Review of

Duke Energy Florida, LLC's Storm Protection Plan Program Internal Controls

May 2026

BY AUTHORITY OF

The Florida Public Service Commission
Office of Auditing and Performance Analysis

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Duke Energy Florida, LLC’s Storm Protection Plan Program Internal Controls

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I. Executive Summary

A. Purpose and Objectives

The Office of Auditing and Performance Analysis initiated this operational audit at the request of the Florida Public Service Commission's (FPSC or Commission's) Office of Industry Development & Market Analysis.

The primary objectives of this audit were to review, document, and assess the adequacy of internal controls in use by Duke Energy Florida, LLC (DEF or Company) governing the cost, scheduling, and project execution of its Storm Protection Plans (SPPs) programs and procedures for:

- Workflow planning and project implementation
- Scheduling and tracking project status
- Cost control, budget adherence, and identification of variances
- Ongoing self-assessment of compliance with its SPP and FPSC rules

Commission audit staff also documented and assessed DEF's SPP process improvements and resulting impacts.

B. Scope

As authorized by Subsections 350.117(2) and (3), Florida Statutes (F.S.), management and operation audits are conducted by staff to assess utility performance and the adequacy of operations and controls:

> (2) The Commission may perform management and operation audits of any regulated Company. The Commission may consider the results of such audits in establishing rates; however, the Company shall not be denied due process as a result of the use of any such management or operation audit.
>
> (3) As used in this section, "management and operation audit" means an appraisal, by a public accountant or other professional person, of management performance, including a testing of adherence to governing policy and profit capability; adequacy of operating controls and operating procedures; and relations with employees, customers, the trade, and the public generally.

Given the audit objectives, Commission audit staff's review focused on assessing DEF's implementation and management of each SPP program and associated projects. Audit staff reviewed and performed assessments of DEF's SPP program-related internal controls in the following key areas:

- Management oversight
- Staffing organizational structures
- Procurement of contracted resources
- Risk assessments and potential impact
- Program planning and execution
- Program project prioritization
- Estimation and revision of project timelines
- Automated scheduling and tracking systems
- Cost-tracking system software
- Inventory control practices
- Internal audits and use of consultants
- Quality assurance/control (QA/QC) reviews
- Contractor performance evaluations
- Performance metrics and accountability tools

This review places primary importance on internal controls as referenced in the Institute of Internal Auditors' *Standards for the Professional Practice of Internal Auditing* and in the *Internal Control - Integrated Framework* developed by the Committee of Sponsoring Organizations (COSO) of the Treadway Commission. The assessment of internal controls focuses on the five key elements of the COSO framework of internal control: control environment, risk assessment, control activities, information and communication, and monitoring. Commission audit staff seeks to comply with the Institute of Internal Auditors' Performance Standards 2000 through 2500.

C. Methodology

The information in this audit report was gathered through responses to document requests and communication with DEF personnel. Commission audit staff also reviewed applicable Florida Statutes and FPSC rules.

D. Audit Staff Observations

Section E in **Chapter II** of this report highlights improvements DEF has implemented to its SPP programs since inception in 2020. Based on its analysis, Commission audit staff presents these observations:

- **DEF should consider including in its SPP Annual Status Report filing the number of projects completed in the prior calendar year regardless of when they were initiated, and the associated total costs per unit (e.g., cost per mile, install, and inspection).** The Company currently provides estimated and actual costs for projects/activities in its SPP Annual Status Reports filed with the Commission. However, because many SPP projects are not planned to begin and finish in the same calendar year, the aggregated data in the SPP Annual Status Report includes: 1) Projects that were initiated in a prior year and not completed, 2) Projects completed in the year reported, and 3) Projects initiated in the year reported but carried over into a subsequent year for completion. Therefore, the specific number of projects completed in a calendar year cannot be determined.

Additionally, the SPP Annual Status Report includes only the costs incurred within the same year for all of the reported projects/activities. Projects, however, typically span multiple years. Therefore, the actual costs do not represent the total costs for *completed projects*, i.e., for the entire life of the projects. If the Company were to separately provide the total costs for the projects that were completed in the year, regardless of when they were initiated, the Commission then could calculate a cost per unit (e.g., mile, install, and inspection) to measure performance.

- **DEF should consider reporting the number of North American Electric Reliability Corporation (NERC) and non-NERC miles maintained and trimmed as part of its Transmission Vegetation Management (TVM) Program.** DEF does not currently differentiate between NERC and non-NERC miles when tracking or reporting on estimated or completed units for its TVM program. While DEF conducts annual inspections of all its transmission lines, the mileage reported in the Company's SPP Annual Status Report reflects only scheduled maintenance miles and not the full scope of all activities in the TVM program.

- **DEF should consider separately identifying in its SPP Annual Status Report the transmission and distribution substation hardening project and cost data for its Transmission Substation Flood Mitigation Program and Transmission Substation Hardening Program.** DEF hardens distribution substation assets as a component of these programs and currently combines the costs for both types of projects in its SPP. The Company states that it will create separate detailed projects to account for transmission versus distribution substation hardening assets. DEF may also want to consider renaming the programs Substation Flood Mitigation Program and Substation Hardening Program.

- **DEF should consider implementing a process to ensure all SPP completed project work orders are identified and included in quarterly reports filed with the Commission.** At the start of each SPP program project, DEF creates a work order coded with a unique SPP project identifier used by its internal systems to ensure all costs are recorded either for recovery through the SPPCRC or base rates. Although Rule 25-6.0346, Florida Administrative Code (F.A.C.), does not require utilities to *identify* completed SPP work orders, utilities are required by the rule to quarterly report completed work orders and associated costs relating to construction and maintenance of transmission and distribution facilities. Based on this rule, the Commission's electric safety engineers conduct follow-up inspections to ensure compliance with requirements which incorporate the National Electric Safety Code (NESC) standards. Therefore, DEF's completed work orders *identified* as either SPP or non-SPP would enable the inspectors to focus on both types of work orders and separately track and assess compliance.

- **DEF's SPP Distribution Feeder Hardening (DFH) Program includes both overhead and underground strategies designed primarily to comply with extreme wind loading requirements and resolve clearance, easement, or relocation issues, respectively.** DEF states that all completed DFH projects are "overhead designed" although certain feeder segments may require undergrounding due to clearance or easement issues or if the feeder needs to be relocated from an inaccessible area to a location with underground facilities. When the Company hardens some of the feeder segments underground, the associated capital costs are recorded in its utility accounts designated for underground distribution assets.

- **DEF and Guidehouse currently conduct follow-up reviews of model-generated circuit-level prioritization results as part of the SPP project development process.** This process helps to identify areas for improvement to ensure that project prioritization is optimized. Similarly, DEF uses the Department of Energy's Interruption Cost Estimate Calculator to estimate the economic costs of power outages and to quantify the benefits of SPP program investments for a more reliable and resilient electric power system during extreme weather conditions.

- **DEF implemented a formalized SPP project variance review process to assist in managing actual performance against estimated to identify needed corrective actions.** SPP project managers regularly monitor and evaluate execution progress on each work order to ensure the project remains aligned with the established scope, schedule, and budget requirements. DEF's project controls and estimating teams also annually review actual costs of completed projects and compares those costs with estimated costs to determine whether corrective action is warranted.

- **DEF created a unit-cost focused team and a new independent estimating team to evaluate specific types of project work plans to more accurately develop SPP project cost estimates.** The Company states that both teams have led to more accurate cost estimates. Commission audit staff notes that an accurate project cost estimate creates a baseline against which costs are measured. It is essential for justifying costs and allows for a prudence review to determine whether a cost increase was avoidable.

II. Duke Energy Florida, LLC's SPP Programs

DEF serves approximately two million customers within 35 counties throughout 20,000 square miles of service territory in Florida. The Company operates a transmission system with approximately 5,400 miles of transmission lines, consisting of more than 60,000 transmission structures with over 6,000 lattice towers, 56,000 poles and other related equipment. The distribution system consists of approximately 18,000 miles of overhead distribution lines on 945,000 distribution poles and 14,000 miles of underground distribution lines. DEF operates over 500 substations that include both transmission and distribution voltages.

A. History of Storm Hardening

In response to the intense impact that the 2004 and 2005 hurricanes had on the state, the 2006 Florida Legislature directed the Commission to conduct a review to determine what should be done to enhance the reliability of Florida's transmission and distribution grids during extreme weather events, including the strengthening of transmission and distribution facilities.

Based on its review of the 2004 and 2005 hurricane seasons, the Commission provided three recommendations in a 2007 report to the Legislature: (1) maintain a high level of storm preparation; (2) strengthen the electric infrastructure to withstand severe weather events with the use of hardening activities; and (3) establish additional planning tools (e.g., cost-benefit models, specialized software) to identify instances where undergrounding is appropriate as a means of storm hardening.

In 2006, the Commission ordered each Florida Investor-Owned Utility (IOU) to file a plan to mitigate restoration costs and outage times associated with extreme weather events and enhance reliability.[1] The plans were to include the following 10 initiatives:

- A Three-year Vegetation Management Cycle for Distribution Circuits
- An Audit of Joint-Use Attachment Agreements
- A Six-year Transmission Structure Inspection Program
- Hardening of Existing Transmission Structures
- Transmission and Distribution Geographic Information System (GIS)
- Post-Storm Data Collection and Forensic Analysis
- Collection of Outage Data regarding Reliability Performance of Overhead vs. Underground
- Increased Utility Coordination with Local Governments
- Collaborative Research on Effects of Hurricane Winds and Storm Surge
- A Natural Disaster Preparedness and Recovery Program

The Commission also ordered electric utilities to file updated storm hardening plans every three years, and begin annual Hurricane Season Preparation Workshops which allow the IOUs,

[1] See Order No. PSC-06-0351-PAA-EI in Docket No. 20060198-EI, issued on April 25, 2006.

municipals, and cooperatives to share individual hurricane season preparation activities. These annual workshops continue today.

After the 2016-2017 storm seasons, with Florida being impacted by two major hurricanes, the Commission opened Docket No. 20170215-EU to identify potential areas where infrastructure damage, outages, and recovery time for customers could be minimized in the future. As part of the docket, the Commission initiated its *Review of Florida's Electric Utility Hurricane Preparedness and Restoration Actions 2018* to evaluate the effectiveness of approximately 12 years of hardening efforts. The report found that Florida IOU's storm hardening programs were working. Outage times from the 2016-2017 storm season were reduced from the 2004-2005 storm season, hardened overhead distribution facilities performed better than non-hardened facilities, and underground facilities performed better than overhead facilities.

Pursuant to Section 366.96, F.S., the Commission promulgated Rules 25-6.030 and 25-6.031, Florida Administrative Code (F.A.C.). Rule 25-6.030, F.A.C., requires the IOUs to file with the Commission an SPP at least every three years, covering a 10-year planning period, beginning in 2020. The rule requires each IOU to submit plans to strengthen its existing facilities against extreme weather. The rule further requires the SPP to include an estimate of rate impacts for each of the first three years of the plan for the utility's typical residential, commercial, and industrial customers. Rule 25-6.031, F.A.C., allows for recovery of associated costs through the Storm Protection Plan Cost Recovery Clause (SPPCRC).

B. Duke Energy Florida, LLC's 2026-2035 SPP Programs

The Commission approved DEF's inaugural SPP in 2020, which served as the basis for the Company's 2023 and 2026 SPPs to build upon. The 2026 SPP encompasses nine distinct programs organized across three major investment categories (Transmission, Distribution, and Vegetation Management):

Distribution Lateral Hardening	Consists of undergrounding laterals most prone to damage during extreme weather events and overhead hardening of those laterals less prone to damage. Activities include structure strengthening, deteriorated conductor replacement, removing open secondary wires, replacing fuses with automated line devices, pole inspection and replacement (when needed), line relocation, and/or hazard tree removal.
Distribution Feeder Hardening	Consists of strengthening structures, updating basic insulation levels to current standards, updating conductors to current standards, relocating difficult-to-access facilities, relocating or undergrounding facilities to address clearance encroachments. Oil-filled equipment is replaced as appropriate. Includes distribution feeder pole inspection and replacement activities.

Distribution Self-Optimizing Grid	Consists of three major components: capacity, connectivity, and automation intelligence. The capacity projects expand substation and distribution line capacity to allow for two-way power flow. The connectivity projects create tie points between circuits. The automation projects provide intelligence and control operations for the distribution grid to have the ability to automatically reroute power around trouble areas.
Distribution Underground Flood Mitigation	Consists of hardening existing underground line and equipment to withstand storm surge through installation of specialized stainless-steel equipment, submersible connections, and concrete pads with increased mass.
Distribution Vegetation Management	Consists of a system-wide program focused on trimming feeders and laterals on three and five-year cycles, respectively. The program includes: routine maintenance "trimming", hazard tree removal, herbicide applications, vine removal, customer requested work, and right-of-way (ROW) brush "mowing" where applicable.
Transmission Vegetation Management	Consists of removing and controlling vegetation within and along the transmission ROW to minimize the risk of vegetation-related outages. The program includes: planned threat and condition-based work, reactive work that includes hazard tree mitigation, and floor management (herbicide, mowing, and hand-cutting operation).
Transmission Structure Hardening	Consists of replacing all wood poles on the transmission system with non-wood structures. Also includes cathodic protection, performing structure inspections, automating gang operated air break switches, and upgrading towers, insulators, and overhead ground wire.
Transmission Substation Flood Mitigation	Consists of upgrading substation sites most vulnerable to flood damage using flood plain and storm surge data. New assets could include control houses, relays, total substation rebuilds to increase elevation, etc.
Transmission Substation Hardening	Consists of upgrading oil breakers to gas or vacuum to mitigate the risk of catastrophic failure and extended outages during extreme weather events. Also includes upgrading electromechanical relays to digital relays allowing for restoration of service more quickly from extreme weather events.

Figure 1 depicts the cost breakdown for each DEF SPP program over the 2026-2035 period. The Distribution Feeder Hardening and Lateral Hardening Programs account for 63 percent of the total SPP projected costs of $8.2 billion. The 10-year expected costs for the Feeder Hardening and Lateral Hardening Programs are $2.2 billion and $2.9 billion, respectively. The remaining three distribution SPP programs (Vegetation Management, Self-Optimizing Grid, and Underground Flood Mitigation) represent 9.0 percent of the total projected SPP costs, amounting to $731 million.

The transmission SPP programs account for 28 percent of the $8.2 billion of SPP projected costs, with the greatest expense of $1.6 billion occurring in the Transmission Structure Hardening Program. The remaining three transmission SPP programs (Vegetation Management, Substation Hardening, and Substation Flood Mitigation) total $707 million.

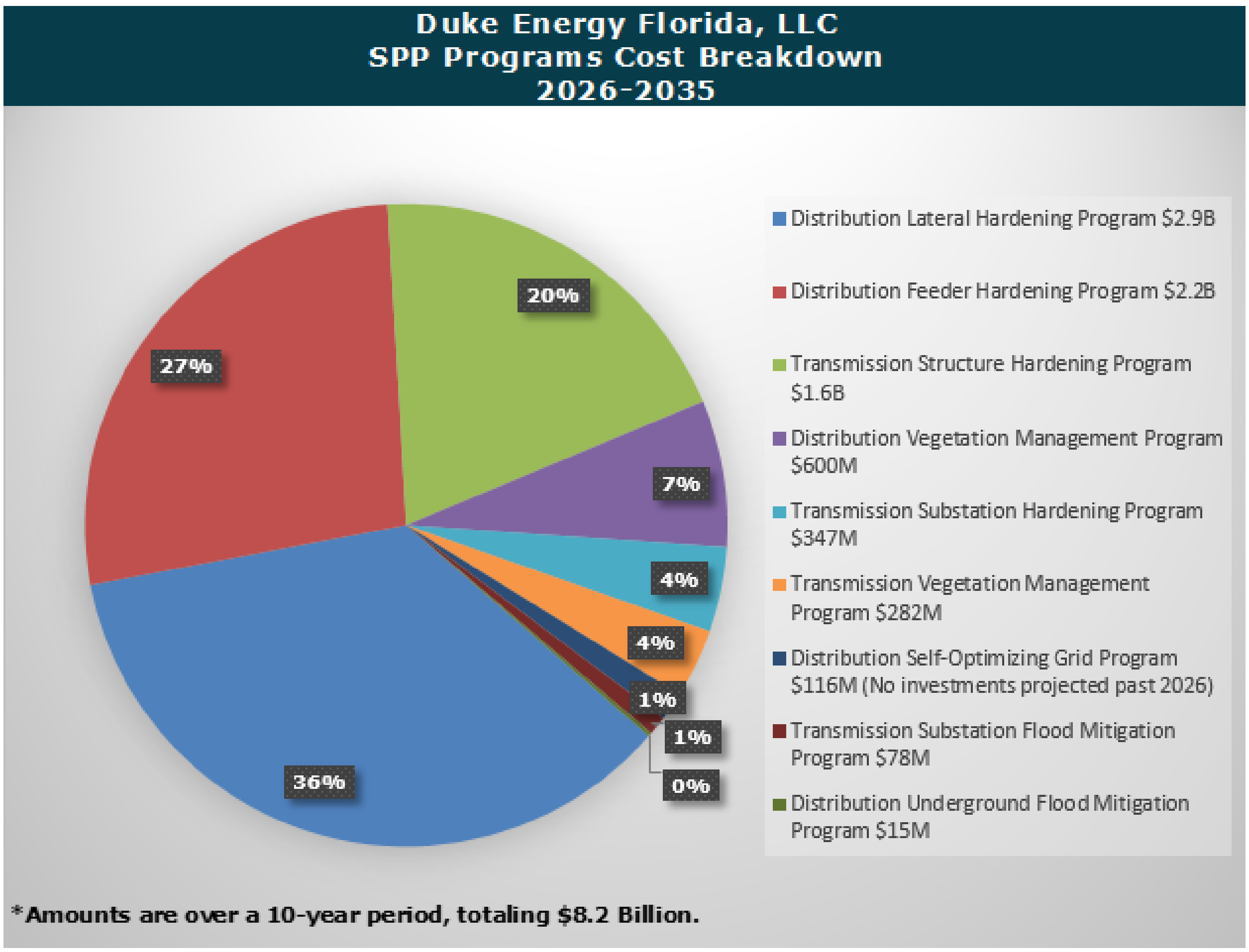

Figure 1 *Source: DEF's 2026-2035 SPP*

According to Rule 25-6.031(6)(b), F.A.C., storm protection plan costs recoverable through the clause shall not include costs recovered through the utility's base rates or any other cost recovery mechanism. **Table 1** depicts a breakdown of activities within each of DEF's SPP programs and its respective cost recovery mechanism (i.e., SPPCRC or Base Rates).

Duke Energy Florida, LLC Cost Recovery Comparison - SPPCRC vs. Base Rates 2026-2035			
SPP Program	**SPP Activity**	**SPPCRC**	**Base Rates**
Distribution Feeder Hardening (DFH)	Hardening feeders pursuant to criteria in approved SPP	X	
	Removing/retiring non-hardened assets		X
	Inspecting and replacing poles, upgrading structures/hardware, installing automated equipment, updating insulation and conductors, relocating inaccessible facilities and undergrounding facilities	X	
	QA/QC and performance monitoring mechanisms	X	
Distribution Lateral Hardening (DLH)	Hardening laterals pursuant to criteria in approved SPP	X	
	Removing/retiring non-hardened assets		X
	Inspecting and replacing poles, upgrading structures/hardware, installing automated equipment, updating insulation and conductors, relocating inaccessible facilities and undergrounding facilities	X	
	QA/QC and performance monitoring mechanisms	X	
Transmission Structure Hardening	Hardening structures pursuant to criteria in approved SPP	X	
	Removing/retiring non-hardened assets		X
	Replacing wood poles with non-wood such as steel or concrete	X	
	Replacing towers, performing cathodic protection, drone, and structure inspections, upgrading OH ground wires/GOAB switches	X	
	QA/QC and performance monitoring mechanisms	X	
Distribution Vegetation Management (DVM)	Conducting system-wide DVM of feeders (3-year cycle)	X	
	Performing targeted DVM of feeders (mid-cycle)	X	
	Conducting system-wide DVM of laterals (5-year cycle)	X	
	Trimming (routine maintenance/customer work requests), removing hazardous trees, applying herbicides, removing vines, mowing ROW	X	
	QA/QC and performance monitoring mechanisms	X	
Transmission Substation Hardening	Hardening substations pursuant to criteria in approved SPP	X	
	Removing/retiring non-hardened assets		X
	Upgrading oil breakers and electromechanical relays	X	
	QA/QC and performance monitoring mechanisms	X	
Transmission Vegetation Management (TVM)	Conducting system-wide TVM, including ROW	X	
	Performing targeted TVM work based on field assessments	X	
	Documenting TVM inspection results and findings, and executing NERC work plan (circuits 200 kV or higher)	X	
	Documenting TVM inspection results and findings, and executing DEF work plan (circuits less than 200 kV)	X	
	Trimming (routine maintenance/customer work requests), removing hazardous trees, applying herbicides, removing vines, mowing ROW	X	
	QA/QC and performance monitoring mechanisms	X	
Distribution Self-Optimizing Grid (DSOG)	Obtaining specialized software to reroute power around faults on line		X
	Removing and retiring non-hardened assets		X
	Increasing capacity on lines or creating additional tie points for circuits to allow power rerouting when faults occur	X	
	Installing upgraded automated switching devices	X	
	QA/QC and performance monitoring mechanisms	X	
Transmission Substation Flood Mitigation (TSFM)	Hardening substations pursuant to criteria in approved SPP	X	
	Removing/retiring non-hardened assets		X
	Elevating or modifying equipment or relocating substations	X	
	QA/QC and performance monitoring mechanisms	X	
Distribution Underground Flood Mitigation (DUFM)	Hardening facilities pursuant to criteria in approved SPP	X	
	Removing/retiring non-hardened assets		X
	Converting to submersible lines and equipment, elevating pad-mounted transformers and equipment	X	
	QA/QC and performance monitoring mechanisms	X	

Table 1 *Source: DEF's Response to DR 6.3*

C. SPP Program Prioritization Methodology/Modeling

DEF engaged Guidehouse, Inc., to serve as the primary technical and analytical consultant to support the development of its SPPs, providing modeling, economic analysis, and strategic recommendations to enhance grid resilience against extreme weather events. As part of its scope of work, Guidehouse refined the analytical methods for project selection and prioritization to target the most cost-effective grid-hardening solutions. It uses the following three-tiered framework to assess the effectiveness of proposed SPP programs and to inform the implementation prioritization process.

- **Risk Modeling** – Estimates expected frequency of asset failures under various weather conditions before and after the SPP programs are implemented.

- **Benefit-Cost Modeling** – Calculates projected cost savings and reliability benefits for proposed hardening programs to ensure that investments are cost-effective and would benefit customers by reducing outages and restoration costs.

- **Decision Analysis** – Projects benefit-cost ratios and uses them to rank projects and create a plan to determine the prioritization and deployment for the SPP programs.

The Risk Model involves conducting probabilistic weather modeling of three scenarios: normal, above-average, and high likelihoods of tropical storms and hurricane categories 1 through 5. This information is then combined with a spatial model of DEF's infrastructure to estimate probabilities of asset failures and the reductions in these probabilities as a function of storm hardening measures.

The second step, the Benefit-Cost Model, is applied to each SPP program and estimates a reduction in storm restoration costs and outage duration using Customer Minutes of Interruption (CMI) for each possible project location. The model uses Department of Energy's (DOE) Interruption Cost Estimate (ICE) Calculator to estimate interruption costs and the benefits associated with reliability improvements.

The final step is a Decision Analysis to rank projects and create an implementation plan for DEF to prioritize the work over the life of each SPP program based on performing the highest benefit work first. While DEF uses the model outputs to determine the optimum deployment plan, the Company must also consider factors such as current projects in the area, critical customers, operational knowledge, and resource availability and efficiency.

D. Storm Forensic Analysis

DEF conducts forensic storm analysis as a critical component of its storm protection strategy. The Company evaluates damage by collecting and analyzing data on the impact to the electrical grid, which helps prioritize repairs, estimate restoration times, and plan for future storm resilience. The costs are not recovered through the SPPCRC, but are instead included in specific storm cost recovery surcharges authorized by the Commission. The forensic analysis process includes:

- **Distribution System Analysis** of broken distribution poles, benchmarked data from other major storms over decades and across the country, and assessment of SPP hardened distribution circuits.

- **Transmission System Analysis** of failed transmission line assets. Analysis is triggered when either a transmission tower fails or five consecutive transmission wood poles fail.

The forensic analysis determines whether Commission-approved SPP programs provide increased transmission and distribution infrastructure resiliency, reduced restoration time, and reduced restoration cost. DEF deploys forensic patrollers to conduct and develop observations and findings, using Light Detection and Ranging (LiDAR) to compare post- to pre-storm scans, and using drones to determine storm impact. The Company’s prioritization of its SPP projects considers storm impacts and lessons learned from forensic analysis, where applicable. Once the analysis is complete, it is further used to:

- Identify specific materials, crews, and equipment needed for repairs.
- Determine estimated times of restoration.
- Assess the performance of storm-hardened facilities versus non-hardened ones.
- Differentiate reliability performance between overhead and underground systems.
- Inform future storm protection and hardening strategies.

E. SPP Program Improvements

Organization

DEF has made several organizational changes to better manage SPP work. There has been a focused effort on the Development teams who identify, scope, and plan the work. The Company has either restructured existing development teams or created new ones. According to DEF, this enables subprograms to be in sync, allowing for cost efficiencies, minimization of outages leading to less operational and system impact, and specialized employees to set up financial accounting to ensure accurate charging.

Improvements have been implemented to accurately develop SPP project cost estimates. For some work streams, a unit-cost focused team was created. For other work streams, a new independent estimating team was created. According to DEF, both teams have led to estimates with a much higher degree of accuracy than what was done in the initial years of SPP. The unit-cost team, for example, analyzed and updated data because it found estimates that were based on outdated information. Actuals, quotes, bids, etc., were used to determine the estimates. The teams also used multi-scenario costs to attain a more realistic blended average, if needed, for some programs and subprograms. The current SPP estimates now incorporate overhead allocations, engineering costs, and material loaders that were not captured with the original estimating process.

The early SPP targets provided only a few weeks of engineering lead time. DEF realized this was not enough time for estimating, cash flow forecasting, material procurement, permitting, etc. The Company established a process to allow for additional lead time for engineering and other activities to be completed. In some cases, the lead time could be up to two years depending on project complexities.

The teams working on DEF's SPP programs are separate from local operations. In the initial years of the SPP, the engagement with and from local operations was not as robust as today. This led to an opportunity to improve coordination and engagement between the teams helping to ensure consistent work prioritization. Regular engagement sessions with the operational stakeholders are conducted to educate and inform. Examples of these sessions included attending staff meetings to review SPP financials, annual meetings to review the SPP work plan, and monthly meetings on the status of work and communication of any escalations. DEF's current state has all levels of the organization taking ownership in the execution and placement of assets in service.

Given the volume of work to be executed (as well as global supply chain issues due to the pandemic), the SPP teams, in conjunction with the Supply Chain Organization, began purchasing some materials in advance of the planned execution year. This provided greater certainty of material availability ahead of the start date of project construction.

The Company implemented a forward purchase strategy in 2022 for the SPP programs to ensure project continuity and to mitigate uncertainty regarding material needs and availability for both DEF and its vendors. Through this strategy, the Company estimates expected material needs one year in advance and shares demand forecasts with its vendors. This enables vendors to validate and prepare for future material availability while allowing DEF to provide firm purchase commitments. If vendors fail to meet forecasted needs, DEF may explore alternative materials or suppliers.

Transmission

The SPP Wood Pole Replacement Subprogram went through several enhancements including improved planning and resource allocation through a balanced mix of internal construction crews and contract crews. This included the strategic incorporation of competitive bidding to enhance cost efficiency, maximize schedule performance, and ensure effective utilization of available resources across the subprogram work.

An additional improvement in the SPP Wood Pole Replacement Subprogram includes the transition from addressing individual wood poles across the entire transmission system to completing all wood pole replacements within a single circuit. This approach reduced mobilization and demobilization costs, enabled the shared use of matting (i.e., to create more stable terrain) and equipment with other SPP subprograms such as Overhead Ground Wire. The approach also allowed for early bulk material purchasing and improved overall efficiency and cost control of the SPP Wood Pole Replacement Subprogram. This has resulted in increased productivity of the subprogram leading to the planned completion date of 2028.

A formalized process for managing and executing distribution underbuild (secondary layers of infrastructure such as third-party attachments) work was established to assist in these activities within the SPP Wood Pole Replacement Subprogram. This process ensures consistent decision-making, coordination between transmission and distribution teams, and effective planning for future projects requiring underbuild considerations.

Transmission Substation Hardening projects are now developed as a single, consolidated project per location, when feasible. According to DEF, this process will improve tracking, reporting, preventing scope omissions, facilitating more accurate project and program management.

Distribution

A large increase in DEF permit requests in areas where SPP work was taking place led to delays due to increased volume and municipality inquiries. The creation of a full-time permitting lead helped manage inquiries and relationships with the municipalities to smooth out the permitting process, thereby allowing SPP work to be executed without hindrance.

In 2022, DEF implemented its Substation Optimization process, an execution strategy focusing on project not program-based work. This strategy identifies all work associated with a substation to be executed at the same time to maximize efficiencies with construction resources and limit extended impact to certain communities. The intent of substation optimization is to not return to that area with any planned work for a minimum of three to five years.

Initial SPP plans were for projects to be completed in a calendar year. After year one, it became clear that this was not feasible. Utilizing the Primavera P6 tool allowed DEF to be more granular in scheduling and identify the numerous activities required to place a project in service. In 2025, DEF implemented Primavera P6 activity updates required by program stakeholders. Metrics were developed to track performance around these activity updates. The intent is to drive stakeholder buy-in to the Primavera P6 process and improve overall forecasting and schedule adherence. Estimating continues to mature as well when comparing actual costs of in-service projects with estimates provided. DEF is continuously evaluating organizational structure to determine the most effective execution strategies for its SPP.

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III. SPP Governance

DEF has established a comprehensive governance framework for its SPP that encompasses multiple layers of oversight, risk management, contractor procurement, and performance monitoring. This framework has evolved significantly, particularly following organizational changes in March 2024 that consolidated transmission and distribution programs under the Power Grid Operations (PGO) Florida organization.

The governance framework includes financial controls to prevent double recovery between base rate revenue and SPPCRC revenue. DEF uses an asset management organization to select targets using prioritization methodology and follows "Plan, Do, Check, Adjust" principles, reviewing jobs during construction for design improvement and cost reduction opportunities.

For all SPP programs, except vegetation management, DEF leverages Duke Energy's corporate Project Management Center of Excellence (PMCoE) procedures. Projects are managed through their lifecycle which includes initiate, commit, build, and close as the primary phases. Each phase follows a documented approval process, up to the highest level of approval required. The adherence to these standards facilitates enhanced engineering oversight, improved project controls, streamlined communications, reduced service disruptions, mitigation of repeat site visits, and improved construction resource efficiency. For SPP vegetation management programs, DEF uses various policies and procedures, along with multiple training documents, process flows, and job aids related to work management.

DEF's distribution programs follow PGO Distribution Policies and Procedures developed with business unit-specific information in compliance with Corporate/Enterprise standards. Transmission programs follow PGO Transmission Project Management Processes and Procedures and applicable sub-processes.

A. Duke Energy Florida, LLC's SPP Organization

PGO Florida is headed by a Senior Vice President. Key management positions for DEF's SPP transmission programs include the Vice President of Transmission Construction & Maintenance, General Manager of Transmission Projects, and General Manager of Transmission Engineering. Similarly, key positions for DEF's SPP distribution programs include the Vice Presidents of Distribution Zones and a General Manager of Distribution Projects and Engineering.

The General Managers for Transmission and Distribution Projects and Engineering report to a Vice President of Region Services. Oversight responsibilities for both operations include the execution of capital projects for grid upgrades, system planning, and asset and resource management. All transmission and distribution SPP programs are currently developed and managed by the Region Services organization with the support from Operations organization and additional input from Enterprise support teams.

Regularly scheduled meetings with PGO leaders are held to review metrics on project performance, regulatory commitments, and the overall capital plan. The Enterprise teams provide data analytics and oversight to ensure estimates and cost assumptions are consistent.

DEF’s SPP Transmission and Distribution Vegetation Management Programs operate under an integrated structure with the entire PGO Vegetation Organization reporting to one General Manager. Vegetation management oversight is provided through dedicated expertise responsible for the design and implementation of vegetation management standards and specifications. All SPP vegetation management activities are primarily captured in its Workforce Planning & Analytics System (WorkPASS), which streamlines worker verification, onboarding, and site access management for compliance and efficiency.

DEF performs monthly management reviews of actual and estimated performance data using variance spreadsheets and makes any necessary adjustments to realign with project budget, scope, and goals. The performance status of all the remaining transmission and distribution SPP projects is reported monthly to a Project Review Board (PRB) that consists of senior leadership. DEF’s vegetation management team reviews the monthly status of transmission and distribution vegetation management programs and measures against key performance indicators. DEF’s Vegetation Management team reviews the program’s financials and workplan status with leadership separate from the PRB meeting.

B. Management Oversight and Contractor Procurement

DEF employs a standardized contractor oversight process for all SPP programs to ensure quality execution and performance management. Cost estimates and expenses are reviewed and trued-up annually in the SPPCRC proceeding for regulatory compliance and transparency.

The Company established protocols for engaging with contractors to supplement workload that would otherwise require increased staffing levels. The contractor procurement process varies depending on the type of work, project value, and specific program requirements. The process is designed to ensure competitive bidding, fair terms, and effective contractor management across all SPP programs.

DEF’s Purchasing Controls Policy defines the roles, responsibilities, and requirements related to the procurement process, including the sourcing process, contract formation, segregation of duties, and standards of business conduct. For work that exceeds $250,000, a competitive bidding process is conducted unless a Master Service Agreement is already in place.

Master Service Agreements for native contractors are generally established for multi-year terms (e.g., a period of three years), while contract terms for non-native contractors may vary based on project needs, ranging from short-term engagements to longer-duration support. Both native and non-native contractors supporting DEF's SPP programs may also perform work on non-SPP activities, including outage restoration (black-sky days), new development/construction, and other system improvement projects For black-sky days, DEF prioritizes the use of native resources already working on the system followed by the deployment of non-native resources.

To distinguish from SPP and non-SPP work, DEF uses a unique identifier in its financial and asset accounting systems for work performed specific to SPP. The identifier is used to ensure SPP project capital and O&M expenses are recovered through the SPPCRC.

C. SPP Project Variances

Project schedules and completion dates may change based on the actual circumstances and conditions encountered or required for a specific jobsite to ensure that resources are being efficiently used. DEF attempts to mitigate the impacts of any variance in the schedule and costs by either accelerating or delaying projects to ensure the SPP program meets its overall objectives. The Company has developed a variance threshold of plus or minus 10 percent to identify areas needing improvement. The mitigating actions help keep the program on track and within budget, despite the various challenges that arise in individual projects.

Projects may be accelerated to maintain overall program objectives when other projects face delays. If other projects are completed at lower costs, the subsequent projects are accelerated to ensure resource efficiency. Project acceleration may also be prompted based on unanticipated availability of permits, engineering estimates, materials, third-party resources and restrictions (e.g., limited work times), and favorable field conditions and construction alignment.

On the contrary, projects may be delayed. Obtaining and limitations of land-use permits and property easements to allow access to public or private land present challenges. Constraints imposed by permitting agencies may require work along high-traffic roadways to be performed overnight to minimize public safety risks. To mitigate permitting issues, DEF works with third-parties and public works departments. To resolve easement issues, the Company requires contractors to perform all project work within ROWs, or within pre-approved DEF easements shared with other utilities.

Extreme weather conditions may cause resources on SPP projects to be reassigned to restoration services or provide mutual assistance to other utilities. An unanticipated condition on a jobsite, such as projects adjacent to environmentally sensitive areas or in higher density locations, may impede the ability to complete a project on schedule. Increases in cost of materials, contract labor, supply chain constraints, and resource availability also impact project schedule completion.

Although variances can occur at any time during a project, every project has a projected timeline, cost, and identified project elements that must be closely monitored. DEF's program managers continuously monitor, identify, and remedy unanticipated issues and delays with projects. The Company has implemented a continuous improvement model to review forecasts for any inaccuracies and make adjustments to work plans accordingly. DEF completes an Apparent Cause Analysis (ACA) to review and seek process improvement when goals were not met as planned. The Company follows up to validate that changes made are providing improvement to the workflow process. Specific improvements include:

- Adding a dedicated estimating team to provide individual estimates for work streams by feeder rather than only using historical completion data.

- Implementing scheduling software (Oracle's Primavera P6) to improve scheduling forecast and accuracy.

- Monitoring changes in the numbers of units to be installed as work moves from planning to design to construction completion.

- Completing design work sooner for future work to improve unit and cost accuracy.

D. Budget Monitoring and Materials/Inventory Management

Through project management and project control organizations, including the appropriate FERC accounting procedures, budget monitoring and variance tracking occur throughout an SPP project lifecycle. With the exception of vegetation management, if SPP distribution program project completion estimates are forecasting overspends, program stakeholders may choose to scale back work, discuss overrun with contractors, use different material suppliers, or closely monitor costs.

If transmission and distribution SPP programs are not within budget, DEF may make several corrective actions including:

- Controlling cost through review and true-up of each project estimate.
- Rescheduling projects or activities between years.
- Applying change control process to update project scope, schedule, or cost changes.
- Engaging stakeholders to facilitate decision-making on tradeoffs.
- Performing cost analysis to identify where and why overruns or underspending occurred.

For the SPP vegetation management programs, monthly actual expenditures are compared to monthly projections for year-to-date variance and reviewed with management to make adjustments depending on variance to budget.

DEF manages materials and inventory for SPP programs through its standard Supply Chain Organization operations process, without requiring specific processes for individual SPP programs. The Company implemented a forward purchase strategy in 2022 for the SPP programs to ensure project continuity and to mitigate removal of uncertainty regarding material needs and availability for both DEF and its vendors. Through this strategy, the Company estimates expected material needs one year in advance and shares demand forecasts with its vendors. This enables vendors to validate and prepare for future material availability while allowing DEF to provide firm purchase commitments. In the event vendors cannot meet the required forecasted need, DEF can begin looking for alternative materials or vendors.

E. External/Internal Audits, QA/QC Process, and Risk Assessments

Since the inception of DEF's SPP in 2020, one external and one internal audit pertaining to the Company's SPP Transmission Vegetation Management (TVM) were performed. The external audit was a compliance audit performed by the Southeastern Electric Reliability Corporation (SERC) in 2022. The audit resulted in one Open Enforcement Action, three recommendations, and positive findings pertaining to transmission substation facility ratings. SERC subsequently verified that DEF implemented corrective actions.

The internal audit also performed in 2022 evaluated the QA/QC processes in place to validate the appropriate completion of TVM work. The audit primarily focused on Duke Energy Carolinas and Duke Energy Progress.[2] However, data analytics were leveraged to evaluate QA on reactive work across all jurisdictions, including DEF. The audit report found no regulatory compliance issues, but recommended that effective TVM monitoring mechanisms be implemented via use of integrated software, WorkPASS, to establish QA accountability and improve execution. The audit report notes that corrective management actions were to be completed by October 31, 2022. According to DEF, all of these actions have since been completed.

a. Transmission Quality Assurance/Quality Control Processes

Transmission contractors are responsible for QA/QC field audits on work-in-progress and completed construction projects. Contractors document evidence throughout the construction process that work has been installed to specifications and tested as required. Digital photographs are required for identified defects. If a project design change is required, the contractor is required to obtain a Construction Authorization Exception approval. These approvals are subject to a subsequent QA/QC field audit by a Contractor Specialist to ensure compliance. This process also verifies that final construction meets specifications, as-builts are properly documented, redline prints are attached when applicable, and jobsites are left in a clean and safe condition.

The contractors are also required to perform QA/QC inspections on a randomly selected sample of work (e.g., at least one percent of transmission poles inspected). Upon DEF's review of the inspection results, any deficiencies must be remedied by the contractor prior to subsequent QA/QC validation. Depending on the level of noncompliance, DEF may implement a Performance Improvement Plan to prevent the problem from recurring. Transmission QA/QC activity costs associated with SPP program execution are recovered through the SPPCRC. Additionally, the Company has a transmission quality audit process that is under development with a target completion by the third-quarter of 2026.

b. Distribution Quality Assurance/Quality Control Processes

DEF's Construction Managers perform QA/QC field audits on work-in-progress and completed construction projects. The audits are conducted on a random basis, with work orders selected weekly in each management area. For tasks with up to 10 inspection locations, a minimum of 5 locations are audited (or 100 percent for 5 or fewer). For 10-20 inspection locations, at least 50 percent are audited. For over 20 locations, at least 25 percent (but not less than 10) are audited.

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[2] Duke Energy formally asked regulators for permission to merge the two utilities into a single operating company effective January 1, 2027.

The contractors are required to randomly select at least one percent of all poles inspected for QA/QC inspections that are to be performed weekly or bi-weekly. If a project design change is required, the verification process described above for transmission would also apply to distribution. For any deficiencies reported based on the audited work orders, the managers review corrections to validate that all issues have been resolved. The distribution construction quality audit results are summarized using an internal PowerBI tool that can generate reports for periodic review. Distribution QA/QC costs are recovered through the SPPCRC.

c. Risk Assessments and Event Analyses

DEF performs risk assessments on SPP distribution projects to identify and correct deficiencies before advancing to distribution engineering. DEF uses a project workbook to manage, track, and document all phases of a construction project. Within the workbook is a template that identifies potential risks, probability of occurrence (i.e., low, medium, or high), mitigating actions, and a contingency plan for each risk.

In 2022, the Company used four event analysis tools to supplement contractor oversight for performing SPP work:

- Prompt Investigation Response Team is used for significant events to determine and communicate immediate learnings, preserve evidence, and establish immediate actions.

- Brief Cause Analysis is used to determine probable causes of poor performance.

- Apparent Cause Analysis is used to determine apparent cause, impact, and corrective actions to mitigate recurrence.

- Common Cause Analysis is used to evaluate a set of data collectively for common cause drivers and establish corrective actions.

These tools allow DEF to review and seek process improvement when DFH and other program and subprogram goals are not met as planned. Since 2022, DEF has completed five ACA investigations which include Substation Optimization projects involving certain substations and associated SPP DFH and other hardening program activities. The scope of work included the hardening of distribution feeder circuits, removing/setting poles, and installing specialized equipment. The ACA results include numerous process improvements necessary for more effective management of project scope, schedule, and cost. DEF has implemented some of the corrective actions, with others pending completion.

In early 2025, DEF's project execution team reinforced communicating and tracking contractor project performance against the Regulatory In-Service Date for each distribution project. The team has weekly or bi-weekly status update meetings and measures performance by comparing the actual level of construction activity to the project schedule. If current level of construction is estimated to exceed the Regulatory In-Service Date, the team may implement mitigating actions, such as assigning additional resources, to meet project completion requirements. To date, DEF encountered one instance where a contractor was removed from a DFH project due to not tracking with the Regulatory In-Service Date timeline.

For Vegetation Management programs, monthly Key Performance Indicators are monitored, and completed work is field validated with QA assessments performed by Duke Energy representatives to ensure scope and specification adherence.

F. Project Management Software

A comprehensive suite of management software systems are used that span across several different functional areas such as project management, work tracking, performance monitoring, analysis, and operational control. Oracle Primavera P6 is used as a scheduling tool to focus on the work that is ongoing. It is integrated with IBM's Maximo Work Management System (WMS) that is used to track projects through their complete life cycles. Specific accounting project codes assigned in WMS are linked to DEF's financial and asset accounting systems, allowing the Company to track costs by both project and program.

Another interactive software platform, PowerBI, allows DEF to connect to data sources, transform data, and create interactive reports and dashboards. Specific PowerBI dashboards and reports can be built for utilities to monitor Key Performance Indicators, optimize resources, and reduce costs.

DEF's Distribution Control Center also operates several critical operational control software systems:

- Outage Management System (OMS)
- Supervisory Control and Data Acquisition (SCADA)
- Distribution Management Systems (DMS)

The Company's OMS determines customer outages based on customer reporting, current technology, and predictive analytics. DEF's SCADA system provides real-time monitoring, alarming, and control of field devices, and its DMS creates accurate real-time field pictures of the distribution system.

Certain high-volume transmission and distribution work that is routine in nature, such as feeder and lateral hardening inspections and pole replacements, are established as blanket projects within DEF's asset accounting system. Each blanket project is assigned a unique work order number to ensure proper cost tracking.

For SPP vegetation management work (both transmission and distribution) DEF has established multiple blanket projects within its asset accounting system to track various types of charges. All SPP vegetation-related costs are assigned to these dedicated blanket projects, which are flagged as SPP and kept separate from base rate projects.

Certain vegetation management job plans, such as Distribution Hazard Tree Removal, may initiate work orders in DEF's WMS. When a work order is created, the system automatically populates default accounting information, including the project ID, based on the selected job plan. Finance maintains a list of valid job plans and their corresponding accounting details within

WMS. This list determines which types of work can be charged to the blanket SPP project. DVM contractors are allocated based on regional zones, where typically one contractor manages all work requirements within their designated area.

Following the set-up processes described above, DEF's Project Controls and Finance teams monitor charges to these projects to identify any missing or incorrect designators. There is a tool in DEF's financial and asset accounting systems to capture any work orders that may be missing these designators or are wrongly assigned so that DEF can correct them as soon as possible.

IV. Distribution Lateral Hardening Program

A. Program Initiatives

DEF's distribution grid is the final network of poles, wires, transformers, and substations that deliver electricity from the high-voltage transmission grid to individual homes, businesses, and industries. A distribution *lateral* is a smaller branch line that extends from a main *feeder* (trunk) line to distribute power to specific areas or individual homes.

The Company's SPP Distribution Lateral Hardening (DLH) program is a long-term initiative that was established in 2020, with actual project construction beginning in 2022. The program focuses on reinforcing its lateral/branch lines to better withstand extreme weather events by reducing outage frequency, improving resilience, and speeding up restoration.

Pursuant to DEF's 2026-2035 SPP Plan, the estimated 10-year cost is approximately $2.9 billion. It is estimated that approximately 800 miles of overhead hardening, 500 miles of undergrounding, and 41,300 pole replacements will be completed during the 2026-2035 10-year plan. The program targets 12,000 miles of lateral lines throughout DEF's service territory and is estimated to take approximately 70 years to complete. The program completion horizon will be reviewed again during the production of DEF's SPP 2029 filing.

After deployment of the 2026-2035 DLH program work, DEF estimates it will reduce CMI by 152-190 million minutes annually. The Company also estimates that it will reduce the restoration cost of extreme weather events on the distribution system by $19.5-$24.4 million annually based on today's costs.

B. Prioritization Methodology

The DLH program employs two main prioritization strategies: lateral underground hardening and lateral overhead hardening. Laterals that are chosen for undergrounding are those most prone to damage during extreme weather events and are in high vegetation areas or inaccessible locations. Overhead hardening of laterals is performed on those less prone to vegetative damage.

Lateral Underground Hardening

When a large portion of an existing overhead lateral line is inaccessible to trucks, has heavy vegetation coverage, or a combination of both, it would be a candidate for lateral underground hardening. DEF considers relocating laterals from the rear of properties to the front for underground construction. Neighborhood boundaries are also taken into consideration to avoid some streets having designs for both overhead and underground lines.

With the aid of DEF's GIS and Guidehouse's weather simulation model (discussed in **Chapter II**), lateral segments most prone to weather damage are prioritized for undergrounding. These lateral lines are converted from an overhead radial network to an underground loop network.

A distribution radial network is the simplest electric grid design where power flows in one direction from a substation to feeders, laterals, and customers. It is cost-effective and easier to operate, but less reliable because any service outages or disruptions along the feeder will affect the entire group of customers. **Figure 2** depicts the configuration of a distribution overhead radial system.

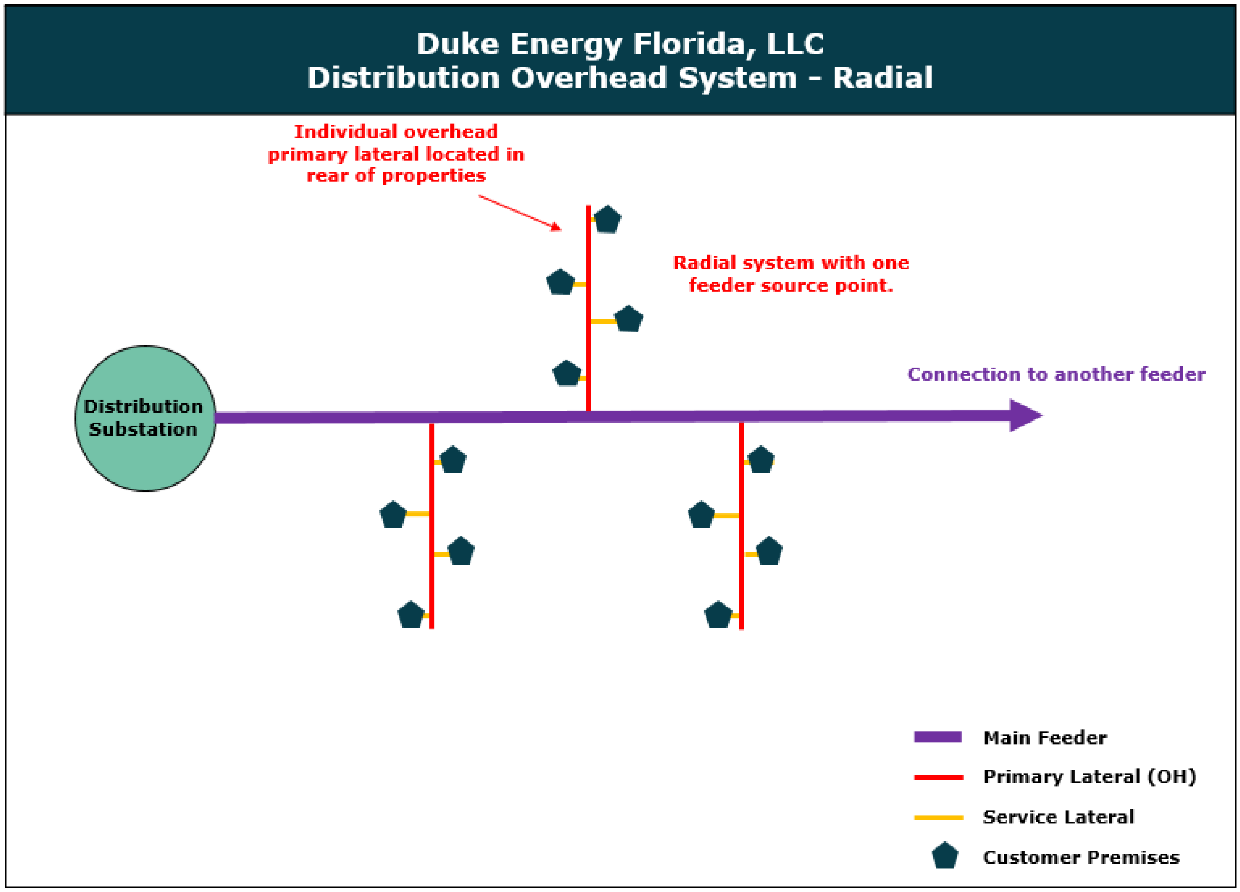

Figure 2 *Source: DEF's Response to Commission Audit Staff's DR 2.11 and 2.12*

In contrast, a looped network, shown in **Figure 3**, is more expensive than a radial network because more distribution equipment and facilities (e.g., switches and conductors) are required; however, the added redundancy contributes to a more stable and reliable power supply. The network is designed to provide customers electricity through a continuous, closed circuit, creating an alternative path for the electricity to flow. Through the use of remote switches and reclosers (i.e., an automated circuit breaker that detects interruptions), if Feeder 1 fails, electricity can continue to flow from Feeder 2 of the loop to ensure continuity of service to customers.

DEF uses a targeted undergrounding strategy that focuses on only the individual high-outage overhead laterals downstream from a feeder. Hence, DEF does not underground *all* laterals downstream of a main feeder, only those meeting undergrounding criteria as shown in **Figure 3.**

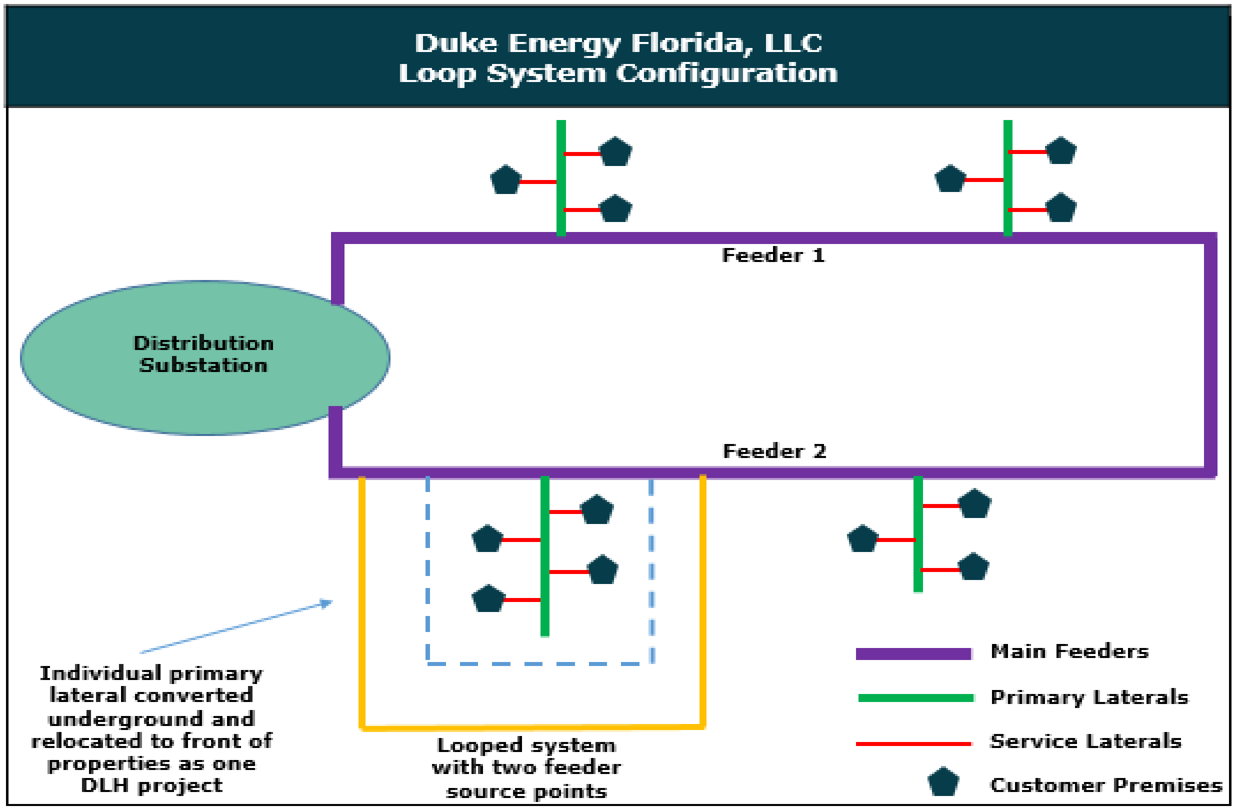

Figure 3 *Source: DEF's Response to Commission Audit Staff's DR 2.11 and 2.12*

Lateral Overhead Hardening

DEF's lateral overhead hardening strategy involves prioritizing and upgrading the existing overhead radial laterals to make them more resilient to severe weather events. The process includes the following seven key activities:

- Structure strengthening
- Conductor upgrading
- Upgrading secondary wires
- Fusing
- Hazard tree removal
- Pole inspections and replacements (when needed)
- Line relocation

Structure strengthening includes upgrading existing poles and other facilities as necessary to align with the current National Electric Safety Code (NESC) extreme wind loading standard. Other related hardware upgrades will occur simultaneously, such as installation of insulators, crossarms, support brackets, and guy wires.

Conductor (power line) upgrading is the process of replacing deteriorated conductors on laterals that are prone to outages due to brittle composition and replacing them with more durable, or higher-capacity materials that meet the current NESC extreme wind loading standard.

Upgrading secondary wires is an activity of eliminating older open secondary wires (i.e., bare or lightly insulated conductors) and replacing them with modern triplex cable (i.e., a cable with three conductors twisted together). A secondary wire on a power line carries the low-voltage electricity from the local transformer down to the customer's home or business. This activity will eliminate an older design standard that is susceptible to wires contacting vegetation and debris.

Fusing is the replacement of "one-time" use fuses with an Automated Line Device (ALD). One-time fuses must be physically replaced, unlike an ALD which is a smart grid device capable of automatically reclosing a circuit. The ALD senses trouble on the power line, such as a short circuit or temporary fault, automatically shuts off and then attempts to restore power.

A hazard tree is a tree that is dead, structurally unsound, dying, diseased, leaning, or otherwise in a condition that is likely to result in striking electrical lines or other assets. Once identified, hazard trees are assigned to a contractor for remediation.

Pole inspections and replacements are safety and maintenance procedures to assess structural integrity, checking for decay, damage, and equipment issues using visual checks, hammering (sounding), digging (excavation), and drilling (boring) to determine the extent of pole decay and any associated loss of strength. DEF performs pole inspections of its feeders and laterals on an eight-year cycle.

Line relocation of lateral power lines are performed in areas hard to access by truck. Power lines in these inaccessible areas are among the most expensive to repair and take the longest to restore power due to their location.

C. Management Oversight

The SPP DLH overhead and underground project/program teams, in conjunction with financial and project controls organizations, have responsibility for overall project management. This oversight includes activities such as scheduling, planning, executing, tracking and monitoring project performance, and implementing any necessary corrective action to ensure projects remain on schedule and within budget.

The Company also conducts event analyses on SPP projects for process improvement. This and other management oversight information are discussed in **Chapter III**.

D. Analysis of Projects and Costs

In DEF's SPP Annual Status Reports filed with the Commission, the company provides a breakdown of its DLH program data by:

- Lateral (circuit) Hardening-Overhead/Underground
- Pole Inspections and Replacements

Section 1 below examines the number of lateral (circuit) hardening-overhead/underground projects/activities, circuit miles, and associated costs. Section 2 examines the number of pole inspections, replacements, and associated costs. The hardening activities involve replacing decayed poles that fail to meet minimum structural and strength requirements.

1. Distribution Lateral (Circuit) Hardening-Overhead/Underground

Table 2 depicts the number of DEF's SPP DLH-OH/UG program projects/activities and associated costs as reported in the Company's SPP Annual Status Reports for each year 2020 through 2024. The planned and completed projects/activities shown in the table represent completed construction circuits (projects), engineering, and partially constructed circuits (activities).

DEF defines a DLH overhead and underground *completed project* each as comprised of all the planned lateral hardening overhead and underground work associated with their respective feeders. The company defines a *completed activity* as partial construction on circuits and engineering activities. These activities reflect work-in-progress as opposed to a completed project (i.e., an entire hardened circuit).

Commission audit staff inquired as to why the number of projects/activities completed can exceed those planned for the same year. According to DEF, the Company does not plan for all SPP projects/activities to begin and finish in the same calendar year. Contributing factors include the size and scale of the targeted projects/activities, lead time needed for engineering, material procurement, resource scheduling, construction, and closeout activities (e.g., invoice reconciliation).

The number of projects/activities planned versus those projects completed may also differ based on variances that occur. Projects/activities may be accelerated or delayed driven by permitting issues, weather conditions, outage availability, or strategic reprioritization. As a result, some projects/activities planned for a future year may be completed early, while others may carry over into the next year, leading to a higher number of completions than originally planned for the year.

The projects/activities data shown in the table for each calendar year represent the DLH program *activities* for hardening projects either initiated, in various stages of construction, or completed. Because the data is reported in the aggregate, Commission audit staff could not determine the number of *activities* that result in *completed projects*. Additionally, the costs in the table for each year represent only those that were incurred within the same year for the identified projects/activities. Projects, however, typically span multiple years. Therefore, the number of *completed projects* not only has to be separately identified in the table, but the total costs for the *completed projects* would also have to be identified for the Commission to assess performance on a cost per project (circuit) basis.

Duke Energy Florida, LLC SPP Distribution Lateral Hardening-OH/UG Program Projects/Activities Planned and Completed 2020–2024				
Year	**Projects/ Activities Planned (Circuits)**	**Projects/ Activities Completed (Circuits)**	**Estimated Cost ($M)**	**Actual Cost ($M)**
Overhead Hardening				
2020	0	0	$0.0	$0.0
2021	0	0	$0.0	$2.0[1]
2022	28	71	$64.0	$38.2
2023	82	104	$87.4	$94.5
2024	113	168	$87.5	$72.4
Total	**223**	**343**	**$238.9**	**$207.1**
Underground Hardening				
2020	0	0	$0.0	$0.0
2021	0	0	$0.0	$2.9[1]
2022	25	53	$99.5	$56.4
2023	27	79	$40.0	$68.1
2024	24	90	$112.4	$13.3
Total	**76**	**222**	**$251.9**	**$140.7**

[1]Engineering costs only.

Table 2 *Source: SPP Annual Status Reports and Response to DR2.16*

DEF began preliminary DLH program planning and engineering design work in 2020 and 2021. Actual construction projects began to be completed in 2022, with more being completed in 2023. For the five-year period 2020-2024, DEF completed 565 overhead and underground hardening projects/activities at a cost of $347.8 million.

In 2021, DEF initiated engineering designs on projects/activities expected to begin construction in 2022. The Company incurred total costs of $4.9 million for engineering and material purchasing for projects expected to start in 2022.

In 2022, DEF completed engineering and construction work on 71 overhead and 53 underground projects/activities. Total 2022 engineering and construction costs amounted to $94.6 million. The Company projected $163.5 million for 2022 costs. The DLH overhead hardening variance was primarily driven by three factors: scarcity and needed materials due to increased demand from both within and outside the utility industry, lack of availability of the raw materials needed to manufacture the assets, and resource constraints at the manufacturing facilities. The undergrounding variance between total projected and actual costs was primarily due to two factors: inability to obtain DLH undergrounding easements from customers and material availability, including poles.

In 2023, DEF completed engineering and construction work on 104 overhead and 79 underground projects/activities. Total 2023 engineering and construction costs amounted to $162.6 million. The Company projected $127.4 million for 2023 costs. The variance between projected and actual costs is primarily due to higher per unit costs related to an increase in the cost of material and labor.

In 2024, DEF completed engineering and construction work on 168 overhead and 90 underground projects/activities. Total 2024 engineering and construction costs amounted to $85.7 million. The Company projected $199.9 million for 2024 costs. The variance between projected and actual costs is primarily due to lack of transformer availability for DLH undergrounding projects and impacts of Hurricanes Debby, Helene, and Milton on both undergrounding and overhead resource allocations.

Table 3 shows the number of lateral miles planned and completed for hardening during each year 2020-2024. The miles completed in each year shown in the table may include costs incurred in prior years for engineering and materials to prepare for construction deployment. Therefore, the calculation of an annual actualized cost per mile would not be accurate due to project durations and costs spanning across multiple years. Over the five-year period, DEF completed the hardening of 305 overhead and underground lateral miles representing about 2.5 percent of the lateral miles throughout its entire service territory.

Duke Energy Florida, LLC SPP Distribution Lateral Hardening-OH/UG Program Projects/Activities, Units, and Costs 2020–2024					
Year	**Projects/ Activities Completed (Circuits)**	**Units Planned (Miles)**	**Units Completed (Miles)**	**Estimated Cost ($M)**	**Actual Cost ($M)**
Overhead Hardening					
2020	0	0	0	$0.0	$0.0
2021	0	0	0	$0.0	$2.0[1]
2022	71	136	54	$64.0	$38.2
2023	104	144	116	$87.4	$94.5
2024	168	101	98	$87.5	$72.4
Total	**343**	**381**	**268**	**$238.9**	**$207.1**
Underground Hardening					
2020	0	0	0	$0.0	$0.0
2021	0	0	0	$0.0	$2.9[1]
2022	53	79	9	$99.5	$56.4
2023	79	28	26	$40.0	$68.1
2024	90	61	2	$112.4	$13.3
Total	**222**	**168**	**37**	**$251.9**	**$140.7**

[1]Engineering only.

Table 3 *Source: SPP Annual Status Reports and SPPCRC filings*

2. Distribution Lateral Pole Inspections and Replacements Hardening

Prior to 2022, DEF's pole inspection and replacement activities included both lateral and feeder poles with all costs recovered through base rates. In 2022, DEF formally incorporated the lateral pole inspection and replacement activities into the DLH program to strategically align the work and increase efficiencies. **Table 4** shows the number of SPP distribution pole inspections and replacements completed during each year, 2022 through 2024, along with their respective project costs as reported in DEF's SPP Annual Status Reports.

All replacements and associated costs each year are based solely on wood pole inspection failures identified in that same year. Some replacements are carried over into the following year.

For example, poles inspected late in the fourth quarter may require more time for engineering and construction after being identified for replacement. If a pole requires extended time for engineering, permitting, or coordination with overlapping SPP programs, its replacement may roll into the subsequent year. DEF's most recent eight-year pole inspection cycle began in 2022, and according to the Company, the subprogram is currently on schedule and within budget.

Duke Energy Florida, LLC SPP Distribution Lateral Pole Inspections/Replacements Subprograms Projects and Costs – Estimated vs. Actual 2022–2024					
Year	**Subprogram**	**Inspection/ Replacement Planned**	**Inspection/ Replacement Completed**	**Est. Cost ($M)**	**Act. Cost ($M)**
2022	Pole Inspections	90,567	71,039	$4.2	$2.7
	Pole Replacements	5,143	2,113	$40.7	$18.1
2023	Pole Inspections	77,591	70,710	$2.8	$2.9
	Pole Replacements	7,058	7,303	$70.6	$67.1
2024	Pole Inspections	72,569	69,667	$2.9	$2.8
	Pole Replacements	6,545	5,639	$69.3	$41.6
Total	**Pole Inspections**	**240,727**	**211,416**	**$9.9**	**$8.4**
	Pole Replacements	**18,746**	**15,055**	**$180.6**	**$126.8**

Table 4 *Source: 2020-2024 SPP Annual Status Reports and DR2.25*

In 2022, DEF completed 71,039 lateral hardening pole inspections instead of the planned 90,567. The costs totaled $2.7 million instead of the previously projected $4.2 million. These variances were primarily driven by completing less units than planned due to onboarding a new pole inspection vendor, lowering unit costs, and moving to a circuit-based work plan to align with other SPP programs.

The Company also completed 2,113 lateral hardening pole replacements instead of the planned 5,143. The costs totaled $18.1 million instead of the previously projected $40.7 million. These variances were primarily driven by material availability constraints.

In 2023, DEF completed 70,710 lateral hardening pole inspections instead of the planned 77,591. The costs totaled $2.9 million instead of the previously projected $2.8 million. The Company completed fewer inspections than planned at a higher cost due to an increase in labor costs.

In 2024, DEF completed 69,667 lateral hardening pole inspections of the planned 72,569. The Company was impacted by three major hurricanes (Debby, Helene and Milton) during 2024, which required resources to be properly assigned to storm restoration work for a period of time. The Company also completed 5,639 lateral pole replacements instead of the planned 6,545 pole replacements. These lateral pole replacements totaled a cost of $41.6 million instead of the previously projected $69.3 million. The primary driver of this variance was that fewer lateral poles were rejected than previously estimated, leading to reduced costs.

Over the three-year period, total costs for pole inspections were $8.4 million, $1.5 million less than the estimated $9.9 million. Actual costs for pole replacements amounted to $126.8 million, $53.8 million less than the estimated $180.6 million.

V. Distribution Feeder Hardening Program

A. Program Initiatives

DEF's distribution feeder circuits are an essential component for transmitting power, balancing load, and regulating voltage to provide efficient, safe, and reliable electric service to customers. These circuits also protect against outages through installed devices that isolate and restore fault conditions. The Commission approved the Company's Distribution Feeder Hardening (DFH) Program in 2020, with implementation beginning in 2021.

The purpose of the DFH program is to strengthen prioritized feeders to meet the NESC extreme wind loading standards. The program includes inspecting and replacing poles with stronger poles, upgrading hardware (e.g., insulators, cross arms, support brackets, and guys), upgrading insulation and conductors to current standards, relocating difficult-to-access facilities, addressing clearance encroachments, and replacing oil-filled equipment with more modern equipment such as dry-type protective equipment.

The annual pole inspection and replacement performance metrics are presented in the SPP Distribution Pole Inspections and Replacements Subprogram data tables in Section D of this chapter. As part of this subprogram, DEF conducts a wind-loading audit on distribution poles with joint-use attachments. The audit is conducted on an eight-year cycle to determine if the existing structural analysis meets wind-loading requirements. The annual inspections of the poles, including guyed poles, are conducted in a specific area by region. It is estimated that 62,000 distribution poles with joint-use attachments are to be inspected annually.

Over the period 2020 through 2024, the Company hardened 325 miles, which is about five percent of the feeder backbone. For DEF's current 2026-2035 SPP initiatives, the Commission approved a joint stipulation between DEF and OPC in June 2025 to reduce the hardening scope targets of 1,400 feeder miles and 15,000 pole replacements in 2026. A reduction of 10 to 13 percent is intended to offset customer rate impact. DEF estimates that it will take 50 years to complete, covering approximately 6,300 miles on over 1,300 feeders. The program completion horizon will be reviewed again during the production of DEF's SPP 2029 filing

The estimated cost for DEF's DFH program during the 2026-2035 period is $2.2 billion. After deployment of the 2026-2035 DFH program work, DEF estimates it will reduce CMI by 20 million to 25 million minutes annually. The Company also estimates that it will reduce the restoration cost of extreme weather events on the distribution system by $7.6 million to $9.5 million annually based on today's costs.

B. Prioritization Methodology

To prioritize the hardening of feeders, DEF uses the third-party Guidehouse model as previously discussed in **Chapter II**. The model uses reliability history and provides a 10-year forward-looking plan focused on SPP hardening work. Commission audit staff notes that DEF does not use as an input its three-percent worst performing feeder list[3] when selecting and prioritizing SPP feeder hardening projects because those are addressed through base rate electric reliability work. DEF compares the three-percent feeder list to feeders planned to be hardened through the SPP DFH program to avoid duplication of efforts.

In 2022, DEF implemented a Substation Optimization project process. It is integrated with the Guidehouse model which serves as the input mechanism that selects and prioritizes feeders for Substation Optimization projects. The process examines all distribution-level components from the substation outward and selects the associated feeders with the greatest opportunity for improvement. Any other remaining feeders from the substation that are on the priority list are expedited for hardening under the DFH program and pole inspection/replacement subprograms.

In addition to feeder hardening, a Substation Optimization project may include self-optimizing grid and lateral hardening projects. These projects associated with the specific substation are executed by the respective SPP program and subprogram teams in coordination with the construction crews to increase cost effectiveness. Substation Optimization project work orders use specific job types, project types, and class codes within the Maximo and PowerPlan systems, distinguishing them from standalone SPP work and from base-rate projects. However, all SPP project work orders, including standalone and those executed under a Substation Optimization project, carry unique SPP flags that identify them as recoverable through the SPPCRC.

Commission audit staff notes that if reconfiguration of a feeder and associated laterals is necessary, the DFH project would not be part of the Substation Optimization process and would be considered a standalone project due to the additional preliminary work (i.e., engineering, permitting, scheduling) that would be needed.

As a component of its SPP Distribution Pole Inspections and Replacements Subprogram, DEF conducts prioritized inspections of distribution poles with joint-use attachments on an annual basis. The poles selected to be modeled for a wind-loading structural analysis are those having the most visible loading, such as longest or uneven span length, greatest number of joint-use cables, and large equipment.

DEF's multi-faceted prioritization process enables its DFH program and subprograms to focus on the most cost-effective and beneficial projects to improve grid resilience and overall service reliability.

C. Management Oversight

Like the DLH program, an SPP DFH project/program team has responsibility for overall project management. Oversight includes scheduling, planning, executing, tracking and monitoring project performance, and implementing any necessary corrective action to ensure projects remain on schedule and within budget.

[3]Rule 25-6.0455, F.A.C. requires each IOU to file data regarding its three-percent worst performing feeders.

During the design phase of a DFH program project, DEF performs a structural analytical test using modeling software, such as PoleForeman, to determine if larger poles are required due to extreme wind-loading conditions. The Company employs specialized software to analyze feeders to ensure compliance with NESC extreme wind-loading standards. The Company also uses a Target Management Tool to maintain and confirm target selection for overhead or underground sections of feeder hardening projects.

The Company conducts event analyses on SPP projects for process improvements. Since transitioning from a program-based work plan to a Substation Optimization project process in 2022, the Company completed five ACA investigations as discussed in **Chapter III**. These investigations included projects involving certain substations and associated SPP DFH and other hardening program activities.

D. Analysis of Projects and Costs

In DEF's SPP Annual Status Reports filed with the Commission, the company separates its DFH program into two components:

- DFH Feeder (Circuits) Hardening
- DFH Pole Inspections and Replacements

Section 1 below examines the number of feeder hardening projects/activities, circuit miles, associated costs, and completed projects by location. The hardening activities include replacing deteriorated or undersized conductors, burying vulnerable lines underground, updating basic insulation levels to current standards, and replacing oil-filled equipment with modern alternatives (e.g., dry-type transformers). Section 2 examines the number of pole inspections, replacements, and associated costs.

Commission audit staff notes that all completed DFH projects are "overhead designed", although certain feeder segments may require undergrounding due to clearance or easement issues or if the feeder needs to be relocated from an inaccessible area to a location with underground facilities. For these instances, DEF records the associated capital costs in its utility accounts designated for underground distribution assets. All of DEF's feeders hardened as of year-end 2024 have required some segments to be undergrounded.

1. Distribution Feeder (Circuit) Hardening

Table 5 depicts the number of DEF's SPP DFH program projects/activities and associated costs as reported in the Company's SPP Annual Status Reports for each year 2020 through 2024. Commission audit staff notes that DEF reported Pole Inspection and Replacement Subprogram costs for 2020 and 2021 in the aggregate of base rates and SPPCRC. Base rate costs reflect the removing and retiring of the non-hardened assets. The costs shown for the 2022 through 2024 period for both the pole inspections and replacements were recovered through SPPCRC only.

The planned and completed projects/activities shown in the table represent completed construction circuits (projects), engineering, and partially constructed circuits (activities).

Duke Energy Florida, LLC SPP Distribution Feeder (Circuit) Hardening Program Projects/Activities Planned and Completed 2020–2024				
Year	**Projects/ Activities Planned (Circuits)**	**Projects/ Activities Completed (Circuits)**	**Estimated Cost ($M)**	**Actual Cost ($M)**
2020	0*	0*	$2.4	$0.7
2021	17	17	$59.5	$35.7
2022**	42	85	$79.4	$57.1
2023	78	125	$145.5	$139.9
2024	117	174	$157.6	$219.3
Total	**254**	**401**	**$444.4**	**$452.7**

*Engineering only.
**Prior to 2022, pole inspections/replacements included both laterals and feeders.

Table 5 *Source: SPP Annual Status Reports and Response to DR 2.28*

DEF defines a *completed project* as the entire hardened feeder circuit that carries electricity along feeders connected at various tie points from the same substation to the customer. In other words, although a circuit typically consists of multiple feeders, when the circuit is fully hardened, it is counted as one completed project regardless of the number of individual feeders hardened on that circuit.

The company defines a *completed activity* as partial construction on circuits and engineering activities. These activities reflect work in progress as opposed to a completed project. DEF began preliminary DFH program planning and engineering design work in 2020 and 2021. The first construction projects were completed in 2022. The Company completed 85 construction projects in 2022 and 125 in 2023. For the five-year period, DEF completed a total of 401 hardening projects/activities.

Like the DLH program the number of projects/activities completed can be higher (or lower) than the number planned for the same year because the Company does not plan for all of them to begin and finish in the same year. Contributing factors include the size and scale of the targeted projects/activities, project reprioritization, permitting issues, weather conditions, outage availability, lead time needed for engineering, material procurement, resource scheduling, construction, and closeout activities (e.g., invoice reconciliation).

Table 5 also depicts the estimated and actual associated annual costs for the projects/activities. Similar to the DLH program, the DFH costs for each year in the table represent only the costs that were incurred for the identified projects/activities reported within the same year. Completed projects/activities may have costs in prior years such as engineering and procuring materials to prepare for construction deployment. Hence, the actual costs for a projects/activities for each year shown in the table do not represent the true costs for those projects/activities shown. Commission audit staff, therefore, could not assess performance on a cost per project (circuit) basis.

In 2020, DEF initiated engineering designs on feeder hardening projects expected to begin construction in 2021. The Company incurred $0.7 million of costs for engineering compared to the estimated engineering costs of $2.4 million. DEF planned to complete 40 percent of the total proposed engineering work in 2020 for the 2021 work plan but instead completed only 12 percent. The variance was attributed to the timing related to program setup factors such as training, employee and contractor placement, and standards updates.

In 2021, the variance between the estimated costs of $59.5 million and actual costs of $35.7 million is due to completing less construction work than anticipated. DEF experienced delays in onboarding new vendors, and lasting impacts from the ongoing pandemic at that time.

For 2022 and 2023, actual costs were lower than estimated because DEF experienced a scarcity in the needed materials. There was an increased demand from both within and outside the utility industry, lack of availability of the raw materials needed to manufacture the assets (wood, steel, chemicals, etc.), and resource constraints at the manufacturing facilities. The material availability constraints, such as wood poles not being available, continued to impact the pace of construction work in 2023, requiring design adjustments for the more prevalent spun concrete pole usage. DEF has begun the transition back to wood poles from spun concrete poles in 2026.

The 2024 actual costs of $219.3 million were substantially greater than the estimated $157.6 million. This resulted from DEF being able to work on more feeders than projected because the Company was not able to complete its planned DLH work due to transformers not being available. DEF also noted that it planned on completing even more feeder hardening but was delayed due to Hurricanes Debby, Helene, and Milton impacts.

Table 6 shows the number of feeder miles planned and completed for hardening each year 2020-2024. Similar to the DLH program an annual cost per mile could not be computed based on the total feeder hardening costs provided in the Company's SPP Annual Status Reports. DEF noted that the miles completed in each year shown in the table may include costs incurred in prior years for engineering and materials to prepare for construction deployment. The calculation of an annual actualized cost per mile would not be accurate due to project durations and costs spanning across multiple years. Over the five-year period, DEF completed the hardening of 325 feeder miles representing about five percent of the feeder miles throughout its entire service territory.

Duke Energy Florida, LLC SPP Distribution Feeder Circuit Hardening Projects/Activities, Units, and Costs 2020-2024					
Year	**Projects/ Activities Completed (Circuits)**	**Units Planned (Miles)**	**Units Completed (Miles)**	**Est. Cost ($M)**	**Act. Cost ($M)**
2020	0	0	0	$2.4	$0.7*
2021	17	56.4	47.0	$59.5	$35.7
2022	85	93.0	38.0	$79.4	$57.1
2023	125	168.0	76.0	$145.5	$139.9
2024	174	198.0	164.0	$157.6	$219.3
Total	**401**	**515.4**	**325**	**$444.4**	**$452.7**

*Engineering only.

Table 6 *Source: DEF's Response to Commission Audit Staff's DR 3.16*

Table 7 depicts the percentage of feeders hardened broken down by DEF's four management areas for each year 2022 through 2024. No data is reported for 2020 and 2021 because only the initial program planning and engineering design work occurred during this period. As shown in the table, the percentages of feeders hardened in each region accelerated in year 2024, up from 8 to 82 feeders hardened (925 percent increase). This significant increase was a result of program ramp up. However, DEF expects the feeder hardening completion percentage to level off moving forward. This resulted in a 4.3 percentage point increase in the cumulative share of total feeders hardened over year 2023. For the three-year period shown in the table, the Company has hardened 106 distribution feeders, representing 7.7 percent of the total distribution feeders within its entire service territory.

Duke Energy Florida, LLC SPP Distribution Feeder Hardening Program Completed Projects by Location 2022–2024				
Management Area	**Total Feeders**	**Feeders Hardened**	**Percentage of Area Feeders Hardened**	**Percentage of Total Feeders Hardened**
2022				
North Central	314	4	1.3%	0.3%
North Coastal	335	2	0.6%	0.4%
South Central	433	5	1.2%	0.8%
South Coastal	291	5	1.7%	1.2%
Total	**1,373**	**16**		**1.2%**
2023				
North Central	314	0	0%	1.2%
North Coastal	335	3	0.9%	1.4%
South Central	433	5	1.2%	1.7%
South Coastal	291	0	0%	1.7%
Total	**1,373**	**8**		**1.7%**
2024				
North Central	314	20	6.4%	3.2%
North Coastal	335	18	5.4%	4.5%
South Central	433	24	5.5%	6.3%
South Coastal	291	20	6.9%	7.7%
Total	**1,373**	**82**		**6.0%**
2022-2024				
North Central	314	24	7.6%	4.7%
North Coastal	335	23	6.9%	6.3%
South Central	433	34	7.9%	8.8%
South Coastal	291	25	8.6%	10.6%
Total	**1,373**	**106**		**7.7%**

Table 7 *Source: DEF's Response to Commission Audit Staff's DR 3.14*

2. Distribution Feeder Pole Inspection and Replacement Hardening

Prior to 2022, DEF's pole inspection and replacement activities included both lateral and feeder poles with all costs recovered through base rates. In 2022, DEF formally incorporated only the feeder pole inspection and replacement activities into the DFH program to strategically align the work and increase efficiencies. **Table 8** shows the number of distribution pole inspections and replacements completed during each year, 2022 through 2024, along with their respective project costs as reported in DEF's SPP Annual Status Reports.

All replacements and associated costs each year are based solely on wood pole inspection failures identified in that same year. Some replacements are carried over into the following year. For example, poles inspected late in the fourth quarter may require more time for engineering and construction after being identified for replacement. A pole replacement may be carried over into a subsequent year if the pole requires extended time for engineering, permitting, or coordination with overlapping SPP programs. DEF's most recent eight-year pole inspection cycle began in 2022, and according to the Company, the subprogram is currently on schedule and within budget.

Duke Energy Florida, LLC SPP Distribution Pole Inspections/Replacements Subprograms Projects and Costs – Estimated vs. Actual 2022–2024					
Year	**Subprogram**	**Inspection/ Replacement Planned**	**Inspection/ Replacement Completed**	**Est. Cost ($M)**	**Act. Cost ($M)**
2022	Pole Inspections	31,857	24,961	$1.5	$0.9
	Pole Replacements	1,826	457	$14.5	$4.9
2023	Pole Inspections	24,501	30,900	$0.9	$1.1
	Pole Replacements	1,730	1,249	$17.3	$15.9
2024	Pole Inspections	28,221	21,366	$1.1	$0.8
	Pole Replacements	1,955	855	$20.7	$7.9
Total	**Pole Inspections**	**84,579**	**77,227**	**$3.5**	**$2.8**
	Pole Replacements	**5,511**	**2561**	**$52.5**	**$28.7**

Table 8 *Source: 2020-2024 SPP Annual Status Reports and DR 2.25*

In 2022, DEF moved to a circuit-based work plan to better align with other SPP programs in addition to lower unit costs. By 2023, DEF completed more inspections than planned in preparation for the 2024 pole replacement work, enabling inspection information to be available sooner. For 2022 and 2023, fewer poles were in need of replacement than planned.

In 2024, the Pole Inspection and Replacement Subprogram was impacted by three major hurricanes (Debby, Helene and Milton), which required resources to be properly assigned to storm restoration work for a period of time.

Over the 2022 through 2024 period, total SPPCRC costs for pole inspections were $2.8 million, $0.7 million less than the estimated $3.5 million. Actual costs for pole replacements amounted to $28.7 million, $23.8 million less than the estimated $52.5 million. The primary driver of the variances in this subprogram was that fewer feeder poles were rejected than previously estimated, leading to cost savings and fewer units needing replacement compared to the prior estimate.

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VI. Distribution Self-Optimizing Grid Program

A. Program Initiatives

The purpose of DEF's SPP Distribution Self-Optimizing Grid (DSOG) Program is to transform the distribution system into a self-healing network. Although the program activities result in hardened feeders, DEF reports DSOG activities as a separate SPP program with its own benefit-cost analysis and target selection. The DSOG program consists of two distinct subprograms:

DSOG Automation (DSOG-A) – Installing automated switching devices on feeders, such as reclosers that communicate with SCADA systems, to segment feeders into smaller line segments to reduce the number of customers affected by extended outages.

DSOG Capacity & Connectivity (DSOG-CC) – Installing conductor tie points and increasing feeder capacity (reconductoring) to enable the grid to dynamically reconfigure around impacted areas and restore service to customers.

The DSOG-A and DSOG-CC components work together to automatically restore power to as much of the grid as possible while isolating the section of the feeder with the fault condition. By the end of 2026, DEF expects to have approximately 80 percent of its distribution feeders hardened with self-optimizing grid functionality to automatically reroute power around damaged line sections (e.g., a tree on a power line). The coordination between the installed automated rerouting and switching devices will further reduce outage times and restoration costs during extreme weather events.

In DEF's 2026-2035 SPP, the Company estimated DSOG costs of $116 million by year-end 2026, with no additional investments projected past 2026 until consideration of multiple factors. Such factors include, the availability of labor, materials, DEF personnel, and potential program continuation to a greater proportion of the distribution system. After deployment of the currently planned DSOG program work, DEF estimates CMI will be reduced by 32 million to 40 million minutes annually.

B. Prioritization Methodology

DEF's prioritization process for its DSOG program is similar to its process for DFH. DEF uses the Guidehouse model, data analytics, and subject matter experts to determine the probability of damage, consequence of damage, consequence of automation, and project deployment plan. Each DSOG project begins with its initiation phase followed by the engineering design, permitting, scheduling, material requisitioning, construction, and closeout phases.

C. Management Oversight

The SPP DSOG project/program team, in conjunction with financial and project controls organizations, has responsibility for overall project management. Project oversight includes scheduling, planning, executing, tracking, monitoring, and implementing any necessary corrective action to ensure projects remain on schedule and within budget.

DEF uses a range of policies and procedures to provide oversight of its DSOG program deployment, cost controls, and accounting. The DSOG program follows standardized Power Grid Operations – Distribution policies and procedures for implementation and management, with comprehensive quality assurance documents and construction quality audits in place since the early 2000s, and Apparent Cause Analyses (ACAs) for process improvement.

DEF also tracks program-level reliability improvements as they relate to its DSOG program. Performance reporting involves analyzing faults that occur within the self-healing network that have automated fault isolation within a given circuit and the capability for that circuit to be energized from another circuit within the network. Each self-healing event is analyzed using various engineering and electrical logic/control tools. The analysis focuses on determining how effectively the DSOG upgrades performed fault location, isolation, and service restoration to reduce the number of customers impacted by the outage.

To address project completion and cost variances, DEF develops and applies certain mitigation measures. The Company monitors and reviews the applied measures to determine whether they are achieving the intended results or need to be altered.

D. Analysis of Projects and Costs

Table 9 shows the DSOG-A and DSOG-CC program projects and costs for the 2020 through 2024 period. For 2020 and 2021, DEF reported program costs in the aggregate of SPPCRC and base rates. The base rate costs are for SPP activities associated with removing and retiring non-hardened assets. Program costs for 2022 through 2024 are SPPCRC only. Over the five-year period, 2,045 DSOG-A and 59 DSOG-CC program projects/activities were completed, totaling $220.4 million and $139.0 million, respectively.

Duke Energy Florida, LLC SPP Distribution Self-Optimizing Grid Program Projects and Costs – Estimated vs. Actual 2020–2024				
Program	**Projects/ Activities Planned**	**Projects/ Activities Completed**	**Est. Cost ($M)**	**Act. Cost ($M)**
2020				
DSOG-A (Installs)	156	410	$35.6	$33.4
DSOG-CC (Miles)	N/A[1]	N/A[1]	$20.9	$33.0
Total	**156**	**410**	**$56.5**	**$66.4**
2021				
DSOG-A (Installs)	741	378	$52.2	$34.3
DSOG-CC (Miles)	N/A[1]	N/A[1]	$26.7	$23.9
Total	**741**	**378**	**$78.9**	**$57.2**
2022				
DSOG-A (Installs)	632	238	$45.9	$32.4
DSOG-CC (Miles)	27	6	$27.9	$11.5
Total	**659**	**244**	**$73.8**	**$43.9**
2023				
DSOG-A (Installs)	746	280	$52.8	$53.9
DSOG-CC (Miles)	40	27	$31.2	$32.4
Total	**786**	**307**	**$83.0**	**$85.3**
2024				
DSOG-A (Installs)	944	739	$43.9	$66.4
DSOG-CC (Miles)	36	26	$35.6	$38.2
Total	**980**	**765**	**$79.5**	**$104.6**
Total 2020-2024				
DSOG-A (Installs)	**3,219**	**2,045**	**$230.4**	**$220.4**
DSOG-CC (Miles)	**103**	**59**	**$142.3**	**$139.0**

[1]Prior to 2022, DSOG-CC projects not individually tracked for reporting purposes.

Table 9 *Source: Response to Commission Audit Staff's DR 3.18*

In 2020, total DSOG-A and DSOG-CC actual costs amounted to $66.4 million, compared to an estimated $56.5 million. The primary driver of this variance was work on DSOG-CC projects that were completed ahead of schedule. In 2021, total construction costs amounted to $57.2 million, compared to the projected $78.9 million. The difference is attributed to work completed in 2020 ahead of schedule and pandemic-related disruptions, which caused unforeseen resource and material constraints.

Total 2022 actual costs amounted to $43.9 million versus an estimate of $73.8 million. The lack of resources and the availability of raw materials needed to manufacture assets, from both within and outside the utility industry, constrained the Company's SPP hardening operations. The lack of material availability continued into 2023, which impacted DEF's ability to meet its estimates.

In 2024, total actual costs of $104.6 million exceeded the estimated $79.5 million by $25.1 million. According to DEF, the Company completed additional work on DSOG-A installations, but those installations were not recognized as "complete" until placed in-service in the subsequent year; the timing of which typically lags construction in the field.

With regard to the variances discussed above, there were other factors outside of the Company's control that led to completion delays such as municipality permitting and easement acquisitions. DEF has improved its DSOG program by:

- Sourcing primary/secondary suppliers for materials.
- Increasing engineering resource scoping/planning.
- Coordinating with the Distribution Control Center for switching requests.

Commission audit staff notes that units completed in each year shown in the table may include costs incurred in prior years for engineering and materials to prepare for future construction deployment. Therefore, the calculation of an annual actualized cost per unit for the DSOG work would not be accurate due to project durations and costs spanning across multiple years.

VII. Distribution Underground Flood Mitigation Program

A. Program Initiatives

DEF's SPP Distribution Underground Flood Mitigation (DUFM) Program is a targeted initiative designed to enhance the resilience of underground electric systems in flood-prone areas by hardening existing facilities to withstand storm surge and flooding during extreme weather events.

The program focuses on the following activities to minimize equipment damage caused by storm surge and flooding, thereby reducing customer outages and restoration costs:

- Installing specialized stainless-steel equipment and submersible connections.
- Replacing conventional lines and switchgear with submersible lines and switchgear.
- Implementing waterproof (submersible) connections and stainless-steel tie downs.
- Constructing pads with increased weight to provide enhanced stability.

The program upgrades existing non-submersible underground distribution assets with new submersible underground assets and applies other storm surge and flood proofing measures such as sealing ducts and equipment enclosures. Each project circuit location includes upgrading the pad-mounted transformer to a stainless-steel corrosion-resistant transformer located on a loop-fed circuit. The loop-fed circuit reduces outages during extreme weather events because an impacted transformer can be isolated from other transformers on the loop so they can remain energized to serve customers.

Although the program experienced significant delays due to material availability issues, particularly with stainless-steel pad-mounted transformers, DEF was able to eventually secure the needed materials in 2025 to allow construction to resume. The Company estimates that it will take 30 years to complete infrastructure hardening at locations identified as having a high risk of flooding. The program completion horizon will be reviewed again during the production of DEF's SPP 2029 filing.

The estimated costs for DEF's DUFM program during the 2026-2035 period is $15 million. The program is expected to reduce CMI by approximately 0.6-0.8 million minutes annually. Additional benefits include reducing the restoration costs associated with extreme weather events on the distribution system by approximately $0.8-$1.0 million annually.

B. Prioritization Methodology

DEF defines a DUFM program project by the substation associated with the transformers to be upgraded and may use the identification of the feeders that serve the transformers for reference purposes. The Company typically considers all transformers downstream of a substation bank in an eligible floodplain area to be a single project. DEF may split the project into more than one if the scope becomes too large to reasonably manage. Each project begins with its initiation phase followed by the engineering design, permitting, scheduling, material/equipment procurement, construction, and closeout phases.

DEF employs the Guidehouse model to identify and prioritize its DUFM projects. DEF's subject matter experts further refine and optimize the deployment plans using the model outputs while considering several practical factors:

- High-Risk Flood Locations – Targets areas identified as high-risk for flooding.
- Current Projects in Area – Coordination with existing work to maximize efficiency.
- Critical Customers – Prioritizing locations serving essential services and facilities.
- Operational Knowledge – Leveraging field experience and system understanding.
- Resource Availability/Efficiency – Considering workforce capacity/logistical constraints.

They further evaluate other projects served from the same substation to identify opportunities with deployment within the next three to four years, allowing for coordinated implementation.

C. Management Oversight

DEF has established management oversight processes and procedures for its DUFM and other SPP programs. The Company uses its PMCoE procedures, as discussed in **Chapter III**, and enforces general compliance requirements related to safety, contractor oversight, physical and cybersecurity, environmental regulations, etc. It also employs a range of policies and procedures to provide oversight of program deployment, cost controls, and accounting.

DEF representatives perform DUFM QA/QC assessments to validate completed field work. The Company also maintains a construction quality audit process and stores the audit results in an internal database for periodic review. It also has independent third-party auditors assigned to projects who conduct spot audits during construction and full audits as work orders are completed. The SPP project managers are responsible for ensuring that follow-up actions are taken to resolve any identified audit issues. QA/QC activity costs are recovered through the SPPCRC.

D. Analysis of Projects and Costs

Table 10 shows the number of DEF's DUFM projects/activities planned and completed along with estimated and actual costs for the years 2020 through 2024. Commission audit staff notes that the Company did not incur any actual costs in 2020 and 2021 as work was projected to begin in 2022.

Duke Energy Florida, LLC SPP Distribution Underground Flood Mitigation Program Projects and Costs – Estimated/Actual 2020–2024						
Year	Projects/Activities Planned		Projects/Activities Completed		Estimated Cost ($M)	Actual Cost ($M)
	Circuits	Installs	Circuits	Installs		
2020	1	0	0	0	$0.3	$0.0
2021	0	0	0	0	$0.0	$0.0
2022	3	49	3	0	$0.8	$0.3
2023	3	49	4	0	$0.5	$0.2
2024	7	0	4	0	$0.3	($0.3)
Total	**14**	**98**	**11**	**0**	**$1.8**	**$0.2**

Table 10 *Source: DEF's Response to Commission Audit Staff's DR 4.18*

DEF's DUFM program faced significant delays in 2022 primarily due to material availability issues. The main challenge was the procurement of stainless-steel pad-mounted transformers. The Company incurred $0.3 million of engineering costs for three feeder circuits without any construction being performed.

In mid-year 2023, without the needed quantities of transformers, DEF continued with its engineering work in preparation for the eventual construction phase. The Company incurred $0.2 million of engineering costs for four circuits without any construction work being performed. It projected $0.5 million for three circuits with 49 pad-mounted transformer installs. DEF took steps to mitigate material availability constraints of stainless-steel pad mount transformers by expanding to international vendors, refurbishing retired transformers, and prioritizing installation of transformers during actual construction.

In 2024, the Company completed some additional engineering. However, the DUFM program was impacted by multiple hurricanes. DEF, therefore, returned transformers into inventory to address high-priority work for storm restoration and the demand from new customers. Hence, the actual program costs for 2024 reflect a credit of $0.3 million.

Commission audit staff notes that in 2025, stainless-steel pad-mounted transformers became available and construction began.

Table 11 lists recent flood mitigation projects for the 2025 through 2029 period. It identifies six projects along with their location, number of pad-mounted transformer installs, and completion dates. Since acquiring the stainless-steel transformers in 2025, the Company completed the hardening of the Port Richey West substation. As shown, other projects are either ongoing or planned.

Duke Energy Florida, LLC SPP Distribution Underground Flood Mitigation Program Projects – Completed and Ongoing/Planned 2025-2029			
Substations	**Location**	**Transformer Installs**	**Completion Date**
Port Richey West	North Coastal	49	10/2025
Ongoing Projects			
Flora-Mar	North Coastal	124	5/2026
Northeast	South Coastal	133	1/2027
Homosassa-Tropic	North Coastal	164	12/2027
Planned Projects			
Bayboro South-Vinoy	South Coastal	152	2028
Seminole	South Coastal	118	2029

Table 11 *Source: DEF's Response to Commission Audit Staff's DR 4.15*

VIII. Distribution Vegetation Management Program

A. Program Initiatives

The single largest cause of electric power outages is fallen or wind-blown trees and limbs. Preventing trees and vegetation from encroaching on overhead conductors and triggering power outages is critical for maintaining service reliability. DEF’s SPP Distribution Vegetation Management (DVM) Program promotes system reliability through increased levels of vegetation maintenance over historical levels, reduced storm restoration costs, and improved day-to-day reliability.

The estimated costs for DEF’s DVM program during the 2026-2035 period are $600 million. No avoided restoration costs or CMI reduction benefits are explicitly tied to the DVM, as these benefits are captured in the overall total for the distribution program.

The program consists of an Integrated Vegetation Management (IVM) approach for managing 18,000 miles of distribution lines within 35 counties. The IVM approach incorporates a combination of both cycle-based maintenance and reliability-driven prioritization of work to enhance overall resiliency, focusing on trimming feeders and laterals on three and five-year cycles, respectively. Additional IVM initiatives include hazard tree removal, reactive work, and routine maintenance.

The Three-Year Cycle is designed to reduce tree-related outages by inspecting and selectively trimming approximately 1,900 miles of distribution feeders annually. The Five-Year Cycle targets the trimming of 2,450 miles of distribution laterals annually. Commission audit staff’s analysis of DEF’s DVM trim cycles is discussed in Section D of this chapter.

To enhance its feeder vegetation management program, DEF implemented a mid-cycle program in 2006. The program includes patrolling, maintaining, and mitigating hazard trees and areas where vegetation grows rapidly and may not be controlled effectively within the DVM Three-Year Cycle for feeders. Hazard trees are defined as dead, diseased, dying, structurally unsound, leaning, or otherwise defective trees that could strike electrical lines or equipment if they fall. Certified arborists conduct hazard tree assessments.

Hazard trees identified within and outside the ROW are removed annually by June 1 each year before hurricane season. Trees outside the ROW require landowner approval prior to removal. Once the landowner is notified and grants permission, tree removal is scheduled for completion before hurricane season whenever possible.

Cyclical and mid-cycle maintenance are each performed by five contractors throughout DEF’s system. These contractors follow the *ANSI 300 Tree Care Standards* for pruning, *ANSI Z133: American National Standards Institute for Arboricultural Operations*, the guide *Pruning Trees Near Electric Utility Lines,* and Occupational Safety and Health Administration (OSHA) requirements.

DEF defines reactive work as any vegetation-related work not previously documented or planned requiring action before the next scheduled maintenance to mitigate any potential safety or reliability issues. Reactive work consists of internal requests (e.g., resulting from hazards identified during ground and aerial inspections conducted by DEF) and external customer requests for vegetation work due to non-extreme weather events, non-scheduled emergencies, etc. DEF requires its contractors to provide a separate workforce with appropriate skill and size to complete reactive work requests daily.

Reactive work requests are assigned to the reactive crew for field evaluation. If actionable, work is then assigned to the reactive crew with instructions. Within 10 business days of receiving a customer-generated reactive work order, the contractor will initiate contact with the customer/property owner providing them with a status update of the request and document the communication. Customer-generated reactive work orders requiring work should be completed within 180 days.

To reduce outages on the distribution ROW, DEF conducts routine DVM maintenance by managing vegetation growth and removing vegetation likely to interfere with system operations during extreme weather. Complementing cyclical maintenance, hazard tree removal, and reactive work, routine maintenance is performed. This maintenance consists of vine removal, herbicide application, and ROW brush "mowing" where applicable.

DEF's Right Tree, Right Place Initiative is a partnership program between DEF, its customers, and local government. The program educates and encourages stakeholders to choose appropriate locations for planting trees potentially avoiding any future outages. The initiative is designed more for customer interaction and messaging and is not a separately budgeted program. Costs for the program are not included in the SPPCRC.

B. Prioritization Methodology

As part of the Integrated Vegetation Management (IVM) approach within its DVM program, DEF employs a comprehensive circuit prioritization model designed to reduce tree-related outages. This model targets feeders and laterals with the highest risk ratings. The prioritization process considers both historical and projected performance, using factors such as the number of tree-related outages in previous years, outages per vegetated mile, and total customer minutes of interruption caused by trees.

Using the reliability-based prioritization model combined with cycle-based maintenance, DEF creates its DVM annual work plan typically in the summer for work to be performed during the next year. DEF communicates the annual work plan to the contractor in November of the preceding year work is to be completed.

Going forward, DEF's DVM program aims to leverage advanced technologies such as remotely sensed imagery (i.e., satellite) and modeling to develop a condition-based maintenance strategy. This type of modeling evaluates vegetation density in proximity to conductors, previous tree-caused outages, equipment configuration, and time since last pruning to determine the risk of a future tree-caused outage and the best time to prune. This will help DEF optimize the annual work plan.

C. Management Oversight

The General Manager of PGO Vegetation Management organization has overall responsibility for the Company's DVM (and Transmission VM) operations. Under the direction of the General Manager is a director, eight regional managers, and distribution leads who ensure regulatory compliance and customer satisfaction. The organization conducts monthly reviews of the DVM program against key performance indicators to ensure work plans are executed timely and within budget.

All positions reporting to the Director are certified arborists. This ensures that DVM leadership and decision making are guided by professionals with recognized expertise in arboriculture.

Presently, DEF has five contractors, employing approximately 600 crew members. Circuit maintenance work is predominantly billed under a unit-based cost structure (e.g., per tree trimmed or per span of line cleared) and is not differentiated between labor and equipment. This approach is used to manage costs, improve reliability, and increase accountability.

DEF's QA process for cycle-based and mid-cycle maintenance requires performing multiple QA audits. The initial QA audit consists of a DEF employee or representative evaluating five to 15 percent of trees that were identified by the contractor before mitigation occurs. A second QA is performed by a DEF representative before mitigation occurs on five to 15 percent of trees identified by a contract forester. Once mitigation is completed, a final audit will occur targeting 25 percent of completed work. If needed, additional auditing will be at DEF's discretion.

Pursuant to DEF's Contracting Oversight and Performance Management Guidelines, 100 percent of routine maintenance work is subject to a QA audit by the contractor. Any work identified during the inspection audit as not meeting DEF's specifications will be reworked at the contractor's expense. Once a DEF representative validates the completed work as planned, the work order is closed in DEF's Work Management System.

As part of its QC process, DVM managers monitor the overall program O&M and capital, budget, actual expenditures, and variances in Excel workbooks. The workbooks encompass actual costs that have passed through DEF's financial systems based on invoices that have been processed/approved, including month-end accruals for completed work not yet invoiced. DEF's contractors submit invoices weekly which DEF representatives then validate and approve in Maximo to ensure timely and accurate reporting. Monthly actuals are compared to the monthly projection for a year-to-date variance and reviewed with management to make any adjustments depending on variance to budget.

QA audit results are trended by monitoring contractor quality scores to determine overall quality performance while noting any negative trends in the quality of work in adherence to DEF technical specifications. At least annually, DEF holds Management Review Meetings with its

DVM contractors who exceed $25 million in costs each year. The meetings focus on supplier scorecards by reviewing metrics such as contractor performance, reliability, safety performance, financial impacts, project completion, and rework/quality audit results. In a collaborative effort, DEF also engages the contractor with areas of opportunity to include strategic growth.

According to DEF, there have not been any incidents of performance levels not meeting contract requirements for DVM work. However, there were two VM contractors that failed to meet established safety performance thresholds due to incidents outside of the DEF system. The two contractors addressed the non-DEF system safety deficiencies to receive conditional approval to work on the DEF system. As a result of the conditional approval, the contractors participate in a bi-monthly call to report on their status of corporate safety performance and initiatives.

D. Analysis of Projects and Costs

Table 12 depicts DEF's related DVM costs of estimated and actual miles maintained and trimmed for each year 2020 through 2024 for the three-year trim cycle for feeders and the five-year trim cycle for laterals. Prior to 2022, the costs for all DVM activities were included in base rates, but are currently recovered through the SPPCRC.

Estimated and actual miles for the mid-cycle activity are not included in the totals because this work is an assessment of feeder miles to identify trees that pose a threat to DEF's distribution system. Therefore, mid-cycle assessments do not involve full specification pruning.

In 2020, DEF maintained and trimmed 2,763 miles for the three-year cycle (feeders) and 2,559 miles for the five-year cycle (laterals) at a cost per mile of $6,822 and $6,530, respectively. Total costs, including the Mid-Cycle and Other (Reactive, Herbicide, etc.) expenses were $43.4 million, $2.0 million less than the estimated $45.4 million.

In 2021, DEF maintained and trimmed an additional 325 three-year cycle (feeders) miles over its 1,891 mile estimate with an actual cost of $17.7 million. This translated to a cost per mile of $7,987. Conversely, DEF fell 169 miles short of its five-year cycle (laterals) estimate of 2,470, with an actual cost per mile of $7,692. Overall, while a total cost savings of $0.3 million was realized for both the three-year cycle (feeders) and five-year cycle (laterals), the cost per mile increased by 15 percent and 16 percent, respectively. Although efficiencies were gained, according to DEF, labor constraints related to COVID and supply chain issues contributed to the cost per mile variance.

In 2022, labor availability continued to be a constraint from the previous year as evidenced by increased costs per mile with an 18 percent and 12 percent for the three-year cycle (feeders) and five-year cycle (laterals), respectively. DEF trimmed an additional five miles of three-year cycle (feeders) miles over its estimate of 1,626 miles while achieving a savings of $0.7 million. For five-year cycle (laterals) miles, DEF fell short of meeting its estimate of 2,601 miles trimming a total of 2,495, a difference of 106 miles. Actual costs were $0.5 million below estimates of $16.2 million.

In 2023, DEF trimmed 10 additional miles over the 1,887 estimate for three-year cycle (feeders) miles, and 57 additional miles trimmed over the estimate of 2,520 miles for five-year cycle (laterals) miles. Overall cost savings came in approximately two percent under budget of $48 million.

In 2024, DEF experienced its most challenging year due to significant restoration and recovery work resulting from the impacts of Hurricanes Debby, Helene, and Milton. For several weeks, DEF redirected resources to complete storm restoration work instead of SPP. DEF exceeded the three-year cycle (feeders) miles estimate by 17 miles, and achieved an actual cost per mile of $9,184, approximately a six percent increase from the previous year. For the five-year cycle (laterals) miles, DEF fell short of its trimming estimate by 24 miles resulting in a cost per mile of $9,383 and a seven percent increase from the previous year.

Over the five-year period, DEF's DVM program has maintained a solid performance coming in under budget by two percent. In total, DEF trimmed 359 additional three-year cycle (feeders) miles over the 9,586 projected miles at a cost savings of $5.0 million coming in at $87.8 million. Furthermore, DEF trimmed a total of 130 five-year cycle (laterals) miles less than the projection of 12,796 miles. DEF averaged an actual cost per mile of $8,831 and $7,767 for the three-year cycle (feeders) and the five-year cycle (laterals) programs, respectively.

Duke Energy Florida, LLC Distribution Vegetation Management Program Maintenance & Trim Costs – Estimated vs. Actual 2020-2024					
Distribution Integrated Vegetation Management Activities	**Estimated Miles Trimmed**	**Actual Miles Trimmed**	**Estimated Costs ($M)**	**Actual Costs ($M)**	**Actual Cost Per Mile**
			2020		
Three-Year Cycle (feeders)	2,761	2,763	$20.9	$18.9	$ 6,822
Mid-Cycle (Three-Phase Assessment)	*	*	$0.5	$0.7	N/A
Five-Year Cycle (laterals)	2,447	2,559	$18.6	$16.7	$ 6,530
Other: Reactive, Herbicide, Program Oversight, and Q/A			$5.4	$7.1	
Total 2020	**5,208**	**5,322**	**$45.4**	**$43.4**	
			2021		
Three-Year Cycle (feeders)	1,891	2,216	$18.3	$17.7	$ 7,987
Mid-Cycle (Three-Phase Assessment)	*	*	$0.6	$0.7	N/A
Five-Year Cycle (laterals)	2,470	2,301	$18.3	$17.7	$ 7,692
Other: Reactive, Herbicide, Program Oversight, and Q/A			$7.3	$8.2	
Total 2021	**4,361**	**4,517**	**$44.6**	**$44.3**	
			2022		
Three-Year Cycle (feeders)	1,626	1,631	$22.4	$21.7	$ 13,292
Mid-Cycle (Three-Phase Assessment)	*	*	$0.6	$1.1	N/A
Five-Year Cycle (laterals)	2,601	2,495	$16.2	$15.7	$ 6,285
Other: Reactive, Herbicide, Program Oversight, and Q/A			$7.0	$7.4	
Total 2022	**4,227**	**4,126**	**$46.2**	**$45.9**	
			2023		
Three-Year Cycle (feeders)	1,887	1,897	$17.7	$16.4	$ 8,640
Mid-Cycle (Three-Phase Assessment)	*	*	$0.7	$1.0	N/A
Five-Year Cycle (laterals)	2,520	2,577	$23.7	$22.6	$ 8,782
Other: Reactive, Herbicide, Program Oversight, and Q/A			$5.9	$7.2	
Total 2023	**4,407**	**4,474**	**$48.0**	**$47.2**	
			2024		
Three-Year Cycle (feeders)	1,421	1,438	$13.5	$13.2	$ 9,184
Mid-Cycle (Three-Phase Assessment)	*	*	$0.7	$1.0	N/A
Five-Year Cycle (laterals)	2,758	2,734	$26.2	$25.7	$ 9,383
Other: Reactive, Herbicide, Program Oversight, and Q/A			$8.6	$7.9	
Total 2024	**4,179**	**4,172**	**$49.0**	**$47.8**	
			Total 2020-2024		
Three-Year Cycle (feeders)	9,586	9,945	$92.8	$87.9	$ 8,831
Mid-Cycle (Three-Phase Assessment)	*	*	$3.1	$4.5	N/A
Five-Year Cycle (laterals)	12,796	12,666	$103.0	$98.4	$ 7678
Other: Reactive, Herbicide, Program Oversight, and Q/A			$34.2	$37.8	
Total 2020-2024	**22,382**	**22,611**	**$233.1**	**$228.6**	

*Miles not included since the mid-cycle activity is an assessment and does not involve full specification pruning.

Table 12 *Source: DEF's Response to Commission Audit Staff's DR 4.11*

IX. Transmission Vegetation Management Program

A. Program Initiatives

Vegetation interfering with transmission facilities can lead to widespread power outages affecting tens of thousands of customers. To prevent and mitigate these disruptions, it is critical to establish clear standards and requirements. DEF's Transmission Vegetation Management (TVM) Program focuses on proactive multi-year maintenance to keep high-voltage lines clear of trees and brush, ensuring reliability and safety.

DEF uses an IVM approach tailored to specific line and vegetation type. The objective of an IVM program is to maintain the lines, before trees and brush are close enough to cause outages, in a manner that is consistent with good arboricultural practices.

The TVM program is expected to incur approximately $282 million in inspection and vegetation remediation activities over the 2026-2035 period as reported in the Company's most recent SPP filing. DEF states that there are no avoided restoration costs or CMI reduction benefits explicitly tied to Vegetation Management programs, as these benefits are captured in the overall totals for distribution and transmission programs.

B. Prioritization Methodology

To support the reliability of the Bulk Electric System (BES), transmission owners such as DEF must comply with NERC vegetation management standards for all overhead transmission lines operating at 200 kV and above. NERC requires each owner to maintain a TVM program that includes the following three elements:

- Transmission Inspections
- Inspection Results and Findings
- Annual TVM Work Plan

1. Transmission Inspections

Pursuant to NERC Reliability Standard FAC-003-5, DEF is required to perform vegetation inspections of 100 percent of its transmission circuits at 200 kV and higher and any other lower voltage lines designated to be critical to the reliability of the BES. All applicable lines must be inspected at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW.

DEF performs visual, ground, and/or aerial inspections of all its transmission lines using helicopters, drones, and LiDAR technology. Approximately 2,006 miles (one-third) of DEF's transmission line corridors are subject to NERC's requirements. Another 3,451 miles of transmission lines are considered non-NERC corridors. The required maintenance and trimming

(NERC and non-NERC) is not forecasted based on time; rather, the work is determined based on threat and condition.

2. Inspection Results and Findings

Completed TVM activities undergo field validation through QA assessments conducted by DEF representatives to verify that work has been performed in accordance with the defined scope and specifications. Pursuant to NERC Standard FAC-003-5, DEF is required to maintain evidence of vegetation inspections for a period of three calendar years. Acceptable forms of such evidence include completed and dated work orders, dated invoices, or inspection records bearing appropriate dates. DEF's QA results records exceed 5,000 entries.

Upon identifying vegetation conditions likely to cause an imminent outage, DEF is required by NERC to promptly notify the control center responsible for switching authority on the relevant transmission line. Evidence of such notification may include control center logs, voice recordings, switching orders, clearance orders, and any subsequent work orders. Unless otherwise directed by the Compliance Enforcement Authority during an investigation, the retention requirement for these records is 12 months for operator logs or, for voice recordings and their transcripts, the most recent three months.

On a quarterly basis, DEF will submit reports to its regional entity detailing all sustained outages on applicable lines operating within their rating, as well as all rated electrical operating conditions that DEF determines were caused by vegetation. The regional entity, in turn, will provide NERC with this outage information on a quarterly schedule, along with any actions taken in response to the reported sustained outages.

3. Annual TVM Work Plan

Central to the TVM program is the management of vegetation within the Minimum Vegetation Clearance Distance (MVCD). MVCD represents the calculated minimum distance in feet required to prevent flashover between conductors and vegetation for various altitudes and operating voltages. NERC Standard FAC-003-5 necessitates that DEF shall complete 100 percent of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD.

DEF's TVM work plan is data driven through the following key steps:

- Network Inventory and Data Gathering
- Threat and Condition-Based Maintenance Scheduling
- Reliability and Risk Prioritization
- Field Inspections
- Environmental and Landowner Coordination
- Resource and Contractor Planning
- Field Annual Work Plan Development

DEF typically creates its TVM annual work plan in the summer for work to be performed during the next year. DEF communicates the annual work plan to the contractor in November of the preceding year work is to be completed. Management and execution of the TVM work plan is captured via the Company's WorkPASS software. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. As evidenced in Section D of this chapter, DEF has met or exceeded 100 percent of its annual estimated miles maintained and trimmed.

As part of its annual TVM program, DEF also performs reactive maintenance, which includes danger tree mitigation, brush management utilizing herbicide, mowing, and hand cutting operations to ensure conformance to the Company's work plan. Reactive work is identified through remote sensing, annual aerial inspections, and ongoing field inspections. For emergency response, helicopters and crews are utilized to quickly identify areas of widespread damage following major storm events. Commission audit staff notes that TVM costs related to major storm events are recovered outside of the SPPCRC.

C. Management Oversight

Similar to the DVM program, the General Manager of PGO Vegetation Management organization has overall responsibility for the Company's TVM operations. Under the Director's leadership is a Transmission Manager overseeing four regional arborists. The organization performs monthly reviews of TVM program status against key performance indicators to ensure work plans are conducted timely, within budget, and comply with federal and state regulatory requirements.

Three additional TVM Managers report directly to the Director: a Lead Program Manager, a Capital Coordinator, and a Regional Program Leader. They are responsible for ensuring system reliability is met, projecting and tracking budget performance, coordinating vendor work with DEF needs, and ensuring the overall QA process is implemented as designed for each region.

At present, DEF has six contractors, employing approximately 164 crew members. Circuit maintenance work is predominantly billed under a unit-based cost structure (e.g., per tree trimmed or per span of line cleared) and is not differentiated between labor and equipment. This approach can be used to manage costs, improve reliability, and increase accountability.

TVM QA and QC audits are conducted on transmission corridors, reactive work, floor management (i.e. herbicide, mowing, and hand cutting within the corridor), and substation property maintenance. QA audits are conducted in two phases. The first being a spot check as crews complete work where direct feedback is given to the crew foreman if applicable. The second phase is a formal assessment of portions or the entire project once work has been completed.

As discussed in **Chapter III**, an internal audit was performed in 2022 that focused on Duke Energy Carolinas and Duke Energy Progress (now one entity) regarding the TVM QA/QC processes. No regulatory compliance issues were identified, but the audit report did recommend implementation of a systematic mechanism to monitor the overall QA status across all of DEF's jurisdictions. In response, DEF now uses WorkPASS to manage its TVM operations.

Commission audit staff notes that DEF's IVM program encompasses both the DVM and TVM initiatives. Accordingly, QC procedures for the budget program and the QA audit process for contractor performance are consistent across both subprograms, as detailed previously in **Chapter VIII**.

D. Analysis of Projects and Costs

Table 13 depicts DEF's related TVM costs of estimated and actual miles maintained and trimmed for each year 2020 through 2024. Prior to 2022, the costs for all TVM activities were included in base rates. Beginning in 2022, costs for TVM activities, with the exception of storm recovery efforts, are recovered through the SPPCRC.

In its SPP Annual Status Report or the SPPCRC filings, DEF does not differentiate between NERC and non-NERC miles when tracking or reporting on estimated or completed units. While DEF conducts annual inspections of all its transmission lines, the mileage reported reflects only scheduled maintenance miles as the Company does not include the full scope of all activities in the TVM program.

In 2020, DEF maintained and trimmed a total of 146 miles of NERC lines while meeting its estimated costs of $3 million. Conversely, DEF fell short of its estimate of 234 non-NERC miles by 128 miles, incurring an additional $2.4 million over its $2.0 million estimate for a total of $4.4 million. The increase in costs is attributed to the implementation of remote sensing for condition-based work planning. As a result, more work was identified in the short-term by conducting more annual planned corridor work to improve and sustain system reliability, integrity, and resiliency. Furthermore, DEF faced labor constraints related to COVID and supply chain issues further contributing to the cost per mile variance.

For 2021, DEF continued to meet its goal of 142 miles trimmed for NERC lines while achieving a cost reduction of $1.7 million resulting in costs of $1.3 million. Expectations again were exceeded when DEF trimmed an additional 59 miles of non-NERC lines by trimming a total of 252 miles. Cost savings of $1 million (18 percent) were realized as DEF achieved actual costs of $4.6 million.

DEF continued to increase its maintenance and trimming efficiency in 2022 by trimming a total of 72 NERC line miles and 429 non-NERC line miles surpassing the estimate by 43 miles and 32 miles, respectively. Actual costs of $1.1 million exceeded estimated costs of $0.8 million by $0.3 million for NERC lines. However, for non-NERC lines, DEF realized cost efficiencies of $0.4 million under estimated costs of $10.4 million with actual costs coming in at $10 million.

In 2023, DEF was able to complete miles more efficiently than anticipated due to sections of transmission lines on the work plan requiring less complex work than anticipated. Although DEF met its NERC miles maintained and trimmed, it exceeded estimated miles by maintaining and trimming an additional 57 miles of non-NERC lines. Actual costs of $0.8 million exceeded DEF's estimate of $0.7 million for NERC lines by an additional $0.1 million (13 percent increase). For non-NERC lines, actual costs of $10 million exceeded the estimated costs of $8.8 million resulting in a cost increase of $1.2 million (14 percent).

In spite of the impacts from Hurricanes Debby, Helene, and Milton, in 2024, DEF met its estimates for NERC miles and non-NERC miles of 233 miles and 522 miles, respectively. Furthermore, DEF attained cost savings for both categories of transmission lines. For NERC lines, DEF realized a $0.2 million cost reduction with actual costs of $2.5 million. Moreover, actual costs of $7.6 million for non-NERC lines were lower than estimated costs of $9.6 million by $2.0 million (21 percent decrease).

Over the five-year period from 2020 to 2024, DEF exceeded its trimmed and maintained miles for NERC and non-NERC lines by 43 miles and 21 miles, respectively. Similarly, DEF came in lower than its estimated $10.2 million for NERC lines with a 15 percent decrease to $8.7 million. While minimal, non-NERC lines incurred a one percent increase ($0.2 million) in actual costs of $36.6 million.

Duke Energy Florida, LLC Transmission Vegetation Management Program Maintenance & Trim Costs – Estimated vs. Actual 2020–2024					
Transmission Integrated Vegetation Management Activities	**Estimated Miles Maintained & Trimmed**	**Actual Miles Maintained & Trimmed**	**Estimated Costs ($M)**	**Actual Costs ($M)**	**Actual Cost Per Mile**
	2020				
NERC (>=200 kV)	146	146	$3.0	$3.0	$20,548
Non-NERC (<200 kV)	234	106	$2.0	$4.4	$41,509
Other: Reactive, Floor Management, Program Oversight, and QA			$7.5	$8.6	
Total 2020	**380**	**252**	**$12.5**	**$16.0**	
	2021				
NERC (>=200 kV)	142	142	$3.0	$1.3	$9,366
Non-NERC (<200 kV)	193	252	$5.6	$4.6	$18,056
Other: Reactive, Floor Management, Program Oversight, and QA			$14.4	$17.6	
Total 2021	**335**	**394**	**$23.0**	**$23.5**	
	2022				
NERC (>=200 kV)	29	72	$0.8	$1.1	$15,278
Non-NERC (<200 kV)	397	429	$10.4	$10.0	$23,310
Other: Reactive, Floor Management, Program Oversight, and QA			$11.8	$12.5	
Total 2022	**426**	**501**	**$23.0**	**$23.6**	
	2023				
NERC (>=200 kV)	38	38	$0.7	$0.8	$21,053
Non-NERC (<200 kV)	481	538	$8.8	$10.0	$18,513
Other: Reactive, Floor Management, Program Oversight, and QA			$11.8	$10.7	
Total 2023	**519**	**576**	**$21.3**	**$21.5**	
	2024				
NERC (>=200 kV)	233	233	$2.7	$2.5	$10,687
Non-NERC (<200 kV)	522	523	$9.6	$7.6	$14,436
Other: Reactive, Floor Management, Program Oversight, and QA			$10.6	$13.7	
Total 2024	**755**	**756**	**$22.9**	**$23.8**	
	2020 - 2024				
NERC (>=200 kV)	588	631	$10.2	$8.7	$13,788
Non-NERC (<200 kV)	1827	1848	$36.4	$36.6	$19,805
Other: Reactive, Floor Management, Program Oversight, and QA			$56.1	$63.1	
Totals (2020-2024)	**2,415**	**2,479**	**$102.7**	**$108.4**	

Table 13 *Source: DEF's Response to Commission Audit Staff's DR 4.14*

X. Transmission Structure Hardening Program

A. Program Initiatives

DEF's SPP Transmission Structure Hardening Program is a comprehensive initiative that focuses on targeting and hardening transmission assets that are susceptible to storm damage. The Company's transmission system is comprised of approximately 60,000 structures, 56,000 poles, and other related equipment that spans over 5,400 circuit miles.

Upon completion of its current 2026-2035 SPP, DEF anticipates hardening a total of 2,000 lattice towers, installing cathodic protection on all eligible towers, upgrading 670 miles of overhead ground wires, replacing 3,000 wood poles, upgrading 25,000 insulators, and automating 40 gang-operated air break (GOAB) switches. The Transmission Structure Hardening Program is estimated to take approximately 30 years to complete from inception and will enhance grid resiliency. The program completion horizon will be reviewed again during the production of DEF's SPP 2029 filing.

The estimated cost for DEF's Transmission Structure Hardening Program during the 2026-2035 period is $1.6 billion. After deployment of the 2026-2035 program work, DEF estimates it will reduce CMI by 22-27 million minutes annually**.** The Company also estimates that it will reduce the restoration cost of extreme weather events on the distribution system by $19.7-$24.6 million annually based on today's costs.

DEF's in-depth Transmission Structure Hardening Program consists of the following seven subprograms:

- Transmission Pole/Tower/Drone Inspections
- Transmission Pole Replacements
- Transmission Tower Upgrades
- Transmission Overhead Ground Wire
- Transmission Gang Operated Air Break Automation
- Transmission Cathodic Protection
- Transmission Insulator Upgrades

1. Transmission Pole/Tower/Drone Inspections

DEF's inspection activities for its transmission system encompass all structure types, line hardware, guying, and anchoring systems. DEF maintains a systematic approach to monitoring transmission pole conditions through regular inspection cycles. DEF conducts field inspections of wood transmission poles on a four-year cycle. Additionally, a more comprehensive wood pole sound and bore line patrol is conducted on an eight-year cycle. These inspections and the data collected help determine the extent of pole decay and any associated loss of strength, which aids in the prioritization of pole replacement or extension of pole life through treatment. Concrete and steel poles, and towers are visually inspected on a six-year cycle, as these materials are less susceptible to deterioration and maintain structural integrity over longer periods.

Aerial inspections are performed using helicopters for rapid assessment over extensive distances, providing an efficient overview of system conditions across multiple miles. For areas that are difficult to access from the ground or require high-resolution imagery, drone inspections are performed for detailed analysis of specific structures. While helicopters offer speed and coverage, drones deliver precision and enhanced visibility for detecting vulnerabilities in hardware or insulation.

2. Transmission Pole Replacements

Due to wood poles higher vulnerability to decay, upgrading wood poles to steel or concrete produces a new, strengthened structure that is more resistant to extreme weather event damage. Data collected from DEF's wood pole inspections help determine the extent of pole decay and any associated loss of strength, which aids in the prioritization of pole replacement or extension of pole life through treatment.

The replacement subprogram has undergone enhancements to improve efficiency and effectiveness. When transmission poles are replaced, the new structures are concurrently fitted with other related hardware upgrades, including insulators, crossarms, switches, and guys. This approach effectively reduces man hours and results in project cost savings when compared to performing each project upgrade separately. This integrated methodology maximizes operational efficiency while minimizing disruption to the transmission system.

The subprogram also transitioned from addressing individual wood poles scattered across the entire transmission system to completing all wood pole replacements within a single circuit. This circuit-based approach improves operational efficiency, reduces system disruptions, and allows for more comprehensive hardening of transmission infrastructure. DEF further enhanced planning and resource allocation through a balanced mix of internal construction crews and contract crews, allowing for more flexible and responsive project execution. According to DEF, all wood transmission poles will be replaced by non-wood structures within three years, with completion targeted for 2028.

3. Transmission Tower Upgrades

The Transmission Tower Upgrade Subprogram focuses on replacing towers that have previously failed during extreme weather events, as well as those identified through comprehensive inspection processes. This includes both lattice and wood-steel tower types that have demonstrated vulnerability to severe weather conditions. The tower prioritization methodology is based on detailed inspection data and enhanced weather modeling to ensure the most critical infrastructure receives immediate attention. Improvements will be realized through measurable outcomes including outage reduction and improved restoration times, directly enhancing the reliability and resilience of the electrical transmission system.

4. Transmission Overhead Ground Wire

The Overhead Ground Wire Subprogram upgrades the lines by replacing ground wire with optical ground wire. High concentrations of lightning events occur in Florida, continually stressing the grid protection of transmission lines. Conductors on the lines degrade when repeated lightning strikes deteriorates the overhead ground wire, thereby reducing their protection of the transmission system. Furthermore, a reduced safety risk benefits workers by not having to remove the overhead ground wire prior to any restoration work. This subprogram will improve ground and lightning protection. It will also provide high-speed data transmission for system protection and command/control communications to locate and repair faults.

DEF prioritizes replacement of deteriorated overhead ground wire by targeting known lines with a frequency and concentration of lightning events, outage history, structure design types, overhead ground wire material, and inspection results of each line.

5. Transmission Gang Operated Air Break (GOAB) Automation

GOAB switches are devices designed to isolate sections of the transmission system, allowing for safer and more efficient maintenance. The GOAB subprogram upgrades these switch locations with advanced, remotely controlled switches featuring Supervisory Control and Data Acquisition (SCADA) systems. SCADA enables remote monitoring and control of equipment, allowing operators in control rooms to receive quicker notifications and isolate disruptions on transmission lines without needing to send technicians into potentially hazardous environments.

Before conducting equipment maintenance or repairs, to minimize grid disruption, technicians must first section off portions of the transmission system. Typically, this process requires technicians to travel to the affected site and manually disengage the line switches. Automated switches not only reduce response time but also enhance technician safety by minimizing the need for manual intervention in dangerous conditions. Additionally, automation improves overall system efficiency and decreases outage duration for customers, resulting in a more resilient and reliable transmission system.

6. Transmission Cathodic Protection

Steel lattice transmission towers face a significant operational challenge due to ground level corrosion that occurs when the steel structure encounters soil. This corrosion process poses a serious threat to infrastructure integrity, as it can weaken the tower structure and potentially cause failure of transmission lines and the electrical grid.

To address this critical issue, DEF has implemented a comprehensive Transmission Cathodic Protection Subprogram specifically designed to extend the operational life of these towers by at least 20 years. This program represents a proactive approach to infrastructure maintenance that helps ensure reliable power transmission while maximizing the return on capital investments in transmission infrastructure.

The subprogram operates through the installation of passive cathodic protection systems, which consist of anodes strategically buried near each leg of the lattice towers. These anodes serve as sacrificial assets that corrode instead of the steel tower structure, thereby preventing loss of structure strength due to corrosion and maintaining the integrity of the transmission infrastructure.

This cathodic protection approach provides DEF with a cost-effective solution for extending asset life while maintaining system reliability and safety standards. By implementing this program, DEF can significantly reduce the risk of transmission line failures while optimizing the lifecycle management of their transmission tower infrastructure.

7. Transmission Insulator Upgrades

In June 2025, the Commission approved the implementation of DEF's new Transmission Insulator Upgrades subprogram. The subprogram, implemented in 2026, focuses on porcelain insulators that exhibit pin erosion, commonly referred to as "penciling" of the connections between the insulators. These porcelain insulators have been identified as particularly susceptible to failure during extreme weather events.

The subprogram involves replacing problematic porcelain insulators with advanced glass insulators. The new glass insulators incorporate several technological improvements designed to address the shortcomings of the previous design. Most notably, the insulators feature a design improvement that effectively mitigates wear, thereby facilitating an enhanced mechanical connection.

The implementation of this upgraded insulator design is expected to deliver multiple operational benefits. The new design will significantly reduce penciling effects over time, which directly translates to reduced failure rates across the transmission system. The subprogram is expected to generate cost savings through reduced restoration costs, as fewer outages and failures will require emergency repair responses.

B. Prioritization Methodology

To prioritize the Transmission Structure Hardening program, DEF uses the third-party Guidehouse model as previously discussed in **Chapter II**. The model uses reliability history and provides a 10-year forward-looking plan focused on SPP hardening work. Guidehouse's analytics aid DEF in targeting the most cost-effective and beneficial grid strengthening solutions ensuring the resilience of transmission assets.

C. Management Oversight

The Transmission Structure Hardening program is reviewed on a monthly basis by the appropriate Project/Program team, Finance and Project Controls, as well as a monthly leadership review led by the Florida Regional Senior Vice President. Project or program variances are discussed along with any changes to proposed execution strategy. Additionally, construction resources and material status are discussed for any current or upcoming work.

As part of DEF's QA/QC oversight, all work must be entirely satisfactory to DEF and is subject to inspection as required by the Company. This establishes DEF's authority to maintain quality standards across all transmission projects. The oversight program includes mandatory internal auditing requirements for contractors. As part of the QA/QC process, contractors must internally audit at least one percent of all towers or poles inspected. Towers and poles are to be selected totally at random and checked for accuracy and quality of work.

Inspections are performed within one to two weeks of completed work. Inspections consist of partial to complete re-inspection of selected poles, including re-excavation and re-boring if those tasks were performed. DEF requires digital photographs of defects to be uploaded to DEF's database. When available, QA/QC is conducted with the contractor's supervisor and a Duke Energy representative.

When deficiencies are identified, the oversight program includes a corrective action process. Significant errors found by DEF are brought to the attention of the contractor. Corrective actions must be remedied before the next quality control check. The corrective action may include re-working all poles back to the previous quality control check point at no cost to the company.

The PGO Central Invoicing Team plays a crucial role in financial oversight by reviewing invoices in accordance with the Transmission Scope Method and Payment guidance to control the work progressing through proper date and schedule management, work progression, work order and task closure, proper billing, finance, GIS, and asset accounting controls. Additionally, the Project Management, Engineering, and Construction Management groups conduct a technical review and approval on final construction invoices greater than or equal to $35,000.

D. Analysis of Projects and Costs

DEF's Transmission Structure Hardening Program was executed in a phased manner. Complete implementation of all subprograms was achieved in 2022, at which point full recovery of costs were captured through the SPPCRC.

Tables 14 through **19** capture annual planned and actual activities and associated costs for each Transmission Structure Hardening subprogram. Commission audit staff could not examine annual costs on a per unit basis because actual costs shown in each table do not exclusively represent costs for units completed in the same year. DEF includes planning, engineering, and sometimes material costs for the following year alongside current year construction costs. Furthermore, the company reports on all projects/activities that had any work completed or incurred cost transactions during that year, regardless of completion status.

1. Transmission Pole/Tower/Drone Inspections

For the years 2020 and 2021 shown in **Table 14**, the actual costs for all transmission inspections, except for drones, were included in base rates. Drone inspections began in 2021. Of the $0.4 million in actual costs shown for 2021, $0.01 million is attributed to drones and those costs were recovered through SPPCRC.

Planned and completed inspections realized a notable increase of 27 percent and 15 percent, respectively, in 2021 from those reported in 2020, as DEF began conducting drone inspections on targeted lattice tower lines. In 2022, DEF incurred increased costs due to higher contractor costs. While fewer inspections were completed, the 2023 and 2024 cost savings were primarily realized through more efficient drone inspections which allowed for coverage of difficult-to-access areas and reduced inspection time, resulting in lower labor costs and faster completion rates. Additional cost savings resulted from DEF securing internal resources in 2024 to execute the drone program.

Over the five-year period, DEF completed a total of 63,793 inspections, representing 908 (one percent), more inspections than the planned total of 62,885. Actual costs summed to $2.3 million, 12 percent less than the total estimated costs of $2.6 million.

Duke Energy Florida, LLC Transmission Pole/Structure/Drone Inspections Subprogram Inspections and Costs 2020-2024				
Year	**Planned Inspections**	**Completed Inspections**	**Estimated Costs ($M)**	**Actual Costs ($M)**
2020	10,959	12,438	$0.4	$0.4
2021	13,900	14,329	$0.5	$0.4
2022	12,747	12,404	$0.5	$0.6
2023	12,459	11,975	$0.6	$0.5
2024	12,820	12,647	$0.6	$0.4
Total	**62,885**	**63,793**	**$2.6**	**$2.3**

Table 14 *Source: FPSC SPP Annual Status Reports 2021 - 2025*

2. Transmission Pole Replacements

As shown in **Table 15,** in 2020, engineering and material procurement work began to facilitate construction activities scheduled for 2021 and subsequent years. The program started with effective execution, completing 19 percent more poles than planned (766 versus 642).

For years 2021 and 2022, DEF experienced shortfalls in completed replacements compared to planned. This variance was primarily due to approximately $4.3 million of work that shifted into 2022 due to outage constraints in 2021. The outage constraints may have included: competing priorities due to needed maintenance or reliability work, limited outage windows on critical transmission lines, and inability to take transmission lines out to perform work due to system or load conditions.

In years 2023 and 2024, DEF completed more pole replacements than planned. The Company also reprioritized $1.7 million of work to 2025 due to impacts from Hurricanes Debby, Helene, and Milton in 2024. Over the five-year period, total actual costs were $465.9 million. DEF replaced 124 fewer poles than originally planned (7,955 versus 8,079), with a $7.0 million cost overrun (1.5 percent).

Duke Energy Florida, LLC Transmission Pole Replacements Subprogram Project and Costs 2020-2024				
Year	**Planned Pole Replacements**	**Completed Pole Replacements**	**Estimated Costs ($M)**	**Actual Costs ($M)**
2020	642	766	$34.3	$39.5
2021	1,495	1,271	$69.7	$66.0
2022	2,180	1,987	$111.5	$116.5
2023	1,909	1,970	$121.7	$120.1
2024	1,853	1,961	$121.7	$123.8
Total	**8,079**	**7,955**	**$458.9**	**$465.9**

Table 15 *Source: FPSC SPP Annual Status Reports 2021 - 2025*

3. Transmission Tower Upgrades

As depicted in **Table 16,** DEF was able to upgrade seven of eight scheduled transmission towers in 2021. The presence of an eagle's nest prevented the upgrade of one tower, causing it to be shifted to early January 2022.

In 2022, DEF encountered challenges. Only seven of 13 planned tower upgrades were completed due to material procurement issues, environmental constraints, and weather-related complications requiring additional infrastructure hardening measures.

For 2023, DEF completed only eight of 22 planned tower upgrades. Like 2022, the shortfall was due to multiple issues with securing materials, including increased lead times, sourcing discontinued materials, and weather-related complications requiring additional infrastructure hardening measures.

In 2024, DEF completed the remaining tower upgrades from 2023, including all the additional upgrades planned for 2024. Cost increases were driven by impacts from Hurricanes Debby, Milton, and Helene which affected site conditions and required additional matting to enable safe equipment access and to protect environmentally sensitive areas, including wetlands. While the program has faced challenges over the five-year period, DEF upgraded 76 towers out of the planned 97 at a cost of $20.6 million.

Duke Energy Florida, LLC
Transmission Tower Upgrades Subprogram
Projects and Costs
2020-2024

Year	Planned Towers	Completed Towers	Estimated Costs ($M)	Actual Costs ($M)
2020	1	1	$0.8	$1.6
2021	8	7	$1.8	$1.4
2022	13	7	$4.3	$1.6
2023	22	8	$5.1	$3.2
2024	53	53	$11.9	$12.8
Total	**97**	**76**	**$23.9**	**$20.6**

Table 16 *Source: FPSC SPP Annual Status Reports 2021 - 2025*

4. Transmission Overhead Ground Wire

While DEF incurred costs in 2020 and 2021, the Company did not complete any hardening of overhead ground wires in either year as shown in **Table 17.** Costs resulted from preliminary work such as engineering and environmental reviews and were recovered through base rates with exception of $0.1 million being recovered in 2021 through the SPPCRC in support of engineering costs for 2022 projects.

In 2022, the estimated costs for overhead ground wire hardening increased to $4.2 million, 180 percent over the 2021 estimate of $1.5 million, indicating DEF's initiative to ramp-up the preliminary work for the subprogram. DEF hardened 13 miles at a cost of $1.6 million. This is significantly lower than the estimated cost as DEF transferred Wood to Non-wood pole replacement activities associated with the Overhead Ground Wires Subprogram to the Wood to Non-wood Pole Replacement Subprogram.

The amount of overhead ground wires hardened in 2023 and 2024 jumped to 38 and 48 miles, respectively. According to DEF, 2024 presented unique challenges due to severe weather events. DEF had planned to complete 63 miles, yet only completed 48 miles. The shortfall of 15 miles was directly attributed to the impact of Hurricanes Debby, Helene, and Milton. Despite these weather-related delays, DEF has since performed work on the incomplete units and completed the 2024 upgrades in 2025.

For the 2020 through 2024 period, DEF planned to harden 115 miles with total estimated costs of $26 million. Actual implementation resulted in 99 hardened miles with total actual costs of $17.6 million, approximately $8.4 million below estimated costs.

Looking ahead, DEF projects significant changes in the subprogram. These changes are driven by modified construction costs based on fewer opportunities to coordinate execution with wood to non-wood pole replacements, as the wood pole population is being systematically reduced.

Duke Energy Florida, LLC
Transmission Overhead Ground Wire Subprogram
Miles and Costs
2020-2024

Year	Planned Miles	Completed Miles	Estimated Costs ($M)	Actual Costs ($M)
2020	3	0	$1.8	$0.6
2021	0	0	$1.5	$1.4
2022	13	13	$4.2	$1.6
2023	36	38	$7.5	$5.3
2024	63	48	$11.0	$8.7
Total	**115**	**99**	**$26.0**	**$17.6**

Table 17 *Source: FPSC SPP Annual Status Reports 2021 - 2025*

5. Transmission Gang Operated Air Break

The GOAB subprogram in **Table 18** began in 2022 with DEF planning to install two switches, yet none were installed. According to DEF, work had to be shifted into 2023 due to outage constraints experienced in 2022. The costs incurred in 2022 were attributed to engineering activities and associated construction.

The challenges continued into 2023, where DEF completed only two units compared to the estimated four units planned. The primary driver for these variances was issues with securing materials necessary to execute the projects. DEF performed work on uncompleted units while anticipating completing the remaining scope of 2023 automation in 2024.

Another particularly challenging year was in 2024, due to external factors beyond DEF's control. DEF’s service territory was directly impacted by Hurricanes Debby, Helene, and Milton, significantly affecting the 2024 work plan. Despite these challenges, DEF managed to install six switches in 2024, which was only one unit less than the estimated total of seven. DEF came in under budget of its $8.3 million estimate with costs of $5.4 million. DEF completed the remaining scope of 2024 automation that was delayed due to hurricane impacts in 2025.

The GOAB subprogram has experienced several challenges and revisions since its inception, impacting project timelines and costs. Throughout the program's implementation, DEF has faced persistent material sourcing difficulties. The utility has experienced challenges with securing switches and switch-related components, as well as increased lead times for critical equipment such as relay cabinets. These material constraints have been compounded by the discovery that most projects are significantly more complex than initially anticipated.

Going forward in the 2026 SPP, DEF has significantly revised its completion targets and cost projections. During project development, it was determined the majority of projects are high in complexity, requiring additional land acquisitions, poles, and switches. This represents a significant departure from DEF's original assumptions in the 2023 SPP, which had assumed a blend of moderate and high complexity scopes. Instead, the combination of additional scope requirements and longer material lead times continues to result in extended project durations and increased estimated costs.

Duke Energy Florida, LLC Transmission Gang Operated Air Break Subprogram Projects and Costs 2020-2024				
Year	**Planned Installs (Switches)**	**Completed Installs (Switches)**	**Estimated Costs ($M)**	**Actual Costs ($M)**
2022	2	0	$1.0	$0.3
2023	4	2	$5.0	$3.3
2024	7	6	$8.3	$5.4
Total	**13**	**8**	**$14.3**	**$9.0**

Table 18 *Source: FPSC SPP Annual Status Reports 2022 - 2025*

6. Transmission Cathodic Protection

As shown in **Table 19,** projects were deferred to 2021 due to a contractor issue. Furthermore, DEF proactively shifted 2022 planned expenditures into 2021 because of repairs not being needed. Actual costs in 2021 also included $0.9 million to acquire materials in preparation for 2022 work creating a $1.3 million variance.

For 2022, DEF exceeded its target of 220 planned tower legs by completing a total of 223. In 2023, the Company adjusted the scope of this subprogram. DEF targeted four-legged structures in its planned projects consisting of 382 tower legs. However, based on field conditions and structural assessments, the 2023 projects included a greater number of two-legged versus four-legged structures than originally planned for a total of 388 tower legs.

In 2024, the Company completed 267 tower legs versus 254 planned. While the subprogram experienced initial delays and cost variations, it ultimately exceeded planned scope, delivering more corrosion protection across DEF's transmission infrastructure than originally anticipated.

Over the five-year period, DEF installed cathodic protection on 1,133 tower legs versus 984 planned (15 percent above the planned target) and total actual costs of $8.1 million exceeded the estimated costs of $7.6 million by $0.5 million.

Duke Energy Florida, LLC Transmission Cathodic Protection Subprogram Projects and Costs 2020-2024				
Year	**Planned Projects (Tower Legs)**	**Completed Projects (Tower Legs)**	**Estimated Costs ($M)**	**Actual Costs ($M)**
2020	0	0	$0.4	$0.0
2021	128	255	$1.2	$2.5
2022	220	223	$0.9	$0.8
2023	382	388	$2.6	$2.2
2024	254	267	$2.5	$2.6
Total	**984**	**1,133**	**$7.6**	**$8.1**

Table 19 *Source: FPSC SPP Annual Status Reports 2021 - 2025*

7. Transmission Insulator Upgrades

As mentioned earlier, the Commission approved the implementation of DEF's new Transmission Insulator Upgrades Subprogram as part of the broader Transmission Structure Hardening Program in June 2025. Measurable costs and results will be reported starting with the Company's 2026 SPP Annual Status Report.

XI. Transmission Substation Flood Mitigation Program

A. Program Initiatives

DEF has transmission and distribution substations that are categorized as follows based on voltage class:

- Transmission only T (69 substations) which handles only transmission-level equipment and voltages.

- Transmission-to-Transmission T-T (57 substations) which steps transmission voltage to a different transmission voltage class (i.e., a voltage range for specific equipment such as circuit breakers and relays).

- Transmission-to-Transmission-to-Distribution T-T-D (57 substations) which steps transmission voltage to lower transmission voltage, with power splitting between the transmission system and further step-down to distribution level.

- Transmission-to-Distribution T-D (350 substations) which steps transmission voltage down to distribution voltage.

- Distribution only D (2 substations) which handles only distribution-level equipment and voltages.

The voltage class of the substation is not indicative of costs for substation flood mitigation. The driver for cost significance is based on the substation size and amount of equipment. All types of substations allow for the integration of generation, transmission, and distribution systems through various functions such as circuit switching, voltage regulation, power monitoring, and fault protection.

DEF hardens distribution substation assets as a component of its Transmission Substation Flood Mitigation Program (TSFM) and currently combines the costs for both types of projects in its SPP. The Company states that it will create separate detailed projects to account for transmission versus distribution hardening assets

DEF's TSFM program is a targeted initiative to upgrade identified substations with flood mitigation strategies. The primary purposes of this program are:

- Outage Prevention to reduce risk of prolonged outages caused by flooding.

- System Hardening to replace or upgrade infrastructure to make it less susceptible to water intrusion and extreme weather conditions.

- Cost Reduction to minimize equipment damage caused by storm surge to reduce customer outages and expedite restoration.

The mitigation solutions may include containment curbing, elevating or modifying equipment, or relocating substations altogether. New assets could include control houses, relays, or total station rebuilds to increase elevation or other measures to mitigate water intrusion.

In its 2026-2035 SPP, DEF plans to harden 11 substations at a cost of $78 million. DEF anticipates completion of the TSFM program within 12 years. Once completed, the Company estimates a cost reduction of extreme weather events on the transmission system by approximately $2.2-$2.8 million annually, with CMI being reduced by 0.7-0.9 million minutes annually. The program completion horizon will be reviewed again during the production of DEF's SPP 2029 filing.

B. Prioritization Methodology

The TSFM program targets sites (substations) as being at risk for significant flooding and facility damage during extreme weather events. Each substation project begins with its initiation phase followed by the engineering design, permitting, scheduling, material/equipment procurement, construction, and closeout phases.

DEF leverages the Guidehouse model to identify and prioritize substation projects across its entire service territory. When a substation project is identified as part of the program, the associated work activities are recorded through the SPP and eventually the costs are filed for recovery through the SPPCRC.

DEF's systematic review and project prioritization process combines advanced modeling techniques, risk assessment methodologies, and expert judgment to minimize substation equipment damage. This results in reduced restoration costs and outage times during extreme weather events, improving grid resilience and overall service reliability.

C. Management Oversight

DEF's Power Grid Operations (PGO) Florida organization manages the TSFM program. As part of the organizational structure, Project Review Board (PRB) meetings are held monthly to review program project performance. Risk assessments are also reviewed during PRB meetings. Additional performance monitoring is completed pursuant to DEF's PGO transmission project management processes and procedures and also includes performance and variance management analyses.

PGO uses various performance measurement tools, as previously discussed, to monitor TSFM program effectiveness and efficiency. TSFM program activities include documenting evidence throughout the construction process to ensure work is performed and tested in conformance with the specifications. DEF is also currently developing a new transmission construction quality audit process with anticipated implementation by the third quarter 2026. The Company's SPP transmission programs will follow this process once implemented.

For hardening assets at distribution substations for flood mitigation (a component of the TSFM program), the contractor is required to have and maintain a QA/QC program and perform quality assessments to validate completed work. DEF also has and maintains a distribution construction quality audit process that has been in place since the early 2000s. The Company documents and stores the audit results in a searchable internal database.

D. Analysis of Projects and Costs

DEF's TSFM program scope was designed to begin after 2022, as Guidehouse's recommendation did not include any projects during the Company's initial three-year SPP period. For 2023 through 2025, there were no projects. The Company had to reevaluate targeted locations and methods of the program due to recent FEMA map updates and more detailed flood studies to review all substations within its service territory.

Table 20 shows the ongoing or planned projects for the 2026 through 2035 period, with estimated costs and construction start/end dates either provided or to be determined for the planned substations to be hardened in 2029-2035.

To date, DEF has not completed any TSFM program projects. Hardening of four substations is planned for completion by year-end 2028. An additional seven substations, yet to be determined, are planned for hardening. The 10-year cost (2026-2035) is expected to be $78 million.

The costs and dates are subject to change as projects progress through the Company's standard development process, including estimating, schedule refinement, and construction scheduling. In recording costs for TSFM program work that is to include hardening assets at both transmission and distribution substations for flood mitigation, DEF will create separate projects and use two distinct utility account numbers.

Duke Energy Florida, LLC SPP Transmission Substation Flood Mitigation Program Projects – Ongoing or Planned 2026–2035				
Substation	**Type (T or D)**	**Total Est. Cost ($M)**	**Construction**	
			Est. Start (Mo/Yr)	**Est. End (Mo/Yr)**
Homosassa	T-D	$6.9	02/2026	12/2026
Crystal River North	T-D	$6.9	01/2027	12/2027
North Bartow	T-T	$7.6	01/2027	12/2028
St. George Island	T-D	$7.6	01/2028	12/2028
Planned Substations 2029-2035				
7 Est. Substations	TBD	TBD	TBD	TBD
Estimated Total Cost 2026-2035 (11 Substations)		**$78.0**		

Table 20 *Source: DEF's Response to Commission Audit Staff's DR 3.24*

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XII. Transmission Substation Hardening Program

A. Program Initiatives

DEF's Transmission Substation Hardening Program is designed to enhance the resilience and reliability of electrical substations against extreme weather events. Like the TSFM program, hardening of distribution substation assets is a component of the Transmission Substation Hardening Program and currently combines the costs for both types of projects in its SPP. The Company states that it will create separate detailed projects to account for transmission versus distribution hardening assets.

For both transmission and distribution, the program focuses on upgrading:

- Oil circuit breakers to state-of-the-art gas or vacuum breakers to mitigate the risk of catastrophic failure and extended outages during extreme weather events.

- Electro-mechanical relays to digital relays with advanced system protection functions and communications to reduce response and restoration times during extreme weather events.

Oil circuit breakers are less reliable than gas or vacuum breakers, especially during extreme weather events. They can generate arcing gasses within the oil tank that can accumulate and result in catastrophic failure during repeated operation. Gas or vacuum breakers allow the transmission system to more effectively and consistently isolate faults, reenergize circuits after momentary interruptions, and improve the customer experience through fewer interruptions.

The electronic programmable relays with their microprocessor technologies and communication capabilities provide prompt and accurate diagnosis of operational conditions to mitigate outages and faster response and restoration during extreme weather events. The relay upgrades are matched with breaker replacements which is part of a coordinated effort to improve the safety, resiliency, and overall reliability of the grid.

Both upgrades implement the latest design standards and technologies that exceed minimum requirements and enhance system resilience. The upgrades to the existing infrastructure reduce risk of system failures during extreme weather conditions, leading to fewer outages and faster restoration times. Upon completion of its current 2026-2035 SPP, DEF anticipates hardening a total of 150 oil-filled breakers and 130 relay groups on the DEF system. The Transmission Substation Hardening Program is estimated to take approximately 15 years and will properly isolate line faults and reduce storm restoration times by automating fault identification. The program completion horizon will be reviewed again during the production of DEF's SPP 2029 filing.

The estimated cost for DEF's Transmission Substation Hardening Program during the 2026-2035 period is $347 million. The Company estimates the program will reduce restoration costs by $90,000 to $120,000 annually, with CMI estimated to be reduced by six to eight million minutes annually.

B. Prioritization Methodology

DEF leverages the Guidehouse model to identify and prioritize substation projects across its entire service territory. Subject matter experts analyze condition of circuit breakers, customer impacts, outage data, and field expertise to set priorities for replacement of both transmission and distribution oil circuit breakers. They also match relay upgrades with breaker replacements, when feasible, considering analysis of relay outages, customer impacts, operational impacts, and field expertise.

Circuit breakers and relays at the same location are replaced in tandem under the same transmission substation project. Each project begins with its initiation phase followed by the engineering design, permitting, scheduling, material and equipment procurement, construction, and closeout phases.

C. Management Oversight

DEF's PGO Florida organization manages the Transmission Substation Hardening program. As part of the organizational structure, Project Review Board meetings are held monthly to review program project performance and risk assessments. Additional performance monitoring is completed pursuant to DEF's PGO transmission project management processes and procedures and also includes performance and variance management analyses.

Transmission organizations within PGO are responsible for maintenance and operation of all assets located in both transmission and distribution substations. All processes, procedures, resource allocation, and QA/QC programs related to these assets are governed by transmission standards and use transmission contractors and resources.

Transmission contractors hardening assets at transmission substations are required to have and maintain a QA/QC program. The program activities include documenting evidence throughout the construction process to ensure work is performed and tested in conformance with the specifications. DEF is also currently developing a new transmission construction quality audit process with anticipated implementation by the third quarter 2026. The Company's SPP transmission programs will follow this process once implemented.

D. Analysis of Projects and Costs

Table 21 shows the number of Transmission Substation Hardening projects, including upgraded circuit breaker and digital relay installations during the period from 2020 through 2025, along with estimated and actual completion dates. For 2020 and 2021, DEF completed 12 substation hardening projects and recovered $4.9 million and $5.5 million through base rates, respectively. Beginning in 2022, costs were recovered through the SPPCRC.

The table also shows the substation types as previously defined in **Chapter XI**. All projects shown in the table were completed either prior to or by the estimated completion date. Commission audit staff notes that DEF inadvertently omitted, in the actual/estimated true-up for the period January 2022 through December 2022, the two electro-mechanical relay groups to be installed at the Frostproof substation. However, DEF accurately accounted for these two units in the final true-up for the same period. The inadvertent omission was not caused by a system issue. The scope of the project was originally split into two separate projects, i.e., one for the breaker and another for the two relay groups.

Commission audit staff inquired whether circuit breakers and relays can be replaced in tandem under the same project. In response, DEF said that transmission substation hardening projects are now developed as a single, consolidated project per location, when feasible. This will improve tracking and reporting and ensures prevention of scope omissions and facilitates more accurate project and program management.

Duke Energy Florida, LLC SPP Transmission Substation Hardening Program Completed Projects and Installs – Estimated vs. Actual 2020–2025					
Substation	**Type (T or D)**	**Projects Completed**		**Installs Completed**	
		Estimated (Mo/Yr)	**Actual (Mo/Yr)**	**Estimated Units (B/R)[1]**	**Actual Units (B/R)**
Base Rate Recovery (2020-2021)					
Fortieth Street	T-T-D	12/2020	04/2020	1/1	1/1
UCF	T-D	12/2020	04/2020	3/1	3/1
Idylwild	T-T	12/2020	06/2020	4/1	4/1
Welch Road	T-D	12/2020	12/2020	1/1	1/1
Bay Hill	T-D	12/2021	05/2021	0/5	0/5
Casselberry	T-D	12/2021	07/2021	3/5	3/5
Apopka South	T-D	12/2021	08/2021	4/1	4/1
Crystal River South	T-D	12/2021	09/2021	1/0	1/0
Lake Emma	T-D	12/2021	09/2021	1/0	1/0
Lady Lake	T-D	12/2021	09/2021	1/0	1/0
Largo	T-T-D	12/2021	11/2021	3/0	3/0
Debary Plant	T-D	12/2021	12/2021	1/0	1/0
SPPCRC (2022-2025)					
Magnolia Ranch	T-D	12/2022	09/2022	0/2	0/2
Dunnellon	T-D	12/2022	11/2022	0/1	0/1
Cassadega	T-D	12/2022	12/2022	1/3	1/3
East Lake Wales	T-D	12/2022	12/2022	0/1	0/1
Frostproof	T-D	12/2022	12/2022	1/0	1/2
Bay Hill	T-D	12/2023	12/2023	2/2	2/2
Belleview	T-D	12/2023	04/2023	1/0	1/0
Bithlo	T-T-D	12/2023	04/2023	1/0	1/0
Econ	T-D	12/2023	04/2023	1/0	1/0
Monticello	T-D	12/2023	12/2023	1/0	1/0
Fort Meade	T-T-D	12/2024	12/2024	1/5	1/5
Lake Wilson	T-D	12/2024	12/2024	1/2	1/2
Altamonte	T-T-D	12/2025	05/2025	2/7	2/7
Elfers	T-D	12/2024	01/2025	9/6	9/6
Lake Bryan	T-T-D	12/2025	04/2025	2/0	2/0
Mount Dora	T	12/2025	05/2025	1/0	1/0
North Longwood	T-T-D	12/2025	05/2025	1/0	1/0
Starkey Road	T-D	12/2025	04/2025	3/0	3/0
Dundee	T-T-D	12/2025	12/2025	1/1	1/1
Eustis South	T-D	12/2025	12/2025	1/3	1/3
Leesburg	T	12/2025	12/2025	2/1	2/1

[1]Breaker/Relay

Table 21 *Source: DEF's Response to Commission Audit Staff's DR 3.28*

Table 22 shows the Company's completed transmission substation hardening projects and estimated and actual costs during each year, 2021 through 2024. This period reflects costs that were recovered through the SPPCRC. For the four-year period, total transmission hardening costs were $18.9 million compared to an estimated $29 million.

The first 11 substations listed were completed in 2022 through 2024, with cost variances that fell below the 10 percent threshold. The variances were primarily due to: favorable grid conditions and execution efficiencies, ability to secure internal crews, avoidance of temporary transmission line boxes, and project scope refinement following detailed field investigation. The Altamonte substation project was completed in 2025, and the cost variance was above the threshold. The variance was driven by a change in construction scope, such as the need for custom cable trenching or additional control cable routing. The Fort Meade substation project was completed in 2024, with a cost variance within the plus or minus 10 percent threshold range. The remaining eight substation projects were completed in 2025.

DEF includes a line item for Engineering/Materials costs to be incurred in support of future construction projects. These costs are not estimated at the substation project level. However, the Company does include the estimates for each project within the planned construction year.

Duke Energy Florida, LLC
SPP Transmission Substation Hardening Program
Completed Projects and Costs – Estimated vs. Actual
2021–2024

Substation	2021		2022		2023		2024	
	Est. Cost ($K)	Act. Cost ($K)	Est. Cost ($K)	Act. Cost ($K)	Est. Cost ($K)	Act. Cost ($K)	Est. Cost ($K)	Act. Cost ($K)
Magnolia Ranch		$37	$489	$160		($1)		
Dunnellon		$8	$564	$152		($2)		
Cassadega		$10	$2,164	$607		$117		
East Lake Wales		$5	$1,657	$505		$0.6		
Frostproof		$44	$2,327	$1,420		$231		
Bay Hill				$96	$2,764	$1,260		$232
Belleview				$34	$419	$137		
Bithlo				$21	$456	$170		
Econ				$30	$501	$157		$3
Monticello				$3	$763	$366		$33
Lake Wilson						$154	$2,424	$1,586
Fort Meade				$204		$1,038	$2,311	$2,111
Altamonte				$1		$192	$1,264	$2,060
Elfers				$0.1		$408	$4,517	$4,306
Lake Bryan						$40		$29
Mount Dora						$31		$29
North Longwood						$19		$12
Starkey Road				$32		$64		$74
Dundee						$200		$55
Eustis South						$141		$129
Leesburg East						$35		$156
Eng./Materials			$621		$4,596		$1,174	
SPPCRC Total		**$104**	**$7,822**	**$3,265**	**$9,499**	**$4,758**	**$11,690**	**$10,815**

Table 22 *Source: DEF's Response to Commission Audit Staff's DR 5.1*

Table 23 shows the number of ongoing or planned transmission substation hardening projects for the 2026 through 2035 period. The estimated completion dates range from year-end 2026 to 2029. Commission audit staff notes that one project, the Umatilla substation, was delayed because of an unplanned equipment failure resulting in removal of a transformer that prevented work on the remaining three of four total units. Once the transformer is replaced, all of the downstream construction activities will continue.

DEF states that major execution phases of circuit breaker and relay upgrades are scheduled in the spring, when feasible. This is primarily because of moderate "shoulder month" temperatures with electricity demand lower than during peak summer and winter months. By doing so, the Company gains additional float within the calendar year, increasing schedule flexibility and mitigating risks from equipment failures or unplanned outages.

Duke Energy Florida, LLC SPP Transmission Substation Hardening Program Mitigation Measures – Ongoing or Planned 2026–2035		
Substation	**Type**	**Estimated Completion**
Ongoing Projects		
Umatilla	T-D	TBD[1]
Brooksville	T-T-D	12/2026[2]
Winter Park	T-D	12/2026
Cypresswood	T-D	12/2026
Desoto City	T-D	12/2026
Cross Bayou	T-D	12/2029
Planned Projects		
Hemple	T-D	12/2026
Zellwood	T-D	12/2026
Lake Placid	T-D	12/2027
Haines City	T-D	12/2027
Maitland	T-D	12/2028

[1]Unplanned equipment failure.
[2]Installed two breakers in 2025, with four other units to be installed.

Table 23 *Source: DEF's Response to Commission Audit Staff's DR 3.29*

According to DEF, lessons learned from the execution of its Transmission Substation Hardening Program projects include: the value of early grid condition assessment to avoid temporary transmission line boxes, the benefits of leveraging internal crews where feasible, and the importance of enhanced field validation to refine construction scope definition.

Additionally, isolated instances of modified scope reinforced the need for reasonable contingencies, while favorable variances led to efficiencies. Ongoing coordination between planning and execution supports improved alignment of estimates, schedules, and filing periods.