BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20240025-EI

Petition for rate increase
by Duke Energy Florida.
______________________________/

VOLUME 2
PAGES 223 - 422

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
TALLAHASSEE, FLORIDA
(850) 894-0828

I N D E X

P R O C E E D I N G S

(Transcript follows in sequence from Volume 1.)

(Whereupon, prefiled direct testimony of Shannon Caldwell 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 SHANNON CALDWELL

On Behalf of Duke Energy Florida, LLC

I. INTRODUCTION AND SUMMARY.

Q. Please state your name and business address.

A. My name is Shannon Caldwell. 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, Compensation. DEBS provides various administrative and other services to Duke Energy Florida ("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. I am responsible for broad-based compensation for Duke Energy, including all of Duke Energy's affiliated regulated and non-regulated companies, including DEF. I am responsible for compensation design and strategy, management of key vendor relationships, compensation administration and compliance.

Q. Please summarize your education and professional qualifications.

A. I graduated from the University of North Carolina with a Bachelor of Science degree in Business Administration and the University of South Carolina with a master's degree in Human Resources. I also hold various certifications including a Certified Compensation Professional designation. I have 10 years of human resource experience, primarily working with compensation programs. I joined Duke Energy in 2013 and have held various positions in human resources. In addition, I have served in key roles on several projects, including the integration of Progress Energy and Piedmont Natural Gas employees into Duke Energy's compensation programs. In my current role as Director, Compensation, I am responsible for all broad-based compensation, including compensation design and strategy, management of key vendor relationships, and compensation administration and compliance.

Q. Have you previously testified before this Commission?

A. No, I have not.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to show that the benefits and compensation opportunities provided to employees are reasonable, customary, prudent and market competitive. My testimony illustrates that the benefit programs and compensation opportunities provided to Duke Energy, including DEF's employees, are critical for attracting, engaging, retaining, and directing the efforts of employees with the skills and experience necessary to efficiently and effectively provide electric service to DEF's customers.

Q. Do you have any exhibits to your testimony?

A. Yes. The following exhibits were either prepared by me or under my supervision and direction:

- Exhibit SC-1, a list of the Minimum Filing Requirements (MFRs) schedules that I sponsor or co-sponsor;
- Exhibit SC-2, Duke Energy 2023 Survey Library;

- Redacted Exhibit SC-3, 2023 Duke Energy Short-Term Incentive Plan
- Redacted Exhibit SC-4, 2023 Duke Energy Short-Term Incentive Scorecard;
- Redacted Exhibit SC-5, 2023 Duke Energy Executive Long-Term Incentive Plan brochure;
- Exhibit SC-6, 2023 Duke Energy Restricted Stock Unit Award Summary; and
- Redacted Exhibit SC-7, Duke Energy Florida Year End 2023 Disclosure and Fiscal 2024 Cost.

All of these exhibits are true and accurate.

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

A. Yes, I sponsor or co-sponsor the MFR schedules noted on Exhibit SC-1, which are true and accurate, subject to being updated in the course of this proceeding.

Q. Please summarize your testimony.

A. The purpose of my testimony is to demonstrate that the compensation and benefits programs provided to Duke Energy employees are necessary to attract, engage and retain the skilled and experienced workforce the Company needs to provide reliable electric service to its customers. I explain how these programs are market competitive and comparable to programs offered by other utilities, as well as other companies outside of the utility industry. My testimony discusses why being market competitive is critical, namely because Duke Energy competes with other utilities and companies in the labor market for talent.

I also outline the design and function of our compensation programs and explain how they are in line with the industry, are market competitive, and how the performance metrics directly benefit DEF customers through safe and reliable service, customer service quality, and managing costs to be as low as possible. As described in greater detail in my testimony, incentive pay is a key component of Duke Energy's compensation program. In the competitive market for talent, employees consider the total rewards package, including base pay, incentive pay, and benefits, as a key determinant in deciding whether to work for a particular employer. Accordingly, whether it is through base pay or a combination of base pay and incentives, Duke Energy must keep its overall compensation package competitive to attract and retain a competent workforce. Incentive pay is therefore similar to other costs necessary to provide customers safe and reliable service. As such, in my opinion, the program expenditures by the Company in connection with these programs are reasonable and prudently incurred costs of service to our customers.

The factors that underpin the importance of full cost recovery have not diminished since our rate settlement agreement in 2021 – to the contrary, many employers and industries have experienced greater workforce turnover as a result of the "Great Resignation," and the electric utility industry is no exception. Employee turnover is expensive, particularly in specialized industries – such as ours – which utilize a highly skilled labor force that requires lengthy and intensive periods of apprenticeship and training. Accordingly, as my testimony demonstrates, the Company's allocated compensation expense, including incentive compensation, is reasonable and prudent, and should be recovered in rates.

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II. WORKFORCE OVERVIEW

Q. Please describe the general composition of Duke Energy's employee populations.

A. As of December 31, 2023, Duke Energy has a total of 26,810 employees. DEF has 2,972 employees, comprised of 1,245 exempt employees, 1,727 non-exempt employees, of whom 1,278 are union employees. DEBS has 6,995 employees, comprised of 5,411 exempt employees, 1,584 non-exempt employees, of whom 781 are union employees. As previously mentioned, DEBS provides various administrative and other services to DEF and other affiliated companies of Duke Energy. These services include but are not limited to: Accounting, Information Technology, Finance, Human Resources, Supply Chain, and Legal.

Q. What type of special skills or knowledge are required to operate an electric utility such as DEF?

A. Generation, transmission, and distribution of electric power are complex undertakings requiring a highly skilled workforce. A few examples serve to illustrate this point:

- Engineering professionals to help design, build, operate, and maintain our generation plants and the transmission and distribution systems that provide power to our customers.
- Plant operators are responsible for generating the electricity that powers our customers' homes and businesses.

- Skilled craft and technical workers, such as lineworkers, must work quickly and efficiently, especially under adverse weather conditions, to maintain, improve, and if necessary, restore our transmission and delivery infrastructure to keep electricity flowing to our customers.
- Field service and call center employees must understand the services provided by the Company, including the metering, billing, and collection processes plus various other customer service matters.
- At the corporate level, highly skilled managers, engineers, accountants, cyber security analysts, and other professionals are needed to support the employees who are directly responsible for generating, procuring, and delivering electricity to the Company's customers.

Q. How important is the recruitment and retention of such employees to DEF's ability to provide service to its customers?

A. The ability to attract and retain employees with the required technical skills is critical to the success of the Company, and very important to our ability to provide safe, reliable, and high-quality electric utility service to our customers. A fundamental factor with respect to the ability of any employer to attract and recruit skilled and qualified employees is the employer's compensation and benefits programs – potential employees will simply look elsewhere if the employer's total rewards package fails to achieve market competitiveness.

As such, compensation and benefits are highly important to the Company's ability to attract, engage, and retain a qualified workforce, especially considering the size of

Duke Energy's approximately 28,000 employees. One of the keys to providing a desirable workplace where employees want to continue working is to ensure that employees have the opportunity to participate in competitive pay and benefits programs.

Q. In recent years, have Duke Energy and DEF experienced challenges attracting and retaining a highly trained and skilled workforce?

A. Yes, Duke Energy, including DEF, has indeed experienced challenges both in attracting and retaining its workforce across the entire enterprise. For example, Duke Energy's enterprise job offer acceptance rate in 2023 was 86.93% compared to 84.05% in 2022, 87.8% in 2021, 90.7% in 2020 and 91.0% in 2019. In addition, regarding retention, in 2023 Duke Energy's enterprise voluntary turnover was 5.63% compared to 8.41% in 2022, 7.06% in 2021, 4.26% in 2020 and 5.18% in 2019. DEF's job offer acceptance rate in 2023 was 83.64% compared to 86.3% in 2022, 87.93% in 2021, 91.32% in 2020 and 92.09% in 2019. DEF's voluntary turnover was 7.10% compared to 8.07% in 2022, 7.88% in 2021, 5.31% in 2020 and 7.31% in 2019. These statistics show that Duke Energy and DEF, despite our best efforts, have not been immune from the challenges that many employers have experienced in attracting and retaining employees in recent years, with tight labor market conditions, marked by high employee mobility and high inflation.

Q. What are the implications of the challenges that Duke Energy has experienced in attracting and retaining employees?

A. Our employees deliver critical services to our customers every day, and the energy industry is a knowledge and experience-intensive industry where the tenure of employees matters.

Maintaining a competitive compensation and benefits package is instrumental in meeting Duke Energy and DEF's shared goals of providing safe, adequate, reliable, and reasonably priced utility service to customers.

III. <u>COMPENSATION OVERVIEW: PHILOSOPHY, COMPONENTS, AND CUSTOMER BENEFIT</u>

Q. What is Duke Energy's compensation philosophy?

A. Duke Energy's overall compensation philosophy is to target total compensation of base pay and incentives, including both short- and long-term, at the median of the market when compared to peer companies, with the opportunity to earn more or less relative to the market median based on actual performance. We have an obligation to be responsive to the market for talent and assure the competitiveness of the total compensation package, consisting of base salary, cash-based incentives, and for some employees, long-term incentive compensation. Duke Energy's compensation philosophy has three major parts:

First, Duke Energy wants its compensation to be market-based, meaning it is competitive with the external labor market, allowing it to remain attractive against competition in order to attract and retain qualified employees. Duke Energy employs a compensation strategy that combines base pay and variable incentive opportunities for all levels of positions. This approach fosters efficiency, safety, and a focus on the customer by aligning our employees' pay to quality service for customers.

Second, Duke Energy is performance oriented. It believes that linking compensation to performance is one way it can engage employees, set high expectations for employees, and reward results that benefit customers. Duke Energy's compensation program is designed to provide total compensation that is consistent with performance.

Third, Duke Energy is fair and flexible. Its well-managed policies and pay administration guidelines ensure that it pays employees consistently and fairly across departments, but it is also flexible when it needs to align its policies with business needs as they grow and change.

Q. Is Duke Energy's compensation philosophy for executives similar to the philosophy applicable to non-executive employees?

A. Yes. The compensation philosophy is similar for both executive employees and for employees below the executive level in that all employees are eligible for both fixed and variable pay. The compensation package for executives consists of a combination of fixed and variable pay using base salary, short-term incentives, and long-term incentives. These components, taken together, are targeted to deliver total compensation that is competitive with Duke Energy's peers and consistent with performance. Duke Energy adopted this executive compensation strategy in order to attract and retain the executive talent required to deliver superior performance. The strategy emphasizes performance-based compensation that balances rewards for both short-term and long-term results and that aligns the executives' interests with the long-term success of Duke Energy, including DEF, and its customers.

Q. Please provide an overview of the compensation programs provided by Duke Energy.

A. Duke Energy's compensation programs consist of a base pay component and incentive pay components that together provide a market-competitive, total compensation package for all employees. The base pay component is a set amount, reviewed by management at least annually, and established at a level that: (1) provides compensation based on the nature and responsibilities of the employee's position; (2) is fair relative to the pay for other similarly situated positions in the organization; and (3) when combined with incentive pay opportunities, is market competitive.

The short-term incentive ("STI") pay component is variable based on performance and is "at risk" pay. All employees are eligible for STI as a component of their total pay. Carving out a portion of employees' total compensation and delivering it through variable incentive pay serves the following multiple purposes: (1) encourages employees to accomplish specific objectives intended to ensure safe, reliable, and economical utility service for our customers; (2) fosters the success of business units and Duke Energy's overall success; and (3) aligns with competitors' pay structures.

The long-term incentive ("LTI") plans round out a competitive total compensation package for certain employees in leadership positions. Including LTI programs as a portion of total compensation for leadership positions is market competitive and necessary to attract and retain the high-caliber leaders needed to ensure safe, reliable, and economical utility service for our customers. Simply put, competent management benefits customers.

For illustrative purposes, the total compensation concept is depicted below in Figures 1 and 2.

Figure 1

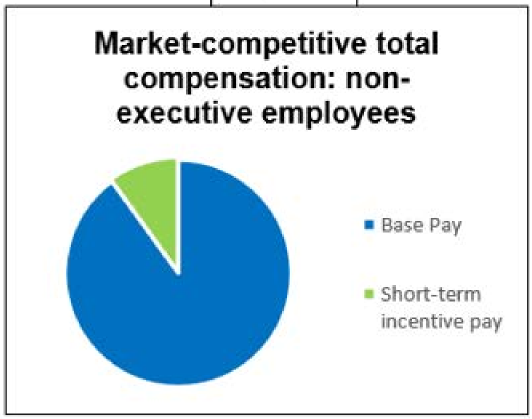
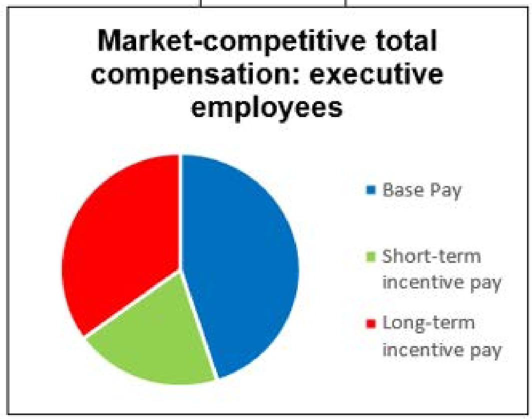


Figure 2



As Figures 1 and 2 make clear, base pay alone does ***not*** equate to market-competitive total compensation – rather, base pay ***in combination with*** incentive pay equates to market-competitive total compensation.

Q. How does Duke Energy know its compensation is market competitive?

A. The Company refers to numerous published surveys to assess whether its compensation is market competitive. As compared to those surveys, the Company's pay levels are competitive with market 50th percentile for base salary and total compensation (base pay plus incentives). As just one example, the salary range for a Senior Engineering Technologist at Duke Energy is \$86,400 to \$129,600, with a midpoint of \$108,000 and total cash compensation of \$118,800. The market median from the WTW Energy Services Mid-Management & Professional 2023 survey is \$107,983 for base pay and \$118,142 for total cash compensation for the same position. Further, we routinely benchmark total compensation (base pay plus incentives) against other similarly sized companies, both within and outside of the utility industry, and participate in a variety of third-party salary surveys on an annual basis. These surveys contain aggregated compensation data, including base pay and incentive targets, from multiple employers for various job functions and career levels. Duke Energy analyzes this data to determine overall competitiveness of pay for jobs throughout the enterprise. A complete list of the salary surveys Duke Energy currently participates in is reflected in Exhibit No._(SC-2).

Q. Does a competitive total compensation package for employees benefit the Company's retail customers?

A. Yes. Our employees deliver critical services to our customers every day. We need to attract, develop, and retain – over the long term – the employees that design, build, and operate our plants, and the employees that maintain and improve the infrastructure necessary to keep the lights on. Many craft positions require lengthy apprenticeships to learn the skills needed to perform work independently and safely. The competencies needed for employees in highly skilled positions – such as Line Technicians and engineers – take many years to develop. If we were to lose such employees, the Company would incur additional costs to train replacements for these positions, while experiencing additional risk with regard to reliability issues. The expense incurred to hire and train new employees, and the loss of productivity realized through high turnover rates, would negatively affect the Company's ability to provide safe and reliable service at a reasonable cost.

This is also true for leadership positions. Duke Energy invests in developing highly effective leaders who develop and carry out the organization's strategy and inspire employees to work together to achieve results the right way. Many of our leaders possess extensive industry experience, advanced degrees, and demonstrated examples of excellent leadership, making recruitment and retention of such leaders critical to the success of the Company, particularly in this changing energy landscape.

Q. Why are LTI Plans a necessary component of executive compensation?

A. LTI pay as a component of overall compensation for our executive ranks is market-competitive and provides Duke Energy with an effective retention tool. Offering less than competitive levels of compensation would put Duke Energy at risk of losing these valuable leaders to other companies and potentially having to pay more to attract the same level of leadership talent externally. In addition, the inclusion of LTI pay ensures that our leadership is focused on the long term, and not overly focused on the short term. Finally, incenting a focus on long-term sustainable company performance provides a benefit to customers, as a financially strong company will have greater access to capital at a lower cost, which in turn benefits customers through a lower cost structure.

IV. <u>DETAILED REVIEW OF DUKE ENERGY'S COMPENSATION COMPONENTS</u>

Q. Please describe Duke Energy's base pay programs.

A. For most non-union positions, Duke Energy utilizes base salary ranges consisting of a minimum and maximum base salary for each job grade. We perform an annual review of market data for both general industry positions and energy services positions and compare that data to our total compensation package (base pay plus incentives). Using this market data, salary ranges are reviewed annually to remain competitive. Market data is also reviewed and used to determine annual wage increase recommendations.

C6-892

To determine the compensation for executive officers on an annual basis, the Compensation and People Development Committee of the Board of Directors of Duke Energy (the "Committee") reviews data from nationally recognized, independent executive compensation consulting firms (Frederick W. Cook and WTW). The peer group of companies used for these analyses consists of companies that represent the talent markets from which Duke Energy competes to attract and retain executive employees.

Hourly represented employees, such as substation operators and line technicians, are provided general wage increases negotiated with the labor unions that represent the employees. Wage increases are just one component of union negotiations and must be negotiated in the larger context of work-related topics, such as benefits, work rules and overtime. These general increases are expressed as percentages of current base pay rates and are consistent with market trends. Duke Energy bases its positions in these negotiations on survey projections for market increases and also utilizes survey market data to ensure pay is competitive to market. DEF has the following collective bargaining agreements in place:

- Three-year collective bargaining agreement effective November 14, 2022, through November 9, 2025, with the International Brotherhood of Electrical Workers System Council U-8, representing I.B.E.W. Local Unions 433, 626, 682, 1412, and 1491 ("SCU-8 Main").
- Three-year collective bargaining agreement effective March 22, 2021, through March 17, 2024, with the International Brotherhood of Electrical Workers System Council U-8, representing operations at the Hines Energy Complex ("Hines").

- Three-year collective bargaining agreement effective March 6, 2023, through March 1, 2026, with the International Brotherhood of Electrical Workers System Council U-8, representing operations at the Citrus Combined Cycle Station ("Citrus").

Q. You mentioned earlier that the incentive pay structure of Duke Energy's compensation program has two components: STI and LTI. Please describe the STI component.

A. All employees are eligible for the STI component of incentive pay, which as I testified previously, puts "at risk" a portion of each employee's compensation. The STI program is designed to promote a workforce culture that responds to pre-determined performance goals set both at the corporate level and at a "team" (for non-leadership employees) or individual (for leadership employees) level. How much of the STI component is actually paid out to an individual employee depends on the degree to which the performance goals are met. The STI plan document is set forth in Redacted Exhibit No._(SC-3).

The process of determining an employee's STI compensation begins with the setting of goals at the commencement of each year. The Committee approves the corporate level performance goals for the upcoming year, as well as individual goals for leadership employees, and executive leadership for each business unit sets the team goals for non-leadership employees.

The corporate goals are reflected in a "scorecard." Each goal reflects the specific metrics required to meet the goal at three different levels – the Minimum, Target, and Maximum level. The payout associated with achievement of each goal is based upon where along the Minimum to Maximum continuum the corporate performance falls. A thorough review is performed at the end of the year to determine the achievement level for each performance goal.

The scorecard reproduced in Redacted Exhibit SC-4 is the 2023 scorecard for non-leadership employees. It indicates that "team" goals are to be set and performance measured against achievement. For leadership employees, individual goals replace the "team" component, with performance also measured against achievement. Redacted Exhibit SC-4 also details the weight given to achievement of each goal. An overview of the STI metrics, weights, and payout opportunities is set forth in the table below:

TABLE 1: SUMMARY 2023 STI PLAN

Goals	Senior Management Committee (SMC) Weight	Leadership (Other than SMC) Weight	Non-Leadership Weight	Payout range
Earnings per Share	50%	50%	50%	0-200%
Operations & Maint.	12.5%	10%	5%	0-175%
Operational Excellence	12.5%	10%	10%	0-175%
Customer Satisfaction	12.5%	10%	10%	0-175%
Climate	12.5%	N/A	N/A	0-175%
Team	N/A	N/A	25%	0-175%
Individual	N/A	20%	N/A	0-175%

Members of the Senior Management Committee ("SMC"), comprised of Duke energy Chair, President, and CEO Lynn Good and her direct reports, are subject to an Individual Performance Modifier pursuant to which the Committee may exercise discretion to increase or decrease the aggregate incentive payment of each SMC member. The calculation of the incentive payments is based on the goals and weightings set forth above by up to 25%, with reference to the SMC member's achievement of their performance objectives during the year.

Q. Please provide additional detail regarding the metrics included in the STI program for 2023 and describe how these metrics benefit customers.

A. As the Scorecard attached hereto as Redacted Exhibit SC-4 reflects, corporate STI metrics are grouped into the categories of Financial Performance & Growth, Operational Excellence, and Customer Satisfaction. A detailed description of these categories is as follows:

Financial Performance & Growth: The Financial Performance & Growth measure consists of Earnings per Share and Operations & Maintenance ("O&M") expense measures, each of which motivates employees to focus on financial discipline, efficient operations, and prudent use of resources, all which are vital to the health and stability of the organization.

(1) Earnings per Share ("EPS"): EPS is an important metric to evaluate the success of our performance and it is a very common practice, both within and outside of the utility industry, to use EPS as a primary goal in incentive programs. A consistently growing EPS benefits customers by allowing Duke Energy to access the capital markets on reasonable terms, which ultimately lowers the Company's financing costs. Lower financing costs is particularly important in today's environment as DEF continues to invest in the critical infrastructure needed to ensure the continued reliability and resiliency of the electric grid, while retiring and repurposing aging infrastructure. The Company's investments are also aimed at transforming the customer experience by providing customers with more billing options, additional energy usage information, and new tools to help manage and

reduce energy costs. Additionally, employees directly impact EPS by finding efficiencies and cost-cutting measures, which are ultimately passed on to customers when new rates reflecting those savings are implemented.

(2) O&M Expense Control: O&M expenses include those costs necessary to support daily operations, as well as operate and maintain the operating efficiency and productive life of assets. Cost control is an integral part of any company's success. The intent of this goal is for employees to focus on cost control on a day-to-day basis, which will allow Duke Energy to incorporate these savings into programs that will benefit customers.

Operational Excellence: This metric motivates employees to provide reliable and safe products and services to customers and consists of two, equally weighted measures: Reliability and Safety/Environmental. This objective emphasizes service reliability and the mitigation of environmental risks associated with our operations.

(1) Reliability: The intent of this metric is to ensure that cost focus does not sacrifice DEF's ability to provide reliable service, which is expected by all customers. By including reliability in its annual incentive metrics, employees are financially motivated to ensure that the Company provides reliable service to its customers.

(2) Safety/Environmental: This metric incorporates safety and environmental stewardship into day-to-day activities, thus making the safety of employees, customers, and communities a priority. The safety and environmental goal payout will be determined by averaging the year-end accomplishment of two goals: (i) Total Incident Case Rate ("TICR"), which measures the number of

occupational injuries and illnesses per 100 employees, including staff-augmented contractors; and (ii) Reportable Environmental Events, which are environmental events resulting from operations that have an impact on the environment, require notification (verbal/written/electronic) to a regulatory agency, or result in a regulatory citation or other enforcement action by a regulatory agency.

Customer Satisfaction: Duke Energy's incentive program also includes a Customer Satisfaction goal, or CSAT, which measures the degree to which customers have a favorable perception of an interaction, product, service, or of Duke Energy overall. Achievement is based on Duke Energy's Net Promoter Score, which is captured through its proprietary survey. Duke Energy fosters a customer-centric culture, and the customer satisfaction goal is intended to keep customers central to all that Duke Energy does across the company, regardless of where its employees work.

Team/Individual: In addition to these corporate metrics, and as I previously mentioned, the performance of non-leadership employees is assessed against pre-determined "team" goals set by their business units. The team goals directly benefit customers by tying employee compensation to reliability, outage frequency, time required to restore service, lost-time accidents, customer satisfaction scores, O&M expense levels, and capital expenditures. These goals are typically tactical and operational goals that align the work of each team to DEF and Duke Energy's overall priorities. Team goal results establish a pool of dollars allocated at the discretion of managers among employees based on their individual performance and contributions to the team.

Executive and leadership employees are assigned individual goals. The individual goals are intended to motivate the executive leadership members to advance strategic and operational objectives and are generally aligned to the business in which they operate. Superior performance relating to these team and individual goals directly benefits DEF customers through safe and reliable service, customer service quality, and managing costs to be as low as possible.

Q. Please describe the LTI component of incentive pay.

A. At a high level, Duke Energy's LTI programs provide equity-based compensation (i.e., stock awards) to executive and leadership-level employees. Compensation including stock awards aligns these employees' interests with the long-term interests of Duke Energy and its customers. The goal of the LTI programs is to attract and retain high-caliber leaders by providing a competitive compensation package and to encourage leaders to make sound business decisions from a long-term perspective. Stock awards are an important component of a compensation package that is reviewed annually to ensure ongoing competitiveness. Duke Energy's LTI opportunities generally vest over a period of three years, thus focusing executives on long-term performance and enhancing retention.

Q. What specific LTI programs are offered by Duke Energy?

A. Duke Energy has two LTI programs. The Executive LTI Plan is reserved for the most senior executives, including the SMC which includes the CEO and her direct reports, and members of the Enterprise Leadership Team ("ELT"), which includes approximately 100 of the top leaders within Duke Energy below the level of the SMC. The second LTI program, the Restricted Stock Unit ("RSU") Program, is available to other strategic leaders below the ELT level who are responsible for the most critical roles in each business group (population generally ranges between 2-3% of the total Duke Energy employee population). The Executive LTI Plan brochure is included as Redacted Exhibit SC-5 and the Restricted Stock Award Summary is included as Exhibit SC-6.

Q. Please describe the Executive LTI Plan.

A. The Executive LTI Plan is designed to drive an ownership mindset for participants and ensure accountability for making short- and long-term strategic decisions. For 2023, participants in this program have 70% of their target LTI opportunity awarded as performance shares and 30% of their target LTI opportunity awarded as restricted stock units ("RSUs").

Performance Shares: The performance shares granted in 2023 incorporate three performance goals: (1) cumulative adjusted EPS, (2) Total Shareholder Return ("TSR") compared to companies in the Philadelphia Utility Index, and (3) Total Incident Case Rate ("TICR"), which (as indicated above in my discussion of STI metrics), is a measure of operational safety – a factor of great importance to Duke Energy and its customers. Similar to the payout associated with meeting STI goals, payout of performance shares occurs only if pre-defined performance metrics related to the goals are met, but in the case of the performance share awards, the goals must be met over a three-year vesting period. The multiyear vesting period ties the number of performance shares participants ultimately earn to Duke Energy's long-term performance, and this correlates to long-term value. Executive LTI Plan participants must generally continue their employment with Duke Energy for a three-year period to earn a payout.

RSUs: The other 30% of Executive LTI Plan participants' target LTI opportunity is awarded as RSUs. Vesting of RSUs is solely tied to participants' continued employment through vesting dates over a three-year vesting period and is not dependent upon Duke Energy's financial performance. Participants who remain employed with Duke Energy through a vesting date receive a share of Duke Energy common stock for each vesting RSU.

Q. Please describe the LTI Program available to leaders below the ELT level.

A. Leaders below the ELT level participate in the RSU program and receive their LTI value in the form of RSUs that vest equally over three years, thereby encouraging retention of high-quality employees. The reward of these RSUs is purely aimed at continued employment and is in no way tied to actual company performance. Participation in the RSU plan is reserved for positions that meet at least one of the following criteria:

- Position has significant responsibility for a broad area or function or geographic region;
- The employee leads major projects or groups with substantial enterprise or business unit strategic or financial impact;
- The employee is in a role that has decision-making authority that impacts company performance; and/or
- Position requires specialized expertise that is critical to business operations or strategy development.

The RSU plan is an equally important component within the total compensation package for eligible leadership positions (below executive level) and is critical to maintaining market competitiveness and retaining key leadership talent. The base salary for these employees is set at such a level, that, when factoring in the retention-driven RSUs, the total package results in market-competitive compensation.

Q. How do goals based on meeting EPS or TSR benefit customers?

A. In order to achieve EPS goals, Duke Energy must have strong cost management, prudent investments, and operational excellence, all of which benefit customers. Achieving financial success benefits customers by reducing the cost of capital as Duke Energy, including DEF, continues to conduct necessary maintenance of the system, invest in modernization of the electric grid, and transform the customer experience by providing customers with more billing options, additional energy usage information, and new tools to help manage and reduce energy costs.

Q. Why is it important to provide incentive opportunities as part of employees' total compensation?

A. STI opportunities are components of market-competitive total compensation that are necessary to attract and retain qualified employees. Similarly, Duke Energy's LTI programs are a necessary component of compensation packages for leaders. They allow Duke Energy to attract and retain high-performing leaders who are capable of leading the way to cleaner, smarter energy solutions that are valued by customers. Incentive pay is similar to the other costs related to providing electric service – it is a necessary cost to provide customers safe and reliable service. In the competitive market for talent, employees consider the total rewards package, including base pay, incentive pay and benefits, as a key determinant in deciding whether to work for a particular employer.

V. COST RECOVERY OF INCENTIVE PAY EXPENSE

Q. What incentive pay expense does DEF propose to recover in this proceeding?

A. DEF proposes to recover the incentive pay expenses at target levels that are directly assigned or allocated to DEF. These expenses are prudent, benefit customers, and are a component of market-competitive pay.

Q. Please further explain DEF's proposal to recover incentive plan expense.

A. As shown above in Table 1: Summary 2023 STI Plan, the Executive and Non-Executive STI continues to include a weighting factor for achieving corporate EPS as well as weightings for achieving other goals such as O&M and reliability targets. Reliability targets provide a balance between the need to prudently manage costs and providing cost-effective, reliable, and safe service to our customers. Other metrics include customer satisfaction, safety, and environmental targets. Safety and environmental targets were added to encourage positive behavior of employees in our day-to-day operations, and customer satisfaction targets were added to keep customers central in all that we do. In 2022, Duke Energy added the climate goal for SMC members to focus on the growth of our non-emitting generation and storage capacity that is not dependent on the retirement of existing coal plants. As previously explained, all the various performance measures included in the Company's incentive plans are designed to benefit customers. Accordingly, DEF proposes to recover the entire amount of incentive compensation costs allocated to Florida, based upon achieving target goal levels, in its revenue requirement calculation.

Table 2

Incentive Plan	**Incentive Plan Components**	**Weighting**
STI – Non-Leadership	EPS O&M Reliability Safety/Environmental Customer Satisfaction Team Goals	50% 5% 5% 5% 10% 25%
STI – Leadership (other than SMC)	EPS O&M Reliability Safety/Environmental Customer Satisfaction Individual Goals	50% 10% 5% 5% 10% 20%
STI – Senior Management Committee (SMC)	EPS O&M Reliability Safety/Environmental Customer Satisfaction Climate	50% 12.5% 6.25% 6.25% 12.5% 12.5%
Non-Executive LTI	Restricted stock units	100%
Executive LTI	Restricted stock units Performance shares (70%) • Total Shareholder Return relative to companies in the Philadelphia Utility Index (25% of 70%) • Cumulative adjusted Earnings Per Share (50% of 70%) • Absolute Total Incident Case Rate (25% of 70%)	30% 17.5% 35% 17.5%

Why does the Company's proposal for incentive compensation assume reaching 100% of target achievement levels?

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A. These are the accrued and budgeted achievement levels for the performance goals for the STI and the LTI. The 100% target achievement level is used for the accruals and budget because this is what the Company expects to achieve on average.

Q. Why does the Company believe short-term and long-term incentive should be recoverable?

A. As I previously stated, incentive pay is similar to the other costs related to providing electric service. It is a necessary cost to provide customers safe and reliable service. In the competitive market for talent, employees consider the total rewards package, including base pay, incentive pay and benefits, as a key determinant in deciding whether to join or continue working for a particular employer.

Incentive pay is one element of Duke Energy's compensation programs, which consist of a base pay component and incentive pay component, that together, provide a market-competitive total compensation package for all employees. Competitive compensation packages are necessary for the Company to attract and retain the skilled workforce needed to provide clean and reliable energy to our customers. The annual STI pay opportunity is an important component of overall total compensation that promotes a corporate culture that is performance-oriented in order to provide the greatest benefit.

The LTI opportunities provided to the Company's leaders are a necessary component of a market-competitive target level of total compensation for these particular positions. This total compensation package allows the Company to attract and retain the experienced leaders necessary to direct the efforts of its employees and make the best strategic decisions on behalf of the Company and align their interests with the long-term strategy of Duke Energy.

VI. <u>BENEFIT PLAN DESIGN</u>

Q. What is Duke Energy's benefits philosophy and how does it tie into the overall total rewards philosophy?

A. At Duke Energy, we place a priority on attracting and retaining a high-performing workforce. An important way we do this is by providing a comprehensive, competitive total rewards package of pay and benefits that includes base pay, incentive pay opportunities, and benefits. Benefits are the non-pay portion of an employee's total rewards. Our benefit programs are designed so that Duke Energy can maintain a highly trained, experienced workforce that can render excellent utility service. Retaining employees is important for us because our business involves complex processes such that employees must receive long-term training to perform their jobs safely and effectively. Generally, benefits are provided through two vehicles: health and welfare benefit plans and retirement plans. Health and welfare benefit plans include medical, dental, vision, life insurance, and disability plans. Retirement plans include pension (limited to a grandfathered population) and 401(k) plans. Our retirement plans are designed to enable employees, through shared responsibility, to accumulate sufficient resources to be able to transition into retirement at the appropriate time. An employee's ability to retire at the right time increases opportunities for the workforce as a whole and also helps the utility manage costs.

Q. Please describe the employee benefit programs provided to Duke Energy employees.

A. The benefit programs in which all eligible employees may participate include medical, health savings account, dental, vision, flexible spending accounts, employee assistance program, wellness, sick pay, short-term disability, long-term disability, life insurance, accidental death and dismemberment and business travel accident insurance. Retirement benefits include a pension plan limited to a grandfathered population and company contributions and company matching contributions to employees' 401(k) plans to promote the shared responsibility between the Company and employees for accumulating retirement resources.

Q. Please describe Duke Energy's post-employment healthcare benefits provided to employees.

A. Duke Energy is the result of a series of many acquisitions and mergers and has worked hard at integration to minimize differences among legacy company employee groups. This includes post-employment benefits available to employees when they retire. Newly hired employees will be eligible to enroll in company-sponsored pre-65 retiree medical, dental and vision benefits at retirement on an unsubsidized basis by paying the full cost of coverage. Additionally, Duke Energy provides retirees access to a retiree exchange program for assistance with exploring options for coverage available on the individual market as an alternative to Duke Energy-sponsored retiree coverage. They will also have the option to convert or port their active life insurance to an individual policy at retirement by paying the required premiums. Active employees who were part of a closed group and eligible for a retiree healthcare subsidy towards the cost of Duke Energy-sponsored retiree health care coverage generally were transitioned to a common approach in the form of a pre-65 Health Reimbursement Account benefit.

Q. Is it common practice in the electric industry to provide post-employment benefits?

A. As Duke Energy periodically reviews healthcare trends, we see that 28% of general industry and 44% of energy & utility industry companies provide financial support for pre-65 coverage for future retirees. We also see that 21% of general industry and 38% of utility industry companies provide financial support for post-65 coverage for future retirees. As Duke Energy's financial support of retiree healthcare has lessened over the years, we have recognized that this is an area of concern for many employees. To address this concern, we encourage employees who are enrolled in a High Deductible Health Plan to contribute to a Health Savings Account and receive company matching contributions to save for their future retiree healthcare costs.

Q. Does DEF have a pension plan?

A. Duke Energy closed its pension plans to non-union new hires in 2014 and has since negotiated closing pension participation for new hires for all union groups. New hires participate in the Enhanced 401(k) Program and receive a Duke Energy retirement contribution to the 401(k) in lieu of pension participation and have an opportunity to receive company matching contributions if they choose to contribute to the 401(k). Some FL union employees represented by IBEW SCU-8 participate in a company-sponsored pension plan. For union employees hired before January 1, 2003, benefits are provided through a Final Average Pay formula. For union employees hired on or after January 1, 2003, but prior to January 1, 2018, benefits are provided through a Cash Balance formula. Union employees hired or rehired on or after January 1, 2018, are not eligible to participate in the defined benefit plan but instead participate in the Enhanced 401(k) Program and have an opportunity to receive company matching contributions if they choose to contribute to the 401(k).

Pension eligible employees have generally experienced reductions in future pension benefit accruals with transitions from a final average pay formula to a cash balance formula. As early as 1997, Duke Energy, through mandatory conversions, choice windows and design change for new hires, moved non-union and many union pension eligible employees to a cash balance design. Moving the existing employees allowed the Company to reduce future pension accrual, and reduce risks associated with longevity and investments (since most participants take lump sum distributions). To offset the impact of these pension reductions, Duke Energy increased its matching opportunity in the 401(k) plan. The emphasis throughout this process was to create a competitive retirement benefit, which provided as much comparability as possible across all legacy organizations and new hires, while aligning to the market.

Employees represented by IBEW SCU-8 who participated in the Pension Cash Balance Program had a one-time opportunity in 2020 to voluntarily move to the Enhanced 401(k) Program effective January 1, 2021. Employees who moved received an employer contribution of 4% of base rate of pay each pay period in addition to current employer match of up to 6% on employee contributions. These employees no longer receive pay credits to their pension cash balance accounts.

Q. In your opinion are Duke Energy's pension plans sufficiently funded?

A. Yes.

Q. How did you come to this determination?

A. Annually Duke Energy engages Willis Towers Watson to prepare an Actuarial Valuation Report of Duke Energy's pension plans. The most recent DEF report is attached at Redacted Exhibit No._(SC-7). This report provides information for year-end financial reporting, net periodic benefit cost, and the year-end funded status of the qualified pension plans for DEF. The funded percentage of the qualified pension plans for DEF by December 31, 2023, under US GAAP accounting was 123%. The qualified pension plans had a projected benefit obligation ("PBO") of $1,069 million and a market value of assets of $1,316 million. Duke Energy is committed to funding its qualified pension plans as necessary to meet all future required contributions.

Q. How does Duke Energy determine that the employee benefit programs that it offers are reasonable and necessary?

A. Duke Energy routinely examines its benefits to confirm how we compare with national trends among comparable employers, and we consider the most effective ways to serve our workforce who reside in over 25 states. Because we are a company with a history of mergers and acquisitions, we try to ensure consistency and fairness among legacy company employee groups as well as cost-effectiveness. We benchmark our programs against other large employers from both the utility industry and general industry so that we are positioned to attract and retain qualified employees needed to support our customers. Duke

Energy leverages its consultants, vendor partners, and nationally recognized surveys to evaluate the competitiveness of its benefits and costs. Examples of surveys include Willis Towers Watson's Financial Benchmarks Survey, Best Practices in Health Care Survey, Emerging Trends in Healthcare Survey and Benefits Data Source. These surveys indicate that Duke Energy's benefit plans and employee contributions are in line with its utility industry and general industry peers, making them reasonable and necessary to compete with other employers for qualified talent. We routinely determine if any changes should be made based on Duke Energy's reviews of the competitiveness and reasonableness of its benefit programs and employee costs as compared to its peers.

Q. Has Duke Energy taken steps to control the cost of employee benefits?

A. Yes. On an ongoing basis, Duke Energy reviews its employee benefits and costs. The Company strives to keep costs reasonable, while continuing to provide benefits that are sufficient to attract and retain employees. Employees pay a portion or all of the cost for many of their benefits, so we strive to manage costs not just for the Company, but for employees as well. Periodically, benefit plan changes or other steps are taken to control costs. The following are some examples of steps taken in recent years to control costs.

<u>Retirement Plans</u>

Duke Energy has taken significant steps to both control costs and reduce the risk associated with its retirement plans. Duke Energy closed its pension plans to non-union new hires in 2014 and has since negotiated closing pension participation for new hires for all union groups. New hires receive a Duke Energy retirement contribution to the 401(k) in lieu of pension participation and have an opportunity to receive company matching contributions if they choose to contribute to the 401(k). Pension eligible employees have generally experienced reductions in future pension benefit accruals with transitions from a final average pay formula to a cash balance formula.

Health & Welfare Plans

Duke Energy undertakes a number of ongoing steps to manage costs associated with health and welfare plans. For example, Duke Energy performs an annual market check on the pharmacy benefit manager contract to ensure competitive contract terms and pricing. These have resulted in savings each year for employees and Duke Energy. The Company also regularly evaluates the need to bid out Health & Welfare vendor contracts through a request for proposal ("RFP") process so that contracts have competitive fees, discounts, and guarantees. In addition, Duke Energy annually reviews its Health & Welfare plan design and costs to determine the need for changes to deductibles, copays, co-insurance, out-of-pocket limits, and cost sharing strategies to align with market trends.

Moreover, an ongoing dependent verification process has been in place since 2010, which requires proof of eligibility to ensure that only eligible dependents are enrolled in medical, dental, vision and life insurance coverage. The Company also annually assesses utilization management programs and processes to help eliminate unnecessary or inappropriate treatments and medications, including pre-certifications, prior authorizations, step therapy, safety and monitoring for fraud and abuse (*e.g.*, opioids), and specialty medication management.

Other cost control measures include reducing active company-paid life and AD&D insurance from two times annual base pay to one-time annual base pay, and generally eliminating Company-paid retiree life insurance for future retirees. Duke Energy also discontinued sponsorship of post-65 medical plan options and implemented a Medicare exchange solution for all retirees and their dependents. This provides retirees with a choice of individual policies to supplement Medicare.

VII. <u>CONCLUSION</u>

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Matthew Chatelain 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

MATTHEW CHATELAIN

On Behalf of Duke Energy Florida, LLC

C7-923

I. INTRODUCTION AND PURPOSE

Q. Please state your name and business address.

A. My name is Matthew Chatelain, and my business address is 525 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I am a Manager of Rates and Regulatory Strategy for Duke Energy Business Services, LLC ("DEBS"). DEBS is a service company subsidiary of Duke Energy Corporation ("Duke Energy") that provides services to Duke Energy and its subsidiaries, including Duke Energy Florida, LLC ("DEF" or the "Company") and its affiliated utility operating companies.

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

A. I am responsible for rate administration, rate design, and pricing for DEF.

Q. Please describe your educational background and professional experience.

A. I received Bachelor of Science in Business Administration degrees in Accounting and Management from Appalachian State University in 2011. I also received a Master of Science degree in Accounting from Appalachian State University in 2012. I am a Certified Public Accountant ("CPA") licensed in the state of North Carolina. I joined Duke Energy in 2016 and worked in asset accounting for three years. I have been responsible for DEF rate administration, rate design, and pricing since 2019. Prior to joining Duke Energy, I was employed as an auditor by CohnReznick LLP, where I had some exposure to renewable energy credit contracts and related industry accounting practices.

Q. What is the purpose of your testimony?

A. My testimony demonstrates that the rates DEF proposes reflect appropriate ratemaking principles when applied to test period billing determinants, and result in an equitable basis for recovery of the Company's revenue requirements across and within its various customer classes and rate schedules. My testimony: (1) describes the changes to the Company's retail electric rate schedules; (2) quantifies the effect of these proposed changes on the Company's retail electric customers; and (3) describes other proposed changes to the Company's tariffs. I am also proposing slight modifications to several customer-centric and innovative pricing changes that continue to address emerging energy trends impacting Florida today.

Q. Have you prepared any exhibits to your testimony?

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

- Exhibit MJC-1, a list of the Minimum Filing Requirement ("MFRs") schedules I sponsor or co-sponsor;
- Exhibit MJC-2, Company-Proposed Allocation of the Target Revenue and Rate Increase/(Decrease) by Rate Class; and
- Exhibit MJC-3, Base Revenue by Rate Schedule – Calculations – Calendar Year Determinants.

These exhibits are true and accurate, subject to being updated throughout the course of this proceeding.

Q. Please describe the overall rate increase results shown in your exhibits.

A. The total revenue increases for each rate class is presented in MFR E-8. The Company projects a decrease in total revenue from 2024 to 2025. Additionally, MFR A-2 presents typical monthly bill calculations for the base rate schedules using present and proposed rates and confirms that most typical bills in every rate class are projected to see a decrease in monthly bills from 2024 to 2025. For example, a 1,000 kWh RS-1 customer is projected to see a \$3.04 (1.86%) decrease in their weighted average monthly bill from 2024 to 2025.

II. <u>OVERVIEW OF RATE DESIGN APPROACH</u>

A. Load Research Study

Q. What is the purpose of the Load Research Study?

A. Load research studies collect data that provide important information on customers' electric load characteristics. The Load Research Study is required by Rule 25-6.0437, F.A.C. ("the Rule").

The Rule requires that all rate classes that account for more than one percent of an investor-owned utility's annual retail sales be sampled and directs investor-owned utilities to submit a sampling plan to the Commission every three years. The sampling plan must be designed to provide estimates of the average of the 12 monthly coincident peaks for each rate class within plus or minus 10% relative precision at the 90% confidence level. The samples shall also be designed to provide estimates of the summer and winter peak demands for each rate class within plus or minus 10% relative precision at the 90% confidence level, except for the General Service Non-Demand rate class, which shall be designed to provide estimates of the summer and winter peak demands within plus or minus 15% relative precision at the 90% confidence interval.

Q. Has the Commission reviewed and approved the load research sampling plan used in this filing?

A. Yes. DEF completed deployment of AMI meters for 1.9 million customers in the spring of 2021. Therefore, in lieu of statistically designed samples, all available interval data for the population for the period of January through December 2022 was used for the Load Research Study. In other words, the precision from the population data studied exceeds that of the precision from even a well-designed sampling approach. Interval data from the population was compiled to provide averages of the 12 monthly coincident peaks and the summer and winter peak demands for each rate class. The data retrieval rate was over 98% for every hour and group. When interval data was unavailable, it was estimated; therefore, the final reporting represents 100% of the population for each rate class. This meets the target level of statistical accuracy required by the Rule.

DEF submitted the original sample plan to Commission Staff on July 25, 2022, with a study period of April 2023 to March 2024, but DEF requested a revised study period of January 2022 through December 2022 on September 22, 2022, and the Commission Staff approved DEF's sample plan via letter on November 18, 2022.

Q. Please summarize the results of DEF's Load Research Study supporting this filing.

A. The results of DEF's most recent Load Research Study using available interval data from January 2022 through December 2022 for all applicable rate classes can be found in MFR E-17. MFR E-17 shows the class demands for the system peak hour, the class coincident peak hour, and the non-coincident peaks for the Residential, General Service, Non-Demand, General Service Demand, Curtailable Service, and Interruptible Service rate classes for each month and the averages of the twelve monthly system peaks for all rate classes. The winter peak hour occurred on Sunday, January 30, 2022, at the hour ending at 8:00 AM, and the summer peak hour occurred on Tuesday, August 1, 2022, at the hour ending at 5:00 PM.

Q. How is the Load Research Study used in setting customer rates?

A. The Load Research Study is primarily used to determine the correct amount of costs to allocate to customer classes in the cost-of-service study. This is further explained in the direct testimony of Witness Marcia Olivier.

B. Billing Determinants

Q. Would you explain the term "Billing Determinants" as it is used in ratemaking?

A. Yes. Billing determinants are those rate parameters or units of measurement of electric service by customers that, by application of the rate charges under the applicable rate schedules, produce the Company's billed revenue. Billing determinants include, at a minimum, a count of active customers and their kilowatt-hour ("kWh") usage under each rate schedule. Additional billing determinants may include measurements of kilowatt ("kW") demand, time of use, power factor, metering and delivery voltage, or other unique units of measurement for the services being rendered under the rate schedule.

Q. How did the Company derive the projected billing determinants for the test years that form the basis for calculating the present revenues and proposed revenues being presented in this proceeding?

A. First, the starting point for deriving the billing determinants in this proceeding is the Company's Customer and Megawatt-hour ("MWh") Sales Forecast for the 2025, 2026, and 2027 calendar year test periods. This forecast is described in the testimony of Witness Benjamin Borsch. The forecast provides numbers of customers and MWh sales by revenue reporting classifications of residential, commercial, industrial, and sales to public authorities. From that forecast, the Company then develops a customer and sales forecast consisting of the Company's major rate classes Residential ("RS"), General Service Non-Demand ("GS"), General Service Demand ("GSD"), Curtailable Service ("CS"), Interruptible Service ("IS"), and Lighting Service ("LS"). Next, actual billing determinants from the same time period as the Company's most recent load research study on historic calendar year 2022 are summarized for each rate schedule to identify lines of billing, sales by delivery voltage, kW to kWh ratios, Time of Use ("TOU") rate relationships, and other rate parameters utilized in calculating customer billings. Lastly, these historic billing relationships are applied to the Company's projected 2025, 2026, and 2027 customer and sales forecast by major rate class to derive the projected billing determinants for each rate schedule that correspond with the test years. These resulting calculations are the billing determinants being employed in MFR Schedule E-13c and are applied to present and proposed charges to produce the revenues attributable to each rate class as shown thereon.

C. Development of Target Class Revenues

Q. Please describe generally the procedure used to determine the portion of the Company's total proposed base rate revenue increase assigned to each rate class.

A. The focus in determining the portion, or percentage, of the Company's proposed base rate revenue increase to be assigned to each rate class is the class cost-of-service study. For this purpose, the cost-of-service study utilizes the Twelve Coincident Peak and 25% Average Demand ("12 CP and 25% AD") production capacity allocation method. The full cost-of-service study is described in more detail in Witness Olivier's testimony.

Rates determined through this proceeding will be informed by the revenue requirement for each rate class as derived from the cost-of-service study. The first step in determining how much each rate class should share in the Company's total revenue increase, i.e., the shortfall between total revenue requirements and total revenues under current rates, is to determine for each rate class the shortfall between the costs allocated to that class and the revenues produced by applying current rates to the class's test year billing determinants. The next step is to determine how much of each class's revenue shortfall will be offset by additional revenues from any increase in other operating revenues, such as the increase in certain service charges proposed by the Company in this proceeding. Once the net revenue deficiency of each rate class has been determined, the final step is to identify whether any ratemaking policy considerations should limit the amount of any rate class's revenue increase. Where an increase limit is imposed on a rate class, the other rate classes must make up the deficiency. This deficiency resulting from limiting class increases is spread to other rate classes in proportion to each of their deficiencies to the extent that the resultant increases do not exceed any imposed limits.

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The three-step procedure described above produces target revenues for each rate class, comprised of both present revenues and apportioned increase for each rate class. The Company is proposing rate changes that will attempt to recover such target revenues, by class, based upon test year billing determinants.

Q. Have you prepared an exhibit that develops the proposed class target revenues from the procedure you have described?

A. Yes. My Exhibit MJC-2 was prepared for this purpose. Note that, per Florida Public Service Commission ("Commission") practice, rate class revenue increases are limited such that an individual rate class increase (1) may not exceed 150% of the overall percentage increase in the Company's total revenues and (2) may not receive a decrease. When moving rate schedules closer to a more cost-justified basis, it is important to consider the impact upon customers and to employ the principle of "gradualism." This principle was applied in this proceeding to update price relationships and moderate the percentage change in rates for participants within the rate class while still moving towards a more equitable pricing structure. This approach also minimizes rate migration concerns as the pricing reflected in each rate schedule moves gradually towards the requested rate class rate of return.

Q. Please describe how the proposed class target revenues are achieved in the rates for each rate class.

A. Exhibit MJC-2 does not account for the change in unbilled revenues directly in the proposed class target revenues. The total proposed unbilled revenues that determine the change in unbilled revenues is the difference between projected bill cycle billing determinants and calendar year determinants. I have applied the calendar year determinants in Exhibit MJC-3 and designed rates to ensure collection of the class-specific target revenue increase shown in Exhibit MJC-2, thereby embedding the change in unbilled revenues for each test year in the final rates shown with the bill cycle billing determinants as presented in MFR E-13c.

D. Summary of Class Proposed Rates of Return

Q. Do you have an exhibit that summarizes the Company's proposed class revenues and the class rates of return that would be realized by the Company's proposed rates and charges?

A. Yes. MFRs E-1 and E-8 show this information. The classes are at parity under the proposed rates to the extent the Company was able to accomplish, considering the benefits of gradualism and the limitation of not increasing any rate class by more than 150% of the total average percentage increase. This is in recognition of the Commission's practice of encouraging rate parity while preventing a class from receiving an increase greater than 1.5 times the system average percentage increase in total.

III. <u>PROPOSED CHANGES TO RATE DESIGN</u>

Q. Would you summarize the more significant emerging energy trends impacting Florida today that call for rate design changes or revisions?

A. Yes. Florida, like many other states, is facing several broad energy trends that create both challenges and opportunities, especially in the realm of rate design. Meter technology advances enable more sophisticated rate designs, which can provide both improved price signals and improved alignment between customer charges and usage behaviors impacting cost of service. Similarly, end-use technology advancements are enabling communication and control of energy loads such that customers can act upon more sophisticated price signals with load management. The decline in price and subsequent proliferation of solar, which is expected to continue, is reshaping net peak demand. Rate design and pricing must adapt to reflect the impacts that such shifts are driving in resource planning and system management. Finally, anticipated growth of technology with unique or controllable load characteristics, such as electric vehicles ("EV"), present opportunities for customers and must be considered in modern rate designs. The Company is proposing rate designs that accommodate and anticipate these trends, while maintaining alignment between cost of service and proposed target revenues for each rate class.

Q. Would you describe the rate design components of the 2021 Settlement?

A. The 2021 Settlement included several significant changes to DEF's rate design offerings that were agreed upon in collaboration with major customer groups and approved by the Commission, including:

a. Updates in Time-of-Use (TOU) Periods and Pricing
b. Proposal for Inclusion of a Minimum Bill for Residential and General Service (non-demand) Customers
c. Redesign of Delivery Voltage Credit and Power Factor Adjustment
d. Adjusting the Seasonality of Residential Rates
e. New Economic Development Tariff

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Q. Would you summarize the more significant rate design changes or revisions the Company is proposing to make in this proceeding?

A. As with any rate case, the rates have been revised to produce the target class and total revenue requirements being sought in this proceeding. In addition, the Company is proposing a series of design changes to limit cross-subsidizations, send price signals that encourage system beneficial consumption, and generally modernize DEF's pricing structure. The proposed changes are as follows:

a. Slight Modifications to TOU Periods and Pricing
b. Changes to Residential Load Management Credit Tariffs
c. Pricing Updates to Delivery Voltage Credits

The Company is also proposing changes to its lighting schedule and general terms and conditions. Those changes, along with tariff sheets reflecting other tariff modifications, are reflected in MFR E-14.

A. Slight Modifications to TOU Periods and Pricing

Q. What changes is the Company proposing to the TOU rate schedules?

A. As a result of the 2021 Settlement, DEF refreshed all TOU periods as follows (peak periods do not include weekends or holidays):

- On-Peak (Year-round) – 6:00 PM – 9:00 PM
- On-Peak (Winter) – 5:00 AM – 10:00 AM
- Super-Off Peak (Non-Winter) – 12:00 AM (midnight) – 6:00 AM
- Winter should consist of the months of December, January, and February.

DEF is proposing to maintain the TOU periods approved in the 2021 Settlement with the following two modifications to the Super-Off-Peak period:

- Change the name of the Super-Off-Peak period to “Discount” period to clarify that usage during that period will be at a lower rate; and
- Add an additional Discount time period in the winter months from 12:00 AM (midnight) – 3:00 AM.

Q. What is the basis for the proposed changes?

A. The Company is proposing the time period changes to enhance the TOU customer experience by providing customers with flexible loads, including EV owners, a consistent, year-round window to save money on usage or EV charging, while benefitting all other customers by concentrating load in hours with much lower than average system costs. Importantly, the Company continues its consideration of rate stability (including TOU period definitions) in developing the proposed times, with the goal of avoiding further changes for several years. Frequent changes to TOU periods are inadvisable and potentially burdensome as customers use price periods to evaluate energy investments and program load management devices (e.g., thermostats, EV chargers). Thus, the Company’s proposed TOU modifications would not impact customers who are already shifting loads to avoid peak times, but would simply add a consistent, year-round Discount period for customers with flexible and programmable loads. The Company proposes using these TOU periods for all TOU rates, residential and non-residential.

Q. After identifying the proposed TOU periods, how did the Company determine appropriate pricing for the newly defined periods?

A. The Company used the "Cost Duration Method," or "CDM," to identify pricing appropriate for the new TOU periods. The same model and approach were used for defining TOU periods in the 2021 Settlement. The CDM establishes a forecast of hourly system costs. Hourly system costs were used to establish prices for the proposed TOU periods with the objectives of (1) better reflecting cost causation in customer charges, and (2) sending time-differentiated price signals to customers to encourage behavior beneficial to the system.

Q. Will you please explain the CDM?

A. The CDM provides improved linkage between recovery of system costs (e.g., tariff pricing) and the time periods during which system assets are being utilized. For all three major utility functions (generation, transmission, and distribution) some assets are only used to meet demand during a small number of peak hours, while other assets are used for all or nearly all hours. The CDM allocates costs for assets across all three functions based on anticipated utilization. Costs for assets used during all hours are assigned accordingly, while cost for assets used only during peaking hours are concentrated in those hours (e.g., early evening hours).

As generation, transmission, and distribution demands are not perfectly coincident, costs for each function were distributed independently, using specific load duration curves. Generation costs were allocated using net peak load duration (gross load net of utility-scale solar), transmission capacity costs were allocated using gross system load duration, and distribution capacity costs were allocated using a distribution load duration curve for the customer class for which rates are being designed (e.g. residential load duration curve for residential customers). The following five steps outline the cost allocation process across all hours, for each function using its respective load duration curve.

- Step 1: Capacity costs were divided by the peak load of each load duration curve to find a unit cost per MW of capacity.
- Step 2: The incremental load in each hour was calculated by taking the difference in load between that hour and the hour with the next highest load. For the lowest load hour of the year, the load in that hour is used. Note that the sum of all these incremental load amounts is necessarily equal to the peak load.
- Step 3: For each hour, the incremental load was shared evenly between the hour in question and all hours of the year that have a higher load than the hour in question. The incremental load at the highest load hour was not shared as there are no higher load hours. The incremental load at the second highest hour was shared evenly between the top two hours, and so forth.
- Step 4: Next, load allocated to each hour was totaled. The highest load hour has a share of load for all hours of the year, the second highest load hour has a share of load for all hours of the year except the highest hour, and so forth.
- Step 5: Finally, the load allocated to each hour in Step 4 was multiplied by the unit cost calculated in Step 1 to calculate the total cost of each hour. This can in turn be divided by the billing load in that hour to calculate the unit cost of each hour.

Combining the results of the Cost Duration Method for each customer class with hourly energy costs provides the variable cost of serving the respective customer class in each hour of the year. In combination with the TOU periods previously described prices for each

TOU period (e.g., On-Peak) can be established to recover those costs for each respective period. Prices may be slightly modified to ensure estimated revenue is as close as possible to, but not exceeding, the class revenue requirement.

Q. Which rate schedules are impacted by the Company's proposed updates to TOU rates?

A. The impacted rate schedules would include RST-1, as well as GST-1, GSDT-1, CST-2, CST-3, and IST-2.

Q. Please describe the pricing changes the Company is proposing for the residential TOU rate (RST-1).

A. Prices were created using the CDM that allocates generation, transmission, and distribution demand costs to the different rating periods based on forecasts for each hour of the year. Forecasted hourly marginal costs were used to allocate energy costs. The proposed TOU prices were then balanced with the residential class revenue requirements.

Q. Please describe the pricing changes the Company is proposing for the non-residential TOU rates (GST-1, GSDT-1, CST-2, CST-3, and IST-2).

A. Similar to RST-1, prices were created using the CDM that allocates generation, transmission, and distribution demand costs to the different rating periods based on forecasts for each hour of the year. Forecasted hourly marginal costs were used to allocate energy costs. The proposed TOU energy prices were then balanced with the respective class revenue requirements. As applicable, the proposed TOU demand prices were set based on the specifically applicable forecasted billing determinants, balanced with both the respective class revenue requirements and the results of the CDM calculations.

Q. Are there other changes the Company is proposing relative to non-residential demand charges?

A. The Company evaluated alignment of bills/pricing to cost causation. Analysis showed that shifting a portion of fixed cost recovery from energy charges to demand charges improved alignment to cost causation across a wide spectrum of customer energy profiles. However, the Company imparted gradualism in the shift year to year, with an annual increase of five percent (5%) to the cap placed on fixed cost recovery of proposed TOU demand charges.

B. Changes to Residential Load Management Credit Tariffs

Q. Please summarize the changes to rate schedules RSL-1, RSL-2, and the new LMR-1 rate schedule.

A. DEF is proposing to move the residential load management credits to a rider, which would allow customers to participate and receive load management credits even if they elect to be on the optional RST-1 rate schedule. This change to a rider format allows for more customer choice by allowing customers to switch to a TOU rate, if it is more affordable, and also elect to support the grid by participating in load management programs. LMR-1 captures the same Load Management Interruption Schedules in RSL-1 and RSL-2 and retains the incentive amounts. The Company is proposing to close RSL-1 and RSL-2 to new customers such that both new load management customers and RSL-1/RSL-2 customers that choose to move to RST-1 will both be on the LMR-1 rider. The Company is proposing to migrate RSL-1 and RSL-2 customers to LMR-1 over the time period of this case, to ensure an orderly transition for billing customers under the new rider. The Company would then propose to permanently close the RSL-1 and RSL-2 rate schedules once the transition of all customers to LMR-1 is complete.

Q. Are there any differences between the language proposed in LMR-1, RSL-1, and RSL-2.

A. LMR-1 is set up as a rider (add-on) to an applicable residential rate schedule. The language around the specific Interruption Schedules in LMR-1 aligns with DEF's proposal in this case to revert RSL-1 and RSL-2 back to a wider period of use than the narrower peak hours. Specifically, the change will allow for demand response events to occur during 6 AM – 11 AM and 6 PM – 11 PM in the winter months (December through February) and 1 PM – 11 PM in the summer months (March through November) to support broader operational availability for reserve margins. The credit values in LMR-1 remain identical to the respective credits received currently in RSL-1 and RSL-2. Additionally, the terms of program participation for the respective programs in LMR-1 are also identical to RSL-1 and RSL-2. The Company's proposed TOU hours recognize that system peaks are, on average, increasingly concentrated in a narrower set of hours as reflected in our TOU rates, while demand response capabilities from programs like RSL-1, RSL-2, and LMR-1 are beneficial for operational challenges across a wider range of hours.

C. Pricing Update to Delivery Voltage Credit

Q. What are the current credits that DEF offers for delivery voltage?

A. DEF's delivery voltage credits include a credit for taking service at the transmission or primary distribution level. These credits are administered through the GSD-1 and GSDT-1 tariffs. The delivery voltage credits for both GSD-1 and GSDT-1 are $1.31 per kW for distribution primary voltage, $5.42 for transmission voltage below 230kV, and $7.50 per kW for transmission voltage at or above 230 kV. In addition, there is a small metering voltage adjustment factor, which reduces the non-fuel energy charges, the demand charge, and also reduces the voltage credit where the metering voltage is either at primary or transmission level. This adjustment factor (1% for primary and 2% for transmission) addresses the difference in losses incurred due to transformation between voltages.

Q. What changes in delivery voltage credit is DEF proposing for these rates?

A. DEF is proposing to update the delivery voltage credit (DVC) rates where the higher the delivery level, the more costs are excluded, and thus a higher credit is given. These calculations are described further in Ms. Marcia Olivier's testimony and in her Exhibit MJO-8.

Q. Is the Company proposing any changes to the Minimum Bill for Residential and General Service customers?

A. No, the Company is not proposing changes to the Minimum Bill for any Residential or General Service, non-demand customers (GS-1 and GST-1).

Q. Has the Company's Off-Peak Charging Credit Pilot been a success?

A. Yes. The Off-Peak Charging Credit pilot was limited to 1,000 customers per year. Customer interest has been strong, and the program has been fully subscribed in each year.

Q. Is the Company recommending any changes to the Off-Peak Charging Program?

A. Yes. The Company is recommending the pilot limitations be removed and the program be converted to a full program with no participation limits. The Company has also proposed a modification of the start of the later weekday off-peak time periods to be changed from 9 PM to 11 PM. DEF has proposed this modification to differentiate the start of the TOU period to mitigate creating future peaks caused by all EVs beginning charging at the same time (i.e., “timer peaks"). Additionally, the Company has proposed a monthly credit of $7.50 based on a comparison of potential EV charging savings on Schedule RST-1 with off-peak charging behavior. The program will continue to be offered for only RS-1 participants – that is, mutually exclusive with RST-1. Customers with EV charging needs will thus be able to choose between the off-peak charging credit program and a whole-home TOU, which provides for a wider array of price-responsive options. The contra-revenue amount attributed to the EV off-peak charging credit for each year of this case are as follows: $620,029 in 2025, $1,278,968 in 2026, and $1,955,316 in 2027, as shown in MFR E-13c with the annual average projected participation numbers shown based on the $90 annual credit ($7.50 x 12 months) displayed as the units. The Company believes that Off-Peak Charging participants are shifting loads and thus benefitting the system with the current program design, but additional program design changes or hardware solutions (e.g., load management or demand response programs) may be complementary or necessary in future years as EV adoption become more widespread. This program is further discussed in the testimony of Mr. Tim Duff.

Q. Has DEF proposed any other changes specific to the Non-Residential Interruptible, Curtailable, and General Service Stand-by Generation Rate Schedules?

A. Not specifically as part of this proceeding. However, DEF has carried over certain changes to non-residential rate schedules from the ongoing Demand Side Management (DSM) goalsetting proceeding. Specifically, based on updated avoided cost evaluations using DEF's 2023 ECCR True-Up filing and as described in the Company's 2024 DSM Goalsetting filing. DEF has used these proposed credit rates where listed in MFR E-14A – Summary of Unit Charges and Unit Cost Data by Rate Class and in the relevant tariff sheets provided that I sponsor or co-sponsor.

IV. <u>CONCLUSION</u>

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Timothy J. Duff 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

TIMOTHY J. DUFF

On Behalf of Duke Energy Florida, LLC

I. <u>INTRODUCTION</u>

Q. Please state your name and business address.

A. My name is Timothy J. Duff, and my business address is 525 South Tryon Street, Charlotte, NC 28201.

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

A. I am the General Manager, Grid Strategy Enablement for Duke Energy Business Services, LLC ("DEBS"). 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. Please describe your duties and responsibilities in that position.

A. I am responsible for the development of strategies and policies related to the implementation of Customer Solutions retail products and service offerings that are designed to create customer and utility system value, such as offerings around customer adoption of electric vehicles. I also oversee the analytics functions associated with evaluating and tracking the performance of Customer Solutions retail products and services. My responsibilities cover all of Duke Energy's utility operating companies, including DEF.

Q. Please describe your educational background and professional experience.

A. I graduated from Michigan State University with a Bachelor of Arts in Political Economics and a Bachelor of Arts in Business Administration and received a Master of Business

Administration degree from the Stephen M. Ross School of Business at the University of Michigan.

I started my career with Ford Motor Company and worked in a variety of roles within the company's financial organization, including Operations Financial Analyst and Budget Rent-A-Car Account Controller. After five years at Ford Motor Company, I started working with Cinergy in 2001, providing business and financial support to plant operating staff. Eighteen months later, I joined Cinergy's Rates Department, where I provided revenue requirement analytics and general rate support for the company's transfer of three generating plants. After my time in the Rates Department, I spent a brief time in the Environmental Strategy Department, and then I joined Cinergy's Regulatory and Legislative Strategy Department. After Cinergy merged with Duke Energy in 2006, I served as Managing Director, Federal Regulatory Policy for four years. In that role, I was primarily responsible for developing and advocating for Duke Energy's policy positions with the Federal Energy Regulatory Commission. In 2010, I was named General Manager, Energy Efficiency & Smart Grid Policy, and Collaboration. Since 2010, I have held a number of positions related to analyzing and gaining regulatory approval of customer product and service offerings, including energy efficiency ("EE") and demand response. I assumed my current position in April 2021.

Q. Have you testified before this Commission in any prior proceeding?

A. Yes. I have provided both written and oral testimony before the Florida Public Service Commission in Docket Nos. 20130200-EI, 20140002-EG, and 20140226-EI.

Q. Do you have any exhibits to your testimony?

A. Yes. I have prepared or supervised the preparation of Exhibit TJD-1 – "Electric Vehicle Make Ready Credit Program." This exhibit is true and accurate.

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

A. Yes. I co-sponsor the following MFR schedules: B-7 (Plant Balances by Account And Sub-Account), B-8 (Monthly Balances Test Year – 13 Months), B-9 (Depreciation Reserve Balances By Account And Sub Account), B-10 (Monthly Reserve Balances Test Year – 13 Months), B-11 (Capital Additions and Retirements), and B-13 (Construction Work In Progress). These schedules are true and accurate, subject to their being adjusted in this proceeding.

II. PURPOSE AND TESTIMONY SUMMARY

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

A. My testimony updates the Commission regarding DEF's electric vehicle ("EV") pilot programs and initiatives and supports DEF's EV-related request in this case.

Q. Please briefly summarize your direct testimony.

A. My testimony provides updates regarding DEF's (1) deployment of electric vehicle service equipment ("EVSE") within its service territory under the Park & Plug Pilot Program; (2) residential EV managed charging pilot program, known as "Off-Peak Credit," and (3) Commercial & Industrial ("C&I") Rebate Program. My testimony also supports DEF's

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proposed expansion of the Off-Peak Credit Program based on the pilot program's success, DEF's request for Commission approval of the Electric Vehicle Make Ready Credit Program ("MRC Program") as an evolution and replacement of the C&I Rebate Program, and, finally, DEF's request to implement a new Fleet Advisory Program.

III. FLORIDA FLEET ELECTRIFICATION & EV DEPLOYMENT

Q. Please describe the current EV landscape in Florida.

A. The EV market in Florida continues to develop and grow. At the end of 2022, Florida had 168,000 EVs on the road,[1] second only to California. Growth in EV adoption is evident in the Company's footprint. At the end of 2020, there were approximately 14,500 registered EVs in DEF's territory. By the end of 2022, that number more than doubled to nearly 34,000. As of the end of September 2023, this number grew to more than 44,000 and is ultimately expected to exceed 530,000 by the end of 2030, representing an annual growth rate of 43% from 2020-2030.

In addition to the Company's offerings, other Florida electric utilities are also delivering EV programs. Florida Power & Light offers its EVolution® programs for charging infrastructure installation and off-peak charging in the home as well as for public and fleet charging infrastructure at non-residential customer sites. Tampa Electric Company's Drive Smart program provides funding and installation services for chargers at workplaces, public and retail locations, multi-unit dwellings, income-qualified locations, and

[1] U.S. Dep't of Energy, *Alternative Fuels Data Center – TransAtlas* (https://afdc.energy.gov/transatlas/#/?state=FL&year=2022&fuel=ELEC&view=vehicle_count) (last visited Jan. 23, 2024).

government locations. In short, Florida utilities have been serving and continue to serve as important enablers of the EV transition that is underway in Florida.

Q. What is DEF proposing as part of this case?

A. DEF is proposing that its pilot Off-Peak Credit Program be modified and made permanent, that participation limits for the program be removed, and that a program called Make Ready Credit be implemented as a replacement for the current C&I Rebate Program. In addition, DEF is proposing a Fleet Advisory Program to assist interested customers in understanding the benefits of electrifying their commercial vehicle fleets.

IV. <u>PARK & PLUG</u>

Q. Please describe the Park & Plug Pilot Program.

A. The Commission approved the 2017 Settlement Agreement that included a provision allowing DEF to initiate the Park & Plug Pilot Program ("Park & Plug"). Park & Plug, which was designed to provide foundational public EVSE infrastructure to support EV adopters, allowed DEF to install, own, and operate EVSE infrastructure for use by the public within its territory.

Q. Did the 2021 Settlement Agreement address the Park & Plug Pilot Program?

A. Yes. The 2021 Settlement Agreement allows DEF to continue certain aspects of Park & Plug. Specifically, the 2021 Settlement Agreement permits the Company to expand its network of DC fast charging ("DCFC") sites at locations that are sufficiently distant from existing public fast charging infrastructure and to upgrade the equipment at existing DCFC sites.

Q. Has Park & Plug been a success?

A. Yes. Park & Plug helped facilitate the installation of a foundational level of EV charging infrastructure within the initial five-year pilot timeframe allotted within the 2017 Settlement Agreement and under the $8 million allocated capital budget. Today, the Company continues its work pursuant to the 2021 Settlement Agreement and, as of the end of 2023, has contracted with fourteen site hosts for new installations and/or upgrades. Of those, five sites have been completed and nine are in progress. Of the completed sites, four sites are new, and one is an upgrade to a previously deployed site.

Q. What lessons has DEF learned from the Park & Plug Program?

A. Park & Plug has provided DEF with comprehensive data on EV charging utilization characteristics within the DEF footprint. Detailed analysis on utilization trends and program costs over time and across segments can be found in DEF's Annual Reports to the Commission. One key takeaway from Park & Plug is that with the growth of the EV market comes greater demand for and utilization of charging infrastructure. To that end, lessons learned from Park & Plug are also actively leveraged to benefit both the state of Florida, as it pursues deployment of National Electric Vehicle Infrastructure program ("NEVI") sites, as well as private businesses that seek to deploy charging stations for public and private use. The Company knows first-hand what it means to deploy and maintain EV charging assets and, thus, is better positioned to serve its customers that seek to do the same.

Q. Is DEF proposing to expand the Park & Plug beyond the parameters outlined in the 2021 Settlement Agreement?

A. No. The Company is not proposing any incremental site deployment beyond what was approved in the 2021 Settlement Agreement. In fact, the Company's current plans do not include deployment of new DCFC sites pursuant to the limits of the 2021 Settlement Agreement. Much has changed since Park & Plug began and, notably, since the 2021 Settlement Agreement. Federal government funding made available through the Infrastructure Investment and Jobs Act ("IIJA") has created a landmark opportunity for the Florida Department of Transportation to spur activity from the private sector to deploy a network of fast charging sites. As a result, Duke Energy Florida need not serve as a driving entity to deploy and operate a public DCFC network.

V. <u>OFF-PEAK CREDIT PROGRAM</u>

Q. Please describe the Off-Peak Credit Program proposal.

A. The Off-Peak Credit Program provides a financial incentive to residential customers that are not on a whole-home Time of Use ("TOU") rate to engage in off-peak charging. In exchange for avoiding on-peak periods when charging their EV at home, participants receive a monthly electric bill credit. Participants may charge during on-peak hours up to twice per month before forfeiting their credit for that month.

Q. Has DEF implemented the Off-Peak Credit as a pilot program?

A. Yes, the EV Non-Time of Use credit program described in the 2021 Settlement Agreement has been implemented with the customer-facing name of Off-Peak Credit. The Off-Peak Credit Pilot Program launched in January 2022. The pilot allows for 1,000 customers to be added to the program per calendar year and provides a $10 monthly credit to participants.

Q. What is the current subscribership to the Off-Peak Credit Program?

A. As of the end of 2023, the program had 2,000 enrolled participants. The enrollment cap for the 2022 and 2023 calendar years was reached, and the same is expected for 2024.

Q. Has the Off-Peak Credit Program been a success?

A. Yes, resoundingly so. Not only is the pilot program hitting its enrollment caps, it is doing so with limited marketing. Further, waitlists have been necessary to capture interested customers so that they may be enrolled in subsequent years. Finally, the pilot is producing results in terms of shaping EV charging behavior. As of December 2023, 65% of pre-enrollment on-peak EV charging consumption has been moved to off-peak hours.

Q. Please describe the updates DEF is proposing related to the Off-Peak Credit Program.

A. Based on the success of the Off-Peak Credit pilot in attracting participants and in shifting load, the Company proposes to progress from a pilot to a full program by removing the 1,000 incremental participant per year limit.

Q. What participation is forecasted for the Off-Peak Credit Program?

A. The program is expected to retain pilot participants as well as participants that have been waitlisted due to the current pilot's annual enrollment limits. Without the annual enrollment limit, a full program is forecasted to enroll approximately 10,000 EVs in its first year of full program participation. Steady growth over the remaining years is forecasted to result in approximately 33,500 EVs by the end of 2028.

Q. How did DEF forecast these participation amounts?

A. The Company forecasts EV adoption using the Vehicle Analytics Simulation Tool ("VAST") modeling platform developed by Guidehouse. With this tool, the Company can estimate the expected levels of light-duty vehicle adoption as a proxy value for the number of consumer-driven EVs that will be in the DEF service territory. The Company estimates that approximately 10% of incremental light duty EVs will enroll in the program by 2028.

Q. Will the updates to the Off-Peak Credit Program be beneficial to all customers?

A. Yes. The purpose of the Off-Peak Credit pilot was to test the ability of a simple program structure to incent customers to modify their charging behavior. Specifically, the Off-Peak Credit Program aims to prevent – and the pilot has proven successful at preventing – EV load during system peak hours. For customers not on TOU rates, this results in system revenues that are steady, while system costs are reduced, thereby creating downward pressure on rates. Additionally, the management of on-peak EV charging can have the benefit of delaying the replacement of system assets, such as transformers, that serve groups of homes, thus deferring costs.

VI. COMMERCIAL & INDUSTRIAL REBATES

Q. Please describe the C&I Rebates Program.

A. The C&I Rebates Program provides a financial incentive to C&I customers that install EV charging stations behind a separate meter and take service on rate schedule GST-1, a non-demand TOU rate schedule.

Q. Did DEF implement the C&I Rebates Program as a pilot?

A. Yes. Consistent with the Commission's Order approving the 2021 Settlement Agreement, DEF piloted the C&I Rebates Program. The program began in January 2022 and paying varying rebate amounts to C&I customers depending on the segment (or use case) of the EV charger.

Q. What is the current participation in the C&I Rebates Program?

A. Currently, the program has minimal participation with three commercial customers and a total of 26 EV chargers installed. The overwhelming majority of chargers supported by the program and associated funding has gone to electric school bus DC fast chargers, but two public DC fast chargers are also included. Fourteen customers are pre-approved, and chargers are pending installation by the respective customers with a total of 79 EV chargers eligible for the C&I rebate. Pending segments of participation include Level 2 for public, workplace, multi-unit dwelling and fleet use, as well as DC fast charging for public, fleet and school bus use.

Q. Has the C&I Rebates Program been as successful as expected?

A. Unfortunately, no. Original projections for the program's first two years of operation were that approximately $8.6 million in customer incentives for 1,420 chargers would be distributed to participants. Twenty-six chargers are currently installed with 79 EV chargers that are pending installation.

One likely reason for customers electing to not participate in the program was the former requirement that the chargers be placed on rate GST-1. The Company implemented a change to this requirement as of November 2023 and will continue to monitor participation to identify if there will be meaningful results from this change. Prospective participating customer feedback also indicated that participation was negatively impacted because EV charger installation costs were viewed as too high, despite available incentives. Finally, some customers did not provide certain requested information and therefore did not complete the application process. Thus, those associated rebates were not processed. To eliminate this potential barrier to participation, the Company plans to develop an online checklist to guide customers before and during the application process.

Q. What does DEF propose regarding the C&I Rebates Program going forward?

A. The Company continues to explore options and alternatives to enhance the participation and offerings for EV programs. However, because the Company believes the modifications made to the program should improve its uptake among C&I customers in 2024, DEF proposes to replace the program in 2025 when new rates become effective. The magnitude of program incentive amounts for several segments are believed to be insufficient to drive meaningful participation. Additionally, the C&I-focused program inherently does not assist residential customers seeking to safely install infrastructure to support EV charging.

As discussed below, the Company proposes to deploy a Make Ready Credit ("MRC") Program as the replacement for C&I Rebates.

VII. MAKE READY CREDIT PROGRAM

Q. Please provide an overview of the MRC Program.

A. The MRC Program aims to simplify EV adoption and charging by providing an incentive, in the form of a credit on a customer's bill or a payment to a contractor, for the installation of the infrastructure needed to bring safe electrical service to EV charging hardware and, at the discretion of the customer, by providing a contractor to perform the work. The credits are designed to defray a portion of EV "make ready" expenses related to the installation of infrastructure necessary to support EV charging.

Q. Who is eligible for the MRC Program?

A. As I describe more fully below, the MRC Program is available to both residential and non-residential DEF customers that install at their premises or place of business the wiring and circuitry required for a Level 2 or higher-powered EVSE(s). The MRC Program is also available to pre-approved homebuilders constructing homes that are served by the Company's distribution system and at which the homebuilder is installing Make Ready infrastructure.

Q. Will DEF own the MRC Program infrastructure?

A. No. The Company will not own the Make Ready infrastructure associated with the MRC Program.

Q. Please explain the residential credit under the MRC Program.

A. A residential customer may receive credits for Make-Ready infrastructure either through a reduction in the price charged by a contractor that has been approved by the Company (the "Contractor Credit Option") or through a direct application submitted to the Company by the customer (the "Customer Credit Option"). These credits for residential customers will not exceed the estimate of the aggregate increase in electric revenue for the first four years following installation of the newly installed charger.

Q. Please describe the Contractor Credit Option.

A. Under the Contractor Credit Option, a residential customer seeking installation of a qualifying charging station and Make-Ready infrastructure at the customer's premises selects a contractor that has been approved by the Company for participation in this program. A list of such approved contractors will be available on the Company's website. The contractor must contact the Company to determine the amount of the customer's Make Ready infrastructure credit based on information provided by the customer, again, not to exceed the estimate of the aggregate increase in electric revenue for the first four years following installation of the newly installed charger. The contractor is then responsible for including the Make Ready infrastructure credits in the price quoted to the customer for

Make Ready infrastructure installation. The customer is responsible for providing the contractor and/or third-party vendor with evidence of EV registration.

After the Company receives and reviews an application for completeness, the Company will, subject to the terms and conditions of this program, make a payment to the contractor in the amount of the calculated make ready infrastructure credits.

Q. Please describe the Customer Credit Option application process.

A. Customers requesting participation in the MRC Program through the Customer Credit Option must first file an application with the Company. The application requires the customer to provide, among other information:

1. Detailed invoice(s) from the contractor for Make-Ready infrastructure. Each invoice from the contractor must include separate line items for labor and materials and the contractor's name, address, and telephone number;
2. A copy of the approved permit from the municipal or local permitting authority; and
3. Evidence of EV registration.

The sum of the costs for Make-Ready infrastructure stated in the invoice(s) submitted with the application are considered the "Demonstrated Costs" subject to crediting; provided, however, that the Demonstrated Costs shall not include any amounts for which the customer expects coverage or reimbursement from a third-party funding source. It is not the intention of the MRC Program to provide credits to defray expenses for which the customer expects to receive third-party funding. To be eligible for credits under this Program, the application must be submitted within 120 days following the later of:

1. The date on the most recent invoice included with the application; or
2. The date of EV registration.

After the Company receives and reviews an application for completeness, including but not limited to the submission of items 1-3 listed above, as applicable, the Company will, subject to the terms and conditions of this program, provide Make Ready infrastructure credits to the customer in the form of a check.

Q. Please explain the Homebuilder option.

A. The Company will provide an incentive of $150.00 to a homebuilder approved by the Company for participation in this Program, if that homebuilder is constructing a home served by the Company's distribution system and if the homebuilder demonstrates, through an application and satisfactory documentation, that it has installed Make Ready infrastructure in a convenient location for residential EV charging. This Program provision differs from other avenues in that available MRC credits are predicated solely on the cost of installing Make Ready infrastructure. This cost is anticipated to be significantly lessened during original construction – as compared to a retrofit scenario under the Customer and Contractor options – and thus limits program expense.

Q. Please explain the non-residential MRC Program.

A. To participate in the non-residential MRC Program, an interested customer must file an application with the Company. The application will require the customer to provide, among other information:

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1. Detailed invoice(s) from the contractor for Make Ready infrastructure. Each invoice from the contractor must include separate line items for labor and materials and the contractor's name, address, and telephone number;

2. For all installations involving installation of more than one charging station or Level 3 or higher charging station, a schematic diagram of the installation;

3. A copy of the approved permit from the municipal or local permitting authority; and

4. A completed customer usage profile form.

The application must be submitted within 120 days following the later of:

1. The date on the most recent invoice included with the application; or

2. The date listed on the approved permit.

The sum of the costs for Make Ready infrastructure stated in the invoice(s) submitted with the application are considered the "Demonstrated Costs" subject to crediting; provided, however, that "Demonstrated Costs" shall not include any amounts for which the customer expects coverage or reimbursement from a third-party funding source. Again, the Program is not designed to provide credits to defray expenses for which the customer expects third-party funding. The customer must acknowledge that a Company representative may, with reasonable advance notice, access the customer's charging station installation to verify compliance with the terms of this Program.

After the Company receives and reviews an application for completeness, including but not limited to the submission of the items listed above, as applicable, the Company will, subject to the terms and conditions of this program, provide Make Ready infrastructure credits to the customer in the form of a check. The Company will determine the Make Ready infrastructure credit amount based on the completed customer usage profile form and the expected increase in revenue to be achieved through such usage for the first four years of operation, with the revenue credits not to exceed the Demonstrated Costs.

Q. Why is DEF proposing the MRC Program in this case?

A. The Company believes that the proposed MRC is an attractive replacement for the C&I Rebate Program. The MRC Program simplifies EV adoption and charging for customers through revenue credits that defray a portion of EV Make Ready expenses. The MRC Program also provides fixed incentives to approved homebuilders installing Make Ready infrastructure for new residential construction. Finally, with the available Contractor Credit Option, the MRC Program will facilitate the safe installation of Make Ready infrastructure for residential customers that may have concerns regarding higher voltage installations.

Q. Please compare the credit amounts for the MRC Program with the C&I Rebate Program.

A. The table below shows the per segment rebate and/or credit maximums for each eligible use case.

Segment	C&I Rebate Amount	Make Ready Credit Amount

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Single Family Home Residential	N/A	$744
Public Level 2	$627	$1,158
Multi-Unit Dwelling Level 2	$304	$1,158
Workplace Level 2	$434	$2,341
Fleet Level 2	$1,175	$4,487
Public DC Fast Charger	$4,195	$9,122
Multi-Unit Dwelling DC Fast Charger	N/A	$9,122
School Bus DC Fast Charger	$20,889	$16,270
Transit Bus DC Fast Charger	$24,423	$26,161
Fleet DC Fast Charger	$35,600	Custom Calculation
Forklift Fast Charger	$3,200	Custom Calculation
Truck Refrigeration Unit	$1,591	Custom Calculation

Q. How are credits for the MRC Program calculated?

A. As briefly discussed above, the determination of Make Ready credits (other than the Homebuilder Option) is based upon the consumption and demand expected from EV charging installations. The Company utilized data from the Charge Florida Residential Load Measurement Program to estimate residential EV charging load shapes and annual energy consumption. Based on that data, the Company estimates that customers utilize an average of approximately 2,700 kilowatt hours ("kWh") per year (or 225 kWh per month) to charge their EV at home. To calculate the maximum credit for a residential customer, the Company utilized this yearly average kWh number to calculate the estimated kWh that a residential customer would use to charge their EV over a four-year period. The Company multiplied the estimated annual kWh for that four-year period by the current residential time of use (RST-1) off-peak base energy rate. The credit calculation follows the long-established Contribution in Aid of Construction ("CIAC") credit methodology, which limits the maximum credit to four years of base revenue.

For the non-residential portion of the MRC Program, the Company utilized data from Park & Plug charger deployments to determine EV charging load shapes and estimates of energy consumption by usage segment. The Company then multiplied the estimated annual kWh for four years by the current general service non-demand ("GSD") base energy and demand rates. Using the results, for loads less than 50 kilowatts, the Company is proposing standard maximum credits for the following segments: Public Level 2, Workplace Level 2, Fleet Level 2, Multi-Family Level 2, Public DCFC, School Bus DCFC, Transit Bus DCFC, and Multi Family DCFC. For charging installations with more than 50 kilowatts aggregate load, the calculations, following the same process, will be performed on a case-by-case basis using information from the Customer Usage Profile form.

Q. Please explain the projected costs of the MRC Program and how DEF is proposing to recover MRC Program costs.

A. As detailed in Exhibit TJD-1, the Company determined the costs by multiplying the proposed revenue credits by the forecasted number of installations for each MRC option. The Company is requesting that the actual credits incurred be deferred as a regulatory asset and amortized over 48 months beginning in the month following the credit. The Company has also included estimated program administration costs and additional revenues resulting from this program. Exhibit TJD-1 provides the estimated costs and revenues for this program, and Company witness Marcia Olivier discusses how this MRC Program was incorporated in DEF's cost of service.

Q. Is DEF proposing any parameters to control the costs of the MRC Program?

A. Yes. The Company is proposing ceilings or upper limits for the MRC on a per charger basis. With these upper limits, the credit paid per charger shall not exceed the lesser of the four-year revenue calculation described above or the customer's demonstrated cost of installing Make Ready infrastructure. Demonstrated costs include physical upgrades necessary to bring power to a charger location on the customer side of the meter. Demonstrated costs may not include permits, installation of the EV charger, or the charger itself. Further, demonstrated costs must be documented appropriately by invoice to the participating customer.

Demonstrated costs cannot include any external funding that the participating customers are able to secure. For example, many non-residential customers could seek funding from one of many federal programs brought about by the IIJA. The MRC Program serves as a complement to such funding but does not duplicate it. Participants can receive credits only for out-of-pocket make-ready infrastructure costs.

Q. Will the MRC Program benefit all customers?

A. Yes. While the Company is proposing to pay the MRC credits to participating customers based on the first four years' estimated revenue, the ongoing increase in energy consumption will continue to add revenue to the system beyond that four-year period without adding cost to the system. The resulting downward pressure on rates is a benefit to all customers.

Q. Please discuss any additional benefits that result from the MRC Program.

A. In addition to simplifying the process of electrification for all customer segments, the MRC Program supports safety, promotes grid readiness, and is a conduit for EV load management. The program supports safety of EV installations because participation in the program requires an installation that has been permitted and inspected appropriately by the local authority having jurisdiction. In doing so, the program provides an incentive to leverage qualified installers and follow local codes and regulations, which provide inherent safeguards. Grid readiness and stability is also enabled by the program because the location of participating EV chargers becomes known by the Company. Insomuch as all customers are encouraged to notify the Company if they install additional loads at their home or business, they do not always do so. The MRC Program provides motivation for customers to engage the Company as they add EV charging loads. Finally, engagement in the MRC Program also affords the Company an ability to market EV load management offerings to known EV charging customers. Today, these programs include TOU rates and the Off-Peak Credit Program for residential customers. In the future, other offerings, including potential rates and programs for non-residential use cases, may also be presented to customers that are identified because of their participation in the MRC Program.

Q. Does the MRC Program support the competitive EV charging market?

A. Yes, in addition to easing the transition to EV for customers, the MRC Program supports the competitive market because it provides funding irrespective of the installation, hardware, and/or software provider(s) a participating customer chooses. Additionally, the MRC Program is agnostic to the EV charger ownership model deployed at a given site. A participating customer may choose to buy their own equipment, lease equipment from a third party, or host equipment from an EV charging network operator.

VIII. FLEET ADVISORY PROGRAM

Q. Please provide an overview of DEF's Fleet Advisory Program.

A. The Fleet Advisory Program is an opportunity for fleet managers to effectively assess the economics and the complex logistical nuances of transitioning to electric vehicles. This is also an opportunity for DEF to learn more from the fleet operators to determine what is most important to them and how DEF can help ease the transition. This relationship will help serve to better understand barriers to electrification and provide DEF with an opportunity to build informed offerings that will help accelerate fleet electrification and contribute to meeting the decarbonization goals for businesses, communities, and the nation. In this program, DEF seeks to meet the fleet operator where they are on their electrification journey. The program is flexible, in that it can more directly assist the customer and vendor complete a fleet assessment or can be removed from the study activities based on customer preference and timing. Benefits will include developing a customer road map to electrification along with a capacity analysis for grid support along affected circuits. Additionally, the Company will establish a relationship specific to the customer's electrification projects, which often take years of planning and implementation.

Q. Please describe the Fleet Advisory Program.

A. The Fleet Advisory Program will provide DEF non-residential customers operating fleets with the opportunity to have a comprehensive analysis completed for switching their fleet vehicles to EVs. This analysis will highlight the total cost of ownership savings available to fleets through conversion to EVs, among other benefits. Through the Fleet Advisory Program, the Company proposes two options for customers. For customers that have an advisory vendor of their own, they may participate by sharing the required study information with the Company. Alternatively, the Company also intends to have a list of qualified vendors who are trained on program requirements, with which customers can contract for advisory studies. The studies will have a maximum per participant funding amount of $12,000, which supports a minimum of 236 fleets to receive benefits from the program. Total program spending is capped at $3,300,000 over three years. DEF determined the rebate amount using data from comparable programs filed in other jurisdictions, and participation estimates were calculated using Company data on fleet customers and public data regarding fleet makeup.

Q. Please further describe the Fleet Assessment Options available to customers under the program.

A. Customers participating in the program will have the option to use a program vendor or have a vendor of their choice complete a study of their fleet. Customers choosing to utilize the program vendor option will select a program vendor that has been approved by the Company for participation in this program to complete a study. The Company will pay the vendor $12,000 for the study, and the customer will be responsible for amounts over the $12,000. Customers choosing to utilize a vendor of their choice will select a vendor, complete a study, and receive a credit for sharing the study and its data with DEF.

Q. What are the participation parameters for customers to qualify for the program?

A. Participation will be available on a first-come, first-served basis to non-residential customers receiving electric service from DEF. Participants must operate a commercial vehicle fleet from their electric service premises. Examples may include schools, transit agencies, logistical companies, municipal fleets, rural transport companies, hospitals, universities, airports, service providers, and non-profit entities. Participants must meet minimum requirements for fleet vehicle size to ensure study results provide beneficial learning and overall customer benefit. The minimum fleet size required to participate are: twenty or greater light-duty vehicles (Class 3 and below), or five or greater medium/heavy-duty vehicles (Class 4 and above), or a fleet with ten or greater vehicles in the light and medium/heavy duty classifications combined. The minimum fleet size requirements apply to vehicles that will be primarily charged at a DEF service territory location, vehicles charging outside of DEF territory will not count toward minimum participation amounts.

For qualifying fleet operators utilizing a vendor of their choice, the customer is responsible for selecting a vendor and ensuring the study meets certain minimum study requirements and learnings to qualify for funding. Minimum study requirements include total cost of ownership savings for all fleet on-road vehicles, including any fuel and maintenance savings, capital cost differences between traditional internal combustion engines and EVs, and the cost of EVSE installations. The studies must also include the quantity of chargers, the location, the charging levels, and the recommended charging power rate, for the vehicles being recommended for conversion. The studies must include education about managed charging benefits and potential options for fleets to reduce costs through available DEF rates. Studies must also highlight the potential Green House Gas ("GHG") emissions reductions from conversions to EVs. Customers must agree to share the study and all related data with the Company prior to receiving funding. Completed studies must include EV and EVSE data that is no older than 2024 to qualify.

Q. What benefits does the Program provide for participants?

A. Program participants will benefit by receiving a study and analysis establishing a roadmap for fleet electrification, learning about the potential total cost of ownership and savings from switching to electric vehicles, receiving a plan for future charging infrastructure needs, learning about available incentives for EVs and EVSE, understanding their carbon footprint and potential reduction, and learning about the opportunities and benefits of managed charging and available rate structures. These benefits will be provided by the knowledgeable electrification industry experts delivering the fleet studies. Additionally, by sharing the data from the study with the Company, participants will build a relationship that will benefit them as they work on long-term plans to deploy EVs in their fleet. This relationship will further benefit the customer with scheduling and planning to help avoid long delays in grid upgrades, which can take years to accomplish.

Q. Is Duke Energy Florida proposing any parameters to control the costs of the fleet advisory program?

A. Yes, the studies will be limited to a maximum funding of $12,000 per participant. Incentive amounts for participants could be lower than maximum if the study cost is less than the maximum amount. The qualifying incentive amount will be the invoiced amount a customer paid for a study, up to $12,000. More studies will be completed if multiple incentives are awarded for less than the maximum amount; however, total costs will be limited to the total program budget.

Q. Does the Fleet Advisory Program support the competitive EV charging market?

A. Yes. This program is open to all vendor studies through the customer choice option and is agnostic towards manufacturers of EVs and EVSE. Customers can research and partner with vendors of their choice and serve their unique needs with equipment they purchase as they electrify.

Q. Does the Fleet Advisory Program provide benefits to non-participants?

A. Yes. Both participants and non-participants benefit from this program. Non-participants are comprised of non-fleet customers and the communities in which fleets operate. All non-participants benefit from the downward pressure on rates from the increase in consumption that EVs bring to the grid. Additionally, data collected from the program will be proactively used to efficiently ready local circuits for future EV load growth through capacity analysis and outreach. The Company plans to perform outreach to fleet customers on the same

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circuit as participants inquire about plans for fleet EV load additions. That information will be used to plan for upgrades along the circuit, factoring in all customers to avoid duplicative work as fleets connect chargers over time.

IX. CONCLUSION

Q. Does that conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Vanessa Goff 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

VANESSA GOFF

On Behalf of Duke Energy Florida, LLC

I. Introduction & Purpose

Q. Please state your name and business address.

A. My name is Vanessa Goff. My business address is 525 South Tryon Street, Charlotte, North Carolina, 28202.

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

A. I am employed by Duke Energy Corporation as a Director of Renewables Business Development.

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

A. As Director of Renewables Development, I am responsible for the development of new solar facilities in Florida on behalf of Duke Energy Florida, LLC ("DEF" or the "Company"). I lead a team that conducts solar development activities including project siting, land acquisition, resource assessment, permitting, obtaining interconnection rights, project layout and design, and arranging contracts for engineering, procurement, and construction ("EPC") services, as well as originating, structuring, and executing transactions to acquire rights to existing solar development projects.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science in Chemical Engineering from Lafayette College in 2002. I began my career as an engineer focusing on coal boilers and steam turbines for Cinergy Solutions. Cinergy was procured by Duke Energy, at which time I moved to development engineering for biomass plants. In 2008, I earned my MBA from St. John Fisher College.

I continued to work for the commercial arm of Duke Energy and in 2009 worked as a development engineer focusing on solar, where I helped site new solar energy facilities across the United States. I moved to the regulated side of Duke Energy and worked in siting and licensing for one year and then became a Business Development Manager for solar and wind, and most recently Director of Renewable Development within the Regulated Renewables Development ("RRD") group. In total, I have over 20 years of professional work experience, including 15 years of renewable energy business development.

Q. What is the purpose of your testimony?

A. My testimony supports DEF's request for cost recovery approval of fourteen, 74.9 MW solar projects to be built between 2025 and 2027. I describe the solar power plants that DEF plans to build to serve its customers, and my testimony includes an overview of the process DEF has used to ensure that its projects are cost effective and cost competitive. My testimony also supports the reasonableness of the proposed project costs.

Q. Do you sponsor or co-sponsor any schedules of the Company's minimum filing requirements?

A. Yes. I sponsor or co-sponsor the following Minimum Filing Requirements ("MFRs"): B-7, B-8, B-9, B-10, B-11, B-13, and B-24. These are true and accurate, subject to being updated during the course of this proceeding.

Q. Have you prepared any exhibits to your testimony?

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

- Exhibit VG-1 – Site plan drawings for the four named 2025 solar projects: Sundance, Bailey Mill, Half Moon, and Rattler.
- Exhibit VG-2 – Project milestone schedule.

These exhibits are true and accurate.

Q. Please summarize your testimony.

A. In 2022 and 2023, DEF placed in-service eight solar sites, resulting in an additional 600 MWs of solar generation. DEF has a history of making targeted solar investments that provide customers with more reliable, resilient, and cleaner power, and as I explain in my testimony, the Company is continuing this trajectory by placing in-service 14 additional solar projects from 2025-2027. The addition of these 14 solar sites to the Company's portfolio will provide cost effective savings for DEF customers, reduce fuel costs, and increase resource diversity on DEF's system.

II. DEF Solar Portfolio & Development Outlook

Q. Please provide an overview of DEF's solar investment portfolio and experience.

A. DEF's experience with developing and building universal solar includes sixteen facilities in the state of Florida in the last five years, representing approximately 1,170 MWs of solar. DEF developed many of these facilities directly, while acquiring others from third-party developers. In all cases, DEF procured all major equipment, selected the EPC contractor through a competitive bid process, oversaw construction, and managed operations and maintenance. With these activities within our scope, DEF was able to ensure that each project sited, developed, and constructed achieved its placed in-service date without any meaningful delays. Since 2018, solar projects have been impacted by a trade war with China, tariffs, duties, a pandemic, supply chain disruptions, inflated shipping costs, forced labor issues in China, unprecedented inflation, and increased competition. Despite all of these challenges, DEF's solar projects have tracked closely to the budgeted amount of capital funding filed with the Florida Public Service Commission (the "Commission"), including during the COVID-19 pandemic.

Q. Please specifically discuss the status of DEF solar investments and planned development in the near-term.

A. DEF anticipates the expiration of high-priced legacy contracts and retirement of numerous older simple cycle combustion turbine ("CT") units offset by a planned investment in new solar and solar plus storage generation. Consistent with DEF's Ten Year Site Plan ("TYSP"), filed with the Commission in April 2023, DEF plans to expand upon its successful deployment of utility scale solar projects approved by the Commission in 2017 and 2021, which will bring over 1,500 MWs of solar generating capacity to the DEF system through the end of 2024. The resource plan and cost-effectiveness evaluation are further explained in Mr. Benjamin Borsch's testimony.

Q. What solar projects is DEF presenting for approval?

A. In this filing, DEF requests cost recovery for 14 new solar projects (representing approximately 1,050 total MWs) that will be completed over the three-year rate period. Specifically, the Company will add six projects in 2025, four projects in 2026, and four projects in 2027.

III. Solar Projects

Q. Please describe the solar projects that DEF expects to place in service in 2025.

A. DEF is adding six projects in 2025. Four of these projects have been identified as Bailey Mill Solar Center, Half Moon Solar Center, Rattler Solar Center, and Sundance Solar Center. Project-specific site plans are provided in Exhibit VG-1 and project schedules in Exhibit VG-2.

- **Bailey Mill Solar Center** is a 74.9 MWac / 111.78 MWdc facility located in Jefferson County. The Project will utilize solar modules mounted to a fixed-tilt racking system with a designed capacity factor of approximately 25%. All environmental assessments have been completed, and prior to site mobilization, DEF will obtain the required site plan approval and all necessary construction permits.
- **Half Moon Solar Center** is a 74.9 MWac / 97.68 MWdc facility located in Sumter County. The Project will utilize solar modules mounted to a single axis tracker racking system with a designed capacity factor of approximately 28%. All environmental assessments have been completed, and prior to site mobilization, DEF will obtain the required site plan approval construction permits.
- **Rattler Solar Center** is a 74.9 MWac / 101.20 MWdc facility located in Hernando County and will provide unique academic benefits to Florida A&M University through the creation of hands-on experiences for students researching a fully operational, utility-scale solar power plant. The Rattler Solar Center will utilize solar modules mounted to a single axis tracker racking system with a designed capacity factor of approximately 29%. All environmental assessments have been completed, and prior to

site mobilization, DEF will obtain the required site plan approval and construction permits.

- **Sundance Solar Center** is a 74.9 MWac / 99.01 MWdc facility located in Madison County. The Project will utilize solar modules mounted to a single axis tracker racking system with a designed capacity factor of approximately 28%. All environmental assessments have been completed, and prior to site mobilization, DEF will obtain the required site plan approval from Madison County and all necessary construction permits.

Two additional 74.9 MW solar facilities are expected to be placed in service in 2025, one in March and the other in December. DEF is currently completing the interconnection process and remaining due diligence for these two projects.

Q. Please describe the solar projects that DEF expects to place in service in 2026.

A. Four 74.9 MW solar projects are anticipated to be placed in-service in 2026. These projects are currently going through the interconnection process, and DEF is finalizing due diligence development activities.

Q. Please describe the solar projects that DEF expects to place in service in 2027.

A. Four 74.9 MW solar projects are anticipated to be placed in-service in 2027. These projects are currently going through the interconnection process, and DEF is finalizing due diligence development activities.

Q. What is the estimated schedule for the 2025 solar investments?

A. As shown on Exhibit VG-2, two of the six 2025 projects are expected to be placed in-service in March 2025, with construction beginning in Q2 2024. Sundance has been identified as one of these projects. The remaining four projects are expected to be placed in service in December 2025, with construction beginning in Q1 of 2025; Bailey Mill, Half Moon, and Rattler represent three of these four projects.

Q. What is the estimated schedule for the remaining solar investments?

All four of the 2026 projects have an anticipated in-service date of June 2026 with construction starting in Q3 2025, and all four 2027 projects have an anticipated in-service date of June 2027 with construction starting in Q3 2026.

Q. How did DEF select and develop the solar projects included in this filing?

A. DEF considers several factors while developing a greenfield project, with interconnection and the ability to connect to the grid as primary factors. DEF will conduct desktop analyses using publicly available data to locate buildable sites adjacent to existing DEF transmission lines. This desktop study will look at parcel size, wetlands, floodplains, slope, soils, and any known environmentally sensitive areas. Once a site has been identified, DEF will work with landowners to execute site control agreements. DEF will then file an interconnection request. If the interconnection studies are favorable, DEF will conduct site due diligence to make sure the site is buildable with minimal environmental impacts. Some of these studies include environmental assessment for species, wetlands delineation, ESA Phase I, cultural assessment, topographical surveys, geotechnical surveys, and American Land Title

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Association surveys. If all results are positive, DEF will add these projects to the solar portfolio.

DEF has several greenfield projects in the interconnection queue with favorable queue positions and will continue to develop most of these solar projects. DEF is willing to purchase solar projects in various stages of completion from third-party developers, but projects must meet DEF's standards of development and construction and fit into our strategic build plan. The factors when considering the purchase of a third-party developed site include interconnection queue position for transmission connection to the grid and expected grid upgrades, environmental impacts, constructability of the site, development status and schedule, overall cost, project location, zoning entitlements, experience and competencies of developer, and construction schedule.

Q. Does DEF believe that its solar development procurement strategies are appropriate and reasonable?

A. Yes. It is important for DEF to remain active in the solar development market. As the Company has developed these projects over the last few years, DEF has taken lessons learned and determined what strategies will ensure success and deliver the best results. DEF has become more focused on utility-developed projects, as these create lower overall costs and allow for greater precision when choosing project development sites.

DEF is advancing siting and design by growing an engineering team focused on internal siting and design along with additional evaluation tools that help with more detailed layouts. DEF can now integrate standard design criteria earlier in the process as well as incorporate lower cost technology choices. To remain cost competitive, DEF works with EPC contractors with extensive experience building solar projects in Florida and that have a proven track record of completing projects cost competitively.

Q. Why has the Company focused on utility-developed projects?

A. Utility-developed projects allow DEF to better assess various site risks such as physical limitations (e.g., wetland or floodplain risks) or procedural limitations (e.g., community risks or regulatory variations). Utility-developed projects also eliminate acquisition fees and legal costs to execute Asset Purchase Agreements. These projects also provide the Company the ability to control the timeline of both development and construction, allowing a pace that aligns with DEF's implementation plan.

Q. What cost-saving measures has DEF implemented for solar projects under development?

A. DEF continually works to be as cost competitive as possible for every solar generation project constructed. DEF has extensive experience in evaluating greenfield sites and projects under development by third party developers. DEF considers several factors during project evaluation, including:

- Cost-effective grid interconnection
- Environmental impacts
- Constructability of the site
- Development status and schedule

- Overall project costs, quality/type of materials
- Project location and zoning entitlements
- Experience and competencies of the developer
- Construction schedule

As I mentioned above, through utility-developed solar projects, DEF has developed robust relationships with key equipment suppliers, EPC contractors, and professional service firms utilized in the development phase. This has provided opportunities for the Company to streamline RFPs for major equipment and EPC services as well as project construction and operations. DEF is continually evaluating suppliers for reliability, deliverability, past performance, and cost. As such, DEF has a successful track record of developing universal solar facilities that are cost effective, within budget, and on schedule.

Q. What is the projected installed cost for each proposed solar project?

A. DEF anticipates that the 2025-2027 projects will each cost approximately $114 million, as shown on MFR Schedule B-13. For each year, DEF assumes costs for modules, generator step up transformers ("GSUs"), EPC, transmission upgrades, project development (including land fees, surveys, and environmental studies), construction oversight, and project contingency. DEF anticipates that the six 2025 projects will each cost approximately $114.0 million, the four 2026 projects are expected to cost approximately $114.5 million each, while the 2027 projects are projected to cost approximately $114.1 million each. All of these project costs include transmission network upgrades, but do not include AFUDC. These costs translate to a per kW cost of $1,522/kWac for the 2025 projects, $1,529/kWac for the 2026 projects, and $1,523/kWac for the 2027 projects inclusive of network upgrades.

Q. How did DEF develop the installed cost estimates for the proposed solar investments in this case?

A. There are multiple components that DEF incorporates into its total project costs. To project the most accurate project costs, DEF evaluates each component separately, using the best available and most accurate information for each year within the development pipeline.

- Modules: Pricing for modules is based off executed agreements with Canadian Solar for 2024 deliveries, First Solar for 2025 and 2026 deliveries, and a combination of both suppliers for 2027 deliveries. DEF assumes that every unit planned for addition in 2025, 2026, and 2027 is a 74.9 MWac single-axis tracking photovoltaic solar project with a net capacity of 27%%.[1] If modules are delivered in a specific year, the in-service date may still be the following year. In addition, the module costs include up to $0.03/W for added freight, tariffs, and silicon market charges.
- GSUs: DEF bases its GSU pricing on the most recent quote received from GE Prolec for a 230 kV, 80MWA transformer. The cost is adjusted yearly assuming a 3% inflation.
- Project Development and Construction Oversight Costs: These costs are based on actuals that occurred throughout DEF's solar program and include an expected 3%

[1] The 27% Net Capacity Factor is also utilized to calculate Production Tax Credits, as described in the testimony of Company witness John Panizza, and shown in Exhibit JRP-1.

inflation year over year. Each project includes a 4% project contingency and does not include AFUDC.

- EPC: Pricing for solar projects starting construction in 2024 with in-service dates in 2025 is based on actual 2022 and 2023 EPC contracts. DEF is anticipating commodity pricing returning closer to pre-pandemic levels and includes a net 2.5% reduction in cost. DEF is also anticipating a $0.005/W annual reduction through 2027, which includes anticipated increases in cost for compliance with the Inflation Reduction Act of 2022 ("IRA").

Q. Does DEF evaluate any other cost category in the solar development process?

A. Yes. DEF includes both direct assigned transmission and transmission network upgrades costs. DEF bases pricing for direct assigned transmission costs on historical actuals that occurred throughout its solar program with an expected 3% inflation year over year. Transmission network upgrades costs reflect the assumed interconnection positions (new switching station, existing switching station, line tap) and the costs associated with the current DEF pipeline of projects (forward looking) and anticipated average costs for each year.

Q. Has the passage of the IRA impacted DEF's solar development?

A. Yes. Projected solar projects may qualify for certain credits under the IRA. DEF witness Mr. John Panizza summarizes the key tax-related components of the IRA and previews provisions most relevant to DEF's proposed solar projects. Witness Panizza also addresses certain assumptions that DEF is making regarding those tax credits.

Q. Are the cost projections for equipment, engineering, and construction of the solar investments reasonable?

A. Yes.

IV. <u>Conclusion</u>

Q. Does this conclude your testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Hans Jacob 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

HANS JACOB

On Behalf of Duke Energy Florida, LLC

I. Introduction

Q. Please state your name and business address.

A. My name is Hans Jacob. 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 Corporation ("Duke Energy") as a Director of Renewable Business Development.

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

A. As a Director of Renewable Business Development, I am responsible for the development of battery energy storage systems ("BESS") projects in Florida on behalf of Duke Energy Florida, LLC ("DEF" or the "Company"). I lead a team of project developers responsible for the initiation and deployment of regulated battery energy storage and microgrid systems.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science in Mechanical Engineering from the University of Florida, and I began my career at Duke Energy in 2012. Since my employment with Duke Energy, I have held various Engineering positions in Nuclear Power generation and Transmission System Operations. For the past four years I have worked in the Energy Storage Development team. I am a licensed Professional Engineer in the State of Florida.

Q. Have you testified before this Commission?

A. No.

Q. What is the purpose of your testimony?

A. My testimony supports the BESS projects that DEF will place in service during the rate case test period: the Powerline BESS Project and the Suwannee Long-Duration Energy Storage Project ("Suwannee").[1] My testimony provides an overview of BESS investments included in this proceeding and DEF's development process for ensuring that BESS investments are cost-effective solutions that benefit DEF customers. I support the reasonableness of the proposed project costs and highlight the benefits associated with the proposed BESS projects.

Q. Do you sponsor or co-sponsor any schedules of the Company's minimum filing requirements?

A. Yes. I sponsor or co-sponsor the following Minimum Filing Requirements ("MFRs"): B-7, B-8, B-9, B-10, B-11, and B-13. These are true and accurate, subject to being updated during the course of this proceeding.

Q. Have you included any exhibits to your testimony?

A. No, I have not.

[1] The 2021 Settlement Agreement, approved by the Commission in Order No. PSC-2021-0202-AS-EI, authorized the Company to pursue pilot projects through the Vision Florida Program. The Vision Florida Program is discussed in greater detail in the direct testimonies of Company witnesses Mr. Brian Lloyd and Mr. Reginald Anderson. My testimony focuses on and supports the Suwannee Project.

Q. Please summarize your testimony.

A. My testimony addresses the storage projects for which DEF requests cost recovery approval in this proceeding. I outline the project scope, costs, benefits, and anticipated timeline for completion. In addition, I highlight the critical importance of battery energy storage as DEF and the industry transition to renewable energy resources. Storage is critical to balancing a grid and maintaining reliability with the addition of low-cost renewables. DEF and its customers benefit from the addition of flexible resources that can serve multiple grid functions across generation, transmission, and the distribution system. To that end, DEF requests cost recovery of these near-term, prudent proposed BESS solutions investments.

II. Battery Energy Storage Projects

Q. Please provide an overview of DEF's proposed BESS projects.

A. DEF has included two BESS projects in this proceeding: (1) the Powerline BESS Project and (2) the Suwannee Project. The Powerline BESS project was developed following the identified need for a 100 MW two-hour duration BESS by the DEF Ten Year Site Plan. The Suwannee Project is a 5 MW, eight-hour duration BESS that was included as a part of the Company's Vision Florida pilot program.

Q. Please discuss how BESS capabilities are vital to enabling DEF's transition to renewable energy generation.

A. Utility-scale battery storage systems support the continued and increasing pace of connecting carbon-free intermittent resources to the grid by storing energy during times of excess generation and shifting this energy to periods of greater customer demand. Battery storage systems can also rapidly change output, allowing the company to respond to rapid changes in intermittent resource output or loss of generation events. Real time balancing between load and generation is essential to maintain adequate system reliability.

DEF can schedule the discharge of energy storage during peak demand periods to provide system capacity and facilitate optimal dispatch of the other utility generation resources. Energy storage also provides other ancillary service benefits to the bulk power system through local frequency response and transmission voltage support.

As discussed throughout my testimony, the proposed BESS solutions included in this case are important tools that will help DEF navigate the renewable energy transition, while continuing to provide customers with safe and reliable service.

Q. Please describe the Powerline BESS Project.

A. The Powerline BESS Project is a 100-MW lithium-ion energy storage project with a 2-hour duration maintained over the asset life. The Powerline BESS is located adjacent to the existing Powerline substation in Citrus County, Florida, where it will interconnect.

Q. How do customers benefit from the proposed Powerline BESS Project?

A. The Powerline BESS Project will serve DEF and its customers by providing bulk system benefits, including energy arbitrage, ancillary services, and bulk storage. The Powerline project will be dispatched to provide production cost benefits across the asset's life. The project provides the system with a fast-ramping resource that can supplement the response of other fleet generation assets. The energy storage provided by this project can respond immediately and does not have start times or minimum run times like thermal generation facilities. The Powerline battery can also be utilized to shift energy from periods of lower system cost to higher system cost providing fuel savings to customers.

Importantly, DEF developed the Powerline BESS Project in a manner that minimizes costs and maximizes economies of scale. The Powerline BESS Project leverages existing infrastructure such as the existing utility land, the adjacent substations and road, and potentially stormwater retention facilities.

Q. What is the estimated project cost and projected in-service date for the Powerline BESS Project?

A. The estimated project cost is $164.5 million, and the projected in-service date is March 1, 2027, as shown on MFR Schedule B-13.

Q. How did DEF develop cost estimates for the Powerline BESS Project?

A. For the Powerline BESS Project, DEF first conducted an engineering study to determine the project requirements. This study calculated the required energy storage asset size to meet the system needs including capacity, duration, and asset life. The engineering analysis calculated the beginning of life energy storage capacity required to sustain the asset life. DEF then utilized the results of this study to estimate the total cost of the project in an industry benchmarked cost estimating tool. DEF benchmarked inputs to this tool against previous projects. In addition, DEF plans to competitively bid the major components and construction of the projects for the benefit of customers.

Q. Please describe how DEF identified and selected the Powerline BESS Projects.

A. DEF considers several factors during project evaluation, such as cost-effective interconnection to the grid, environmental impacts, constructability of the site, development status and schedule, overall costs, quality/type of materials, project location, zoning entitlements, experience and competencies of the developer, and construction schedule. As explained more fully in Company witness Mr. Benjamin Borsch's testimony, the DEF Ten Year Site Plan identified the need for a 100 MW/200 MWH battery storage system. DEF reviewed its system for cost-effective siting locations for the energy storage. DEF identified the Powerline location, because it is one of the few locations within the DEF service territory eligible for the Inflation Reduction Act's ("IRA") Energy Community tax credit. The substation had spare capacity to accommodate interconnection of the energy storage facility. The Powerline location is also located near DEF's Citrus and Crystal River generation stations.

Q. Please describe the Suwannee Project.

A. The Suwannee Project is a non-lithium electrochemical battery. This asset will deploy a Sodium Sulfur ("NaS") technology to create a long-duration (8 hour) energy storage asset. The equipment capacity will be 5 MW/40 MWh. This system will interconnect at the existing Suwannee Combustion Turbine generating site in Suwannee County, Florida.

Q. How do customers benefit from this project?

A. This asset will serve DEF customers by providing system benefits, including energy arbitrage, ancillary services (i.e., system ramping, load following, contingency reserves), and bulk storage. The Suwannee Project will test the capability for battery technology to provide a future long-duration storage solution to better integrate and enable a renewable energy transition in a cost-effective and reliable manner. This project will provide opportunities to test flexibility, reliability, and integration with existing Duke Energy systems, including plant controls, Energy Management Systems, protection and controls systems, and metering. This pilot testing will enable the Company to better select required storage assets in the future.

Q. What is the estimated project cost and what is the projected in-service date?

A. The estimated project cost is $29.8 million, and the projected in-service date is first quarter 2025.

Q. How did DEF develop cost estimates for the Suwannee Project?

A. For the Suwannee Project, DEF conducted an RFP to receive firm quotes from a variety of non-Lithium long-duration energy storage technologies. Following selection of the NaS technology, the Company solicited bids from multiple engineering and construction firms to build the project. DEF has also estimated internal costs based on experience from previous projects and utilized the interconnection study cost estimates. DEF developed the cost estimate based on these combined project costs.

C10-1042

Q. Please describe how DEF identified and selected the Suwanee Project.

A. DEF considered several factors during project evaluation, such as cost-effective interconnection to the grid, environmental impacts, constructability of the site, development status and schedule, overall costs, quality/type of materials, project location, zoning entitlements, experience and competencies of the developer, and construction schedule. The existing Suwannee Generation station contains maintenance facilities and Company personnel. The location is also in a region of DEF's service territory experiencing a large growth of transmission-connected solar generation facilities, allowing the facility to support the integration of intermittent solar energy using long duration energy storage.

III. Project Cost Savings

Q. Does DEF include assumed benefits from the IRA in its pricing models?

A. Yes. As discussed in further detail in the direct testimony of Company witness Mr. John Panizza, DEF is evaluating ways to leverage tax credits from the IRA to maximize the benefits to customers. The project is also strategically sited within an Energy Community, which increases the total Investment Tax Credit the project will be eligible for.

Q. Has DEF explored or adopted strategies to improve efficiencies and reduce development costs to customers?

A. Yes. As described above, DEF is leveraging benefits from the IRA in order to maximize cost savings for customers. Additionally, Duke Energy identified existing utility owned land adjacent to substations as part of the project siting.

Q. Does DEF believe that its battery energy storage development and procurement strategies are appropriate and reasonable?

A. Yes.

IV. <u>Conclusion</u>

Q. Does this conclude your testimony?

A. Yes.

C10-1044

(Whereupon, prefiled direct testimony of Jeffrey T. Kopp 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

JEFFREY T. KOPP

On Behalf of Duke Energy Florida, LLC

I. Introduction and Summary

Q. Please state your name and business address.

A. My name is Jeffrey (Jeff) T. Kopp, and my business address is 9400 Ward Parkway, Kansas City, Missouri 64114.

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

A. I am employed by 1898 & Co., part of Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") as the Senior Managing Director of the Energy & Utilities Consulting department. Burns & McDonnell has been in business since 1898, serving multiple industries, including the electric power industry. In 2023, Burns & McDonnell was rated No. 7 overall of the Top 500 Design Firms by the Engineering News Record ("ENR"). Burns & McDonnell was rated as the No. 1 engineering design firm in the United States serving the electric power industry by ENR in 2023.

1898 & Co. and Burns & McDonnell has vast experience in both preparation of dismantlement studies and executing construction and demolition projects, including hundreds of construction projects totaling more than $3 billion dollars of construction last year alone. In order to execute over $3 billion dollars of construction projects on an annual basis, Burns & McDonnell has to win this work through competitive bidding processes, which requires us to be able to accurately prepare cost estimates.

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Our long history, large market presence, and top industry rankings demonstrate our ability to effectively and accurately estimate costs. In addition, we have worked with demolition contractors over the years to refine our estimating process for dismantlement studies to align our costs with theirs.

Q. Please briefly describe your duties as the Senior Managing Director of the Energy & Utilities Consulting Department of 1898 & Co.

A. I am a professional engineer with 22 years of experience consulting to electric utilities. I have been involved in numerous decommissioning studies and served as project manager or project director on the majority of them. I have helped prepare decommissioning studies on all types of power plants utilizing various technologies and fuels.

As a Senior Managing Director at 1898 & Co., I oversee a group of more than 250 engineers and consultants who provide consulting services to clients primarily in the electric power generation and electric power transmission industries, but also to other industrial and commercial clients. The services provided by this group of engineers and consultants include decommissioning cost studies, independent engineering assessments of existing power generation assets, economic evaluations of capital expenditures, new power generation development and evaluation, electric and water rate analysis, electric transmission planning,

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generation resource planning, renewable power development, and other related engineering and economic assessments.

Q. Please describe your educational background and professional experience.

A. I have a bachelor's degree in Civil Engineering from the University of Missouri – Rolla (now the Missouri University of Science and Technology) and a Master of Business Administration from the University of Kansas. In my role as a group manager, project manager, and project engineer, I have worked on and have overseen consulting activities for coal, natural gas, wind, solar, hydroelectric, and biomass power generation facilities. I have included my resume and curriculum vitae as Exhibit JTK-1.

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

A. Yes. I provided rebuttal testimony on behalf of Progress Energy Florida, Inc. in Docket No. 20090079-EI in support of the dismantlement study I prepared for Progress Energy Florida to support their depreciation rates in that filing. While I did not provide testimony in connection with Duke Energy Florida, LLC's ("DEF" or the "Company") last rate case settlement, I did perform the dismantlement study that was included as an exhibit and approved as part of that settlement. I provided direct testimony and deposition on behalf of Florida Power & Light Company in

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Docket Nos. 202110015-EI and provided direct testimony on behalf of Tampa Electric Company in Docket No. 20200264-EI.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to describe and support DEF's 2023 Final Dismantlement Cost Study (the "Dismantlement Study") for its electric generating units, as prepared by 1898 & Co. The Dismantlement Study report is attached to my testimony as Exhibit JTK-2. The Dismantlement Study is an update of a prior study that I prepared for DEF to support the 2021 Settlement Agreement as approved by the Commission in Docket No. 20210016-EI. DEF witness Nicole Aquilina supports sections 1-6 of the 2023 Dismantlement Study and the impact on rates.

Q. Was the Dismantlement Study attached to your testimony as Exhibit JTK-2 prepared by you or under your supervision?

A. Yes.

Q. What qualifies 1898 & Co. to prepare accurate estimates of dismantlement costs and why should the Commission put weight into these estimates?

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A. Over the years, 1898 & Co. has worked closely with demolition contractors in developing decommissioning cost estimates in order to more accurately estimate the costs for activities that the demolition contractors will perform. 1898 & Co. has prepared numerous decommissioning studies for various clients considering different technologies in several different states and has provided services to clients on decommissioning project execution that has included review and evaluation of bids from demolition contractors. 1898 & Co. has utilized this experience preparing decommissioning estimates as well as reviewing demolition contractor bids to confirm the reasonableness of the cost estimates prepared by 1898 & Co.

At the time the Company decides to decommission the Plants, means and methods will not be dictated to the contractor by 1898 & Co. It will be the contractor's responsibility to determine means and methods that result in safely decommissioning and dismantling the Plants at the lowest possible cost. However, based on 1898 & Co.'s experience with decommissioning projects and discussions with demolition contractors, the costs estimated by 1898 & Co. are reflective of what contractors would bid, through a competitive bidding process, given the option to select safe and efficient means and methods.

As indicated above, 1898 & Co. has vast experience in preparation of decommissioning studies, overseeing demolition projects, and executing construction projects. In order to execute over $2 billion of construction projects on an annual basis, 1898 & Co. has to win this work through competitive bidding processes, which requires us to be able to accurately prepare cost estimates. If we routinely estimated costs too high, we would not be successful in winning projects. If we routinely estimated costs too low, we would not be able to execute projects profitably and would no longer be active in this market.

Our long history, large market presence, and top industry rankings demonstrate our ability to effectively and accurately estimate costs. In addition, we have seen competitive bids from demolition contractors for power plant demolition projects, and we have worked with demolition contractors over the years to refine our estimating process for decommissioning studies to align our costs with theirs.

II. DEF's Dismantlement Study

Q. Please describe the Dismantlement Study Prepared for the Company.

A. The Company retained 1898 & Co. to provide it with a recommendation regarding the total cost, in 2022 dollars, of dismantlement of each Company-owned generation unit at the end of its useful life as well as the total cost of dismantlement of the common facilities at these generating plants. The total dismantlement cost, as determined by 1898 & Co. and reflected in the Dismantlement Study, is net of salvage value for scrap materials at each plant. 1898 & Co. had previously prepared a similar study for DEF in 2020 in support of DEF's 2021 rate case. This Dismantlement Study serves to update the costs presented in the 2020 study for

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changes to market conditions, physical changes that have occurred at the Plants, and incorporating new facilities that have been constructed or acquired since 2020.

Q. What Plants did 1898 & Co. evaluate in the Dismantlement Study?

A. For purposes of the Dismantlement Study, we evaluated the following Company-owned electric generating plants.

- Anclote Station
- Bartow Station
- Bartow CC
- Bay Ranch
- Bay Trail
- Bayboro Station
- Cape San Blas Storage
- Charlie Creek
- Citrus County Combined Cycle
- Columbia Solar
- Crystal River Common
- Crystal River Mariculture
- Crystal River North
- DeBary Station
- DeBary Solar
- Duette Solar

- Falmouth
- Fort Green
- Hamilton Solar
- Hardeetown
- High Springs
- Hildreth
- Hines Energy Complex
- Intercession City Station
- Jennings Energy Storage
- John Hopkins Microgrid
- Lake Placid Solar and Storage
- Micanopy Energy Storage
- Mule Creek
- Osceola Solar Center
- Osprey Energy Center Power
- Perry Solar Center
- Proxy Solar
- Sandy Creek
- Santa Fe Solar
- St Petersburg Pier
- Suwannee River Station
- Suwannee River Solar

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- Tiger Bay Station
- Trenton Solar
- Trenton Storage
- Twin Rivers Solar
- University of Florida Station
- Winquepin

Q. Were any Company-owned generating facilities excluded from the Dismantlement Study?

A. No. All Company-owned facilities that were in operation at the time of the Dismantlement Study were included.

Q. Did the Company include dismantlement costs for any plants that were not yet in operation at the time the Dismantlement Study was completed?

A. Yes. As part of the Dismantlement Study, 1898 & Co. provided an estimate for a proxy solar site that could be used to estimate costs for solar facilities that were installed after the completion of the Dismantlement Study in order to estimate total dismantlement costs for those facilities.

Q. Is this an appropriate method for estimating the total net dismantlement costs for those solar facilities?

A. Yes. Since those facilities were not in operation at the time of the Dismantlement Study, there were no drawings or site data available at the time that could be used to develop site specific estimates. Applying the costs from the proxy solar site estimate developed by 1898 & Co. is a reasonable proxy for site specific estimates until the time that site specific estimates can be developed in the future.

Q. What was the extent of your personal involvement in the preparation of the Dismantlement Study?

A. I served as the 1898 & Co. project manager on the Dismantlement Study. I worked directly with all individuals and parties involved in the preparation of the dismantlement cost estimates in the Dismantlement Study. I was responsible for the overall project and was involved in the development of the dismantlement assumptions, dismantlement estimating methodology, preparation and review of the estimates, and preparation and review of the report.

Q. What was the extent of your personal involvement in the preparing of the prior Dismantlement Study prepared for DEF?

A. I also served as the project manager on the prior study.

Q. What approach was used to develop the dismantlement estimates in the Dismantlement Study?

A. The estimates of direct dismantlement costs were prepared with the intent of most accurately representing what 1898 & Co. would anticipate contractors bidding to dismantle the equipment, address environmental issues, and restore the site through a competitive bidding process, based on performing known dismantlement tasks under ideal conditions. In addition to these known tasks under ideal conditions, indirect costs were added to cover cost incurred by the Company in executing the projects, and contingency were added to account for unknown, but reasonably expected to be, incurred costs.

As outlined in the Dismantlement Study, we prepared these cost estimates by estimating quantities for equipment based on a visual inspection of the facilities, review of engineering drawings, 1898 & Co.'s in-house database of plant equipment quantities, and 1898 & Co.'s professional judgment. This resulted in an estimate of quantities for the tasks required to be performed for each dismantlement effort. Current market pricing for labor rates, equipment costs, scrap, and disposal costs specific to the area in which the work is to be performed. These rates were applied to the quantities for the plants to determine the total cost of dismantlement for each site.

Q. What level of dismantlement and demolition was assumed to be performed at each of the sites?

A. The basis of the estimates was that all sites will be restored to an industrial condition, suitable for reuse for development of an industrial facility.

Q. What does restoring the site for industrial use require?

A. The sites will have all above grade buildings and equipment removed, foundations removed to two feet below grade, be rough graded, and seeded. Sites also will have small diameter underground pipes capped and abandoned in place. The sites can remain in this condition in perpetuity, until the site is specifically redeveloped for industrial use.

Q. Did you visit each of the sites for which the site-specific cost estimates were developed?

A. No. I visited a representative portion of sites for which site-specific dismantlement cost estimates were prepared as part of the previous study, along with other individuals from 1898 & Co., and representatives from the Company.

III. Description of Dismantlement Costs

Q. Please generally explain the type of costs developed by 1898 & Co. and reflected in the Dismantlement Study.

A. The cost estimates reflected in the Dismantlement Study are inclusive of direct costs associated with dismantling the plant equipment and facilities and restoring

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the sites to an industrial-ready condition. The direct costs include environmental remediation costs for asbestos removal and other hazardous material handling and disposal, as well as costs for removing and disposing of contaminated soil around transformers. The Dismantlement Study also includes estimates of indirect costs to be incurred by the Company during dismantlement, and contingency costs.

Q. How were the direct costs developed for the purposes of the Dismantlement Study?

A. As part of the Dismantlement Study, site-specific cost estimates were developed using a "bottom-up" cost estimating approach, where cost estimates are developed from scratch through the development of site-specific quantity estimates and the application of unit pricing rates to the quantity estimates.

As outlined in the Dismantlement Study, 1898 & Co. prepared these cost estimates by estimating quantities for existing equipment based on visual inspections, review of engineering drawings, review of 1898 & Co.'s in-house database of plant equipment quantities and using 1898 & Co.'s professional judgment. This resulted in an estimate of quantities for the tasks required to be performed for each dismantlement effort. Current market pricing for labor rates and equipment were used to develop unit pricing rates for each task. These unit pricing rates were applied to the quantities for the Plants to determine the total direct cost of dismantlement for each site. Additionally, unit pricing for scrap values was applied to the scrap quantities to determine anticipated salvage values, which were subtracted from the gross direct costs to arrive at a net project cost in 2022 dollars.

Q. How were scrap values determined?

A. Scrap metal prices used in the development of the scrap credit were based on a review of pricing trends for various types of materials published by American Metal Market, which is an industry standard publication and information subscription service[1] that reports the prices paid for scrap metals in transactions worldwide.

American Metal Market is the leading independent supplier of market intelligence and pricing to the North American metals industries and publisher of widely used reference prices for scrap. American Metal Market also has extensive experience in reporting scrap prices in a wide range of grades and locations. American Metal Market has been reporting on the U.S. scrap market for more than 100 years, providing benchmark prices to users in the scrap metal industry.

Q. What is included in the project indirect costs included in the Dismantlement Study?

A. This category includes costs expected to be incurred by the Company during the dismantlement process, which would be in addition to the direct costs paid to a demolition contractor. This includes the costs for staff of the Company providing

[1] See http://www.amm.com

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oversight during demolition activities, as well as Company overheads and general and administrative costs. Project scope intended to be covered by this category includes obtaining permits; construction services, such as water and electricity; security facilities; environmental monitoring; and the costs of construction management which include scheduling, monitoring, and supervising the contractors who will be doing the actual demolition work. It is also intended to cover such additional expenses as the relocation/modification of switch yard facilities where that is necessary.

Q. How were the indirect costs determined?

A. Indirect costs were determined as a percentage of the direct costs, as is a typical approach when preparing these types of cost estimates. The percentage of direct costs that was applied to determine the indirect costs was developed by 1898 & Co. based on experience with past dismantlement estimates.

Q. What is included in the contingency costs?

A. A contingency cost includes unspecified but reasonably expected additional costs to be incurred by the Company during the execution of dismantlement activities. For any project, there is always some uncertainty associated with work conditions, the scope of work, and how the work will be performed. There is also some uncertainty associated with estimating the quantities for dismantlement of facilities. These uncertainties result from the age of the Plants, limits on drawing availability, and the absence of detailed data for environmental remediation (such

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as identification of asbestos, lead based paint, soil testing around transformers, etc.), prior to preparation of these types of studies. Contingency costs account for these unspecified but expected costs and are in addition to the direct costs associated with the base dismantlement known scope items.

Q. Are contingency costs standard industry practice?

A. Yes. The application of contingency is not only appropriate, but also standard industry practice. Even on a project where firm pricing has been agreed upon with a successful bidder, it is typical that a client carry some level of contingency to cover potential change orders. It is even more important to carry contingency on planning-level cost estimates such as those presented in the Dismantlement Study. Furthermore, Florida Administrative Code 25-6.04364 Electric Utilities Dismantlement Studies includes a provision for contingency costs.

Q. Did 1898 & Co. include any other costs in the Dismantlement Study?

A. Yes. In addition to the physical dismantlement and dismantlement scope itself, we also included the expense provided by the Company for remaining inventory balances at the time of retirement. An appropriate credit for potential reuse or resale of remaining inventory was also included.

Q. Did 1898 & Co. apply any cost escalation factor to these estimates?

A. No, we did not. All of the estimates are in year 2022 dollars.

Q. What is your opinion of the reasonableness of the dismantlement and dismantlement cost estimates that 1898 & Co. has prepared for DEF?

A. In my opinion, these estimates were carefully prepared using standard and accepted estimating techniques and the best information available and are consistent with our industry experience. Although assumptions had to be made, I believe these assumptions are reasonable and that the estimates are reasonably accurate. Further, the inclusion of remaining inventory balance expenses is also reasonable. Maintaining an adequate inventory for the operation and maintenance of the generating units up to their end of life represents a prudently incurred cost for providing service to customers.

IV. Conclusion

Q. Are the estimated costs reflected in the Dismantlement Study reasonably reflective of the actual costs necessary to dismantle the Company's plants and expense remaining inventory?

A. Yes, they are.

Q. Are these estimated costs appropriate for use in the development of the dismantlement accrual for the Company's electric generating plants?

A. Yes.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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(Whereupon, prefiled direct testimony of Brian M. Lloyd 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

BRIAN M. LLOYD

On behalf of DUKE ENERGY FLORIDA, LLC

I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Brian M. Lloyd. My current business address is 3250 Bonnet Creek Road, Lake Buena Vista, FL 32830.

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, Florida Major Projects.

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

A. My duties and responsibilities include planning for grid upgrades, system planning, and overall Distribution asset management strategy across Duke Energy Florida, as well as the Project Management for executing the work identified. Additionally, I manage organizations that execute the developer interactions and engineers large residential developments across the DEF territory.

Q. Please describe your educational background and professional experience.

A. I have a Bachelor of Science degree in Mechanical Engineering from Clemson University and am a registered Professional Engineer in the state of Florida. Throughout my 18 years at Duke Energy, I have held various positions within Distribution ranging from Engineer to General Manager focusing on Asset Management, Asset Planning, Distribution Design, and Project Management. My current position is General Manager of Projects and Engineering for Power Grid Operations.

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

A. Yes. I have submitted pre-filed testimony and testified before the Florida Public Service Commission in support of the Company's Storm Protection Plan (Docket No. 20220050-EI) as well as the Storm Protection Plan Cost Recovery Clause (Docket No. 20220010-EI). In Storm Protection Plan Cost Recovery Docket No. 20210010-EI and Docket No. 20230010-EI, I only submitted pre-filed testimony.

Q. What is the purpose of your direct testimony?

A. My testimony supports the Company's distribution capital and operations & maintenance ("O&M") expenses.

Q. How is your testimony organized?

A. My testimony is organized as follows:

I. In Section I of my testimony, I provide background on my education and experience, as well as a summary of my testimony and a list of the exhibits I sponsor in support of the Company's request.

II. In Section II of my testimony, I describe DEF's distribution system, explain the costs now recovered through the Storm Protection Plan versus those requested in this base rate case, and describe notable base rate investments

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made in our system since the Company's 2021 Settlement Agreement and how they have benefitted our customers.

III. In Section III of my testimony, I provide an overview of the operational performance of the Company's distribution system, outline DEF's reliability performance, and highlight DEF's storm response efforts.

V. In Section IV of my testimony, I summarize DEF's distribution capital and O&M requests for 2025-2027 and demonstrate that the costs are reasonable.

Q. Do you have any exhibits to your testimony?

A. Yes, I have prepared or supervised the preparation of the following exhibits to my direct testimony:

- Exhibit BL-1, a summary of co-sponsored schedules of the Company's Minimum Filing Requirements ("MFRs");
- Exhibit BL-2, a summary of Distribution reliability results for the years 2018-2023; and
- Exhibit BL-3, a summary of Distribution Maintenance Subprograms.

These exhibits are true and correct.

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

A. Yes, Exhibit BL-1 to my testimony lists the schedules of the Company's MFRs that I sponsor or co-sponsor with respect to the Company's distribution system. These MFR Schedules are true and correct, subject to being updated during the course of this proceeding.

Q. Please summarize your testimony.

A. My testimony provides an overview of DEF's distribution system, initiatives to improve reliability and enhance the customer experience, and the distribution capital and O&M investments the Company has made and proposes to make over the 2025-2027 timeframe. Continued investment in the distribution system is necessary to continue to maintain and operate the Company's distribution assets safely and reliably and to implement planned work to accommodate customer growth and other major projects initiatives.

I first provide a comprehensive overview of DEF's distribution system and its management and work programs. The system is managed through a zone and regional support network, which allows for quick and responsive support to customers in each area. DEF's Customer Delivery work is organized into four major distribution programs: Expansion, Restore, Maintenance, and Major Projects.

Looking forward at investments for new load and future growth, DEF's Capacity Planning Engineering department analyzes the distribution grid and substation transformers to determine where grid capacity investments are required to maintain service to customers. This data informs the team as to where overload situations

C12-1270

may exist and allows the team to develop new solutions. I also discuss several reliability programs.

DEF has taken several steps to improve the customer experience related to distribution resources. We have improved response times to customer inquiries related to new growth or service improvements, and introduced the Ping It program, which allows remote checking of smart meter status, saving time and costs. We also developed a specialized portal and mobile application for builders and developers and have made it easier for customers to report outages on the website and via the mobile application.

Part III of my testimony focuses on DEF's storm response strategies, particularly for hurricanes and major storms. DEF uses the Incident Command Structure ("ICS") Event Response Organization, a nationally recognized emergency response model. DEF has improved its storm response with crew tracking enhancements and GIS technology use, resulting in increased productivity, reduced costs, and shortened restoration times. DEF also conducts annual drills to prepare for major weather events, assessing the Transmission and Distribution teams' preparedness and response effectiveness and identifying gaps in knowledge, tools, and processes. I also discuss recent extreme weather events in DEF's service territory, including Hurricanes Ian, Nicole, Elsa, and Idalia. DEF's response to these events demonstrated the team's ability to mobilize resources and restore power quickly

C12-1271

and efficiently. In fact, in 2023 DEF was awarded Edison Electric Institute's Emergency Recovery Award for its 2022 response to Hurricane Nicole.

The next section discusses DEF's investments since the 2021 Settlement Agreement and the Storm Protection Plan ("SPP"). The 2021 Settlement Agreement confirmed the transfer of costs previously recovered through base rates to the Storm Protection Plan Cost Recovery Clause ("SPPCRC"), enabling additional base rate investment in areas such as customer delivery to maintain reliability and meet new customer growth needs. Because the SPPCRC is focused on investments related to improving resiliency of the grid, a base rate increase is necessary to fund investments for ongoing maintenance and customer growth. The SPP investments will harden the system to better withstand extreme weather conditions, while the distribution investments included in the base rate request are for increased customer growth and maintenance of distribution facilities.

I also discuss Vision Florida, a pilot program approved as part of the 2021 Settlement Agreement. This program consists of capital and O&M investments associated with various projects, including up to four Emergency Relief Microgrid projects, a floating solar pilot project at the Hines generating station, a hydrogen power investment, and solar plus storage projects. The total costs under this pilot must not exceed $100 million in capital and $12 million in O&M. Each project was selected to provide benefits to customers, such as cost savings, load shaping,

C12-1272

distributed energy solutions, and solutions that defer or eliminate the need for traditional capital investment.

Part V discusses the reliability, customer satisfaction, cost control, resource management, and future planning of DEF's distribution system. DEF uses several industry-standard metrics to measure service reliability. Over the past five years, DEF's performance on these metrics has shown a favorable downward trend, indicating improved reliability. DEF recognizes the intrinsic value of customer satisfaction. The Company provides personalized communication and services tailored to individual customer needs. By understanding and addressing customer needs, DEF can deliver more focused and tailored services.

To control costs, DEF optimizes resource schedules, conducts peer reviews of design work, requires authorization for construction exceptions, and has implemented cost-saving measures where feasible. DEF ensures it has the necessary resources to operate, maintain, and invest in its distribution system by keeping its workforce trained and flexible and using contract labor for periods of high demand. The Company also improved its procurement activities in order to continue obtaining the best available pricing for materials and implementing a process that packages all material for an activity together in a single "kit" with a packing list, similar to how large product delivery companies ship all items in an order in one box. This process creates efficiencies at both the supply warehouse

C12-1273

and at the work site.

DEF anticipates an increase in electricity demand over the next few years due to the demands of interconnected homes, electric cars, pools, and continued growth of residential customer count. To plan for this growth, DEF monitors the demand on its distribution infrastructure and plans for new or upgraded feeders at least two years out.

Finally, Part VI discusses the capital needs and O&M expense of DEF's distribution system. DEF confirms that its capital and O&M requests are not duplicative of any activities related to the Storm Protection Plan and are within the Florida PSC O&M benchmark costs. Recent economic conditions and inflation have impacted DEF's expenses, but the Company has mitigated O&M expenses where possible. Despite increasing costs and inflation, DEF's distribution expenses per customer are projected to remain lower than 2022 levels through 2027.

DEF asserts that its distribution system capital and O&M requests are reasonable and necessary to provide reliable distribution service to customers. The Company sets annual budgets with growth forecast and reliability needs in mind and monitors each budgeted program and department throughout the year for adherence to the budget. DEF also ensures cost-effective designs are created to minimize capital expenditure and future O&M maintenance spend as new customers join the DEF

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distribution grid.

The Company emphasizes the need to maintain existing overhead and underground infrastructure and to continue its environmental stewardship by mitigating potential hazards to waterways and wildlife. DEF acknowledges the need to continue capital investments and incur O&M expenses necessary to replace assets as they reach the end of their useful life, maintain existing distribution assets, and reliably serve customers. Managing our costs moving forward, however, is a challenge in this economy with rising costs and inflationary pressures. Additionally, we must continue to invest in capital improvements to our distribution system and incur O&M expenses to maintain it to preserve the reliability gains we have achieved and that our customers expect. To accomplish these objectives, the Company needs $1,718 million for distribution capital investments and $300.5 million for distribution O&M expenses over the 2025-2027 period. These expenditures are reasonable and necessary to continue to reliably distribute power to our customers in a cost-effective manner.

II. DEF'S DISTRIBUTION SYSTEM AND INVESTMENTS MADE SINCE THE 2021 SETTLEMENT AGREEMENT

Q. Please generally describe the Company's distribution system.

A. DEF's distribution system reliably delivers power to almost 2 million customers across a service area in north and west central Florida that is 20,000 square miles and includes the densely populated areas around Clearwater, Orlando, and St. Petersburg, along with rural areas in both coastal and inland areas. DEF's distribution system includes approximately 18,000 circuit miles of overhead primary voltage distribution conductors, approximately 16,000 miles of underground primary voltage distribution cable, distribution substations, and related poles, transformers, secondary cables, secondary wires, and other material and equipment, such as bucket trucks, to provide reliable service. To ensure that DEF reliably delivers power around the clock to its customers, DEF must continually invest in capital additions and replacements and incur the necessary expenses to operate and maintain the distribution system.

Q. How does the Company manage its distribution system?

A. DEF manages its distribution system through a zone and regional support network. The service territory is split into four separate zones (North Central, South Central, North Coastal and South Coastal), which are further separated into three areas each with each area maintaining local control over design, construction, maintenance, and restoration activities. The Company's lighting program, geographic information system ("GIS") technology, distribution control center, health and safety, emergency preparedness, training, procurement, and contract management are all supplied through a zone and regional support network. This design allows the Company to provide quick and responsive support to customers in each area and fosters a sense of local ownership when working with our customers.

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Q. Please summarize your understanding of DEF's last base rate settlement agreement.

A. I understand that DEF entered into a comprehensive settlement agreement with key consumer groups, that was approved by the Commission, in 2021, which I will refer to as the 2021 Settlement Agreement. My understanding is that it confirmed the transfer of costs associated with hardening and resiliency previously recovered through base rates to the SPPCRC, while maintenance and growth costs continue to be recovered through base rates. It also provided additional revenue requirements necessary for Customer Delivery investments to maintain reliability and meet new customer growth needs. To that end, since the 2021 Settlement Agreement was approved, the Company has continued to invest in the system to enhance the reliability and resilience of the distribution grid. Some examples of these investments and how they have benefitted customers include the following examples:

- Apalachicola substation (April 2023): A second 20 MVA transformer bank was added and one of the existing feeders was relocated to the new bank, more than doubling the capacity of the substation. The scope of substation work also included upgrading the control house and other improvements. Approximately 3,500 feet of feeder near the substation was upgraded to increase the capacity of the circuit.

C12-1277

- Monastery substation (July 2021): A second 30 MVA transformer was added and approximately one mile of new feeder was installed. The new feeder relieved the existing feeders and provided backup to the Halifax hospital.
- Dog Island System wide maintenance (2023): Rebuild existing overhead lines and facilities to meet extreme wind and coastal construction standards, thus improving the reliability of the service for the customers on the island.
- Monticello N69 - SR 259 (2022): Increase the capacity of the distribution circuit by rebuilding the line with larger overhead conductor and underground cable.
- Murray Rd Upgrade (2023): Increase the capacity and resiliency of the distribution circuit by rebuilding the line with larger overhead conductor, which will allow for more switching options thus improving the overall reliability for the customer served in this area.
- Replaced 685 miles of underground cable that reached end of life to ensure that reliability levels for customers were maintained.

Q. You mentioned the SPP cost recovery clause. What is the SPP cost recovery clause?

A. The SPP cost recovery clause was created by the Florida legislature to achieve "the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability." (Section 366.96(3), Florida Statutes). DEF has submitted, and the Commission has approved, the first two iterations of its plans in response to this legislative directive, which include a series of carefully designed programs to achieve those very specific objectives. While some of this work was previously recovered in DEF's base rates, some of the work was accelerated or expanded.

In 2006, in response to the damage caused by the active 2004-2005 hurricane seasons, the Commission adopted Rule 25-6.042, F.A.C. (the "Storm Hardening Rule"). As required by the Rule, under the Commission's direction, DEF has made significant investments in storm hardening to prepare its electric system to withstand and/or quickly recover from storm damage. Luckily, Florida enjoyed relatively calm storm seasons from 2006 through 2016.

However, over the last several years, Florida has experienced active storm seasons including landfalls and near landfalls from several named storms, including multiple major storms. In response, during the 2019 legislative session, the Florida legislature passed the Storm Protection Plan Cost Recovery Statute, codified as section 366.96, Florida Statutes ("SPP Statute").

DEF's Storm Protection Plan is designed to cost-effectively "strengthen [the Company's] infrastructure to withstand extreme weather conditions by promoting overhead hardening of electrical transmission and distribution facilities, the undergrounding of certain electrical distribution lines, and vegetation management." The SPP, as a whole, is projected to achieve the multi-pronged goals

C12-1279

of reducing storm restoration costs and outage times and improving overall reliability.

With the establishment of the SPP Statute, costs associated with the distribution SPP programs (Feeder Hardening, Lateral Hardening, Self-Optimizing Grid, Underground Flood Mitigation, and Vegetation Management) are now proposed for recovery through the SPPCRC instead of through base rates.

Q. Since DEF is now recovering storm-hardening costs through the SPPCRC, what type of distribution costs are now included in base rates?

A. The distribution system investments included in this base rate request are representative of more typical distribution investment for increased customer growth, storm restoration, and maintenance of distribution facilities and are not duplicative of any funds recovered through the SPPCRC. In addition, costs are rising as inflation and interest rates have increased significantly in recent years leading to higher labor and material costs for new and replacement assets. The costs included in this case are for programs and initiatives focused on maintaining reliability, investing in the electric grid to prepare for incremental growth over the next several years, and continuing to provide DEF customers with a high level of electric service.

Q. What are the major Customer Delivery capital investment programs?

C12-1280

A. DEF's Customer Delivery's work is organized into four major distribution programs: 1) Expansion, 2) Restore, 3) Maintenance and 4) Major Projects. All Expansion, Restore and Maintenance costs are recovered in base rates and Major Projects work is either recovered through base rates or the SPPCRC, depending on the nature of the project.

Q. Please provide additional details regarding Customer Delivery's Expansion program.

A. This program represents distribution line construction work for adding customers to DEF's distribution system and includes costs of internal/external resources, materials, and support costs. Due to the nature of customer requests for this type of work, forecasting for new customer additions is performed using a combination of historical trends, analysis of load predictions and understanding of current pricing of materials and resources.

Q. Please provide additional details regarding Customer Delivery's Restore work.

A. Restore is a reactionary process across Customer Delivery. The purpose of the Restore process is to provide safe, efficient, and timely restoration of electric service to all Duke Energy customers. The Restore process starts with the report of an outage event. The process stops when service is restored and made safe. An outage event may be the result of weather, equipment failure, vegetation, animals,

C12-1281

or Public Damages. Public Damages to Company property units, for example vehicle accidents hitting poles, are also included in the Restore process.

Q. Please provide additional details regarding Customer Delivery's Maintenance work.

A. This program represents replacement of upgrades of and life extensions to existing assets to maintain and/or improve the reliability and integrity of DEF's distribution system as well as long-lived assets that support operations. Specific device-level improvements are measured and prioritized at a system level to ensure maximum benefit for resources expended.

Q. Please provide additional details regarding Customer Delivery's Major Projects work.

A. This program represents large capacity increase projects such as substation additions or upgrades; relocation work associated with roadway expansion; major conversions; and new customers, as well as technology, software and equipment deployments/upgrades identified to modernize grid activities. Also included in Major Projects are those dedicated to storm hardening the system to make it more resilient through the SPP. These SPP projects, which are not included in base rates, include Feeder and Lateral Hardening, Pole Replacements, and Self-Optimizing Grid.

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Q. How does DEF ensure the reliable distribution of power to its customers?

A. The Company's work in this area generally falls into three categories which I discuss in more detail below: 1) ongoing maintenance of the distribution network; 2) integration of new customer load, including electric vehicles and solar resources; and 3) programs aimed at improving reliability.

Ongoing Maintenance

Q. Please elaborate on the Company's ongoing maintenance of the distribution network.

A. With respect to maintaining the distribution network, DEF has maintenance and replacement programs for capacitors, underground cable, transformers, regulators, reclosers, and pad mounted switchgear. The pole inspection and replacement program and annual vegetation management trim cycles have moved out of our base rates and into clause recovery under the SPP; however, DEF maintains a base rate budget to address reactive pole replacement and vegetation management for issues discovered during day-to-day operations.

Q. What maintenance activities are necessary to maintain a reliable distribution system for DEF's customers?

A. DEF has inspection and replacement programs for poles, capacitors, underground cable, transformers, regulators, reclosers, riser retrofit, arrestor retrofit, and pad mounted switchgear in addition to follow up on reactive maintenance for issues

C12-1283

discovered during normal day-to-day outage response or customer queries. Please see Exhibit BL-3 for more detail on the Company's distribution maintenance programs.

<u>Integration of New Customer Load</u>

Q. The State of Florida continues to be one of the fastest growing states. Has DEF considered this in its rate case?

A. Yes. DEF has taken this into consideration with its planned investments and maintenance cost estimates included in this rate case. In order to provide electrical service to a growing customer base, DEF must construct line extensions or upgrades to new customer loads and expand its grid capacity to prepare for this growth.

Q. Does the Company anticipate demand for electricity to increase over the next several years?

A. Yes. DEF expects and is planning for incremental growth over the next several years. Although incremental load increase may be partially offset by improved energy efficiency and renewable energy, DEF still expects a net gain due to the demands of an interconnected home paired with electric cars and pools as well as continued growth of residential customer count. Please see the Direct Testimony of Benjamin Borsch for further detail on load growth expectations. No matter how electricity demand trends evolve, capacity must always be added at the point of service and DEF's plan includes resources to expand grid capacity.

Q. How is the Company planning for load growth and additional customer demand?

A. DEF monitors the demand on the distribution infrastructure, including feeders, branch lines and transformers. For feeders, the Company's planning group tracks current loading and forecasted loading based upon historical and proposed growth in the areas served, planning for new or upgraded feeders at least two years out. Area designers also share any new incremental load growth of 1000 kW or more for tracking purposes. The centralized subdivision teams employ conceptual planning to aggregate all expected load for subdivisions, both current and proposed, to avoid reworking in developed areas. DEF continuously monitors economic conditions and customer requested work on the distribution system and can adjust the workforce based upon the location and type of work.

Q. As more consumers and companies transition to electric vehicles, how does that impact DEF's investment needs?

A. As discussed further in the testimony of Witness Tim Duff, Florida is second only to California in the number of electric vehicles on the road and we anticipate this number will continue to grow significantly. There were approximately 44,000 electric vehicles in DEF's territory by the end of the third quarter of 2023. The electrification of vehicles increases demand on the electric grid and requires DEF to plan for this at multiple levels. For example, as consumers transition to electric

C12-1285

vehicles, they typically install Level 2 chargers at their residence.[1] Level 2 chargers typically are rated at 40 amps up to 100 amps at 240 volts. A 40 amp charger is similar to the load pulled by a large hot water heater; however, while a hot water heater comes on at full load for 15 minutes at a time, the electric vehicle chargers will be pulling full load for 6 to 8 hours in a single session. These Level 2 chargers increase the load on the typical residential transformer; therefore, DEF must take this into consideration when sizing its equipment. Beyond Level 2 chargers, the number of Level 3 or DC Fast Chargers, are projected to dramatically increase over the next several years. These "super chargers" require significant capacity on the system and, at times, are in less dense areas such as along highways; therefore, requiring line extensions to serve.

Q. How does DEF integrate new customer load?

A. To integrate new customer load, a DEF Designer visits every site to assess production and potential impacts to grid. The DEF Designer will review existing loading on DEF assets, such as transformers and wire/cable, to determine if the proposed new load can be served without the need for modification or upgrade. If a modification or upgrade is required, a work order is only created for the supported line extension or upgrade. DEF also maintains a grid capacity program and upgrades and adds additional feeders based upon loading in high growth areas.

[1] Level 1 chargers are the standard 120 volt outlets in most residences.

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Q. What is the process that DEF uses to increase grid capacity for future growth?

A. DEF has a Capacity Planning Engineering department that studies the distribution grid and substation transformers to determine where grid capacity investments are required to maintain service to customers. The Capacity Planning Engineers utilize a load forecasting tool that creates five-year forecasts of load growth, coupled with spot load information identified by DEF Distribution Designers based on field assessments conducted as described above. The DEF Capacity Planning Engineering department has also begun incorporating fleet electrification cluster forecasting into the capacity planning process. All of these data points are utilized to predict where overload situations will exist due to customer growth and identify solutions such as conductor upgrades; substation transformer upgrades; substation transformer or breaker additions; or net new substations. The solutions identified by this process are including in the System Capacity and Retail Capacity investment programs. These investments ensure that DEF can provide service to the continued growth in the state without impacting the reliability of the existing customers.

Q. How does DEF integrate solar resources?

A. The integration of solar on the Company's distribution system is mostly behind the meter by individual residential and business customers and is generally sized between 8 kW and 100 kW; however, there are some larger installations as well. Similar to the integration of new customer load described above, DEF reviews each customer's Interconnection Application and Interconnection Agreement. For larger

C12-1287

customer-owned solar PV systems especially if sized greater than 100 kW, DEF studies the customer's installation to ensure the existing infrastructure can accept excess customer solar energy production with no adverse impacts on neighboring customers or equipment that could create safety or reliability concerns. The Company's goal is to protect its customers, employees, and the distribution grid. DEF has seen an increase in customer-owned renewable generation from around 21,200 customers at the end of 2019 to about 82,000 as of December 2023. This represents about a 386% increase in customers with renewable generation added to the distribution grid in four years' time. Solar customers are using the grid and distribution assets 24/7. Solar customers continuously rely on the grid in three different ways for bi-directional power flow – (1) solar customers require the grid to receive their excess solar energy production to when they cannot use it, (2) to balance their load at their premise to maintain good power quality, and/or (3) to receive power from the Company when their solar generator is not producing enough electricity for the premise.

<u>Upgrades to Improve Reliability</u>

Q. What kinds of reliability improvements has the Company made in recent years?

A. To improve reliability, the Company has undertaken several initiatives, including a Recloser Replacement subprogram that installs automated line disconnect devices, an Outage Investigation program, and a Major Reliability program. In addition to these programs, DEF continues to utilize construction standards on new facilities that provide high levels of reliability, such as conduit, to better protect underground cable and larger poles and insulators that provide higher basic insulation levels and are more resistant to damage and executing grid improvement program changes (which are now part of the recovery clause under the Storm Protection Plan) such as self-healing grid capability. The Company continues to improve its storm response and restoration.

Q. What is the Recloser Replacement Program?

A. In 2019, the Company started installing automated line disconnect devices, such as the TripSaver, on power lines to help limit the frequency and duration of service interruptions. TripSavers are installed on local power lines that branch from the main power lines serving an area and are essentially similar in action to a recloser. When there is a temporary issue that could cause an outage requiring a first responder, TripSaver responds in seconds to clear a temporary fault resulting in the customer experiencing no outage. In addition, by containing issues at the feeder level and isolating them as a localized event, TripSavers allow the Company to reduce its overall exposure to momentary outages, power quality complaints, and fault tolerance of branch lines. The Company installed 4,700 TripSavers in 2021, 3,300 in 2022, 1,100 in 2023, and is projected to install 1,300 in 2024.

Q. What is the Outage Follow-Up Investigation Program?

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A. Outage Follow-Up Investigations are designed to provide both operational and strategic benefits for the sample of outages where we do post-outage, field investigations.

- Operational – The investigations are designed to prevent a similar outage at the same site from the same primary root cause. The investigations also can find and fix unrepaired damage related to the recent outage that could cause a repeat outage.
- Strategic – The information collected from the Outage Follow-Up investigations is used to determine the drivers for outages that impact larger numbers of our customers, develop programs to address the outage causes (e.g. Overhead Transformer Retrofit, Riser Pole Retrofit, Arrester Station Retrofit), and drive needed improvements to existing construction standards or new construction standards.

Q. What is the Major Reliability Program?

A. The Major Reliability program involves replacement of existing assets and/or installation of new assets to address sections of the distribution grid that do not meet service level expectations for our customers. A thorough analysis is performed to determine the most efficient way to replace the assets while minimizing the interruptions of our customers. Some analysis includes reliability performance, frequency of outages, line patrol, conductor replacement to improve power quality, overhead to underground conversion, etc.

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Q. Could the Company have saved costs if it opted to maintain the same reliability levels rather than make these investments?

A. No. Investments made to improve reliability are intended to reduce the frequency and duration of customer outages. Beyond the benefit that the customers are not as impacted by outages, reducing outages have inherent cost savings. Each outage that is prevented is a reduction in the need to dispatch a resource to restore service. Reducing outages through these reliability investments helps to offset increasing cost pressures for restoration, including growth of the Company's customer base that requires increased quantity of assets to serve; aging infrastructure that has higher likelihood of failure; and increased costs of materials and labor due to inflation. Despite these headwinds, DEF's distribution restoration costs have trended downward over the last six years as a result of investment in the grid.

Q. Why did the Company decide to make the reliability improvements?

A. The Company's focus on customer needs and satisfaction led to the recognition that in a tightly interconnected world where individuals and companies rely on "always on" technology, we have a part to play in ensuring customers have quality power available at all times. In the past, loss of power was an inconvenience, but today it pauses life and can have a real dollar cost impact. DEF wants to help ensure our customers experience the best power delivery available.

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Vision Florida

Q. What is Vision Florida?

A. Vision Florida refers to a pilot program that the Commission approved as part of the 2021 Settlement Agreement. Specifically, paragraph 25 states:

> The Parties recognize that several factors are making future electric and grid investment a more dynamic environment. DEF shall be allowed to implement a Vision Florida pilot program. This program may consist of capital and Operating & Maintenance ("O&M") investments associated with but not limited to: up to four Emergency Relief Microgrid projects; a floating solar pilot project at the Hines generating station; an investment in some form of hydrogen power; and solar plus storage projects that are intended to delay or avoid future transmission or distribution investments (for example - substation, breaker, or line upgrades and it will incorporate a partnership with the local community to assist in siting). O&M investments in this program will be deferred for recovery in conjunction with DEF's next general base rate case over a 5-year period. As Vision Florida eligible capital projects go in service, DEF shall be authorized to defer all financial impacts associated with the capital projects to a regulatory asset, which will be allowed to earn an AFUDC carrying cost and will be recovered in DEF's next base rate proceeding. Total costs under this pilot shall not exceed $100 million in capital and $12 million in O&M. These expenditures may be incurred at any time during 2021 – 2025.

I will explain the process for selecting projects. Then I, along with Witnesses Reginald Anderson and Hans Jacob, will describe the specific projects in detail.

Q. How did DEF determine which projects to pursue as part of the Vision Florida pilot program?

A. DEF Leadership created the Vision Florida Core Team to develop processes for selecting pilots and providing governance and oversight. DEF then created the Vision Florida Board, a group of employees that provides cross-functional leadership and expertise as part of the project intake, selection, and oversight

C12-1292

process. These are key components of a comprehensive application process to evaluate and select projects that maximize customer benefits, while providing technological and geographic diversity. Projects are selected that use renewable technology solutions to offset traditional investments, improve resilience, and help meet carbon reduction goals. Vision Florida consists of Community Pilots and Technology Pilots. Community Pilots focus on providing: (1) Cost savings for customers, (2) Load shaping, (3) Distributed energy solutions, and (4) Solutions that defer or eliminate the need for traditional capital investment. Technology Pilots concentrate on: (1) The future of the grid, including renewable solutions and resilience, (2) New projects that complement existing DEF Business Unit strategies, and (3) Exploring dynamic approaches versus traditional solutions.

Q. What criteria did the Company use to select the projects that would make up the Vision Florida pilot program?

A. The Vision Florida Core Team developed overarching selection criteria to filter proposed projects. These include: (1) Deploy microgrids, hydrogen, floating solar or other innovative technologies to prepare for the future of the grid, (2) Implement projects prior to the conclusion of Vision Florida in 2025, (3) Prefer lower cost projects (less than $20M in capital spending and $2M in O&M spending), (4) Encourage cross-functional problem solving, (5) Deploy new technologies or existing solutions in innovative ways, and (6) Align with enterprise and business unit strategies for carbon and resiliency goals.

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Q. Based on those criteria, what projects did DEF select to complete as part of the Vision Florida Program?

A. DEF has selected five projects: (1) Floating solar at the Hines Energy Complex ("Hines Floating Solar"); (2) Residential Battery Storage; (3) Linear Generator & Microgrid; (4) Hydrogen Production & Storage System at the DeBary site ("DeBary Hydrogen"); and (5) Suwannee Long-Duration Energy Storage ("Suwannee"). I will provide additional details on the first three projects, while Reginald Anderson will explain the DeBary Hydrogen project and Hans Jacob will provide details on the Suwannee project.

Q. What is the Hines Floating Solar project?

A. The Hines Floating Solar project is a floating solar installation in Bartow, Florida. The project is located in and around the cooling pond within the Duke Energy Hines Energy Complex. The bifacial solar panels are affixed to floating blocks and then anchored to the bottom of the pond to remain stationary.

Q. How does this project benefit customers?

A. This project directly exports power from the solar array to the associated feeder and support customers on that feeder. Long-term, the intent is to monitor the efficiency of the solar panels, expected to be improved by the cooling effects of the water. Furthermore, deploying the solar array in a cooling pond would also allow DEF to learn about the technology and evaluate the possibility of deploying similar projects

C12-1294

in the future. The ability to deploy solar arrays in bodies of water would allow solar energy to be deployed closer to load centers which is traditionally a challenge due to lack of land availability.

Q. What will the estimated project cost and what is the projected in-service date?

A. The estimated total project cost is $3.2 million and was placed in service on December 11, 2023.

Q. What is the Residential Energy Storage project?

A. The Residential Energy Storage project will install up to 100 customer sited residential energy storage systems along a feeder in the Hunter's Creek area of Central Florida. These systems will be owned and operated by DEF to determine the viability of residential battery storage as a suitable option to defer distribution feeder upgrades through peak load shaving.

Q. How does this project benefit customers?

A. This project benefits customers by allowing DEF to determine if utility-owned residential storage is a viable option to:

- Test and evaluate the impact of a grid-edge, distributed energy technology on both the feeder and the overall distribution system.
- Provide customers with backup power during periods when utility service is unavailable.

- Add capacity to the grid by charging the storage systems during times when lower cost generation is in excess and then dispatching the systems during periods of peak demand.
- Manage residential peak demand by addressing grid constraints associated with vehicle electrification.
- Evaluate viability of residential battery storage as a suitable option to defer distribution feeder upgrades through peak load shaving.

Q. What will the estimated project cost and what is the projected in-service date?

A. The estimated project cost is $3.4M, with a projected in-service date of Q2 2024.

Q. What is the Linear Generator project?

A. This project in Orange County will install two (2) 240kW Mainspring Linear Generators and associated equipment on DEF's primary feeder serving a customer's facility. A linear generator is a type of technology that converts motion along a straight line into electricity using chemical energy. It can rapidly increase or decrease generation, working in parallel with other energy sources such as solar while matching the customer power needs. The linear generators will enable DEF to integrate and evaluate a new distributed energy system technology capable of using natural gas and hydrogen fuel mix for generation. The project will also allow testing of the linear generators within a microgrid environment.

Q. How does this project benefit customers?

A. This project benefits customers by allowing DEF to gain learning in the following areas:

- Evaluating a new generation technology capable of using multiple fuel mixes.
- Understand linear generator integration and operation within a microgrid.
- Developing and running specific scenarios to test and ensure proper usage of this type of generation resource for this and future microgrid installations.
    - Black start and grid forming
    - Load following
    - Frequency control
- Resiliency benefit of efficient, persistent 24/7 generation.
- Support for carbon neutrality and resiliency when using fuels such as hydrogen, landfill gas, and ammonia.

Q. What is the estimated project cost and what is the projected in-service date?

A. The estimated project cost is $6M, and the projected in-service date is Q2 2025.

III. <u>OPERATIONAL PERFORMANCE OF DEF'S DISTRIBUTION SYSTEM</u>

Q. Have the distribution investments that the Company has made since the 2021 Settlement Agreement allowed it to meet its operational performance and customer satisfaction goals?

A. Yes. DEF's principal goal is to deliver safe and reliable electric service at

C12-1297

reasonable prices. We measure this goal based on customer satisfaction, safety, and reliability of the Company's distribution system, while responsibly managing operational and capital expenditures for the benefit of our customers.

Q. What reliability metrics does the Company use to determine that it is providing reliable distribution service to its customers?

A. DEF, along with others in the industry, uses several metrics to measure reliability of service. Primary among those metrics are:

- System Average Interruption Duration Index ("SAIDI") – a composite indicator of outage frequency and duration. SAIDI is calculated by dividing the customer minutes of interruptions by the number of customers served on a system.

- Customer Average Interruption Duration Index ("CAIDI") – an indicator of average interruption duration, or the time to restore service to interrupted customers. CAIDI is calculated by dividing the total system customer minutes of interruption by the number of customer interruptions.

- System Average Interruption Frequency Index ("SAIFI") – an indicator of average service interruption frequency experienced by customers on a system. SAIFI is calculated by dividing the number of customer interruptions by the number of customers served.

- Momentary Average Interruption Event Frequency Index ("MAIFIe") – an indicator of average frequency of momentary interruptions, or the number of times there is a loss of service of less than one minute. MAIFIe is calculated by dividing the number of momentary interruption events recorded on primary circuits by the number of customers served.

- Customers Experiencing More Than Five Interruptions ("CEMI5") – the percentage of retail customers who have experienced more than five service interruptions of one minute or longer duration during the year.

Q. How has DEF's distribution system performed under these metrics?

C12-1298

A. Our system has performed well, and we have continued to provide safe, reliable, and affordable electric service to our customers. DEF's reliability metric results from 2018-2023 are provided in Exhibit BL-2 to my testimony. Over the 5-year period from 2018-2022, DEF's SAIDI, SAIFI, CAIDI, MAIFIe and CEMI5 results are all trending favorably (downward). When compared to EIA-861 annual federal reliability filing results from 26 other United States investor-owned utilities with similar system characteristics as the Company, DEF's SAIFI trend is improving at a faster rate than the group's average from 2014-2022. The group's average SAIDI was also a worsening trend from 2014-2022, while DEF's SAIDI trend is improving for the same period. The system improvements and process enhancements, previously discussed, will continue to improve DEF's reliability performance and metrics.

Q. How does the Company communicate to customers when there are outages and provide high levels of service to its distribution customers?

A. Providing customers with a high level of communication that can be tailored to their personal needs has intrinsic value, as recognized by many companies in other industries providing consumer products and services. DEF aims to provide this high level of service and communication to its customers during outages. For example, the Company proactively provides Initial Time of Restoration ("ITR") and Estimated Time of Restoration ("ETR") alerts to help customers plan around the inconvenience of being without power. In addition, DEF provides customers with

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access to an outage map for real-time information on outages in their neighborhoods.

By proactively discovering and targeting customer needs and requests, DEF can provide a more focused and tailored level of service to its customers. While a commercial project customer may find value connecting directly with the local Engineering Design Associate, a residential subdivision builder may find more value in our builder portal and concierge team to help monitor multiple projects. Similarly, while some residential customers may find that tracking energy consumption is critical to their needs, others may decide that limiting interruptions in service is their highest priority. By communicating with customers and assessing their needs, DEF can more readily deliver the services customers desire.

Q. What steps has the Company taken related to distribution resources to improve customer satisfaction?

A. DEF has focused heavily on improving response times to customer inquiries related to new growth or questions about service improvements. The Company set expectations on turnaround times, updating customers on construction timelines, and meeting customer goals for power delivery.

The Company is also improving digital transformation efficiencies with programs like Ping It, which allows Company employees to remotely connect to and check

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the status of a smart meter in lieu of sending a technician to the premises. By checking remotely, the Company can save significant time and travel costs. The Ping It program is especially useful during major storm events where the Company can use Ping It to determine which customers are out of power without the need for them to call and report an outage.

DEF is also focused on supporting the state's residential and commercial builders and developers. The Company delivered a specialized portal and mobile application for builders and developers to provide an improved customer experience through a pilot with one of Florida's largest residential builders to tie its scheduling software into the portal for ordering construction power, running underground trenching and permanent metered power, and transmitting an average of 40 service requests per week to DEF. The Company is developing further plans to make this service available to other large builders and developers wishing to interface their construction systems with DEF's request process. There currently are 8,550 registered users in Florida participating in the builder portal. DEF's New Construction team is available to offer a demonstration of the Builder Portal and the services that can be completed through the Portal. In addition, our Customer Experience team has created a video that will be added to the registration page on how to use the Builder Portal.

The Company has also held Builder Summits across the service territory inviting

C12-1301

builders and developers the opportunity to meet with members of our Residential Development and New Construction team members to ask questions, raise issues, and offer feedback on areas to improve the new construction process.

The Company also recently made it easier for customers to report outages on the website and via the Company mobile application, adding to the proactive communication of outage updates to customers, via text or email, and up-to-date information on the new in-house built outage maps without requiring the customer to call.

In 2020, the Customer Delivery organization completed a reorganization effort that aligned the structure to the areas that are served by DEF, putting local leadership over all operational aspects of the customer experience, including reliability, new customer expansions and modification requests. This allows direct contact and assistance to DEF customers. For example, each area has a Reliability Technologist that monitors reliability for the customers in the area and generates projects to improve reliability; these Technologists also respond directly to customer inquiries regarding service interruptions.

DEF has also dedicated an Engineering Design Associate position to each of our operations centers. This position allows our customers to have a local point of contact via phone or email for any construction-related issue they may have with

C12-1302

DEF. The Engineering Design Associate is highly focused on customer service but has considerable knowledge of the electrical distribution system and construction. DEF also has a local position with a focus on repair and replacement of failed facilities. If a customer experiences an issue with a bad underground service conductor or reported street light cable that requires additional work, our customers will receive timely work updates along with a local contact name and number for any follow-up questions.

Q. Does DEF engage stakeholders in its efforts to make the grid more reliable and resilient?

A. Yes. DEF identifies projects where customers may be impacted by the construction of grid improvement projects and communicates with those customers to help them understand the work that is being completed, how it benefits the community, and the construction timelines for the project. For example, the Company worked with a homeowners' association in Pinellas County to organize a community meeting to educate residents on the benefits of undergrounding powerlines, address any concerns, and obtain their approval for easements necessary to make the improvements to provide more reliable service. Recently, DEF completed the first substation optimization project in Florida in the Panhandle working closely with the community and local government to explain the work process, determine equipment placement around environmentally sensitive areas, and minimize the impact to the residents and local businesses.

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Q. What actions has the Company taken to control its costs while continuing to provide reliable distribution service?

A. Distribution manages its costs as part of its normal course of business. For example, Distribution optimizes resource schedules for construction and restoration activities, conducts peer reviews of design work to ensure the most economical design is utilized, and requires authorization for construction exceptions that differ from the original design. In addition to these ongoing cost management activities, over the period of 2018 to 2023, Distribution has implemented the following:

- Ping It: In 2022, Distribution identified opportunities through a Process and Productivity Cost Savings review. As previously discussed, one area identified for cost savings opportunities was the reduction of truck rolls for issues on the customer side of the point of service. Through the use of the recently deployed Advanced Metering Infrastructure ("AMI"), DEF was able to identify when a customer called in to report an outage but there was no interruption to electric service. By determining that there was no outage, DEF could communicate that the trouble was on the customer's side of the meter and eliminate an unnecessary deployment of a line tech and truck. This reduces overall costs and allows DEF's line resources to focus on actual outages and improve overall service.
- Process and Productivity Cost Savings: DEF identified opportunities that focused on optimizing resources on capital projects, reducing project O&M

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costs, and managing business support costs such as travel, training, and fleet expenses.

- Substation Optimization: DEF is executing base rate maintenance work with Storm Protection Plan ("SPP") work when all such work is associated with the same substation. DEF maintains discrete accounting to maintain separation of SPP costs from base rate maintenance work. The focus on this work is to improve the overall reliability and resiliency of the service provided to customers served from specific substations. This allows construction crews to work more efficiently as well as for design and engineering to be completed without extra trips. This allows both base rate maintenance work and SPP work to benefit from a reduction in travel time and set up and reduces the impacts of maintenance of traffic and planned outages on customers.

Q. How does DEF ensure it has the appropriate level of resources needed to operate, maintain, and invest in the distribution system?

A. DEF keeps its workforce trained, engaged and nimble to adjust to differing workload demands. The Company watches trends and uses contract labor for periods of high demand or workload. DEF has moved from hourly sourcing (i.e., using time and equipment) for our contract labor to a per unit costing for work tasks performed. This change improves job forecasting by knowing in advance what a task will cost. It encourages contractors to look for and avoid obstacles to timely

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work completion because they are better rewarded for working efficiently. DEF leverages Duke Energy's combined size to improve vendor pricing and supply, striving for the highest quality products at the best prices with on time delivery. The Company's corporate-wide software, Maximo, allows for better streamlining of materials used in construction, improved supply chain management, and improved scheduling. These improvements have allowed DEF to better work with customers on installing facilities as they are needed rather than based upon availability of material and labor.

Q. Can you provide an example where the Company has taken measures to adjust staffing without decreasing services?

A. DEF has evaluated what number of the Company's full-time employees are needed to meet our growing customer base and related needs. DEF continuously reviews the types of work required and determines if the work is ongoing baseline work or special project or limited occurrence work. DEF will then employ contract labor, with DEF employee oversight, for the non-baseline type work. DEF tries to ensure that customer-facing work is performed by DEF employees to the greatest extent practicable. While contract crews may provide engineering and construction tasks, the goal is for all Company-to-customer interactions to be through a DEF employee.

One such example is the Centralized Design group which DEF uses to provide optimum subdivision designs utilizing specialized software to help ensure our

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builder partners always receive a similar product regardless of project location. Designs are created by Centralized Design and shared with the customer-facing Residential Design team to allow the customer-facing employees to spend time meeting customer needs and ensuring timely construction. Centralized Design is staffed with a baseline number of employees and augmented with contract engineering firms as needed to meet peak demands.

Q. Please discuss the Company's use of contractors.

A. DEF uses a vetting process to identify contractors eligible to work in the DEF system. The Company establishes contract pricing through a blind-bidding process for both contract engineering and construction resources. DEF managers and resource schedulers are aware of both the quality of work and the unit pricing of the contractors for each type of work they perform, and they assign work accordingly.

Q. Does the Company have any recruiting practices specific to lineworkers or veterans to support the distribution grid?

A. Yes. As Melissa Seixas introduced in her testimony, the Company actively recruits distribution lineworkers through programs with Lake Sumter State College, South Florida State College, St. Petersburg College, and Valencia College to ensure we attract and develop a skilled workforce that is representative of the communities DEF serves. DEF is committed to providing support for these programs in the forms

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of engaging regularly and meaningfully on campus, providing guest speakers and work demonstrations, supporting community connections to help market the college's program, and providing expertise in curriculum. DEF hires between 40-100 Apprentices each year to advance Line Technicians and replenish the attrition we experience.

Also, DEF is proud to employee veterans. The Company utilizes the Recruit Military platform to engage transitioning and civilian-experienced miliary veteran men and women in addition to attending military career fairs and participating in the SkillBridge program, which provides retiring and transitioning service members the opportunity to participate in industry training programs while transitioning out of their military careers. Since 2020, DEF has hired 97 individuals that have identified themselves as a veteran to support the distribution grid. We are thankful to have these employees to assist DEF in modernizing the grid and maintaining reliable service.

Q. Please provide more information about the Company's procurement activities.

A. DEF works to obtain the best available pricing for the materials used on the distribution system. Through a job kitting system, key materials needed to construct a job are packaged and sent from the main store's location, minimizing the amount of construction inventory needed to be stored locally in each operations center. In fact, Southeastern Electric Exchange recently selected Duke Energy for a 2024 Industry Excellence Award for its transformer acquisition strategy amidst the recent material availability challenges seen across the industry.

Storm Response

Q. Please discuss the Company's hurricane and major storm response efforts.

A. DEF is proud of its hurricane and major storm response efforts, and I detail our success in restoring power further below. DEF has implemented the Incident Command Structure ("ICS") Event Response Organization to rapidly and efficiently support a successful emergency response throughout the organization. The ICS is the nationally accepted model for responding to incidents in accordance with the National Incident Management System. The ICS establishes an organized way to respond to emergencies using standard job roles, forms, and terminology. This method of organizing an emergency response is used for short- and long-term operations across the government, industry, and private sector. As a common structure, the ICS ensures a fast and efficient emergency response. The most important benefit provided by an ICS-based organization is the clear identification of the response leader and the response leader's chain of command. This approach is designed to optimize Duke Energy's operational, planning, and logistics capabilities while providing effective communication to our customers and partners. DEF has also made improvements to its hurricane and major storm response. One example is crew tracking enhancements, including daily timesheets

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and an exception approval process for time reporting, lodging, meals, and fuel. These improvements increase the amount of work done during productive daylight hours, lower overall event cost, and reduce the number of restoration days. As briefly mentioned above, the Company also developed a way to use GIS technology to improve its hurricane response. After Hurricanes Hermine and Matthew in 2016 and Irma in 2017, DEF developed a way to help its crews navigate debris-covered and flooded roads. DEF was able to utilize this improvement in the Company's response to Hurricanes Ian, Nicole and Idalia while partnering with local emergency response personnel. The Company uses GIS technology, which is often more reliable than using GPS routing, to monitor changing road conditions, understand how flooding is affecting customers and equipment, and help crews reach their locations safely and quickly.

Q. Does DEF perform any storm drills or simulations outside of hurricane season?

A. Yes. DEF conducts annual exercises to prepare for major weather events that have the potential to disrupt electric service to customers in Florida. The drills are intended to assess the effectiveness of the Transmission and Distribution teams to respond to major weather events. Team members participating in the exercises are expected to respond as if there were an actual event and to apply their knowledge of the emergency response plan to restore power to customers safely and efficiently. Identification of knowledge, tool, and process gaps to be addressed prior to the start of each hurricane season is a key outcome of the exercises.

Q. Is DEF's service territory more prone to severe weather and storms than that of other utilities?

A. Yes. Florida leads the nation in the number of named, or tropical storm landfalls and has the highest average probability of future landfalls.[2] It is projected that these storm events will increase in severity, and the accompanying rainfall and storm surge impacts will intensify and be felt further inland.[3] Florida is a historical path of major hurricanes, which increases the risk of vegetation-related outages from tree species with low wind resistance. Examples of these species prevalent in DEF's territory are laurel oak, water oak, pecans, and sand pines in North Florida as well as Australian Pines, Melaleuca, Washington palms, and queen palms in South/Central Florida. In addition, the various types of vegetation seen in the region contribute to outages during extreme weather events. Pine tree species cover a large portion of DEF's Northern footprint and are very sensitive to wind damage, flooding, and salt inundation which are typical conditions during storm events especially with storm surges. Storm surges affect soil stability around trees rendering them more prone to fall and cause customer outages. Salt inundation from storm surges typically kills impacted trees within two years which can also lead to more vegetation-related outages. Much of the affected dead and dying trees are

[2] Colorado State University, *CSU Tropical Cyclone Impact Probabilities*, https://tropical.colostate.edu/TC_impact.html (last visited Mar. 15, 2024).
[3] *See* Li, L., Chakraborty, P. *Slower decay of landfalling hurricanes in a warming world.* Nature 587, 230–234 (Nov. 11, 2020).

outside DEF's right-of-way easements therefore preventing pre-emptive removal unless a customer grants permission for removal. Approximately 48% of DEF's Transmission system footprint and approximately 66% of DEF's Distribution system footprint is forested. In addition, approximately 26% of DEF's territory has a wetland classification, which impacts several upland tree species when these areas get inundated, especially water and laurel oak decline. Trees impacted by storm surges may become susceptible to insect infestation and debris from these trees frequently impact DEF facilities causing increased vegetation related outages. Florida's climate provides a year-round growing season which is a continuous challenge to maintain fast growing species near our facilities. The large population of palm trees in South and Central Florida pose a specific challenge to DEF's distribution system due to their aggressive growth habit with a propensity to produce two sets of fronds per year. While DEF maintains a tree trim cycle, palm tree fronds are frequently blown into power lines and transformers, causing momentary flickering and outages during storms due to their rapid growth.

In addition, DEF's service territory is comprised of both the most densely populated county in the state (Pinellas), as well as some of the most rural counties in the state. The geographic span of DEF's service territory impacts storm restoration in that it takes longer to restore power in more rural areas.

Q. Are there other factors unique to DEF's service territory that further enhance

C12-1312

this storm risk?

A. Yes. DEF's service area is also unique since the state of Florida is a peninsula with two coastlines (Gulf of Mexico to the west and the Atlantic Ocean to the east); therefore, two sea breezes develop – one along the west coast and one along the east coast. When prevailing winds are light (very typical in the summer months), the continued replacement of the rising warmer air by the cooler oceanic air pushes the sea breezes inland. With both sea breezes moving inland, they eventually collide over the interior peninsula. This collision causes the air to rise even more and creates thunderstorms.

Thus, the geographical location combined with the shape of Florida's peninsula is the main reason for frequent thunderstorms during the warm season. Florida also has some of the highest total lightning density in the United States.[4] While Florida is not the only place with sea breeze thunderstorms, it is unique in the fact that it has sea breezes develop on both coasts and the inland collision of these sea breezes produces larger, longer-lasting, stronger thunderstorms, which occur almost daily.

Q. What are some of the recent extreme weather events experienced in the DEF service territory?

A. Since 2021, customers in DEF's service territory experienced Hurricanes Ian, Nicole, Elsa, and Idalia.

[4] Vaisala Lightning 2016-2023

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Q. Can you share more details on the Company's response to the hurricanes mentioned above?

A. Yes. Hurricane Elsa impacted DEF's territory Tuesday, July 6, 2021, and made landfall as a Tropical Storm on Wednesday, July 7, 2021, near Horseshoe Beach. The 65 mph winds and heavy rains lasted for several hours over DEF's North Coastal area before exiting the system in the early evening the following day. The storm impacted over 30,000 DEF customers with more than 2,000 resources mobilizing to restore service to these Floridians within 24 hours of Elsa exiting DEF territory.

With sustained winds of 150 mph, Hurricane Ian made landfall on September 28, 2022, as the fourth-strongest hurricane to hit Florida and the fifth-most-powerful hurricane to hit the United States. This powerful storm led to over 1.1 million customers losing power. DEF mobilized nearly 10,000 line workers, tree professionals, damage assessors, and support personnel to safe locations in its Florida service area. Additional line workers and support personnel from Duke Energy's service territories in Indiana, Kentucky and Ohio assisted in restoration efforts. Through the work of these nearly 10,000 resources and the investments that have been made in the grid, DEF restored power to 97% of customers within 72 hours.

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Hurricane Nicole made landfall on November 10, 2022, on the east coast of Florida as a Category 1 hurricane with widespread rainfall and strong winds. DEF's service territory experienced an array of damage spanning from broken poles, down wire and trees on our Transmission and Distribution infrastructure. Through teamwork and dedication, line workers restored power to 98% of impacted customers within 12 hours of Hurricane Nicole leaving the Company's service territory. This storm impacted over 303,000 customers. To expedite restoration, Duke Energy's logistics team staged 5,000 workers across the state. During Hurricanes Ian and Nicole, our self-healing technology helped avoid nearly 215,000 extended customer power outages, saving more than 200 million minutes of total lost outage time. Duke Energy was awarded the Emergency Recovery Award from the Edison Electric Institute for its response to Hurricane Nicole.

Hurricane Idalia made landfall on Wednesday, August 30, 2023, near Keaton Beach quickly moving ashore between Perry and Salem, with maximum sustained winds of 125 mph. In addition to major hurricane force winds, Idalia produced devastating storm surge along coastal communities causing severe flooding and widespread destruction. Hurricane Idalia impacted more than 200,000 customers in DEF's service territory. More than 5,000 line workers, tree professionals, damage assessors, and support personnel were staged strategically throughout the state to respond and restore power to customers and communities as quickly and safely as possible. Self-Optimizing Grid investments have helped Florida customers avoid

C12-1315

7.6 million minutes of interruption during Hurricane Idalia. Duke Energy was selected for a 2024 Industry Excellence Award by Southeastern Electric Exchange for its response to Hurricane Idalia.

While restoration costs associated with these extreme weather events are not recovered through this base rate proceeding, DEF's ongoing preparedness practices described above contribute to the excellence in restoration following hurricanes and other major events.

IV. DEF'S DISTRIBUTION SYSTEM CAPITAL AND O&M EXPENSES

Q. What are the Company's distribution capital and O&M requests?

A. The distribution capital expenditures and O&M requests included in this case are:

	2025	2026	2027	Total 2025-2027
Capital Expenditures	$571.9M	$570.5M	$575.6M	$1,718M
O&M	$96.6M	$99.6M	$104.3M	$300.5M

Q. Are DEF's capital and O&M requests duplicative of any activities taken or that will be taken in response to the storm hardening initiatives or SPP requirements?

A. No. DEF's capital and O&M requests are not duplicative of any funds previously requested under storm hardening, now replaced by the SPP. DEF has accounting tools in place to charge and track work under SPP separately even when the same employees are doing regular and SPP work.

Q. How does DEF determine its capital and O&M distribution annual budgets?

A. DEF sets distribution capital and O&M annual budgets each year with growth forecast and reliability needs in mind. Each budgeted program and department is monitored throughout the year for adherence to the budget. Planned distribution system upgrades related to expected growth are monitored and scheduled based upon an overall expansion plan. As new customers join the DEF distribution grid, the Company's customer-facing design team ensures cost effective designs are created to minimize capital expenditure and future O&M maintenance spend.

Q. Have recent economic conditions impacted DEF's distribution capital and O&M expenses?

A. DEF reviews capital and O&M expenditures on an ongoing basis to verify both current and forecasted need for the projects. State and municipal partners have reviewed and adjusted some road projects, either delaying or cancelling them, resulting in some reallocation and adjustment in capital funds. Inflation has also impacted project costs, in that both labor and materials have increased. O&M expenses have also been mitigated through reduction in travel and other expenses where possible.

C12-1317

Q. Are the Company's distribution 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 distribution O&M costs per customer 2025 through 2027?

A. As shown in MFR C-33, distribution expenses are projected to remain lower than 2022 actual expenses with projected values of $47.44, $48.13, and $49.60 per customer in 2025, 2026, and 2027, respectively. In fact, 2027 distribution expense per customer is projected to be $2.39 per customer less than 2022 actuals.

Q. Are DEF's distribution system capital and O&M requests reasonable and necessary?

A. Yes. DEF's capital and O&M requests are necessary for DEF to continue to provide reliable distribution service to customers and build for new customer growth. DEF will need to continue to maintain existing overhead and underground infrastructure. Maintaining the infrastructure will require continued vigilance and reasonable funding of our pole replacement, transformer replacement, and other programs summarized in Exhibit BL-3. DEF also continues its environmental stewardship by mitigating potential hazards to waterways by oil-filled equipment and ensuring hazards to birds and other animals are mitigated at every location DEF performs work.

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DEF has proven to be a good steward of capital and O&M funds while continuing to improve the reliability of the distribution system consistent with customer needs and expectations. However, as the expanding distribution system ages, it requires additional expense to maintain it. DEF must continue the capital investments and O&M expenses necessary to meet future customer growth needs, replace assets as they reach the end of their useful life, maintain existing distribution assets, and reliably serve our customers. DEF will continue this focus on reasonable and efficient spending on future distribution capital and O&M expenses to continue to deliver cost efficient, reliable, and safe energy.

Q. Does this conclude your direct testimony?

A. Yes, it does.

C12-1319

Company's design team and construction crews also work to resolve any deficiencies found in the distribution system while performing work or designs. One such program, implemented in 2016 is Standing Orders, allowing DEF's crews to address needed repairs or upgrades to facilities while in the field performing other work, thereby improving reliability and power quality while saving a second trip for crews and design teams.

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(Whereupon, prefiled direct testimony of James J. McClay 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

JAMES J. MCCLAY, III

On Behalf of Duke Energy Florida, LLC

C13-1331

Q. Please state your name and business address.

A. My name is James J. McClay, III. 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 Carolinas ("DEC"), an affiliate company of Duke Energy Florida, LLC ("DEF," "Petitioner" or "Company") as the Managing Director Natural Gas Trading. As it relates to DEF, I manage the organization responsible for natural gas trading, optimization, origination, strategy, pipeline transportation for the regulated gas-fired generation assets fuel oil procurement, and emissions compliance trading.

Q. Please describe your education background and professional experience.

A. I received a bachelor's degree in business administration majoring in Finance from St. Bonaventure University. I joined Progress Energy in 1998 as an Energy Trader, was promoted to Manager of Power Trading and held that position through early 2003. I then became the Director of Power Trading and Portfolio Management for Progress Energy Ventures through February 2007. From March 2007 through late 2008, I was the Director of Power Trading for Arclight Energy Marketing. From March 2009 through present I have been employed in various managerial roles at Progress Energy and Duke Energy overseeing Natural Gas Trading and Origination, Pipeline Transportation, Oil Procurement, Power Trading, and various jurisdictions'

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hedging programs. Prior to my tenure with Duke Energy, I was employed for approximately 13 years in Capital Markets as a U.S. Government fixed income securities trader with various banks, and broker/ dealers.

Q. What is the purpose of your testimony?

A. My testimony outlines the Company's proposal to implement an updated incentive mechanism. I also summarize the Company's current Commission-approved incentive mechanism and explain why the Company feels its proposal provides a more significant opportunity to benefit customers than the current mechanism.

Q. Please explain DEF's current incentive mechanism.

A. Per Order No. PSC-00-1744-PAA-EI in Docket No. 991779-EI, the following incentive was established for the IOUs (DEF, Florida Power & Light ("FPL"), Tampa Electric Company ("TEC"), and is applicable to the gains from all non-separated wholesale power sales, firm, and non-firm, excluding emergency sales, made under current or future FERC-approved schedules. By Order No. PSC-97-0262-FOF-EI, the Commission defined non-separated wholesale power sales as sales that are non-firm or less than one year in duration. The Commission adopted a three-year moving average of gains on all non-separated wholesale power sales, firm, and non-firm, excluding emergency sales, as the threshold for application of the incentive. All gains below this threshold are credited to ratepayers. All gains above this threshold are split 80% / 20% between ratepayers and shareholders, respectively.

Q. Does the current incentive mechanism provide for the potential to maximize savings to customers?

A. No. Although the incentive mechanism has provided benefits to DEF's customers, the current program is focused solely on non-separated wholesale power sales, firm, and non-firm, excluding emergency sales, made under current or future FERC-approved schedules and ignores other potential opportunities for DEF to maximize customer savings. The current incentive mechanism may be limiting the benefits that the Company may be able to generate for its customers compared to a broader incentive mechanism.

Q. Does DEF have a proposal for improving the existing incentive mechanism?

A. Yes. DEF proposes to implement an Asset Optimization Mechanism ("AOM") effective January 1, 2025. The proposed mechanism is similar to the Commission approved Asset Optimization Incentive Program and Asset Optimization Mechanism currently in place for FPL and TEC, respectively. FPL and TEC previously had the same incentive mechanism in place as DEF, but replaced their programs with updated, broader mechanisms. DEF believes that by updating the existing incentive mechanism to its proposed AOM, it will potentially be able to provide customers with greater savings opportunities. While the AOM will operate as an incentive for DEF to maximize gains to the mutual benefit of customers and the Company, DEF is not requesting cost recovery of any incremental expenses it may incur to implement the proposed AOM.

Q. Please explain DEF's proposed Asset Optimization Mechanism.

A. DEF is proposing to implement an AOM that would consist of both short-term wholesale power purchases savings and gains on short-term wholesale power sales, as well as gains on all forms of asset optimization. For purposes of the AOM, the "asset optimization" includes but is not limited to the following:

- Gas storage utilization - DEF could release contracted storage space or sell stored gas during non-critical demand seasons.
- Delivered gas sales using existing transport - DEF could sell gas to Florida customers, using DEF's existing gas transportation capacity during periods when it is not needed to serve DEF's native electric load.
- Production (upstream) area sales - DEF could sell gas in the gas-production areas, using DEF's existing gas transportation capacity during periods when it is not needed to serve DEF's native electric load.
- Capacity release of gas transport and electric transmission - DEF could sell temporarily available gas transportation and/or electric transmission capacity for short periods when it is not needed to serve DEF's native electric load.
- Asset Management Agreement ("AMA") - DEF could outsource optimization functions to a third party through assignment of power, transportation and/or storage rights in exchange for a premium to be paid to DEF.
- Coal Transportation Savings – DEF could generate savings through the re-deployment of transportation assets when they are not required for coal delivery.

- Sales of Renewable Energy Credits – Includes sales of RECs associated with DEF's Clean Energy Impact program. This mechanism would not include RECs transferred as part of DEF's Clean Energy Connection.

The customers' portion of total gains will be shown as a reduction to the fuel costs that are recovered through the fuel clause factors. DEF will recover its portion of total gains through adjustments to its fuel clause factors that are made in the normal course of calculating those factors and that flow through to all rate classes in the same manner as other costs recovered through the factors. This proposed process is consistent with the current incentive mechanisms that FPL and TEC have in place.

Q. Does DEF propose a revised threshold mechanism for this updated incentive mechanism?

A. Yes. DEF proposes the following thresholds to the AOM: On an annual basis, DEF customers will receive 100% of the gains up to a threshold of $4.9 million ("Customer Savings Threshold"). The $4.9 million threshold represents the annual average short-term wholesale power purchases savings and gains on short-term wholesale power sales achieved by DEF for ten calendar years, which occurred over the most recent twelve calendar years (2012 – 2023) when excluding the highest (2022) and lowest (2012) years of gains. DEF believes that by eliminating the two extreme years the threshold will be more representative of prospective savings. Incremental gains above the Customer Savings Threshold will be shared between DEF and customers as follows: DEF will retain 60% and customers will receive 40% of incremental gains between $4.9 million and $9.8 million; and DEF will retain 50% and customers will receive 50% of all incremental gains in excess of $9.8 million.

Q. Does DEF propose any type of AOM reporting to the Commission?

A. Yes. DEF will file annually as part of its fuel cost recovery clause final true-up filing a schedule showing its gains in the prior calendar year on short-term wholesale sales, short-term purchases, and all forms of asset optimization that it undertook in that year. DEF's final true-up filing will include a description of each asset optimization measure for which gains are included for that year, and such measures shall be subject to review by the Commission to confirm that they are eligible in the AOM. The customers' portion of total gains will be shown as a reduction to the fuel costs that are recovered through the Fuel Clause factors. DEF will recover its portion of total gains through adjustments to its Fuel Clause factors that are made in the normal course of calculating those factors and that flow through to all rate classes in the same manner as other costs recovered through the factors.

Q. Does this conclude your testimony?

A. Yes.

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(Transcript continues in sequence in Volume 3.)

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 4thth day of September, 2024.

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH575054
EXPIRES AUGUST 13, 2028