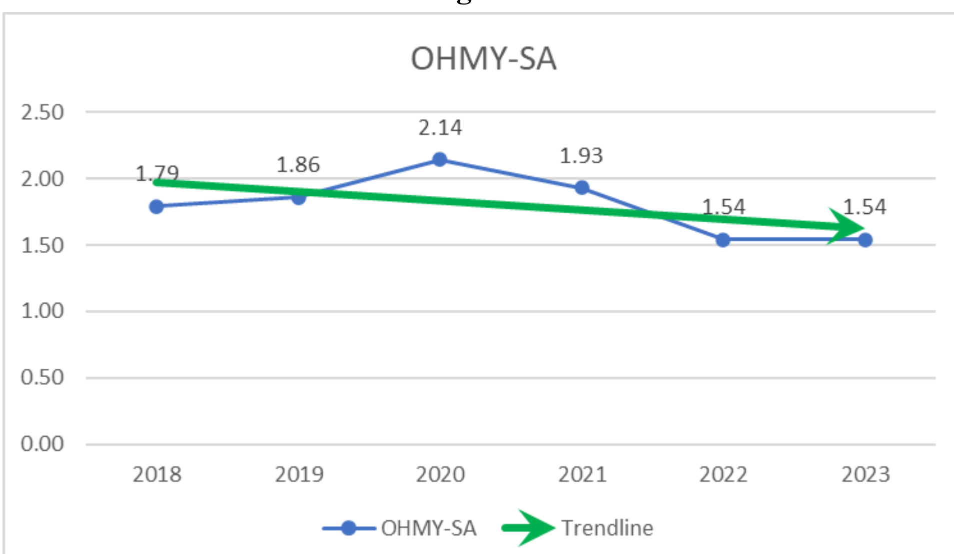


Figure 2



Q. What factors drive the results measured by the Grid SAIDI and OHMY-SA metrics?

A. The main drivers of Grid SAIDI and OHMY-SA performance are transmission line equipment, animal, and breaker events. DEF plans to invest approximately $280M to address such events throughout years 2025-2027.

Q. How does DEF ensure that funds are prudently allocated to the improvement of the transmission system?

A. DEF has processes in place to ensure prudent use of funds allocated to the transmission system. These processes combine long-term planning and asset evaluation along with robust cost and project management, demonstrating the Company's commitment to prudent and cost-effective stewardship of funds allocated to the transmission system.

Q. How does the Company determine the capital investments that are needed for continued positive reliability performance?

A. DEF performs annual evaluations to determine capital investment needs. The Company's transmission planning function annually analyzes the 10-year long-term capital investment plan based upon NERC, FRCC, and FERC regulations and standards. These assessments help the Company in its long-term transmission planning efforts, as the regulatory standards drive decisions regarding the Company's ability to meet reliability requirements. Likewise, DEF's transmission asset management function annually utilizes system reliability performance and asset assessment results to determine long term capital investments needs. I provide additional detail with respect to these processes below.

Q. Please elaborate on the annual transmission planning process.

A. Each calendar year, DEF's Transmission Planning group performs analyses for the long-term, ten-year transmission planning cycle. These analyses are performed from three distinct planning perspectives. First, Transmission Planning must demonstrate that the DEF system will be in compliance for the ten-year planning period with the mandatory and enforceable NERC Reliability Standards, particularly NERC Reliability Standard TPL-001. If the analysis shows that the DEF system deviates from these standards, the Company must initiate either an operational mitigation strategy or a new transmission capital project to bring the system back in compliance with the standards. Second, analysis is performed to demonstrate transmission system compliance with FRCC reliability standards. This analysis is similar to the analysis performed to ensure system compliance with the NERC Reliability Standards, the primary difference between the two analyses being that the FRCC treats the 69 kV system as if it is part of the Bulk Electric System (normally 100 kV and higher voltage facilities). Third, additional analysis is performed to address the interconnection of generation, transmission, and end-user facilities. This includes new residential and commercial loads that require capital expansion of DEF's existing transmission system. Proposed transmission capital investment projects resulting from these analyses must, per DEF's transmission planning process, be reviewed by other DEF departments and work groups affected by the proposals for feasibility and implementation. Projects are then added to the overall Transmission long term capital plan.

Q. Please elaborate on the annual asset management evaluation process.

A. DEF's Transmission Asset Management group annually analyzes long-term system and asset performance to identify proactive asset investment projects. The analysis includes tracking and trending of reliability metric data and review of ongoing health monitoring system data. In addition, Asset Management identifies crucial asset or system performance deficiencies from asset/system outages and other current data that require emergent projects or urgent site-specific reliability projects. Lastly, the group proposes capital investment projects which are prioritized based on risks. Asset Management prioritization includes health analysis of assets, reliability metrics, customer impact, environmental impact, regulatory compliance, field & engineering expertise, and industry standards. Asset Management leadership then reviews the prioritization, approves the project, and adds them to the overall Transmission long term capital plan.

Q. How do customers benefit from these long-term planning and assessment processes?

A. DEF's annual capital investment identification process, both with respect to long-term transmission planning and also transmission asset evaluation, ensures that replacement of the aging infrastructure, strengthening the transmission grid and enhancing the operation of DEF's transmission system is done on a periodic basis.

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This process ensures that capital investments continue to be evaluated using up-to-date information and reliability trends and is kept within NERC and FRCC regulatory standards and requirements. This results in continued improved reliability and operational performance for our customers.

Q. How has the Company provided a reliable transmission system to customers at reasonable cost?

A. DEF has proven to be a good steward of capital and O&M funds while continuing to improve the reliability of the transmission system consistent with customer needs and expectations. The Company continually incorporates processes, procedures, and practices to manage and control transmission-related capital and O&M costs. While certainly not an exhaustive list of implemented cost savings and/or efficiency enhancements, here are several examples of applicable practices:

- The establishment of an enterprise-wide Project Management Center of Excellence ("PMCoE") in 2014, followed by additional transmission project governance and oversight implementation, which further enhanced the Company's performance in project planning, execution, and effective cost control.
- The utilization of internal crews where feasible and utilizing contract strategies—such as estimate comparisons against internal estimates, competitive bid events, and bundled bid awards to drive cost savings.
- Capital project funding requests are scrutinized by multiple approvers to

ensure cost estimates are in line with comparable projects and have sufficient business justification.

- Transmission system engineering projects employ a comprehensive design review process across the various engineering disciplines that ensures an in-depth review of the project design at various points in the project life cycle (Conceptual Design/Final Design/As Built). The process requires review and sign-off from key stakeholders before the design packages are released for construction resulting in the most efficient design with a high degree of quality, maintainability, and constructability.

IV. DEF's Transmission Request

Q. What is the Company's transmission capital expenditure request in this case?

A. The transmission capital request included in this case is set out in Table 2, below:

Table 2

	2025	2026	2027	2025-2027 Total
Capital	$503.8 M	$416.2 M	$407.3 M	$ 1,327.2 M*

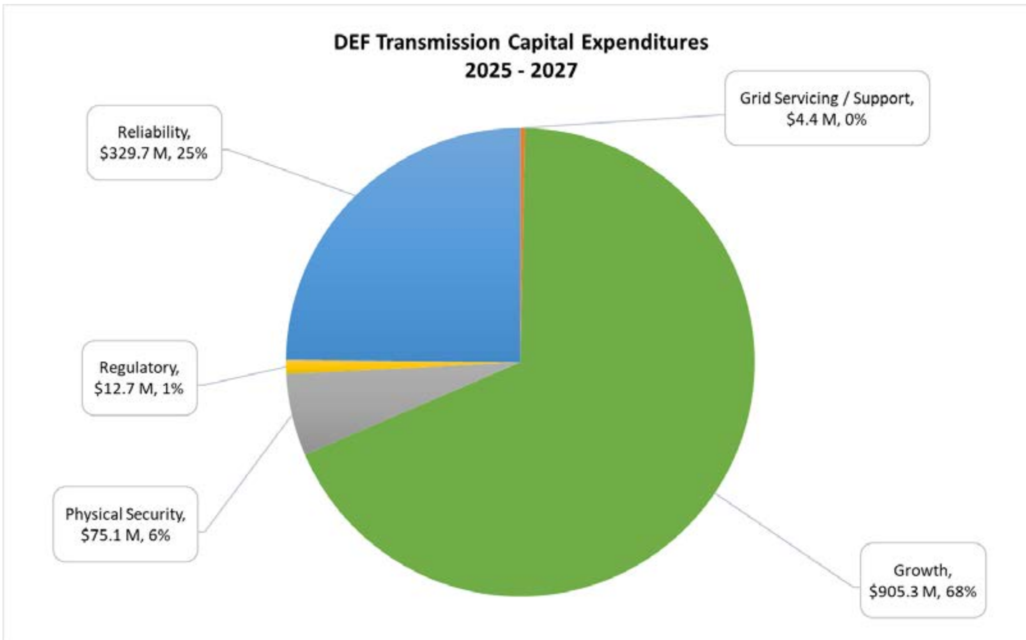
** 2025-2027 Total may not foot due to rounding.*

Q. What segments of transmission capital expenditure are included in the Company's request?

A. Transmission capital investments are organized into five major categories: (1)

Growth, (2) Reliability, (3) Physical Security, (4) Regulatory, and (5) Grid Servicing/Support. Figure 3 below illustrates the major categories of the transmission system's 2025-27 $1.3 billion capital expenditure request:

Figure 3



Q. Please provide additional detail of the Transmission Growth investment request.

A. As Figure 3 shows, approximately two-thirds of DEF's transmission capital expenditure requirements for 2025-2027 are allocated to the Growth category. Growth and system expansion include new service accounts, new major construction projects, and increased electrical demand in an area, all of which affect planning and operations on the transmission system. In planning for growth, DEF Transmission Planning uses load forecast data published in the annual DEF Ten Year Site Plan. Increased load due to new customers and/or increased customer usage/demand in certain areas requires additional infrastructure and/or installation of new facilities.

Q. Earlier in your testimony you indicate that the reliability standards the Company must meet are becoming increasingly stringent. Please elaborate.

A. I previously described in my testimony the interaction between transmission planning and NERC and FRCC reliability standards – briefly, the Company's Transmission Planning group performs an annual evaluation to demonstrate the transmission system's compliance with these standards over a ten-year planning horizon and identifies deviation from these standards. Any deviation must be addressed, either by operational changes or additional transmission investment. Much of the request allocated to the growth category is dedicated to projects identified by these NERC and FRCC reliability standards analyses.

In particular, the NERC reliability standard TPL-001 has undergone increasingly prescriptive modifications that directly relate to our request for 2025 and beyond. These TPL-001 revisions include mandatory performance requirements, which in most cases must be accomplished through the implementation of transmission capital projects such as new or upgraded 500 kV, 230 kV, and 115 kV lines and substations. An example of one such capital project is a new 230/115 kV Substation and two new associated 230 kV lines that are projected to be in service during the 2025-2027 time period. During certain system conditions, the 230kV lines will offload major power corridors while providing system voltage and stability support to our Bulk Electric System (BES) under various NERC TPL-001 contingencies. Furthermore, the new 230kV lines will enhance the reliability for the rapid load growth of a major residential developer in the Central Florida area. The lines will also provide additional significant grid benefits, such as providing transmission capacity for potential solar and other inverter-based resource interconnections.

Q. In addition to the need to meet expected growth, what other factors drive anticipated investment in DEF's transmission system during the test year periods?

A. Another important transmission investment category is Reliability, making up approximately one-fourth of DEF's transmission capital expenditure requirements for 2025-27, as shown in Figure 3 above. The primary investment focus here is around transmission asset health reliability to ensure outage reductions and improve restoration times. The factors that drive spending in this category include animal event mitigation; and replacement of obsolete, aging, and worn infrastructure.

Animal Events

Since 2018, numerous outages were caused by animals contacting energized equipment inside DEF substations. Fencing upgrades and installation of industry best practice animal mitigation guards offer the best deterrent to animal outages.

Obsolete Assets

Relay protection systems are designed to detect and isolate faulty elements on a system, thereby limiting the severity and spread of system disturbances, and preventing possible damage to protected elements. Industry retirement of older relay communication equipment is pushing a need to upgrade the relay communication technology to current standards. Upgrading to modern relay designs with communication capabilities and microprocessor-based technologies enables quicker restoration from outage events.

Aging and worn infrastructure

Transformers are monitored to determine the thermal, electrical, chemical, and mechanical stresses. The combination of all these stresses contribute to the deterioration of the condition of a transformer. Critical power transformers in poor condition can fail and result in costly unplanned outages. Proactive replacement of aging transformers before they fail ensures reliable customer service.

Q. You mentioned Physical Security is one of the categories of investment. Please explain further.

A. Based on recent incidents targeting energy infrastructure at DEF, as well as other utilities nationwide, the Company's Transmission Physical Security program focuses on hardening substations and implementing additional security to detect and deter against physical attacks.

Q. In addition to transmission capital expenditures, does the Company's request also include transmission O&M expenses?

A. Yes. Table 3 describes the categories of O&M expense included in DEF's transmission request:

Table 3

O&M Categories	2025	2026	2027	2025-2027 Total	Category Includes
Inspection and Maintenance	$9.8 M	$10.2 M	$10.6 M	$30.7 M*	Transmission substation and line inspections, maintenance, and repairs
System Operations	$6.9 M	$7.1 M	$7.3 M	$21.3 M	Energy Control Center desk operators, outage coordinators, and operations engineers
Industry Fees	$5.2 M	$5.4 M	$5.6 M	$16.2 M	NERC, SERC and FRCC annual dues
Other	$3.7 M	$3.9 M	$4.1 M	$11.8 M*	Safety materials, small tools, EPRI Dues and utility payments
Technology	$3.1 M	$3.1 M	$3.1 M	$9.3 M	IT hardware & software maintenance and license renewals
Training	$1.4 M	$1.5 M	$1.5 M	$4.4 M	Safety, compliance, general crew training
Environmental	$0.7 M	$0.7 M	$0.8 M	$2.2 M	Maintenance of oil spill protection, waste disposal and environmental clean-up
Compliance	$0.7 M	$0.7 M	$0.8 M	$2.2 M	Oversight of compliance to NERC standards
Total	**$31.5 M**	**$32.7 M**	**$33.8 M**	**$98.0 M**	

** 2025-2027 Total may not foot due to rounding.*

Q. What maintenance activities are necessary to maintain a reliable transmission system for DEF's customers?

A. Key transmission system reliability activities include facility and system inspections, targeted maintenance as a result of those inspections, and asset evaluations. Facility and system inspections include activities such as conducting ground and aerial patrols of lines, relay and battery testing and calibration, breaker assessment and testing, station infrared inspections, transformer diagnostic testing, and routine station inspections. During routine station inspections, the Company's maintenance crews are tasked to correct deficiencies found in our system while onsite as well as address and report back any discovered discrepancies. Transmission uses prediction analytic tools to monitor asset health and perform ongoing asset evaluations to ensure asset health deterioration is addressed before failure.

Q. Are the Company's transmission O&M requests within the FPSC O&M benchmark costs?

A. Yes, this is shown in MFR C-37.

Q. What are the projections for the Company's transmission O&M costs per customer 2025 through 2027?

A. As shown in MFR C-33, transmission expenses are projected to be $15.50, $15.77, and $16.06 per customer in 2025, 2026, and 2027, respectively.

V. Conclusion

Q. Are the Company's required transmission-related capital and O&M expense requests reasonable and necessary?

A. Yes. These requests (both capital and O&M) are needed to provide reliable transmission service to the Company's customers, meet expected growth, comply with mandatory NERC, FRCC, and FERC reliability standards. Furthermore, the requests aid in the implementation of the Company's transition to cleaner energy generation. DEF has a track record of improving system reliability through cost effective transmission investments. As such the transmission funding requests in this case are prudent, reasonable, and necessary.

Q. Does this conclude your direct testimony?

A. Yes, it does.

(Transcript continues in sequence in Volume 4.)

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 4th day of September, 2024.

Debra R Krick

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH575054
EXPIRES AUGUST 13, 2028