Review of Electric IOU Transmission Structure Inspection and Maintenance Procedures and Processes

MARCH 2020

BY AUTHORITY OF
The Florida Public Service Commission
Office of Auditing and Performance Analysis
Review of Electric IOU Transmission Structure Inspection and Maintenance Procedures and Processes

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March 2020

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The State of Florida
Public Service Commission
Office of Auditing and Performance Analysis

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Executive Summary

1.1 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) Division of Engineering. The purpose of the audit was to review the procedures and processes used by electric investor-owned utilities (IOUs) to inspect and schedule maintenance on transmission structures.

The primary objectives of this audit were met by examining the following for each utility:

♦ Policies and procedures governing maintenance and inspections of transmission facilities and substations.

♦ Compliance with applicable standards and procedures.

♦ Organization and key management team responsible for transmission facility and transmission substation inspections and maintenance.

♦ Adherence to the IOU’s Commission-approved storm hardening plans required by Rule 25-6.0342, Florida Administrative Code (F.A.C.).

♦ Compliance with applicable National Electric Safety Code (ANSI C-2) pursuant to Subsection 25-6.0345(2), F.A.C.

♦ Written safety, reliability, pole loading capacity, and engineering standards and procedures for attachments by others to the utility’s electric transmission poles (Attachment Standards and Procedures).

♦ Use of industry benchmarking in the administration and implementation of transmission structure inspection and maintenance.

♦ Vegetation management program and its compliance with North American Electric Reliability Corporation (NERC) requirements.

1.2 Scope

As authorized by Chapter 350.117 (2) and (3), Florida Statutes (F.S.), management 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 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 project objectives, the scope of the review focused on the organizations within each utility that are responsible for developing, implementing, and monitoring policy for the inspection and maintenance of transmission structures. Audit staff performed assessments in the following transmission areas of operation as they relate to each utility:

- Internal inspection requirements
- Key transmission structure inspection and maintenance management
- Transmission structure inspection and maintenance practices
- Transmission substation inspection and maintenance practices
- Quality control reviews
- Storm hardening of transmission substations and structures
- Vegetation management programs
- Audits and/or risk assessments of transmission inspections and maintenance
- Internal reporting of transmission structure inspection and maintenance activities
- Storm preparation and drills
- Benchmarking of similarly-situated utilities’ transmission structure inspection and maintenance programs
- 2016 – 2018 hurricane seasons damage to transmission structures and substations

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. Audit staff’s reviews are completed in compliance with Institute of Internal Auditors Performance Standards 2000 through 2500. 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.
1.3 Methodology

The information in this audit report was gathered through responses to document requests and on-site interviews with key employees accountable for directing, developing, and implementing each utility’s transmission structure inspection and maintenance programs. Commission audit staff also reviewed Florida Statutes, FPSC rules and orders, Annual IOU Electric Distribution Reliability Reports, each company’s 2019–2021 storm hardening plan, and applicable filings regarding electric IOU storm restoration costs.

Audit staff assessed the collected information to gain a thorough understanding of the processes used by each utility to manage and implement transmission structure inspection and maintenance programs. Specific information collected from each utility included:

♦ Transmission structure inspection and maintenance program policies, procedures, and processes.
♦ Approach and methodologies used to determine inspection and maintenance development.
♦ Organization and administration of the transmission inspection and maintenance programs.
♦ Transmission inspection and maintenance program results reported to senior and executive management.
♦ Internal and external audits completed on transmission structure inspection and maintenance programs.
♦ Metrics or quantification tools used to assess transmission inspection and maintenance program effectiveness.
♦ Participation in industry groups to compare similarly-situated utilities’ transmission inspection and maintenance programs.

1.4 Commission Audit Staff Findings

Based on its evaluation and analysis, Commission audit staff developed company-specific observations which are detailed in Chapters 3 through 7. Several common threads were identifiable among these company-specific observations, leading to the following general findings:

Finding 1: Florida IOUs have changed transmission construction specifications and presently install concrete or steel poles instead of wood transmission poles.
Finding 2: Florida IOUs are carrying out initiatives to eventually replace all wood transmission poles with concrete or steel poles.

Finding 3: Florida IOUs presently perform Commission-required collection of forensic data on transmission pole/structure failures in widely varying manners. In some cases, they provide detailed and conclusive results, while in other instances, as the Commission noted in 2006, “lack of readily available performance data makes it difficult to conduct forensic reviews…and determine whether appropriate maintenance has been performed.”

Finding 4: Florida IOUs are re-assessing and updating their transmission structure inspection and maintenance practices and procedures and are making improvements where deficiencies have been found.

Finding 5: Florida IOUs should consider adopting new corrosion prevention and detection standards developed by the Institute of Electrical and Electronics Engineers, the National Association of Corrosion Engineers, the American Society for Testing and Materials, and other applicable standards organizations.

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1 Order No. PSC-06-0351-PAA-EI, issued April 25, 2006, in Docket No. 060198-EI.
2.0 Background and Perspective

Transmission structures are the interconnected lines and supporting structures and associated equipment that transmit electric energy between points of supply and points at which it is transformed for delivery to customers or to other electric systems. Florida’s transmission system network is comprised of lines rated at 69 kV, 115 kV, 138 kV, 230 kV, and 500 kV.

The transmission grid is built and maintained according to standards which include the National Electrical Safety Code (NESC), and the United States Department of Agriculture’s Rural Utilities Service (RUS) guidelines regarding pole inspection cycles.

2.1 Federal Energy Regulatory Commission Standards

The Federal Energy Regulatory Commission (FERC) regulates the interstate transmission of electricity, natural gas, and oil, but does not control or operate the electric grid. FERC oversees the development, approval, and enforcement of reliability standards developed by the NERC.

2.1.1 NERC Reliability Standards

Under Federal Power Act Section 215 authority, FERC developed regulations regarding the process for NERC to delegate authority to propose and enforce NERC Reliability Standards to regional entities. NERC oversees eight regional reliability entities and encompasses all of the interconnected power systems of the contiguous United States, Canada and Mexico. Effective July 1, 2019, Florida became a member of SERC Reliability Corporation (SERC) which includes most of Southeast North America, serving Missouri, Alabama, Tennessee, North Carolina, South Carolina, Georgia, Mississippi, and portions of Iowa, Illinois, Kentucky, Virginia, Oklahoma, Arkansas, Louisiana, and Texas.

NERC’s mission is to ensure the effective and efficient reduction of risks to the reliability and security of the electric grid. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. NERC's jurisdiction includes users, owners, and operators of the bulk power system, which serves more than 334 million people. Although NERC’s authority generally applies to transmission elements operated at 100 kV or higher, if the regional entity deems a lesser transmission line critical to bulk power system reliability, the owner of that line must meet NERC standards.

NERC’s compliance and enforcement tools include compliance audits, investigations, spot checks and other procedures for the identification, mitigation and assessment of penalties for non-compliance. NERC oversees the regional entities’ enforcement programs and appeals processes.
2.1.2 **NERC Vegetation Management Standard FAC-003-4**

NERC’s tree-trimming standard applies only to high-voltage transmission lines of 200 kV or higher, or to transmission lines of lower voltages if the Regional Entity deems the line critical to bulk power system reliability.

The Facilities Design, Connections, and Maintenance FAC-003-4 Reliability Standard was developed to maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights-of-way (ROWs) and minimize encroachments from vegetation adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to cascading outages. Transmission ROW widths vary considerably based on company policies and industry standards. Corridor widths vary by transmission line voltage:

- 69,000-volt lines typically require a 50- to 100-foot corridor
- 115,000-volt lines typically require a 100-foot corridor
- 230,000-volt lines typically require a 100-foot corridor
- 500,000-volt lines typically require a 170-foot corridor

Operating experience clearly indicates that trees that have grown too close to power lines could contribute to a serious cascading grid failure, especially under heavy electrical loading conditions. To reduce and manage this risk, it is necessary to apply the Standard to applicable lines on any kind of land or easement, whether they are federal lands, state or provincial lands, public or private lands, franchises, and easements.

The following transmission facilities are required to follow this Standard:

- Each overhead transmission line operated at 200 kV or higher
- Each overhead transmission line operated below 200 kV identified as an element of an Interconnection Reliability Operating Limit under NERC Standard FAC-014 by the Planning Coordinator
- Each overhead transmission line operated below 200 kV identified as an element of a Major The Western Electricity Coordinating Council (WECC) Transfer Path in the Bulk Electric System by WECC
- For the above identified criteria, each overhead transmission line located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence

### 2.2 Transmission Structure Maintenance Standards

#### 2.2.1 NESC Wood Pole Maintenance Requirements

The National Electrical Safety Code (NESC) is the widely accepted U.S. standard for the safe installation, operation, and maintenance of electric power and communication utility systems. It
applies to electric and communications overhead lines and related structures, electric and communications underground lines, and electric substations.

The NESC is written as a voluntary standard, but is typically adopted as law by individual states or other governmental authorities, including Florida. Section 366.04(6), F.S., and Rule 25-6.0345, F.A.C., require electric IOUs under Commission jurisdiction to comply with the NESC as the applicable safety standards for transmission and distribution facilities. Section 26 (Strength Requirements) of the NESC contains provisions for the strength factors of poles which must be maintained for the period that the pole is in service.

Wood poles are a primary component of the transmission grid, and eventually suffer significant deterioration. The NESC requires electric IOUs to strengthen or replace wood poles in excess of 18 meters (60 feet) in length that have lost one-quarter of their original strength at installation under full load-bearing conditions. Transmission poles are typically greater than 18 meters in length. The NESC requires strengthening or replacement of wood poles equal to or less than 18 meters in length (typically distribution poles) that have lost a third of their original strength at installation under non-load bearing conditions.

Poles greater than 60 feet (typically transmission poles) are also required to have sufficient strength to withstand extreme wind loading, considering loads associated with attachments and conductors. Poles less than 60 feet are exempt from extreme wind loading requirements, but must be able to withstand winds of 60 miles per hour.

The NESC strength requirements can only be met if the electric IOU in question conducts wood pole inspections in a manner to detect weakening of the poles. The code is not specific as to the exact schedule within which inspections must be made, but Rule 214.A.2, states the following: “Lines and equipment shall be inspected at such intervals as experience has shown to be necessary.” The utility is responsible for considering the conditions of service which the installation reasonably can be expected to be exposed.

2.2.2 New IEEE/NACE Steel Structure Maintenance Standards
The National Electrical Safety Code provides safety and other general guidance regarding steel transmission structures. However, it does not provide specific guidelines for the inspection of steel transmission structures mirroring those in place for wood poles. This may be a reflection of the fact that U.S. electric industry has for decades been able to rely on the greater long-term durability of steel transmission structures.

In the past, an ongoing inspection regimen, such as the one required under the Commission’s Six-Year Transmission Structure Inspection Program, was not widely perceived as necessary across the industry. According to Materials Performance Magazine,

The argument against implementing aggressive maintenance programs for electric utility transmission and distribution steel structures may have been based on the belief (now known to be misguided) that steel lasts forever….That belief, that steel has unlimited longevity is no longer valid, of course, as utility companies
have watched their aging steel transmission towers and distribution structures succumb to the ravages of corrosion.²

In recent years as these structures have aged, the industry has begun to address the issue of corrosion and mechanical damage. In 2015 the Institute of Electrical and Electronics Engineers (IEEE) and the National Association of Corrosion Engineers (NACE) jointly released three standards for the inspection, assessment, and protection of steel towers and poles.³ These standards are intended to provide guidance to utilities seeking to maintain system reliability by managing the unique corrosion issues they face. It is conceivable that these voluntary standards may become de facto minimum standards and best practices in the eyes of state or federal regulators. Commission audit staff notes that these new standards may benefit Florida IOUs in assessing their transmission maintenance practices and procedures.

2.3 FPSC Jurisdiction and Rules

2.3.1 Section 366, Florida Statutes (F.S.)
The FPSC has broad authority over the adequacy and reliability of the state’s electric transmission and distribution grids. According to Section 366.04(5) F.S., the Commission has “jurisdiction over the planning, development, and maintenance of a coordinated electric power grid” assuring “an adequate and reliable source of energy for operational and emergency purposes in Florida and the avoidance of further uneconomic duplication of generation, transmission, and distribution facilities.”

Section 366.04(6), F.S., provides the Commission exclusive jurisdiction to prescribe and enforce safety standards for transmission and distribution facilities of all public electric utilities, cooperatives organized under the Rural Electric Cooperative Law, and electric utilities owned and operated by municipalities. The safety standards include adoption of the latest edition of the National Electrical Safety Code, which presently is the 2017 Code.

Section 366.05(1), F.S., requires the Commission “to prescribe fair and reasonable rates and charges, classifications, standards of quality and measurements, including the ability to adopt construction standards that exceed the National Electrical Safety Code, for purposes of ensuring the reliable provision of service.” The Commission also has the power to require “repairs, improvements, additions, replacements, and extensions to the plant and equipment of any public utility when reasonably necessary.”

Section 366.05(7), F.S., allows the Commission to require reports from all electric IOUs to assure the development of adequate and reliable electric grids.

Under Section 366.05(8), F.S., the Commission has the power to require Florida electric utilities to install or repair any necessary facility “if the Commission determines that there is probable cause to believe that inadequacies exist with respect to the energy grids developed by the electric utility industry, including inadequacies in fuel diversity or fuel supply reliability.”

2.3.2 Transmission Requirements of Chapter 25-6, F.A.C.
Chapters 25-6 of the F.A.C. are intended “to define and promote good utility practices and procedures, adequate and efficient service to the public at reasonable costs, and to establish the rights and responsibilities of both the utility and the customer.”

Rule 25-6.0143(1)(m), F.A.C., Use of Accumulated Provision Accounts 228.1, 228.2, and 228.4, requires each utility to file a report with the Commission Clerk providing information concerning its efforts to obtain commercial insurance for its transmission and distribution facilities and any other programs or proposals that were considered. The report must be filed annually, by February 15 of each year, for information pertaining to the previous calendar year.

Rule 25-6.0342, F.A.C., Electric Infrastructure Storm Hardening, is intended “to ensure the provision of safe, adequate, and reliable electric transmission and distribution service for operational as well as emergency purposes; require the cost-effective strengthening of critical electric infrastructure to increase the ability of transmission and distribution facilities to withstand extreme weather conditions; and reduce restoration costs and outage times to end-use customers associated with extreme weather conditions.”

The Rule requires each utility to file with the Commission a detailed storm hardening plan which must be updated every three years. The Commission then considers whether the utility’s plan meets the desired objectives of enhancing reliability and reducing restoration costs and outage times in a prudent, practical, and cost-effective manner to the affected parties.

Rule 25-6.0345, F.A.C., Safety Standards for Construction of New Transmission and Distribution Facilities, “adopts and incorporates by reference the 2017 National Electrical Safety Code (NESC) C2-2017, as the applicable safety standards for transmission and distribution facilities subject to the Commission’s safety jurisdiction. Each investor-owned electric utility, rural electric cooperative, and municipal electric system shall, at a minimum, comply with the standards in these provisions.”

Rule 25-6.036, F.A.C., Inspection of Plant, requires that “Each utility must operate and maintain in safe, efficient, and proper condition, pursuant to Rules 25-6.034, 25-6.0341, 25-6.0345, and 25-6.040, F.A.C., all of the facilities and equipment used in connection with the production, transmission, distribution, regulation, and delivery of electricity to any customer up to the point of delivery. The utility is also responsible for the measurement of electrical consumption consistent with test procedures and accuracies prescribed by the Commission... Each utility must adopt a program governing the inspection of its electric facilities and equipment in order to determine the necessity for replacement and repair. Each utility must keep records to establish compliance with its inspection program.”

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4 Amended 12-30-19.
Rule 25-6.037, F.A.C., *Extent of System Which Utility Shall Operate and Maintain*, requires each utility to operate and maintain in safe, efficient, and proper condition, all of the facilities and equipment used in connection with the production, transmission, distribution, regulation, and delivery of electricity to any customer up to the point of delivery. The utility is also responsible for the safe, efficient measurement of electrical consumption consistent with test procedures and accuracies prescribed by the Commission.

Rule 25-6.044(3) & (4), F.A.C., *Continuity of Service*, requires each utility to make all reasonable efforts to prevent interruptions of service and when such interruptions occur the utility must attempt to restore service within the shortest time practicable consistent with safety.

When the service is necessarily interrupted or curtailed for planned maintenance, it must be completed with the least inconvenience to customers and be preceded by reasonable notice whenever practicable to affected customers.

### 2.3.3 FPSC-Mandated Hardening Initiatives

By Order PSC-06-0144-PAA-EI, in Docket No. 060078-EI, the FPSC required wood pole inspections be based on the sound-and-bore technique on an eight-year cycle. This method produces information about remaining pole strength requirements as required by the NESC, whereas visual and infrared inspection methods cannot provide such information. In accordance with the Rural Utilities Service guidelines, the sound-and-bore technique employed must include excavation for all southern pine poles and other pole types as deemed appropriate.

By Order No. PSC-06-0351-PAA-EI, issued April 25, 2006, in Docket 060198-EI, the Commission ordered IOUs to inspect wooden poles every eight years to assure weakened ones are replaced, and to implement 10 storm preparedness initiatives:

- Three-Year Vegetation Management Cycle for Distribution Circuits
- Audit of Joint-Use Attachment Agreements (shared use of poles with telecom)
- Six-Year Transmission Structure Inspection Program
- Hardening of Existing Transmission Structures
- Development of Transmission and Distribution Geographic Information System
- Collection of Post-Storm Data and Forensic Analysis
- Collection of Detailed Outage Data Differentiating Between the Reliability Performance of Overhead and Underground Systems
- Increased Utility Coordination with Local Governments
- Collaborative Research on Effects of Hurricane Winds and Storm Surge
♦ Development of Natural Disaster Preparedness and Recovery Program Plans

The Commission also ordered electric utilities to file updated storm hardening plans every three years, and began annual Hurricane Season Preparation Workshops, which allow the IOUs, Municipals, and Cooperatives to share individual hurricane season preparation activities. These practices continue today. A further discussion of the 10 storm preparedness initiatives can be found in Appendix 1 of this report.

2.3.4 FPSC-Mandated Post-Storm Forensic Analysis

Post-storm forensic analysis of distribution and transmission structure failures is one of the most valuable tools IOUs can employ for assessing the effectiveness of maintenance and inspection programs. Forensic analysis is done very differently by each of the IOUs. The quality, scope, level of detail, and determination of when forensics should be done, are decided by each company. Accurate maintenance records for damaged or fallen poles or towers are necessary tools in assessing the failure causes. Performing forensic analysis is sometimes passed over in favor of a “restoration first and fast” approach, and broken poles may be removed before being assessed by a consultant.

Order No. PSC-06-0351-PAA-EI created the requirement for annual storm implementation plans and instructed IOUs to develop a program that collects data for purposes of forensic analysis, but did not specify what information should be collected or when a forensic analysis should be completed. The Order stated the following:

We intend for utilities to have the flexibility to propose a methodology that is efficient and cost effective in assuring the utility collects sufficiently detailed data to conduct forensic reviews and become better able to evaluate storm hardening options…utilities capture and maintain varying degrees of inspection data, vintage data, and other performance related data pertaining to the electric infrastructure. Lack of readily available performance data makes it difficult to conduct forensic reviews, assess the performance of underground systems relative to overhead systems, determine whether appropriate maintenance has been performed, and evaluate storm hardening options…

2.3.5 2019 Florida Legislation

Public Utility Storm Protection Plans

Committee Substitute/Senate Bill 796 was signed into law on June 27, 2019. The new law (Section 366.96, Florida Statutes) creates a recovery mechanism for storm protection costs instead of recovering these costs through base rates, as is done now, and provides for recovery of a return on capital costs (profit) through the clause.

The law provides that the FPSC must adopt rules to implement and administer this recovery clause and propose the rules for adoption no later than October 31, 2019. The FPSC will also be required to submit an annual report to the Governor, the President of the Senate, and the Speaker of the House of Representatives on the status of utilities' storm protection activities.
Each Florida Electric Company IOU will be required to file a 10-year transmission and distribution storm protection plan to achieve the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability. Within 180 days after the filing, the Commission must determine whether it is in the public interest to approve, approve with modification, or deny the plan. At least every three years after approval of a utility's storm protection plan, the utility must file an updated transmission and distribution storm protection plan addressing each element specified by commission rule for Commission review and approval.

**Vegetation Management Jurisdiction Limits**
Committee Substitute/Senate Bill 1159 was signed into law on June 26, 2019, with an effective date of July 1, 2019. The new law (Section 163.045, Florida Statutes) prohibits local governments from requiring notices, applications, approvals, permits, fees, or mitigation for the pruning, trimming, or removal of trees on residential property if a property owner obtains documentation from a certified arborist that the tree presents a danger to persons or property.

It also prohibits local governments from requiring property owners to replant a tree that was pruned, trimmed, or removed in accordance with the new law, deletes a provision that authorizes electric utilities to perform certain ROW tree maintenance only if a property owner has received local government approval, provides an exception for mangrove protection actions, and creates a Property Owner Bill of Rights.

These new statutes provide greater freedom for Florida utilities in managing vegetation encroachment that can result in damage and outages, particularly during storm conditions. Notably, local government restrictions on private property tree trimming often involve areas of high population density, where customer impact is likely to be higher than in rural areas.
3.0 Duke Energy Florida, LLC

Duke Energy Florida, LLC (DEF) provides service to approximately 1.8 million customers in 35 counties throughout Florida, of which ninety percent are residential customers. The Duke Energy Florida transmission system consists of more than 5,100 miles of transmission lines, 58,000 structures, and 500 substations.

3.1 Transmission Structure Inspections

Duke Energy Florida has more than 5,100 miles of largely overhead transmission lines ranging from 69 kV to 500 kV. DEF’s transmission structures are comprised of about 20,000 wood poles, 12,300 concrete poles, 17,700 steel poles, and over 3,300 lattice towers. DEF owns 73.8 miles of underground transmission lines in Sumter, Orange, and Pinellas County, comprising 1.3 percent of all transmission mileage for Duke Energy Florida. There are 13 miles of transmission fluid-filled underground cables and nearly 42 miles of gas-filled underground cables that require regular maintenance. The remaining 18 miles are solid dielectric cables. DEF states it uses underground transmission for special applications such as water crossings due to the higher cost.

In 2010, DEF performed sound-and-bore inspections on a total of 4,545 wood pole structures. This is approximately 22 percent of all wooden transmission structures. During 2019, the company performed visual ground inspections on 25 percent of wooden transmission structures to maintain the four- and eight-year cycles established in DEF’s policies and procedures.

During 2018, DEF conducted 280 inspections of its 682 transmission circuits, covering 41 percent of its transmission circuits. In 2018, DEF inspected 994 of its 3,435 steel and concrete transmission structures. In 2019, DEF inspected 33 percent of its steel lattice towers and 23 percent of all circuits in accordance with the six-year cycle established in DEF’s policies and procedures.

3.1.1 Types and Frequency of Inspections

DEF states it has been committed to operating and maintaining its transmission system in the safest and most reliable way possible. The company explained the main focus of the transmission maintenance program has been proactive maintenance of all equipment, components, and systems to promote optimal performance, safety, and reliability.

Ground patrol inspections are ground-level visual inspections performed of transmission structures. Wood poles are inspected on a four-year cycle. Concrete poles, steel poles, and lattice towers are inspected every six years. These ground patrol inspections for all pole types look for visible rot, rust, broken hardware, lightning damage, or broken static wires. Structure condition is rated from State 1 to State 5. A State 4 or 5 indicates a failed structure to be replaced. The company states that if a structure is inaccessible due to terrain conditions, the contractor is expected use ATVs, Marsh Masters, or boats to inspect the structure or return to conduct the inspection when access is improved.
Since the early 2000s, DEF has used cathodic protection corrosion control for some concrete and steel transmission structures located in tidal or flood-prone areas. Buried sacrificial anodes provide protection by attracting corrosion away from steel structures. Replacement of depleted anodes occurs when evidence of rust appears on the structure. These anodes are part of the construction standard for new steel poles, but as of 2019 were not retrofitted to existing structures. Prior to the use of cathodic protection, the company used tar dipping to prevent corrosion. DEF states that anodes provide better protection than this coating approach and it therefore committed to beginning a pilot program for the addition of cathodic protection at the foundation of towers.

Sound-and-bore inspections are conducted on wood transmission poles on an eight-year cycle. Core samples are taken to examine the wood poles for rot and insect damage. Signs of rot or damage are to be noted by the contractor and communicated to the company for further inspection and possible replacement.

DEF uses infrared thermography scans on three-way switches attached to transmission poles to locate problems such as insulator breakdown. The infrared inspections target high-load periods and are done once per year on substations. Splices on the line, especially those close to a substation, are addressed as priorities. Batteries are to be tested at five-year intervals.

DEF targets an aerial inspection of its entire transmission system conducted in the spring and fall of each year. These aerial inspections are done by a crew that includes both vegetation management and transmission maintenance personnel. DEF additionally uses remote sensing technologies to detect vegetation issues, line sag, and other trouble areas on the line or hardware when deemed necessary. Aerial inspections are not intended to provide ground-level examination of corrosion on steel structures. DEF is currently in the beginning stages of incorporating the use of drones for future transmission inspection and post-storm forensic work.

### 3.1.2 Forensic Engineering-Based Lattice Tower Inspection Results

DEF’s transmission system contains 35 lines supported by steel lattice towers. Though DEF stopped building new lines using lattice towers in the 1980s, older lines, one dating back as far as the 1920s, remain in service.

As discussed in detail in section 3.4.2 below, DEF’s Higgins-Griffin line (constructed in the 1950s) received close scrutiny following the collapse of structure number HG-160 during Hurricane Irma. A forensic consultant’s analysis concluded that despite prior inspections, extensive corrosion was not detected and remedied, leading to HG-160’s failure and collapse.

In 2018, DEF’s forensic consultant inspected adjoining HG structures and identified five additional corroded towers needing replacement. During 2019, DEF completed these recommended tower replacements.

Based upon the concerns raised with the Higgins-Griffin line, DEF commissioned the consultant to perform detailed inspections of 82 structures on two additional 115 kV lines. These inspections identified corrosion and other conditions, and the consultant’s findings led DEF to identify 2 additional lattice structures in need of replacement by storm season 2020.
During 2020, DEF plans to complete an enhanced inspection of its Higgins-Disston line. This inspection was originally scheduled for 2021, but was rescheduled after the findings of the forensic consultant’s November 2019 report were received.

### 3.1.3 DEF Lattice Tower Inspection Procedures

Given the forensic consultant’s findings, Commission audit staff questioned DEF transmission management regarding the adequacy of its current written lattice tower inspection practices and procedures. DEF identified its Transmission Line Material Condition Assessment Procedure; Ground Patrols (TECP-MIM-TRM-00026, Rev 003) as the governing document guiding its various inspection processes. More specifically, DEF specified Section 3.8 of this procedure as containing the written instructions for use in steel lattice structure inspections.

This section presents, in less than a full page, very general descriptions of three priority ratings that can be assigned based upon observed conditions such as “deep rust”, “needs cleaning, priming, and painting,” and “requires mitigation.” These terms are not defined, and no means of measuring the degree of deterioration are mentioned. Unlike DEF’s analogous wood pole inspection written procedure, no photographs of deterioration examples are provided for reference regarding the range of deterioration warranting repairs, structure replacement, etc. Also, no follow-up action to be taken is specified for each of the three priority ratings. No reporting mechanism for creating a work order for repairs or replacement is mentioned.

After discussion with Commission audit staff, the company made a one-sentence addition to each of the three priority ratings discussed in Section 3.8. Audit staff believes this procedure, even as amended, is not adequate and is unlikely to provide the additional direction and precise material strength assessment needed by inspectors. Commission audit staff believes lack of effective targeting of detection of severe corrosion may be indicated by the documented findings of DEF’s forensic consultant that in some instances severe corrosion had been developing undetected over a period of years.

DEF also provided Commission audit staff a draft procedure, entitled Transmission Lattice Tower Inspection and Repair Guidelines (GDLP-MNT-TRM-000010) which was developed by Duke Energy in 2016, but never implemented. According to DEF,

> This document…was developed at an enterprise level but was never implemented. Consistent with prudent utility management, there are on-going discussions within the Transmission group to explore more efficient methods and tools for performing work across a range of activities.

Unlike TECP-MIM-TRM-00026, this proposed Duke Energy procedure would provide a comprehensive and detailed guide of procedures and processes for lattice tower inspections. According to DEF,

> This [proposed] procedure [was] intended to be utilized on aged tower lines with known deficiencies or ground line deterioration issues needing repair and/or recoating. This maintenance procedure provides specific guidance and expectations in performing tower inspections that may include any or all of the
following; soil property testing, excavation of soils from tower legs, measurement and determination of the percent metal loss, coatings application, and the installation of replacement or reinforcing angles.

Proposed within GDLP-MNT-TRM-000010 were requirements that would require contracted inspectors to detect and determine the extent of measured steel loss for various tower components. Based upon the extent of the quantified steel loss, various remedial measures are specified. In a discussion of the merits of GDLP-MNT-TRM-000010, DEF stated that this draft procedure was provided to its forensic consultant to use as a guide in assessing the HG-160 collapse. This action indicates that DEF does recognize the value of the document’s engineering-based approach for assessing corrosion damage, and that further use of it can be beneficial to the company.

The processes described in GDLP-MNT-TRM-000010 are reminiscent of the quantification of the loss of strength in wood transmission poles that have sustained center rot damage. This quantification of the extent of damage is necessary to maintain compliance with the National Electrical Safety Code requirement that taller wood poles be replaced upon the loss of 25% of original strength.

Commission audit staff notes that, if adopted, the processes once proposed within GDLP-MNT-TRM-000010 would likely lead to higher inspection costs for steel lattice structures. Still, audit staff encourages DEF to consider cost-benefit tradeoffs of more extensive engineering-based inspection practices, as it continues discussions of more efficient methods and tools for performing transmission maintenance. Finally, audit staff believes new corrosion protection and detection industry standards developed by the Institute of Electrical and Electronics Engineers and the National Association of Corrosion Engineers (described in Section 2.2.2 above) are worthy of consideration by DEF during this discussion and evaluation process.

### 3.1.4 Wood Transmission Structure Replacement Program

DEF has a plan to assess the need to change out wood poles with steel or concrete as a normal work process. The company changes out wood poles according to the remaining life of the pole and/or the results of pole inspections. Its wood pole replacement plan is intended to replace existing wood poles once there is a need to do so from an asset management standpoint, or before it becomes prudent to do so as part of a line segment rebuild or relocation. If inspections rate a pole as a State 4 or 5, the company replaces rather than repairs the pole, believing repairs are not effective in the long run. At the current pace, using a five-year average of pole replacements, and not considering additional or unplanned rebuilds or DOT relocations, DEF estimates all wood transmission poles being changed out no later than 2050.

During the period 2006 to 2018, DEF replaced over 11,000 wooden poles, approximately 36 percent of all transmission wood poles. DEF replaced 796 wood transmission poles in 2018 and 1,027 wood transmission poles in 2019. The company spent $37.1 million (2018) and $33.6 million (2019) in capital improvements, which includes pole change-outs. Over the next 10 years, DEF hopes to reduce the total percent of transmission wood poles from 50 percent to 25 percent. In 2020, DEF is projected to replace 620 wood poles as part of its maintenance change-
out program, plus about 200 additional poles as part of DOT relocations and rebuild projects, for a total of approximately 820 wood poles.

### 3.1.5 Inspection Tracking and Scheduling
DEF’s transmission and substation inspections and maintenance activities are headed by the Vice-President of Construction and Maintenance, located in Florida. Inspections and maintenance activities are divided geographically into three areas, North, Central, and Coastal. Each area is served by an assigned transmission line crew. Additionally, DEF employs five line maintenance crews stationed throughout the state that work closely with the Vice-President of Construction and Maintenance.

The Manager of Transmission Work Management is responsible for the planning and scheduling of all transmission work that goes through his department. The Manager of Transmission Asset Management is considered the decision point for transmission maintenance, activities, and priorities, including compliance with North American Electric Reliability Corporation (NERC) standards. DEF tracks transmission structure and line inspections through Maximo, its transmission asset management system. This enterprise-wide system tracks the inspection intervals for each asset. The asset management system also creates and tracks work orders from inspection results, allowing annual compilation and creating a job plan for the next year.

In 2017, the company switched from Cascade to Maximo asset management software. The change from Cascade to Maximo was an enterprise-wide decision. DEF is working to consolidate all information in Maximo. The company is working to combine DEF’s GIS system with Maximo’s pole location data. DEF is conducting a data true-up that is planned to be completed by the end of 2020.

DEF uses the Power BI system to create dashboards of all transmission maintenance activities from data gathered from Maximo. Power BI is a reporting system that tracks spending, safety, operational, and environmental compliance against goals and targets for the year. This system reports weekly on open work orders. Power BI can be used to provide reports for senior management. Dashboards show the percentage of maintenance activities completed and other transmission maintenance measurement criteria.

### 3.1.6 Contractor Management
To effectively manage costs, DEF uses contractors to perform ground patrol and sound-and-bore inspections of transmission structures. The company provides the contractor GPS locations of all poles to be inspected. This information is uploaded to the contractor’s system, for use with tablets in the field. Contractor personnel input the results of the inspections, and a master sheet of ratings and other inspection data is compiled by the contractor.

DEF tracks contractor performance using periodic meetings and quarterly business reviews. The Manager of Transmission Work Management checks weekly progress of all transmission contractor inspection and maintenance work. During quarterly meetings, the company and the contractor review work completed and discuss any issues the contractor has encountered such as access difficulty or vegetation problems. After damage from Hurricane Irma in 2019, DEF instituted a practice of rating the contractor with an annual performance score that evaluates safety and work quality. If the contractor’s performance falls below a satisfactory level, the
contractor will be placed on a Performance Improvement Plan. Failure to meet the terms of the agreement on a consistent basis may include reduction of work and/or termination of the contract.

The DEF contractor operations group performs spot-checking of contractor inspections on at least one percent of the contractor inspected structures in a region. DEF’s Quality Assurance process was formalized and implemented in April 2019. The formal inspection audits take place at the end of an inspection season, and provide for one percent of inspected structures to be randomly selected, without regard to structure type. The selected structures are then inspected by DEF personnel to validate both the condition ratings assigned by the contract inspectors and that the notes associated with the structures accurately reflect DEF’s rating standards.

In the past, although additional data fields on the inspection form were available to the inspectors for comments, DEF simply received the State 1 through 5 rating for each structure inspected. According to DEF, after award of the new inspection contract in 2017, it met with its inspection contractor to ensure expectations were clear, including DEF’s expectation that the contractor provide not only the grade of the structure in question, but also completion of all other supplemental data fields applicable for a given structure and any other information the contractor deems appropriate to provide a full understanding of the condition of the structure. This data is uploaded monthly into the asset management system. According to DEF, poles with a State 1-3 inspection rating require no follow-up work. If a pole is rated a 4, it is scheduled for replacement the following year, but may remain in use up to two years. If a pole is rated at 5, it is replaced the following year, and any 4 rated poles on the same line are replaced at that time.

3.1.7 Internal Reporting
DEF senior management holds biweekly calls and quarterly meetings of the Transmission Jurisdictional Operations Committee. Members of this committee include the department heads of Construction and Maintenance, Contractor Oversight, Resource & Project Management, Vegetation Management, System Operations, Planning, and Engineering and Asset Management. During these meetings, the committee discusses topics such as:

- Safety
- Compliance with transmission vegetation management and maintenance guidelines
- DEF Performance Metrics
- Budget Updates/Financials
- Operational Items (construction and maintenance, asset management, engineering, etc.)

At the Duke Energy level, Enterprise Senior Leadership holds monthly calls or meetings. Participants include the Duke Energy SVP of Transmission, SVP of Construction & Maintenance, VP of Transmission Engineering & Asset Management, VP of Transmission Planning, VP of System Operations, Director of Transmission Compliance, and Director of Transmission Finance. The Senior Leadership discusses topics such as:

- Safety
- NERC Compliance
- Asset/Grid Management
During these enterprise meetings, regional performance metrics are presented and analyzed by the Enterprise Senior Leadership. The Duke Energy Board of Directors is provided status reports when requested.

Rather than conducting internal audits, DEF relies on external audits of its transmission facilities inspection program. In 2017, NERC conducted an audit of Duke Energy’s compliance with NERC reliability standards. The audit examined compliance with all reliability standards applicable to which DEF is registered: Balancing Authority, Distribution Provider, Generator Owner and Operator, Planning Authority, Resource Planner, and Transmission Owner, Operator, Planner, and Service Provider.

DEF participates in various industry groups to share and learn about transmission facilities and vegetation management benchmarking, lessons learned, and best industry practices. The company participates in the following industry groups:

- North American Transmission Forum Peer Review Programs
- Electric Power Research Institute Transmission and Substation Groups

### 3.2 Transmission Vegetation Management

#### 3.2.1 Inspections and Trimming
DEF applies similar inspection and trimming strategies and procedures for BES and non-BES transmission systems. The company inspects vegetation growth on every mile of transmission annually. The scheduled biannual aerial inspections described in Subsection 3.1.1 provide opportunity for vegetation management personnel to identify and document danger trees and vegetation encroachments. Herbicide is applied between the months of April and November. Trimming work needed is identified as described below.

DEF uses NERC and National Electrical Safety Code standards to develop its threat trigger distances. The company’s vegetation management program is designed on an Integrated Vegetation Management (IVM) strategy that targets removals of incompatible vegetation to minimize potential outages to the Transmission system and ensure necessary access within all transmissions corridors. Vegetation is evaluated based on many factors including legal ROW standards to existing transmission lines.
Potential vegetation issues and encroachments spotted during any inspection are reported to the vegetation management team and field verified. If DEF identifies a danger tree outside of its ROW, the company works with the landowner to remove the tree at its own expense.

3.2.2 Inspection Tracking and Scheduling
In 2018 and 2019, DEF inspected 100 percent of all transmission lines and cleared vegetation on 397 and 422 miles of transmission lines, respectively. In 2020, it plans to inspect 100 percent of all of its lines and clear approximately 400 miles of overhead transmission lines. DEF’s Director and Manager of Transmission Vegetation Management oversee four geographical vegetation management areas (North, South, Coastal, and Central). Each area staff includes a team of foresters. The Director of Transmission Vegetation Management also oversees a Program Manager, who performs compliance documentation, tracking, and budgeting.

DEF uses an integrated vegetation management (IVM) strategy to manage vegetation. DEF creates and updates an Annual Work Plan to schedule and track planned work for the year. The plans are developed based on previous work completed, inspection data, existing and anticipated vegetation conditions, and other factors. Vegetation management activity work is tracked by the Vegetation Management Program Manager and reported monthly to leadership.

3.2.3 Contractor Management
All vegetation management work including trimming, herbicide application, tree removal, and aerial trimming is performed by contractors overseen by DEF or DEF representatives. This work is to be performed in accordance with ANSI, OSHA and other applicable safety requirements, laws, and company guidelines. Similar to transmission facilities maintenance, some of DEF’s vegetation management program is governed by policies and procedures that are used throughout the Duke Energy enterprise, while other policies and procedures are specific to DEF. Contractors submit required documentation for completed work along with an invoice including daily activity logs for review by DEF.

DEF tracks and reviews vegetation management contractor performance quarterly, assigning the contractor a Quality Assurance score. Deficiency or performance issues are discussed with the contractor. If the contractor does not perform as anticipated, a Performance Improvement Plan may be initiated. A contractor that does not meet the expectations of the Performance Improvement Plan, may receive a reduction of work and/or termination of the contract.

DEF inspects and documents completion of 100 percent of planned contractor work as it is completed for compliance with specifications. Work that does not meet specifications is re-worked by the contractor at no additional cost to DEF. All lines must be inspected and documented as accepted by DEF on a Transmission Line Completion Form.

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5 IVM practices reduce the need for pesticides, promote healthy ecosystems, and provide measurable results, such as greater natural species diversity along ROWs and better control of invasive species. The desired outcome of IVM around utility ROWs is the development of lush shrub or grassy areas that do not interfere with overhead power lines, pose a fire hazard, or hamper access.
3.2.4 Internal Reporting
Transmission senior management is updated monthly on vegetation management program results at the biweekly Transmission Jurisdictional Operations Committee meeting. Operational scorecards track the performance of vegetation management at the regional and enterprise levels. These operational scorecards display performance metrics results regarding O&M and capital expenditures, safety, and reliability numbers. The DEF Board of Directors is presented with status reports when requested.

3.3 Transmission Substation Inspections

3.3.1 Inspections
DEF conducts monthly visual inspections of all 500 transmission substations. These inspections are performed by DEF area substation and relay crews working under the Vice-President of Construction and Maintenance. During visual inspections, technicians inspect fencing, vegetation, batteries, breakers, the control house, transformers, and other equipment. The tech notes any issue identified, and the Maximo asset management system creates and tracks only work orders generated from the inspection.

Similar to the transmission structure inspections, DEF performs infrared thermography scans of all transmission substation equipment annually. Battery maintenance is performed every two years. DEF uses in-house technicians to conduct all substation facilities inspections. During 2018 and 2019, DEF inspected all transmission substations.

3.3.2 Inspection Tracking and Scheduling
Like the transmission structure inspections, DEF utilizes its transmission asset management system to assign and track all substation inspections. The system tracks inspection intervals for each inspection type. It also creates and tracks the completion of all work orders generated from substation inspections. DEF uses Power BI to create dashboards to track the progress and completion of all substation inspections.

Employees working with the outage incident command center receive computer-based training based on industry standards that varies by job duties. The company tracks all employee training.

3.3.3 Quality Assurance
To ensure that inspections are being conducted properly, the company rotates inspection personnel during the monthly substation inspections to apply quality self-checks. The asset management system has built-in internal controls to alert management of incomplete work orders.

3.4 2016–2018 Hurricane Season Transmission Facility Damage

During the period 2016 to 2018, four major storms affected DEF’s service territory. These storms were Hurricane Hermine, Matthew, Irma, and Michael. Each electric IOU’s storm
hardening plan is required to address post-storm forensic analyses. Depending on the nature of the failure, the type of structure that failed and/or the criticality of the structure, forensics may be ordered immediately or after the structure has been replaced. In any case, the forensics analysis is ordered as soon as possible after the failure. These analyses review storm-related data and assess damaged facilities that may not have performed as designed.

### 3.4.1 Hurricane Michael Damage

Hurricane Michael made landfall in the Florida Panhandle on October 10, 2018, as a Category 5 hurricane, sustaining 161 mph winds. The storm caused extensive damage in DEF’s service area between the areas of Panama City and Cape San Blas.

DEF employed more than 5,100 line and field crews to replace 130 transmission towers, 775 distribution poles, and 351 transformers. Hurricane Michael was the first hurricane to cause the company to completely rebuild three distribution feeders. DEF restored power to 75,000 customers within eight days.

DEF’s procedures require post-storm forensic analysis using a third-party contractor when there is a cascading failure of five or more structures, failed steel or concrete pole, or failed dead-end or large angle structure. The forensic analysis is delivered to DEF and reviewed by DEF leadership. The transmission structure failures and forensic analyses triggered by Michael are discussed below.

#### Port St. Joe–Callaway 230 kV Line

During Hurricane Michael, the Port St. Joe–Callaway 230 kV transmission line was severely affected. Between pole PX-1 and PX-144.5, 146 structures were damaged or destroyed. This included insulator/hardware failure, broken wire, and support structure failure.

Of the 146 structures affected, only 32 remained standing. The line was originally constructed in 1961/1962, when wind loading standards were lower than current standards. DEF has rebuilt the complete line using new light-duty steel tangent poles and guyed light-duty steel dead-end poles.

According to the forensics report, the Port St. Joe–Callaway transmission line outage occurred approximately one hour and twenty minutes in advance of Hurricane Michael’s eye passing directly over the line, though the time of the outage is not necessarily indicative of the time of a structure failure. At the time of the initial Port St. Joe–Callaway outage, two local weather stations, Tyndall Air Force and Apalachicola, provided wind velocities ranging from 43 to 62 mph and wind gusts ranging from 70 to 77 mph as the hurricane approached the transmission line. The forensics report stated the following:

The line failure was caused by one or more of the wire breakages resulting in a cascading failure of tangent towers. Lack of dead ends within long runs of tangent tower sections contributed to the high amount of tower failures…Tangents generally failed in a longitudinal direction, but some were at an angle possibly due to the wind direction. Others failed perpendicularly to the alignment due to conductor breaking and torquing the tower to the ground; sometimes into the wind direction. Of the two failed medium angle structures, one failed transversely, roughly along the angle bisector, and the other failed longitudinally.
The forensic analysis makes no mention of deterioration contributing to the 114 structures taken down by Michael.

**Port St. Joe-Beacon Hill 69 kV Line**
The Port St. Joe–Beacon Hill (PBH) 69 kV transmission line sustained 14 structural failures. The line consisted mostly of wood transmission poles. The engineering forensic analysis stated that the available weather data indicated wind speeds below 60 mph at the time of initial outage, though it is noted that the time of the initial outage is not necessarily indicative of when the structures failed. At that time, the hurricane eye was approximately 50 miles southwest of this section of the PBH 69 kV line. According to the forensic report, it was not apparent what caused the initial outage (e.g. pole failure, line clearance).

At the time when the center of the eye was only 12.4 miles away, Hurricane Michael was a Category 4 hurricane indicating winds speeds of 130 mph-156 mph. The PBH 69 kV line plan and profile drawings indicate that the line was designed for a 36psf wind load (120 mph wind speed). The forensic engineer believes that the extreme winds caused wood pole failures and subsequently broken wires and post insulator failures. This line was subsequently restored with the use of new light-duty steel poles. No mention of deterioration was made in the forensics report.

**Jackson Bluff–Tallahassee 69 kV Line**
The Jackson Bluff–Tallahassee 69 kV transmission line consists of structures JT-44 through JT-48, and JT-103 through JT-111. Five transmission poles were damaged or failed, four lines suffered fallen trees or limbs, eight structures had insulator or hardware damage, and seven wires were broken between poles. According to the forensic analysis, additional recent maintenance data beyond what was discussed in the analysis report was “not available” for poles JT-43 through JT-48 and JT-103 though JT-111. The engineering forensics report notes there were conflicting structure numbers from JT-43½ through JT-46. These poles were physically labeled as JT-44 through JT-46½.

The damaged or failed poles that needed replacement were JT-45½ (70ft class 1 guyed dead-end), JT-46 (70ft class 1 guyed dead-end), JT-104 (75ft class 1 tangent), JT-109½ (70ft class 1 tangent), and JT-110 (70ft class 1 tangent). The forensics report outlined the cause of the failures as follows:

The failures on the southern line segment (structures JT-44 ½ through JT-48) were precipitated by a tree falling across all three conductor phases and the static wire between structures JT-46 and JT-47. Consequently, guyed dead-end pole JT-46 was pulled over by the increased loading and failed above the bottom conductor phase attachment … All three phase conductors appear to have broken, causing insulator damage to structures JT-47 and JT-48 due to the tension imbalance pulling line ahead … Structure JT-45 ½ appears to have been pulled over by the jumper wires attached to structure JT-46, falling at the ground line … The failure point of the pole, standing water, protective fabric wrapped around the base, and apparent charring on the interior all indicate that the pole was not in good health prior to the hurricane. In turn, the collapse of pole JT-45 ½ led to
additional wire and insulator failures at structures JT-45 and JT-44 ½ before being stopped at guyed dead-end structure JT-44. The failures of the northern segment (structures JT-103 through JT-110 ½ appear to have been multiple isolated failures caused by fallen trees and tree limbs.

The report also states, “Possible wood rot could have also contributed to the failure of guyed dead-end pole JT-45½ which was located in standing water and broke at the ground line.”

JT-45½ was last inspected in July 2018. A portion of the Jackson Bluff–Tallahassee 69 kV transmission line had been targeted for relocation due to planned widening of Highway 20. Pole JT-45½ was to have been replaced during the widening work; DEF stated that no necessary maintenance was delayed due to the anticipated widening project. The company stated it has over time changed out poles hit by cars on this line, using light-duty steel poles.

Regarding specific weather conditions, the engineering forensics report stated,

Category 4 hurricane wind velocities (130 to 156 mph) were reported in the vicinity of structures JT-44 to JT-111 by the National Oceanic and Atmospheric Administration (NOAA). The outage occurred approximately 2 hours in advance of the hurricane being at a location nearest to the poles… NOAA cyclone activity at the time of the outage was also reviewed, and multiple mesocyclones had occurred in the general area… The closest was 4.5 miles from the Jackson Bluff–Tallahassee 69 kV transmission line.

3.4.2 Hurricane Irma Damage
Hurricane Irma made landfall in Collier County on September 10, 2017 as a Category 3 hurricane with maximum sustained winds up to 115 mph. Hurricane Irma traveled north up the west coast of the Florida peninsula into Georgia where it weakened to a tropical depression.

DEF experienced 1.3 million customer outages, replacing 141 transmission poles and restoring 124 transmission circuits. During Hurricane Irma, DEF experienced five contiguous transmission structure failures. Hurricane Irma was the first hurricane on record to have impacted all 35 counties served by DEF.

**Tower HG-160 Failure**
As noted previously, tower HG-160, a steel lattice tower located in northeast Hillsborough County, collapsed causing a power outage on the 115 kV Higgins-Griffin transmission line, though no customers were impacted by the outage. DEF commissioned an independent engineering forensic analysis that concluded:

Although the reported 74 mph wind velocity did not exceed the tower’s 134 mph design wind velocity, Hurricane Irma’s wind in combination with the corroded stub angles caused the tower’s collapse.

In November 2016, the HG-160 tower was inspected and rated to be in State 2 condition, meaning that it was not in need of replacement. The next inspection was to be done in the fall of
2020, as the line was inspected on the four-year wood pole inspection cycle. The company indicates that when a contract employee inspects these structures, DEF receives no formal inspection report beyond the assigned numerical rating of the tower (in this case, the State 2 rating). If a structure is rated State 4 or 5, DEF is to be immediately notified to begin planning the replacement. In the case of HG-160, the State 2 rating did not require further action by DEF.

The company states that the HG-160 tower foundation was underwater or covered in weeds at the time of the 2016 contractor inspection, bringing into question whether the State 2 condition rating was based on adequate effort and information, and whether it was accurate. During a June 20, 2019 conference call with DEF, audit staff asked if a re-inspection of HG-160 was done because inspectors could not see the stub angles in the concrete foundation. The company responded that “a re-inspection was not required because HG-160 was graded as in State 2 condition.” Commission audit staff determined that prior to 2017, inspection field notes on tower condition information were not reviewed by DEF if a structure “passed” inspection. DEF stated, …it was not DEF’s practice to review or QA/QC the ancillary notes associated with structure inspections that resulted in a satisfactory rating. Upon a review of the forensics reporting associated with the failure of HG-160 and the status of the surrounding structures, there was a greater awareness of the need to perform review or QA/QC of the ancillary notes. That is now DEF’s standard practice.

DEF believes that significant corrosion did exist prior to the HG-160 failure and that the 2016 inspection rating of a State 2 condition is indeed questionable, constituting a “miss” or failure by the inspector. Commission audit staff questioned DEF as to what actions would be taken as a result of the failure of HG-160. DEF responded:

DEF Transmission did review the forensics report, and took the actions described below:

The failure mode was a combination of a tension/shear failure of the stub angles due to significant loss of the cross-sectional area. The severe corrosion of the embedded stub angle projecting directly from the top of the concrete foundation was one of the attributing factors. Because of the corrosion found at the foundation, Duke Energy had the remaining towers on the entire line inspected by an engineering firm to see if there were any other structures exhibiting the same corrosion. There were 5 additional towers (HG-34, HG-86, HG-93, HG-95 and HG-99) that were identified with severe corrosion at the ground-line. Duke Energy plans to change out all 5 towers by January 31st, 2019.

DEF stated that the five towers identified were also inspected in November 2016, and believes the corrosion, as seen with HG-160, was most likely present at the time but not identified or reported by the contractor. The five towers were rated as States 1 or 2 (not in need of replacement) by the prior inspector. As a preventative measure, DEF replaced these towers. Work began on December 4, 2018, and all five structures were completed and in-service in January 25, 2019. The forensic analysis results and corrective actions were verbally shared with the DEF Transmission Jurisdictional Operating Committee.
Additional Diagnostic Line Inspections
As a result of the HG-160 failure and replacement of the five adjoining lattice towers on the HG line, DEF targeted a more detailed inspection on two additional tower lines that are in the same area and vintage of the HG line, Higgins Plant to Curlew (HGC-1 to HGC-23), and Higgins to Tarpon Springs (HTE-23 to HTE-60-1/2).

Each structure location was visited by an inspection team including a professional engineer. Every structure location was visually inspected, and deficiencies were noted and photographed. All structures were inspected for the following items:

- Rust or corrosion
- Buried steel leg members
- Missing members
- Damaged members
- Missing or detached bonding wire (at the base of the structure)
- Cracked or damaged concrete foundations
- Damaged insulators
- Insulator strings out of plumb
- Additional items that were apparent upon visual inspection

In general, all but a few towers were, at a minimum, rusting at the steel tower leg member base. Where the structure design had no base plate (steel leg member embedded directly into concrete foundation), signs of rust were often moderate to severe. Rusting was most severe where the galvanized steel was in direct contact with the soil.

The engineering firm ranked each of the inspected towers in one of three categories:

1. Anything classified as a 1 requires immediate attention and is either recommended to be replaced or remediated.
2. Anything classified as a 2 would be a minor issue recommended for replacement or remediation.
3. Anything classified as a 3 is a structure observed to be in good condition.

The engineering report recommended that if maintenance is performed on all 2-rated structures, that maintenance (galvanizing, coating, etc.) is also recommended to be performed at all 3-rated structures as a preventative measure.

The following exhibit recaps the results of the DEF engineering inspections on the HGC and HTE lines:
DEF Engineering Inspection Ratings of HGC and HTE Lines

<table>
<thead>
<tr>
<th>Line</th>
<th># of Towers</th>
<th>Rating of 1</th>
<th>Rating of 2</th>
<th>Rating of 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>HGC</td>
<td>21</td>
<td>4 (19%)</td>
<td>15 (71%)</td>
<td>2 (10%)</td>
</tr>
<tr>
<td>THE</td>
<td>61</td>
<td>12 (20%)</td>
<td>32 (52%)</td>
<td>17 (28%)</td>
</tr>
<tr>
<td>Total</td>
<td>82</td>
<td>16 (20%)</td>
<td>47 (57%)</td>
<td>19 (23%)</td>
</tr>
</tbody>
</table>

Exhibit 1  
Source: Pickett and Associates Engineering Report, November 20, 2019

DEF has begun replacement of two towers, and repairs to another 10 towers, in the HTE and HGC line. These were rated as “1” indicating a need for immediate repair or replacement. As a result of these findings, DEF has scheduled the completion in 2020 of the inspection of the Higgins-to-Disston lattice tower line previously planned for 2021. DEF states it will continue to perform visual inspections on the remaining lattice tower structure lines on the normal six-year cycle. Commission audit staff notes that depending upon the outcome of the Higgins to Disston line inspection, DEF may benefit from considering inspection of additional lines to determine the extent of lattice tower rust and corrosion within its system.

Commission audit staff inquired whether consideration was given to revising DEF’s ground inspection processes to better identify corrosion occurring where visibility for inspection is limited. The company stated, “On the whole, the Transmission Line Ground Patrol Inspection procedure is sufficient and does not need to be revised.” However, DEF later advised Commission audit staff its inspection process had been revised to better identify corrosion. DEF stated:

Supplemental data fields are now expected to be filled out from the contractor when completing annual inspections. These fields give us more descriptive comments on the condition of the pole and its accessibility. For example, if a structure is unable to be inspected completely because of an accessibility issue, a comment shall be provided with detailed information.

During 2019, DEF also implemented a quality assurance/quality control process where it internally audits at random at least one percent of the poles inspected by its contractors to ensure they meet its inspection criteria.

Avon Park-Desoto City 69 kV Line
Eleven wood pole failures occurred on a 69 kV transmission line in northwest Highlands County. Transmission Line Structures AD-12 to AD-22 wood poles failed and a conductor failure occurred on a twelfth adjacent pole. Aside from the collapsed poles, other transmission structures on the line sustained structural and wire hardware damage. According to the forensics report, at the time of the outage, 69 mph wind velocities were reported in the vicinity by NOAA.

The DEF consultant’s analysis concluded that the cause of the outage appeared to be a fallen wooden pole (AD-18) caused by Irma’s high wind velocities (69 mph at the time of the outage) that caused cascading failures in poles north and south of it. Steel pole AD-23 apparently prevented further cascading failures, though its post insulator hardware was bent in a
longitudinal direction. Recognizing that “maintenance” records are not synonymous with “inspection” records, according to the forensics report:

Maintenance report indicated that poles AD-15 and AD-20 were last serviced on 11/09/2013...Maintenance information is not available for the remainder of the AD-12 to AD-22 poles. Wood pole AD-20 was significantly rotted & had a wood pecker hole near the OHGW attachment.

The engineering forensics analysis indicated that:

Wood rot was noticed in the following poles: AD-12, AD-13 in the bottom portion of the pole, AD-14, AD-18, AD-19 contained slight wood rot, AD-20 was significantly rotted & had a wood pecker hole near the OHGW attachment, AD-21 and AD-22 contained slight wood rot. Poles AD-15 and AD-16 did not contain wood rot. According to the maintenance records, poles AD-15 and AD-20 were last serviced on 11/09/2013.

Commission audit staff believes these references to wood rot bring into question the adequacy and accuracy of prior wood pole inspections.

**Crooked Lake 69 kV Tap Line**

A 69 kV transmission line in central Polk County suffered five fallen wood poles as well as various insulator and wire failures. All failed wood poles were replaced with light-duty steel poles. The forensic analysis concluded:

Per a discussion with the construction inspector, there were five (5) wood poles, various insulators and wire failures. At the time of the field visit all failed poles and insulators had been replaced and new wire installed. Crews were in process of removing the failed material.

The failed portion of the tap line is located on a slightly higher elevation and open landscape without vegetation or manmade cover. The open landscape increases wind exposure which in turn increases the risk of pole failure due to wind damage.

The pole and hardware failures most likely occurred due to high wind velocities as a result of Hurricane Irma’s landfall. Possible wood rot could have aided in some of the wood pole’s failures followed by additional cascading failures of adjacent structures.

At the time of the outage, 63 mph wind velocities were reported in the vicinity of structures AL-14-1 to AL-14-13 by NOAA. The forensics report states that “Maintenance data is not available at this time for poles AL-14-1 to AL-14-13.” Commission audit staff asked DEF why maintenance data is not always available to the forensics engineer. DEF’s response states:
DEF does keep maintenance records when maintenance has been performed on a structure; these records are kept in the work management system (Maximo). Maintenance records may include work such as insulator replacement, grounding replacement, wood pecker hole filled, etc. If a forensics report states, ‘no maintenance information is available’, that means either there were no maintenance actions required on the structure receiving post-storm forensics (and therefore no notes of maintenance) or the forensics engineer simply did not have the reports at the time of the analysis.

Commission audit staff believes these accounts bring into question the adequacy of prior wood pole inspections, the completeness of maintenance recordkeeping, and availability of information necessary to perform thorough forensic analysis.

**Avon Park-Lake Placid 69 kV Line**

DEF suffered transmission wood pole failures on the Avon Park – Lake Placid 69 kV line, while adjacent steel poles were undamaged, and likely prevented further structure failures on the line. The Avon Park – Lake Placid 69 kV Transmission Line Structures include ALP-205 through ALP-208 and ALP-221 through ALP-226 in central western Highlands County. The forensic analysis concluded that:

The pole and hardware failures most likely occurred due to high wind velocities resulting from Hurricane Irma’s landfall. Possible wood rot could have aided in some of the wood pole’s failures followed by additional failures of adjacent structures, especially as most of the failed poles were located on a culvert embankment near standing water.

Additionally, the line was located on a higher elevation and open landscape, which increases the risk of pole failure due to high wind exposure. At the time of the forensic field visit, all failed poles and insulators had been replaced with light-duty steel poles and removed from the site. They were not available to be analyzed for the forensic analysis.

At the time of the outage, which cannot necessarily be correlated with structure failure, the hurricane was designated as a Category 2 hurricane with 81 mph wind velocities reported in the vicinity of structures ALP-205 to ALP-226 by NOAA. The outage occurred approximately 1.5 hours in advance of the hurricane being at a location nearest to the poles. Hurricane Irma’s eye passed approximately 23.6 miles west of poles ALP-205 to ALP-226. The forensics report states:

Maintenance data is not available at this time for poles ALP-205 through ALP-208, ALP-223, and ALP-226.

The 09/20/2017 maintenance report indicated that poles ALP-224 and ALP-225 were identified as requiring replacement with a target date of 10/26/2013, but it is unclear what maintenance work was performed....

Commission audit staff believes these accounts bring into question the adequacy of prior wood pole inspections, the completeness of maintenance recordkeeping, and availability of information necessary to perform thorough forensic analysis.
**Country Oaks-Dundee 69 kV Structures**

The Polk County Country Oaks to Dundee 69 kV transmission line suffered an outage as a result of several wood pole failures. The forensic analysis concluded that:

The wood poles failures most likely occurred due to high wind velocities as a result of Hurricane Irma’s landfall. Wood rot additionally aided in the following pole failures: DCO-72, DCO-78 and DCO-79; the same poles were replaced in 2012 per maintenance reports. Poles DCO-76, DCO-77 and DCO-80 failed as a result of adjacent poles collapsing…Also, the open landscape increases wind exposure which in turn increases the risk of pole failure due to wind damage.

The wood poles snapped at various points along their length. According to DEF, because of construction in progress, not all the broken poles could be safely inspected. All damaged structures have been replaced with light-duty steel poles.

According to the forensic analysis report, at the time of the outage, 75 mph wind velocities were reported in the vicinity of structures DCO-72 and DCO-76 to DCO-80 by NOAA. The outage occurred approximately 80 minutes in advance of the hurricane being at a location nearest to the poles.

Commission audit staff believes these accounts bring into question the adequacy of prior wood pole inspections, the completeness of maintenance recordkeeping, and availability of information necessary to perform thorough forensic analysis. As discussed in Order PSC-06-0351-PAA-EI, issued April 25, 2004, in Docket No. 060198-EI, the Commission found:

Utilities capture and maintain varying degrees of inspection data, vintage data, and other performance related data pertaining to the electric infrastructure. Lack of readily available performance data makes it difficult to conduct forensic reviews, assess the performance of underground systems relative to overhead systems, determine whether appropriate maintenance has been performed, and evaluate storm hardening options.

### 3.4.3 Hurricane Matthew Damage

Hurricane Matthew was the first major hurricane to hit Florida’s Atlantic coast since 2004, causing extensive damage without making landfall on the Florida peninsula. It began as a Category 4 hurricane on October 7, 2016, but weakened and later became a Category 2 hurricane northeast of Jacksonville Beach on October 8, 2016. During Hurricane Matthew, over 316,000 DEF customers experienced outages and were restored in less than 72 hours. The company experienced no failed transmission structures.

### 3.4.4 Hurricane Hermine Damage

Hurricane Hermine made landfall in the Florida Panhandle on September 02, 2016, with 80 mph winds. The eye of the storm entered the state east of St. Marks and headed north into Georgia. Hurricane Hermine was accompanied with severe flooding and an eight to nine feet storm surge along the North Florida coastline. Hurricane Hermine impacted around 240,000 DEF customers throughout North Florida. The majority of these customers were restored within 48 hours.
During Hurricane Hermine, DEF suffered two transmission structure failures in Lakewood Acres in Pasco County. A falling transmission pole caused a break in a three-pole 80-foot Class 1 dead-end structure supporting a 69 kV conductor. The three poles were designated as BWR-126A, BWR-126B, and BWR-126C, and were installed in 1982. The engineering forensics report noted the following regarding the weather conditions.

Even though the available weather data shows little wind at the time of failure, we do believe there were remnant bands coming through the area at the time of failure and believe the Service Electric foreman's reporting of heavy rain and gusts up to 30 mph to be accurate. While it’s impossible to know for a fact what the wind was doing at the time of failure, it is interesting to note that the direction of the wind (according to the weather stations) was south. This would have had an additive effect to the top 6 feet of the pole being pulled on by the static to the south.

Maintenance logs show that in a July 2015 inspection, poles BWR-126A, and BWR-126C were graded as in State 4 condition, and recommended for replacement due to woodpecker damage. BWR-126B was graded as in State 5 condition (5 being the worst rating condition) because of woodpecker damage, and recommended for replacement. The company has stated that if a pole receives a State 4 or 5 score, a work order is created for the next year, but replacement could take up to two years. The forensics report noted that it didn’t see any wood rot in the area of the failure.

However, the line was in the process of being rebuilt prior to the storm. Static wire, which provides linear stability, had been removed as part of the construction process two months prior to the storm, causing an imbalance between two towers. The forensics report identified the following as the likely cause of the failure:

The removal of the west static wire created an unbalanced condition and although the math indicates that the pole should still be in tact, it is not, so we know that something caused the pole to fail. I believe that the storm (admittedly mild at 30 mph) exploited the imbalance and found the weak spot in the pole which failed exactly where we’d expect it to fail if the static was the cause of the failure. In addition to failing exactly where we’d expect it to, the pole in question had a knot at the point of failure. While the knot wouldn’t cause the pole to fail, it could well have contributed to the point of failure. I.e. you had a knot in the pole just above the guy wire which is where you’d expect the failure point to be. So the removal of the west static wire two months prior set the failure mechanism in place and then the storm came through and finished it off.

1) Would the pole have failed during the storm if the west static had not been removed?
Very doubtful. Our analysis didn’t record any cyclone activity at the time of failure and with the static in a balanced condition; we believe that the pole would have survived the storm. Our analysis (PLS Pole) shows the pole should have survived a 100 mph wind (w/ 0.75 reduction factor).

2) Did the fact that the pole in question was rated State 4 contribute to the failure?

I’m sure it didn’t help, but we don’t see any rot in the area of the failure, so it’s hard to attribute the failure to the State 4 rating. Probably could be more attributed to a 34 year old pole in general.

The engineering analysis noted that future construction work processes should be discussed with an emphasis on considering the likelihood of a storm during construction.

**JS-169-26 1/2**

JS-169-26 ½, a 70 foot Class 1 tangent transmission pole located 15 miles northeast of Live Oak, Florida, failed at the ground line. The pole fell and rested on pine trees to the west of the line causing an outage. The static wire and conductor remained on the pole and, along with the pine trees, essentially held the pole up. Maintenance records indicate that the pole in question was installed in 1978. The forensic analysis concludes that the pole failure was caused by rotting at the ground line and 40 mph winds.

Maintenance records show that the pole was rated in State 4 condition in September 2012 after a sound-and-bore inspection, yet in 2013, it was rated in State 3 condition after a visual inspection. It had not been replaced by the time Hermine hit in September 2016.

According to DEF, poles are assigned a pass or fail grade and rated from States 1 to 5 during inspections. If a pole is rated as State 4 or 5, which are considered failures, the contractor is required to tell DEF immediately so a work order can be created in DEF’s Asset Management System. The company advised that it creates a job plan for the next year and assigns the work to in-house crews. If a pole is rated a State 4, it is scheduled for replacement the following year, but the replacement may take up to two years. The engineering forensic analysis concluded the following:

As part of this investigation, we interviewed the DEF transmission line supervisor, who indicated that the pole was rotten at the ground line. In fact, he had to dig out around the base in order to have enough to grab on to pull the butt. We also did a site visit on 10-12-16 to take photos and measurements on the pole (both pieces were left on site for the land owner). We saw the same rot that the DEF transmission line supervisor mentioned during our site visit.

The engineer’s site visit noted that the pole had two white tags (one on each side) indicating that the pole was marked for replacement. That indicates the pole was marked for replacement in September 2012, but not replaced until the failure after the September 2016 hurricane. The engineering report recommended two areas for further discussion:
1) How did the 2013 visual inspection rate the pole as State 3 when the 2012 sound-and-bore inspection rated the pole as State 4, and,
2) What caused the pole to not be changed out from 09/2012 until it failed 09/2016?

Commission audit staff believes that references to wood rot bring into question the adequacy and accuracy of prior wood pole inspections.

### 3.5 Commission Audit Staff Observations

**Observation 1:** Based upon DEF’s 2017 through 2019 forensic inspection results, it appears the company’s routine inspection procedures and execution did not provide adequate protection for some transmission lines, structures, and poles. DEF has revised some procedures and states that it is exploring more efficient methods and tools in a variety of activities.

**Observation 2:** Based upon structure failures during 2017 storms, DEF has conducted enhanced diagnostic inspections of transmission lines that have identified lattice towers in need of replacement or repairs. DEF states these inspections will continue, allowing the company to determine the extent of severe corrosion damage within its system.

**Observation 3:** DEF plans to replace wood poles with steel or concrete poles based on the remaining life of the pole and the results of pole inspections. At the current pace, and not accounting for relocation or rebuild projects, the company estimates all wood poles will be changed out by 2050.

### 3.6 Company Comments

Duke Energy-Florida provided the following comments in response to Sections 3.1 through 3.5:

Duke Energy Florida (“DEF” or the “Company”) appreciates the thorough and professional analysis provided by the FPSC Staff as well as the opportunity to provide these comments for inclusion with Staff’s Audit Report.

DEF is committed to a process of continual improvement. The Company strives to improve our processes and procedures based on actual experiences, industry information sharing (or
benchmarking) and the development of new technologies. Our inspection and maintenance practices and procedures for transmission poles and structures are no different in that they always present opportunities for improvement. The Company also notes its desire to make all necessary and prudent improvements while remaining mindful of the impact on customers’ bills. DEF welcomes the audit’s assistance in improving our processes, including specifically processes for inspecting steel lattice towers (particularly lattice towers of a certain vintage), and for improvement in contractor oversight (which DEF is in the process of implementing). The Company also believes it is important to recognize that DEF proactively ordered the inspection of the remainder of the HG line and the enhanced inspections discussed below as soon as it first became aware that there was a potential issue with the state of certain steel lattice structures. This staff audit was performed concurrent with DEF’s ongoing investigation and analysis. Indeed, as of the date of this writing, some final decisions which require balancing storm preparedness, overall reliability, customer impact, etc., have not yet been finalized or implemented.

That said, DEF disagrees with the generalized observations reached by Staff. DEF believes Staff has misinterpreted the causes of the structure failures discussed in the body of the report, and when properly understood, it becomes clear that neither DEF’s inspection nor maintenance practices played a part in those specific failures. Rather, the structures were damaged during severe weather events that produced conditions beyond the structures’ design capabilities. Moreover, Staff’s focus on specific failures during extreme weather events as an indicator of the efficacy of the Company’s inspection and maintenance practices is misplaced. Such a narrow analysis ignores the resiliency of the system overall (during blue-sky days and extreme weather conditions). Further, the Audit Report did not adequately weigh the fact that the vast majority of structures (95.5% during Hurricane Irma and 97.5% during Hurricane Michael) held up well during the storm events, and the great improvement in resiliency since the 2004/2005 storm seasons, when the Commission and utilities placed greater emphasis on storm hardening.

However, DEF recognizes the Audit Report’s Observation that the Steel Lattice Tower Inspection and Maintenance program has not adequately addressed some of the known major-storm reliability concerns the industry is experiencing with aging towers. For that reason, Duke Energy is currently developing a new Tower Inspection and Maintenance program that will consist of the following activities:

- **Tower Cathodic Protection Program:** DEF is performing a pilot in 2020 with plans to start implementation of a cathodic protection installation program for Steel Lattice Towers across its footprint starting in 2021. Cathodic protection installation is a proactive approach that adds resiliency to Steel Lattice Towers by preventing any further corrosion of the steel. In conjunction, Duke Energy will take this opportunity to perform a sub-surface assessment of the Steel Lattice Tower legs to evaluate steel loss and address any discrepancies accordingly. Lastly, the Company will use this opportunity to collect soil data at each structure to develop a database that can be used to help determine areas that are more susceptible to steel corrosion and allow the Company to make more informed inspection and maintenance practice decisions in the future.
- **Drone Inspections:** Duke Energy plans to pilot a drone Tower inspection in 2020 with a target of implementing this inspection in all jurisdictions starting in 2021. The use and caliber of drones has become more attainable in recent years for an activity of this kind, and Duke Energy has proactively trained a select group of linemen to operate drones in and around our equipment. This gives Duke Energy a safe and effective method for evaluating the condition of aging hardware, insulators and other Tower components so that repairs or replacements can be made accordingly. The Company also plans to work with EPRI to help them build their Artificial Intelligence (A.I.) machine learning database that will eventually be able to effectively review these photos and recognize any discrepancies, leading to a more cost-efficient program in the future.

- **Tower Ground Line Patrols:** DEF plans to continue Ground Line Patrols of Towers and plans to establish a Tower Ground Line Patrol specification to clearly list the discrepancies to look for during these inspections and the actions to be taken as a result. Once the specification is finalized, DEF will work with its contractor to implement these changes.

**Observation 1:** Based upon DEF’s 2017 through 2019 forensic inspection results, it appears the company’s routine procedures and execution did not provide adequate protection for some transmission lines, structures, and poles. DEF has revised some procedures and states that it is exploring more efficient methods and tools in a variety of activities.

- DEF disagrees with the auditors’ observation. As noted above, DEF continuously reviews its practices, procedures, and execution in order to improve. However, concentrating on specific failures during a major storm event does not necessarily provide a representative sample of the overall inspection policies and procedures. DEF notes that the auditors failed to include any analysis of overall system reliability or the trend of improving system reliability when measured against comparable major storm events.

- Moreover, DEF does not agree that the forensic analyses the report relies upon support the conclusions drawn. Rather, DEF believes the Report’s Observations are over-broad and at times contradictory to the conclusions (or lack of conclusions) drawn in the forensic analyses.

**Observation 2:** Based upon structure failures during 2017 and 2018 storms, DEF has conducted enhanced diagnostic inspections of transmission lines that have identified lattice towers in need of replacement or repairs. DEF states these inspections will continue, allowing the company to determine the extent of severe corrosion damage within its system.

- DEF agrees that after Hurricane Irma in 2017, additional inspections of lattice tower lines similar to the HG line were warranted to increase confidence in the conditions of those lines. In the context of steel lattice towers, DEF notes that since the 2004/2005 storm season, DEF’s inspection and maintenance practices have been largely focused on wood
poles; indeed, prior to the HG-160 failure in Hurricane Irma, no steel lattice structure on DEF’s system had ever failed due to weather. DEF acknowledges this lack of failures likely contributed to less emphasis on the lattice tower inspections relative to wood pole inspections. However, as discussed herein, the Company has taken proactive steps in the wake of the HG-160 failure.

- DEF does not agree that structure or pole failures identified in Section 3.4.1 of the Audit Report related to Hurricane Michael, a category 5 storm with winds exceeding the facilities’ design standards, support the conclusions in Observation 2. The wind speeds associated with Hurricane Michael exceeded the design limits of those facilities and, along with flying debris and vegetation, were the cause of the failures. Therefore, references to 2018 storms should be stricken from this Observation.

- Based on the damage discovered to the HG-160 tower (discussed further below) as a result of Hurricane Irma (2017), DEF inspected the remainder of the HG line (238 structures) and determined 5 additional towers warranted replacement (completed in January 2019). As stated above, DEF believes it is important to recognize that this audit has been ongoing while DEF has been learning of the issues and deciding on the appropriate next steps from both inspection and proactive maintenance perspectives.

- As discussed in §3.4.2, under the heading “Additional Diagnostic Line Inspections”, based on the findings of the additional HG line inspections, DEF decided to move ahead with more detailed inspections of three lines comprised of similar structures of similar vintage and located in comparable environmental conditions (the Higgins Plant-Curlew line (HGC), the Higgins-Tarpon Springs line (HTE), and the Higgins-Disston line (HD) (rescheduled to 2020 from 2021)). Out of the 82 structures on the HGC and HTE lines, these additional inspections led to the replacement of 2 structures and planned remediation of 14 structures. DEF also notes that additional enhanced diagnostic line inspections may be included in the Company’s Storm Protection Plan filing; however, as the Plan is still being developed and any potential components must be evaluated against the requirements of Rule 25-6.030, F.A.C., DEF cannot be certain of the Plan’s final composition at this time.

§ 3.4.1 – Hurricane Michael Damage -
As discussed above, DEF does not agree the damage caused by Hurricane Michael supports the Report’s Observations as the facilities in Michael’s path were simply not designed to withstand the force of a category 5 storm. Moreover, the forensic analyses discussed in this section do not call into question the company’s inspection or maintenance procedures; indeed, of the forensic analyses discussed in the section, there is only one reference to even “possible wood rot” on one structure that was, at the time of the analysis, found to be in standing water.
§ 3.4.2 Hurricane Irma Damage –
It is important to note that while there were structure failures on the HG line during Hurricane Irma, no customer outages were prolonged due to any transmission structure damage. The damage that was discovered on the HG line led DEF to commission more detailed structural analyses of similar vintage lines located in similar environmental conditions (as discussed above). DEF believes that the forensic analyses discussed in this section of the Report lead to the conclusion that Hurricane Irma’s high winds caused the structure failures being discussed. DEF disagrees that the analyses support a conclusion that questions the adequacy or accuracy of the wood pole inspection process. Rather, DEF believes the conclusion is an over-generalization drawn from a very limited, statistically insignificant sample size.

§ 3.4.4 Hurricane Hermine Damage –
DEF agrees with the general observation noted in this section that Transmission construction projects should be scheduled and performed with an eye towards storm season and its potential impacts. However, DEF notes that transmission construction projects can take multiple months, meaning it is impossible to schedule all such projects around storm season and that all projects are made safe when a storm approaches.

Observation 3: DEF plans to replace wood poles with steel or concrete poles based on the remaining life of the pole and the results of pole inspections. DEF estimates all wood poles being changed out by 2050.

DEF agrees that, under current projections using a 5-year average for planned maintenance change-outs, it estimates that all wood poles on the Transmission system will be changed out by 2050. For context, when considering wood pole replacements for maintenance/hardening reasons, at present DEF does not change out a wood pole before the end of its useful life unless a maintenance-need to do so is indicated by inspection. That said, the 2050 date itself is subject to other variables that could, and likely will, accelerate that timeframe (though the Company cannot provide an estimate of the degree of acceleration), including the Storm Protection Plan that is currently being developed pursuant to section 366.96, Fla. Stat., and Rule 25-6.030, F.A.C. Other reasons a wood pole would be changed out prior to the end of its useful life are for line rebuild projects or DOT relocation projects.
Florida Power & Light Company (FPL) is a wholly-owned subsidiary of NextEra Energy, Inc., providing generation, transmission, and distribution service to nearly five million retail customer accounts. As of December 31, 2018, FPL’s transmission and substation system consists of over 7,100 miles of transmission lines, nearly 68,000 transmission structures, and 645 substations. The majority of circuit miles are overhead with five different voltages ranging from 69 kV to 500 kV, with 6,150 of the 7,100 miles of transmission lines being 138 kV, 230 kV and 500 kV. Ninety-three percent of the transmission structures are made from concrete or steel. Exhibit 2 shows the transmission circuit miles by voltage.

<table>
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<tr>
<th>Voltage</th>
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<tr>
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<tr>
<td>115 kV</td>
<td>772</td>
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<td>138 kV</td>
<td>1,660</td>
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<td>230 kV</td>
<td>3,382</td>
</tr>
<tr>
<td>500 kV</td>
<td>1,108</td>
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</table>

**All Voltages** 7,133

Exhibit 2  
*Source: FPL March 26, 2019 Presentation to Staff*

The company has between 100 – 110 miles of underground transmission, 75 percent of which is located in Dade County. Exhibit 3 shows FPL’s underground transmission miles during the period 2013–2017.

<table>
<thead>
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<td><strong>105</strong></td>
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</table>

Exhibit 3  
*Source: FPL Response to Staff DR-2, Docket 2017-0215-EU*
4.1 Transmission Structure Inspections

4.1.1 Types and Frequency of Inspections
Two annual patrols are conducted to review FPL transmission lines. The first is a cyclical climbing/bucket inspection for all transmission structures. They are conducted by contractors on a six-year inspection cycle for wood structures, and ten-year cycle for concrete or steel structures. Inspectors observe conductors, insulators, guy wires, static/shield wires, anchor rods, grounds, vegetation, danger trees, hardware, and braces and arms.

or the second annual patrol, FPL employees perform ground visual inspections on 100 percent of the 68,000 transmission structures. FPL considers the ground visual inspections to be a quality check on the climbing/bucket inspection. Ground level visual inspections are performed by different assessors than those who perform climbing and bucket truck inspections. FPL believes that using different assessors provide additional safeguards for quality and compliance.

FPL performs helicopter transmission aerial inspections once a year. They may also be completed post-storm for observing vegetation conditions. During the annual aerial inspection, FPL linemen partner with the vegetation management personnel. An FPL arborist observes tree conditions while linemen review the system components. FPL has used a drone inspection program for five years. In 2018, FPL drones flew more than 4,000 miles of transmission lines in Florida. The drones take infrared pictures to identify hot spots at each location. During Hurricane Irma, FPL utilized over 70 certified drone pilots and flew over 1,300 flights within 10 days to assess facility damage.

FPL prioritizes its transmission pole/structure inspections based on factors such as framing configuration (structural loading), transmission components, system importance, customer count, and inspection history for a transmission line section. Other economic efficiencies, such as multiple transmission line sections within the same corridor, are also considered.

If transmission structures are located in hard to reach places such as areas subject to flooding, FPL schedules inspections for when conditions are as dry as possible. Inspectors can use amphibious track vehicles to carry crew and equipment through wetlands, and bucket trucks to assist with inspection of poles.

FPL’s equipment installed in outdoor locations is subjected to the elements, and may rust or deteriorate unless protected. Metals which are not in contact with the earth or bodies of water can be protected by a coating, such as paint. FPL uses cathodic protection for corrosion protection of metals buried in the moist earth, or submerged in water such as underground cable and other equipment. Cathodic protection uses a sacrificial metal anode to attract corrosion, protecting the steel structure.

In 2018, FPL completed all transmission pole/structure inspections consistent with its FPSC approved plan. In 2018, FPL performed ground level visual inspections on 100 percent of its transmission poles/structures. In 2018, FPL also performed climbing or bucket truck inspections on approximately 17 percent of its wood poles/structures, 10 percent of its concrete and steel poles/structures, and conducted storm and pre-construction mitigation patrols on all concrete and
steel poles/structures. Additionally, FPL completed follow-up work in 2018 resulting from its 2017 inspections. In 2019, FPL plans to conduct the same number and type of inspections along with completing follow-up work identified from the 2018 inspections.

4.1.2 Inspection Tracking and Scheduling
FPL’s Asset Management Program (AMP) software includes details for all Transmission and Substation tracking and scheduling. AMP documents inspections, measures compliance with standards/procedures, and provides status updates for each transmission structure. A number is assigned to each structure and specific inspection work task. Assessors perform inspections using field computers to document completion of work tasks for each transmission structure. At the time of inspection, assessors can generate follow-up work tasks directly into AMP. Results are tracked daily with automatic updates directly from AMP dashboards. Results are reviewed monthly with the Power Delivery Lead Team. The same AMP software is used for substations including tracking of breaker number, transformers, and switches.

To assist AMP in tracking inspections, it is tied to the company’s Graphical Information Systems (GIS). Latitude and longitude of all assets in the system is documented. Contractors or FPL employees use field computers to update this information if a pole location proves incorrect.

FPL states that inspections are planned to maximize efficiency and each transmission inspection item is assigned a work task in the program. This inspection data is updated in FPL’s system overnight. FPL states that its systems are standalone and can operate in a disconnected mode. For security, FPL notes it saves documentation and requires users to login and validate identity prior to uploading inspection data.

Through AMP, FPL can track individual transmission structures and review upcoming tasks, create the second inspection for ground visual inspections, and create work tasks. Both contractors and FPL personnel carry computers during transmission inspections and can either complete or follow up work tasks in the system. FPL states it uses dashboards and monthly reports to ensure completion of inspections and follow up items. A monthly status report of execution performance is provided to each Operational Area Manager and the Director of Transmission & Substation Field Operations. These performance charts are reviewed with the Power Delivery Management during monthly operational performance review meetings. Exhibit 4 displays a sample of FPL’s AMP line work tasks dashboard.
The FPL Transmission Technical Services (TTS) and Transmission and Substations Field Operations (TSFO) groups are responsible for transmission facility and substation inspections and maintenance. TTS schedules and tracks transmission climbing and bucket truck inspections and creates the work plan for substation inspections. TSFO schedules and executes ground level transmission inspections and executes substation inspections. All follow-up work identified through inspections is executed by TSFO.

FPL personnel and contractors performing inspections attend annual inspection training based on requirements contained in FPL’s inspection manual. Inspections can only be performed by trained transmission crews, patrolmen, or contract personnel. FPL’s inspection manual provides instructions on conducting transmission structure assessment to determine deterioration levels.

4.1.3 Contractor Management
FPL utilizes contractors to perform cyclical bucket/climbing transmission inspections. Climbing and bucket truck inspections are scheduled and managed by FPL Transmission Technical Services. FPL subject matter experts review safety, reporting requirements, and ongoing activities with the bucket/climbing inspection contractors. Ground visual inspections are performed by independent FPL assessors. If either bucket/climbing or ground visual inspections identify items, the follow-up work is performed by resources different from the inspectors. FPL states that these resources provide FPL feedback on whether the inspection classification was appropriate. FPL states if there is a transmission component failure where the contractor missed a problem on a past inspection, the contractor is sent back to inspect every structure on that circuit.
FPL performs annual ground level visual inspections on 100 percent of its wood transmission poles/structures, inspecting from the ground line to the pole top. The visual inspection includes a review of the pole’s/structure’s condition as well as pole attachment conditions. If a wood transmission pole/structure does not pass visual inspection, it is not tested any further and is designated for replacement with a concrete or steel transmission pole/structure.

At time of inspection, contractors generate any needed follow-up work tasks directly into AMP. Scheduling for contractors to complete work tasks compiled in AMP targets post-storm season months. FPL states it attempts to complete all wood transmission structure inspections prior to June 1st to address concerns before storm season. Quality control reviews of transmission inspections are conducted by service center patrolmen to confirm the reported inspection information.

### 4.1.4 Internal Reporting

Follow-up work tasks from inspections are also documented in FPL’s AMP. Status of each work task is reflected daily on a dashboard linked to AMP. A monthly report, which includes performance charts, is sent to each Operational Area Manager and the Director of Transmission & Substation Field Operations. These performance charts are reviewed monthly with the Power Delivery Leadership team during operational performance review meetings. Material updates on transmission facilities and substation inspections and maintenance progress are provided to senior executive officers and the Board of Directors of FPL as needed. Monthly reliability reports are also provided during the monthly operating performance review, which includes members of FPL’s Board of Directors.

In 2017, FPL conducted an internal audit of its transmission vegetation management program for compliance with North American Electric Reliability Corporation (NERC) Guidelines. NERC Reliability Standard FAC-003-4, *Transmission Vegetation Management*, requires utilities to maintain a reliable electric transmission system by using an in-depth transmission vegetation management strategy to prevent the risk of vegetation-related outages. The overall audit found the controls surrounding the transmission vegetation management program are compliant. The positive results of the audit testing confirmed ongoing compliance with reliability standards.

FPL participates in the North America Transmission Forum, where member utilities advance industry performance by sharing information, including lessons learned and superior practices, to foster effective and efficient reliability improvement. The Forum is built on the principle that open and candid exchange of information among its members is key to improving the reliability of the transmission systems in the U.S. and Canada. Member subject matter experts interact through a private web portal, internet meetings, online surveys and conference calls. Periodic face-to-face meetings allow knowledge transfer on key reliability issues.

### 4.1.5 Wood Transmission Structure Replacement Program

As noted, FPL performs annual ground level visual inspections on 100 percent of its wood transmission poles/structures, inspecting from the ground line to the pole top. The visual inspection includes a review of the pole’s/structure’s condition as well as pole attachment conditions. If a wood transmission pole/structure does not pass visual inspection, it is not tested any further and is designated for replacement with concrete or steel transmission pole/structure.
FPL performs a climbing or bucket truck inspection on all wood transmission poles/structures on a six-year cycle. If a wood pole/structure passes this visual inspection, a sounding test is performed. If the result of a sounding test warrants further investigation, the wood pole/structure is bored to determine the internal condition of the pole. All bored poles not designated for replacement are treated with an appropriate preservative treatment.

FPL’s efforts continue to focus on replacing all remaining wood transmission structures. By year-end 2018, less than 4,900 wood transmission structures remained in place, resulting in a transmission structure population that is 93 percent steel and concrete. During 2019 through 2021, FPL expects to replace 1,000-1,500 wood transmission structures each year with steel or concrete structures. By year-end 2022, FPL expects its transmission structure population to be 100 percent steel and concrete.

4.2 Transmission Vegetation Management

The FPL transmission vegetation management program is designed to manage vegetation from encroaching into the Vegetation Action Threshold (VAT) on 7,100 overhead line miles, which include 74,000 acres of ROWs.

The company notes an important component of FPL’s vegetation program is providing educational information to customers on its trimming program and practices, safety issues, and the importance of placing trees in the proper location. FPL uses its Right Tree, Right Place program as a public education program based on its core belief that providing reliable electric service and sustaining our natural environment can go hand-in-hand and is a win-win partnership between the utility and its customers.

4.2.1 Inspections and Trimming

FPL’s primary objective for its vegetation management program is to clear vegetation in areas where FPL is permitted to trim near the vicinity of its facilities and equipment to provide safe, reliable and cost-effective electric service. The program is comprised of multiple initiatives designed to reduce the average minutes of customer interruption resulting from vegetation-related interruptions. This includes preventive maintenance initiatives (planned cycle and mid-cycle maintenance), corrective maintenance (trouble work and service restoration efforts), and customer trim requests. These initiatives support system improvement and expansion projects, which focus on long-term reliability by addressing vegetation that will impact new or upgraded overhead facilities.

FPL and its contractors use the National Electrical Safety Code and the American National Standards Institute A-300 as standards when performing line clearing. The American National Standard Institute A-300 standard has been accepted as the industry standard for tree and plant pruning and is endorsed by the National Arbor Day Foundation and the International Society of Arboriculture. Danger trees (leaning, structurally damaged, or dead) outside of ROW, which cannot be trimmed by FPL, are candidates for customer-approved removal.
The key elements of the transmission vegetation management program are to inspect the ROWs at least once each year (one ground and/or aerial), document vegetation, prescribe a work plan, and execute the work plan. FPL’s specifications for trimming and pruning are designed to either comply with, or exceed, clearance distances required by NERC.

The company uses an integrated vegetation management (IVM) program to inspect ROWs, promote compatible vegetation, and discourage incompatible vegetation. The company performs post-storm helicopter surveys to assess line and tree conditions after a named storm event. FPL works to inspect flood-prone areas early in the season to ensure access. Aerial patrols are performed each year prior to the peak of the Atlantic Tropical Cyclone season.

Peer patrols are used for corridors designated 200 kV and above to assess the general condition of the line and ensure that every line meets program expectations. An independent patroller performs a peer patrol to create prescriptions and ensure vegetation management practices are aligned with the Vegetation Management Program expectations. The vast majority of peer patrols are done by FPL employees, but FPL may use qualified contract arborists for peer inspections. FPL looks for danger trees and approaches landowners to remove these trees.

Light Detection and Ranging (LIDAR) technology was incorporated in 2018 and is used annually for inspecting NERC lines. Aircraft-based LIDAR equipment occurs along the corridor ROW and is classified by feature class. Vegetation analysis is conducted, and vegetation encroachment risks are identified and categorized by severity. LIDAR allows FPL to issue the inspection results directly to line clearing vendors.

4.2.2 Inspection Tracking/Scheduling
Transmission vegetation management is tracked in FPL’s Transmission Vegetation Management System (TVMS), a geospatial system used to track trees, inspection work types, and due dates. Compliance with transmission vegetation management standards and procedures is measured and verified in TVMS. The work flow and information provided to field crews ensure they are targeting the right trees. Contractors use tablets to document work performed, get work prescriptions approved, and have FPL patrols follow up to ensure that the work has been done. FPL states that TVMS improves efficiency by providing information about accessing ROWs, gate codes, locations, eagle nests, and due dates for the work. Weekly reports identifying completed inspections and exceptions are reviewed by the vegetation management group and tracked against the Annual Work Plan.

The key elements of the program are inspecting ROWs, documenting vegetation status, prescribing and executing the work plan to prevent vegetation from encroaching into the

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6 IVM practices reduce the need for pesticides, promote healthy ecosystems, and provide measurable results, such as greater natural species diversity along ROWs and better control of invasive species. The desired outcome of IVM around utility ROWs is the development of lush shrub or grassy areas that do not interfere with overhead power lines, pose a fire hazard, or hamper access.

7 A prescription defines and quantifies the work activity to meet the objectives of the plan and identifies when the work should be completed.

8 LIDAR is a remote sensing methodology using a pulsed laser to measure ranges, usually from an airborne system. These light pulses are combined with other data to create precise, three-dimensional information about terrain surface characteristics.

9 Every LIDAR point can have a classification that defines the type of object that has reflected the laser pulse. LIDAR points can be classified into a number of categories including bare earth or ground, top of canopy, and water.
Vegetation Action Threshold. Every six months, qualified FPL arborists perform condition assessments of every transmission ROW. Based on the inspections, work prescriptions are defined and managed in TVMS. These work prescriptions are developed based on vegetation growth rates and environmental conditions observed. The identified work prescriptions are prioritized and organized into batches of work which become the annual work plan.

Transmission line maintenance progress is tracked weekly through the System Dashboard. For 2019, the Vegetation Management Program will oversee more than 430 transmission line inspections using LIDAR technology; 5,100 prescriptions or work units including over 250 Quality Assurance locations; 5,800 acres of mowing; and 6,300 acres of herbicide application.

### 4.2.3 Contractor Management

Work by contractors such as mowing, applying herbicide, and tree trimming is managed and documented in TVMS. FPL allows only utility-qualified professional tree-trimming contractors to manage trimming trees and plants around its power lines and equipment. FPL believes its contractors are leaders in the field of utility arboriculture and use industry-standard pruning techniques. Tree-trimming contractors perform the work using “directional pruning” to help trees grow away from power lines. Directional pruning does not interfere with the tree’s natural defense system that protects it from decay.

FPL contractors’ inspection schedules are entered into TVMS and tracked to completion. An FPL independent patroller ensures that previous inspections comply with Vegetation Management Program expectations. FPL performs quality assurance by random sampling of open, scheduled, and completed work, which is reviewed annually to assess performance and identify improvement opportunities.

### 4.2.4 Internal Reporting

Updates on transmission vegetation management and maintenance progress are provided to senior executive officers and the Board of Directors of FPL as needed. Monthly reliability reports are provided during a monthly operating performance review, which includes members of FPL’s Board of Directors. Vegetation management issues addressed by senior executives or the Board of Directors include budgetary and regulatory issues. The Leader of Transmission Vegetation Management meets quarterly with the Senior Director, Central Maintenance and Construction. A weekly report is sent to each Regional Vegetation Specialist, the Leader in Vegetation Operations, and the Manager of Vegetation Management.

### 4.3 Transmission Substation Inspections

#### 4.3.1 Inspections

Substation inspections, including associated breakers, relays, and substation pull-off towers, are conducted by FPL employees. FPL’s Asset Management Program (AMP) documents inspections, measures compliance with standards/procedures, and provides status updates. Infrared (tomography) inspections are performed in substations with vintage connectors and insulators in the spring and fall. The company selectively uses tomography on transmission structures most likely to experience failures.
In 2013, FPL initiated several transmission storm surge/flood initiatives to better protect certain transmission facilities and expedite restoration of service to customers. This included water intrusion mitigation and the installation of real-time water level monitoring systems and communication equipment inside 223 flood-prone substations in FPL’s system. The substation flood monitors have two elevations; the higher monitor is for protective relay equipment. In the event that debris or flooding damages substation equipment, FPL can set up a substation on wheels to restore service to customers.

During the 2016–2018 storm seasons, the majority of substation outages resulted from transmission outages. Flooding did occur at two substations, however, as a result of FPL’s flood mitigation equipment/emergency alarms; FPL was able to proactively de-energize these substations, which prevented significant damage. Substation flood monitoring is maintained 24/7 at the FPL Control Center in Miami.

### 4.3.2 Inspection Tracking and Scheduling

As with Transmission Tracking and Scheduling, AMP software includes details for all substation tracking and scheduling. AMP documents inspections, measures compliance with standards/procedures, and provides status updates. Assessors perform inspections using field computers and document completion of inspection work tasks for each transmission structure. FPL Transmission and Substations Field Operations executes ground level transmission inspections, substation inspections, and follow-up work identified through inspections.

Inspections are performed by trained transmission crews, patrolmen, or contract personnel. FPL’s inspection manual provides a methodology and basic instructions to properly conduct transmission structure assessment to determine deterioration levels.

### 4.3.3 Quality Assurance

Ground level visual inspections are performed by different assessors than those who perform climbing and bucket truck inspections. Quality control reviews of transmission inspections are conducted by service center patrolmen to confirm the reported inspection information.

### 4.4 2016–2018 Hurricane Season Transmission Facility Damage

With Florida’s significant coast-line exposure, FPL believes it is the most susceptible electric utility to storms. Between 2016 and 2018, FPL was impacted by four hurricanes, Nate, Hermine, Matthew, and Irma.

Post-storm forensics reviews are conducted based on the level of damage to infrastructure and the perceived priority of deploying forensics teams to review damage before completing restoration. FPL forensic investigators use pole failure rates as the primary measurement criteria to evaluate performance of hardened vs. non-hardened feeders within the impacted areas. Based on these findings, FPL’s damage forecast models can be re-calibrated and lessons learned incorporated into future engineering design standards.
Storm track information is imported to FPL’s mobile mapping and field automation software for identification of storm-affected equipment. This software visually identifies the facilities to be patrolled and provides the tools needed to perform forensic work.

4.4.1 Hurricane Irma Damage
Hurricane Irma made landfall in Florida on September 10, 2017, as a Category 4 hurricane in the Florida Keys and Monroe County; then made a second landfall on the same day as a Category 3 hurricane in Marco Island and Collier County. The storm continued to weaken as it moved over Florida, affecting all 67 counties in the state and resulting in widespread power outages. Hurricane Irma impacted all 35 counties across the 27,000 square miles of FPL’s service territory causing outages for 4.4 million (90 percent) of FPL’s customers. All FPL substations were energized within two days after Irma made landfall. Fifty percent of the outages were restored within one day, with all service restored within ten days.

FPL provided post-storm forensic reviews that identified five wooden transmission pole failures, one wood pole on a Bulk Electric System 115 kV circuit, and four wood poles on a 69 KV circuit, which are further described below. In total, FPL’s system experienced 127 transmission line outages, 215 transmission line section outages, and 92 transmission substation outages. Of the 92 transmission substations, 86 were out due to transmission line outages, four for equipment damage (Delta, Haulover, Lighthouse and Memorial), and two were proactively de-energized due to flooding (St. Augustine and South Daytona).

According to FPL, most of the outages were caused by falling vegetation and some by wind-blown debris. Thirteen underground line sections were isolated due to contamination at the substation line terminals, two line sections were de-energized to isolate the St. Augustine substation due to flooding, and two line sections were de-energized to isolate South Daytona substation due to flooding.

Overhead, non-hardened transmission facilities experienced a 20 percent outage rate, while overhead hardened transmission facilities experienced a 16 percent outage rate. Protective relay systems and breakers were called on to clear 150 short circuit events and had only two misoperations. Substations were back in service in one day. No underground section was damaged or failed causing an outage.

**Deland-Putnam 115 kV - One Wood Transmission Structure**
As a result of Hurricane Irma, one single pole wood structure (75G3) was replaced on the Deland-Putnam 115 kV Line, Satsuma Tap-Putnam Tap Section. The poles had been inspected earlier in 2017. The pole was reported as Level 4 condition. Winds in the area were reported to be 61-80 mph gusts or higher. An approximately 80 foot tall slash pine tree was reported to have fallen on the transmission line which caused the pole to fail.

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10 A relay misoperation is a failure to trip or tripping unnecessarily.

11 FPL transmission structure inspection results are categorized into four (4) levels as follows: Level 1: condition approaching the minimum NESC requirements with potential to fall below the minimum during current year; Level 2: condition approaching the minimum NESC requirements but will not fall below the minimum before the end of the following year; Level 3: additional inspection required; and, Level 4: component currently above the minimum NESC requirements and expected to remain as such until the next climbing or bucket inspection.
Okeechobee-Sherman #1 69 kV Sweatt Tap - Four Wood Structures
As a result of Hurricane Irma, four single pole wood structures (73K13, 74K1, 76K8, and 81K8) with distribution underbuilt were replaced on the Okeechobee-Sherman #1 69 kV Line. There were three separate failure locations. All four poles were inspected in June 2017, and only 76K8 and 74K1 (two of the four poles) were identified for replacement in 2018/2019. Deterioration in 74K1 left a 1” thick shell remaining at ground line. Its fall brought down 73K13. Structure 76K8 came down alone. Structure 81K8 was identified as a level 4 (replacement not required) in its last inspection. All wood transmission structures are scheduled to be replaced with concrete or steel structures as part of FPL’s storm hardening plan.

4.4.2 Hurricane Matthew Damage
Hurricane Matthew began as a Category 4 hurricane on October 7, 2016, but weakened to become a Category 2 northeast of Jacksonville Beach the next day. Hurricane Matthew never made landfall in Florida, remaining a few miles off the eastern coastline where some areas experienced sustained hurricane force winds. The storm impacted more than 1.2 million customers across major portions of FPL’s service area. FPL restored 99 percent of customers affected within two full days following Hurricane Matthew's exit from its service area.

No FPL transmission poles failed due to high winds. One transmission pole was replaced due to wave action washing out the foundation, however it did not cause an interruption. Trees falling from outside the ROW caused 39 transmission line section outages, 22 substations were out of service, seven substations experienced transformer lock-outs, and the St. Augustine substation experienced flooding and was de-energized.

4.4.3 Hurricane Hermine Damage
Hurricane Hermine made landfall east of St. Marks on September 2, 2016, near Wakulla and Jefferson counties. Hurricane Hermine was a Category 1 hurricane when it made landfall, primarily affecting the Big Bend area, but also impacted FPL’s service territory. During Hurricane Hermine, FPL crews worked to restore service to 100 percent of the 119,898 customers impacted by the storm within 24 hours of Hermine's passing. Customers experienced average outage duration of less than three hours. FPL experienced two transmission line failures caused by vegetation, but no poles down. FPL believes that smart grid automated switches helped prevent 25,000 customer interruptions.

4.5 Commission Audit Staff Observations

Observation 1: FPL plans to proactively replace all 4,900 remaining wood transmission poles with steel or concrete by 2022.

Observation 2: Lattice towers have never been an engineering design for transmission line towers at FPL. The company does have lattice pull-off towers inside substations.
4.6 Company Comments

FPL opted to provide no comments regarding Sections 4.1 through 4.5 above.
5.0 Florida Public Utilities Company

Florida Public Utilities Company (FPUC), a subsidiary of Chesapeake Utilities Corporation, acquires electricity for approximately 30,000 customers through purchased power agreements. FPUC operates a Northeast Division in Nassau County and a Northwest Division in Calhoun, Jackson, and Liberty counties. Company-owned transmission facilities are exclusively located in the Northeast Division in Fernandina Beach, Amelia Island. FPUC’s transmission system contains 267 structures, 11.45 miles of 69 kV lines, 4.42 miles of 138 kV lines, and four substations.

Due to its small Amelia Island service territory, FPUC’s transmission structures are limited in number compared to other Florida investor-owned utilities. Concrete structures account for 56 percent of all transmission structures. There are no wood structures in the 138 kV system. The company has four, 138 kV lattice towers fortified with cathodic protection via sacrificial anodes. Exhibit 5 lists company-owned transmission structures by material and voltage:

<table>
<thead>
<tr>
<th>Material</th>
<th>69 kV</th>
<th>138 kV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wood and Wood Span Guys</td>
<td>112</td>
<td>0</td>
</tr>
<tr>
<td>Concrete</td>
<td>105</td>
<td>44</td>
</tr>
<tr>
<td>Steel</td>
<td>0</td>
<td>6</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>217</strong></td>
<td><strong>50</strong></td>
</tr>
</tbody>
</table>

Exhibit 5

In a purchased power agreement effective January 2018, FPUC sold 45 of its 138 kV structures and 3.6 miles of 138 kV transmission lines to Florida Power & Light (FPL). The sale reduced FPUC’s company-owned 138 kV structures by 47 percent. FPUC states that the sale was required to provide clear operating boundaries and to maintain NERC compliance. FPL is now responsible for inspecting and maintaining the lines and structures. FPUC receives updates on the operational status of the third-party transmission system.

FPUC has no underground transmission lines in its system. A private committee met with FPUC to propose undergrounding part of a 69 kV line on Amelia Island in 2017; however, the project did not proceed. FPUC states that its transmission lines that extend over or near coastal waterways were planned to meet or exceed NESC requirements for those conditions. FPUC installs concrete poles that meet current NESC requirements when there is new construction and as wood poles are replaced due to concerns about structural integrity.
5.1 Transmission Structure Inspections

FPUC schedules four transmission inspections at different intervals to ensure that all transmission structures and associated hardware are regularly reviewed and maintained.

5.1.1 Types and Frequency of Inspections

**Annual EOP T-01 Overhead Transmission System Inspections**

FPUC staff inspects its company-owned transmission system structures, equipment, and conductors annually. This visual review looks for deterioration, broken ground wires, damaged arresters, leaking oil, damaged conductors, code violations, and unsafe conditions, including those caused by danger trees. Inspectors use hard copies to input pole material, condition, grounding, statics, arrestors, insulators, and field notes, which the company retains. The inspections are shared with the Electric Operations Manager to address problems found.

**Eight-Year Inspection Cycle Program for Wood Poles**

FPUC uses a contractor to inspect wood transmission structures on an eight-year cycle. Approximately 12 percent of structures are reviewed each year. Management states that the inspection looks for danger poles at risk of failure. The contractor performs several steps to systematically identify reject poles. First, the inspector visually reviews poles for defects that require a pole to be replaced. The poles that pass the review are sounded and bored to identify internal decay. The poles that pass the sound and bore are excavated and subject to strength and loading assessments. Poles that are suited for continued service are chemically treated.

Chromated copper arsenate (CCA) poles less than 21 years old undergo a modified inspection process. The poles are sounded and only bored if internal decay is suspected. The poles that fail the sound and selective bore are excavated for further review. FPUC formerly performed excavation sampling on one percent of CCA poles that would not normally meet the criteria for a full excavation. FPUC discontinued sampling in its 2013–2015 Storm Hardening Plan, noting that sampling data had not indicated a need to continue.

In carrying out the eight-year wood pole inspections, the contractor gathers information including pole specifications, treatments, and field notes. The contractor classifies poles as rejects or non-rejects and uploads the inspection results to its online data center. FPUC accesses the results to run reports, review findings, gather information to be submitted in annual reliability filings, and plan replacement work. A reject pole is an excavated pole with less remaining strength than what is required for its current application or less than 33 percent of its original strength. A transmission pole may also be rejected if its minimum average shell thickness is less than three inches.

FPUC inspects the rejected poles using bucket trucks to verify the contractor inspection results and plan replacements. The company prioritizes transmission replacements based on the severity of decay and pole location. Although there is no formal timeline to replace failed transmission poles, FPUC states that replacements generally occur within a year.
**Six-Year Transmission Structure Drone/Climbing Inspections**

All FPUC transmission structures are subject to a detailed, six-year inspection to review structures, insulators, grounds, cross-braces and cross-arms, splicing, shield wires, and bolts to ensure they are secured and in good condition. The most recent inspection occurred December 2018 and a contractor inspected 263 structures. In previous years, when transmission structures were difficult to access, FPUC waited until flood-prone areas were dry prior to inspection. At the most recent inspection, contracted personnel certified by the Federal Aviation Administration used drones to assess the structures. The contractor also visually reviews structures at the ground level. Although no sounding or boring is done, the contractor may excavate if there is a concern about pole condition.

The contractor records field notes, grades each structure between 1 and 5 with 1 indicating no issues, and recommends monitoring, minor maintenance, work plan activity, or action required. Monitoring is advised for poles with surface rust, minor cracks, or minimal bird damage. The company monitors these structures through its annual EOP T-01 overhead transmission inspections. The contractor advises minor maintenance for non-critical issues that require minimal repairs. Transmission structures identified for the work plan may have significant rust, missing concrete pieces, deep cracks, decay, or bird damage near hardware. Action required is advised for steel structures that are missing parts, structurally unstable, or deeply rusted, and for wood poles with hollow cores or extreme bird damage. FPUC plans to replace wood poles marked action required as soon as possible.

Climbing patrols may supplement this inspection if FPUC believes that the drone results are unclear or suspects that wood pole damage is more extensive than what is visible in drone footage. As a form of quality assurance, FPUC staff uses a bucket truck to perform a visual follow-up inspection on poles recommended for minor maintenance or the work plan.

**Annual Infrared and Cathodic Protection Inspections**

FPUC conducts annual infrared inspections to review the entire transmission system for hot spots, which indicate poor connections. This inspection is done by FPUC staff and scheduled in summer periods of high load. FPUC surveys transmission lines from the ground using a vehicle to take photos and temperature readings. The inspection results are documented using hard copies and retained for at least seven years.

FPUC observes that transmission facilities in the Northeast Division are at increased risk for corrosion due to salt exposure, which can affect connectors, terminals, and splices. The company’s four 138 kV steel lattice towers are equipped with sacrificial anodes. Twice annually, FPUC staff reviews the status of the cathodic protection to ensure it is sufficient to protect the structures.

In 2018, eight-year transmission wood pole inspections and planned replacements of four transmission structures were delayed due to Hurricane Michael. FPUC will perform the delayed and current wood pole inspections in 2019. In December 2018, the six-year transmission inspection utilizing drones identified decay, corrosion, or wood pecker damage on several structures. FPUC has not yet repaired any corrosion identified on steel structures but plans to brush rust and repaint the affected areas. Fourteen wood poles are scheduled for replacement...
with concrete in 2019 and 2020, including those identified at the six-year inspection and the four replacements delayed from 2018.

5.1.2 Inspection Tracking and Scheduling
Transmission structure inspections are tracked via Excel spreadsheets, Word documents, and hard copies. Eight-year wood pole inspection results are tracked via the contractor’s online data center, which incorporates information from FPUC’s geographic information system. The company uses the third party data center to track inspection data and gather information for reliability filings.

FPUC’s Outage Management System (OMS) serves as a general asset management tool to track service outages, calculate reliability indices, and aid restoration activities. The company updates information in the OMS after the wood pole ground line inspections. The outage management system incorporates data from the company’s geographic information system, illustrating spatial connections between transmission and distribution systems and substations.

FPUC’s Director of Electric Operations and Northeast Electric Operations Manager are responsible for overseeing transmission maintenance and inspections. The Northeast Electric Operations Manager oversees 18 staff including substation technicians, engineers, and linemen. The Operations Manager is responsible for ensuring that transmission inspections are scheduled and performed and that any problems are corrected.

FPUC uses contractors to conduct transmission maintenance and inspection activities requiring specialized equipment such as bucket trucks with heights exceeding those owned by the company. Work involving energized transmission lines is also outsourced to a contractor.

As noted, the eight-year wood pole inspections and the six-year transmission inspection utilizing drones are performed by contractors.

5.1.3 Contractor Management
FPUC performs quality assurance reviews by re-inspecting structures rejected in the eight year transmission wood pole inspections to verify the contractor results. FPUC also re-inspects transmission structures recommended for maintenance or the work plan in the six-year transmission inspection.

FPUC states the Manager of Electric Operations assigns routine transmission structure and substation inspections based on the availability of staff or outside contractors to ensure the inspections are high quality. FPUC provides training to outside crews involved in restoration activities. These crews undergo a safety and work process briefing on arrival, prior to commencing activities.

5.1.4 Internal Reporting
FPUC states that the Board of Directors is generally not updated about transmission inspections and maintenance unless a significant expenditure is involved. Senior management conducts quarterly operational meetings to review overall performance, including updates on electrical inspections. Senior staff meetings occur every one to four months and review any abnormal transmission inspection findings. These meetings are scheduled immediately if safety concerns are discovered or if post-inspection activities require further approval.
FPUC internally tracks transmission inspection results using hard copies, Word documents, and Excel spreadsheets. Transmission inspection results are reviewed by management to develop and address corrective actions. The company states that annual transmission inspection reports are monitored for budgeting and tracking needs.

**Audits**

In 2014, FPUC completed an internal audit of its vegetation management practices, which evaluated contractor selection, safety training, compliance with trim specifications, and performance assessments of transmission and distribution vegetation management. Based on audit recommendations, FPUC updated contractor insurance coverage and safety training and required additional documentation and performance assessments for vegetation management.

FPUC received a NERC compliance audit in 2010, which reported no findings. The company currently completes an annual self-certification with the SERC.

FPUC meets with the Edison Electric Institute and the Southeastern Electric Exchange each year to discuss lessons learned, best practices, and restoration logistics.

**5.1.5 Wood Transmission Structure Replacement Program**

FPUC replaces wood transmission poles with concrete poles due to maintenance or construction requirements or when the company is concerned about the integrity of the pole. FPUC elects to replace wood poles that fail inspection rather than to brace them. Transmission wood pole replacements are prioritized based on the severity of decay and pole location. Of FPUC’s current 112 wood structures, the company estimates the failure rate of wood pole inspections of transmission and distribution poles to be at or below 5 percent annually.

FPUC states that it replaces failed wood poles with concrete rather than steel because its transmission system on Amelia Island is near the ocean and salt spray and rust are concerns. Hardened poles must comply with the National Electrical Safety Code and Commission wind specifications. After the Commission ordered new storm hardening initiatives in 2006, FPUC adopted a NESC extreme wind loading standard of 130 mph in its Northeast Division.

Although scheduled wood pole inspections were delayed to 2019 due to Hurricane Michael, FPUC completed its six-year transmission inspection using drones on 263 transmission structures in December 2018. FPUC states that structural and material failures identified by the inspection will be addressed as soon as practical. The company plans to replace 14 wood poles with concrete in 2019 and 2020. FPUC will carry out delayed transmission wood pole inspections alongside regularly scheduled inspections in 2019. Moving forward with the creation of Section 366.96, F.S., the company hopes it will have the ability to replace wood transmission poles more quickly in the future.

**5.2 Transmission Vegetation Management**

FPUC’s transmission vegetation management procedures are designed to ensure safe and reliable electric service and to comply with the National Electric Safety Code, Commission rules, and
local ordinances. Vegetation management contractors are required to furnish personnel trained in ANSI A300 tree trimming standards and an OSHA-approved line clearance certification program.

Management states that standards regarding transmission rights-of-way (ROWS) are based on codes, clearances, and specific industry standards. Optimal clearance for 138 kV transmission lines is 30 feet with a minimum of 15 feet and optimal clearance for 69 kV lines is 15 feet with 10 feet of minimum clearance. FPUC does not apply these standards to scenic or canopy roads as designated by Nassau County or the city, nor does the utility engage in trimming on private property without authorization from the landowner.

5.2.1 Inspections and Trimming
Transmission vegetation management activities include inspecting, mowing ROWs, following trim cycles, removing danger trees, and processing customer trim requests. In 2018, FPUC contractors trimmed all 15.8 miles of its transmission lines, 100 miles of distribution feeders, 47 miles of distribution laterals, and removed 102 danger trees.

Transmission lines in the Northeast Division are trimmed on a three-year cycle, although spot trimming may occur more frequently. As part of this cycle, FPUC visually checks transmission lines at least twice annually, with the first inspection occurring before hurricane season. Certain transmission structure inspections may also note overgrown vegetation conditions. Transmission ROWs are cleared using a bush hog to ensure vegetation does not reach the lines or limit site access. FPUC prioritizes removal of danger trees near main feeders.

When vegetation encroachments occur on private property, FPUC works to obtain permission from the landowner to address them. When a danger tree poses an immediate risk to 69 kV lines and FPUC requests the removal, the customer will not be charged for the removal or clean up. Vegetation management requests from customers are required to be reviewed within four days of receipt. If the customer requests removal of a danger tree, FPUC will trim the tree so that the customer may safely remove the remaining structure and clean up at their own expense.

The company notes that most customers do not complain about the removal of dead trees. However, FPUC states it has experienced pushback on tree trimming outside of ROWs. FPUC’s Manager of Government Relations in the Northeast Division interfaces with local government and community leaders and responds to customer concerns. The company notes that it engages with communities on undergrounding and vegetation management to address vegetation management concerns and enhance reliability.

5.2.2 Inspection Tracking and Scheduling
The key managers responsible for transmission vegetation management are the Director of Electric Operations and the Electric Operations Manager in the Northeast Division. The company tracks transmission vegetation management through hard copies, Excel spreadsheets, and Word documents. The Line Supervisor pulls contractor data from weekly time sheets into a productivity log and produces monthly vegetation management progress reports. Vegetation management progress is reported to the Commission through reliability filings. The company’s geographic information system is used to obtain the current miles of feeders and laterals upon the completion of a six-year cycle in order to plan for activities in the next cycle.
FPUC engages in transmission vegetation management throughout the year, noting that the area has a high water table and experiences constant vegetative growth. Scheduling is handled in accordance with the operational requirements for each division and compliance with the three-year transmission cycle. Trimming activities are scheduled by the Electric Operations Manager.

5.2.2 Contractor Management
Vegetation management contractors are overseen by the Electric Operations Manager and the Assistant Manager. They meet with contractors weekly to monitor compliance with internal procedures and schedules. The Line Supervisor oversees vegetation management crews, specifying locations to be trimmed and reviewing contractor work weekly for safety, productivity, and compliance with FPUC standards. The Line Supervisor verifies contractor timesheets and invoices and tracks contractor output. Internal policies require vegetation management contractors to meet FPUC guidelines for purchasing and safety and ensure that contractor personnel are trained in ANSI A300 standards and an OSHA-approved line clearance certification program.

Quality assurance for transmission vegetation management occurs through on-site reviews and documentation provided by contractors to FPUC management. The Line Supervisor provides feeder maps and supervises contractor tree trimming crews daily. The Electric Operations Manager conducts random field inspections of transmission vegetation management weekly and will dispatch contractor vegetation management crews immediately to address any issue that could affect system reliability. The contract crews are subject to periodic on-site visits by the contractor’s area supervisor. Vegetation management contractors submit weekly cutting reports, which track compliance and productivity.

5.2.3 Internal Reporting
The Board of Directors reviews updated vegetation management expenses during routine meetings. The Line Supervisor develops and shares completed feeder maps and progress reports with the Electric Operations Manager. FPUC uses weekly reports provided by contractors to develop internal monthly progress reports and to provide data to the Commission through annual reliability filings.

5.3 Transmission Substation Inspections

5.3.1 Inspections
The company’s Northeast Division operates four transmission substations, including one 138 kV stepdown substation subject to NERC standards. FPUC staff performs annual substation inspections and quarterly and monthly walkthroughs. Contractors are used for most substation tests involving relays, potential transformers, current transformers, and substation construction.

Annual transmission substation inspections review structures, grounding, bolts, bracing, buss work, and insulators for integrity. Oil testing for transformers, regulators, and oil circuit breakers is done annually. Staff performs quarterly and monthly walkthroughs of substations to determine whether equipment is performing within parameters. The monthly walkthrough is a visual inspection and the quarterly inspections involve more detailed analyses of battery components.
FPUC is subject to NERC maintenance intervals in accordance with PRC-005-6. FPUC elects to inspect substation equipment using NERC time-based rather than performance-based maintenance because performance-based maintenance intervals require extensive data and analysis.

During 2018, FPUC completed four annual transmission substation inspections and tested or maintained substation components. The company has scheduled regular substation maintenance and inspection activities through 2019. FPUC is hardening certain substation control buildings to protect its system against future storms. The company recently hardened a control building at its 138 kV transmission substation, installing a new roof and replacing a window with concrete.

5.3.2 Inspection Tracking and Scheduling
Transmission substation inspections are tracked using Excel spreadsheets, Word documents, and hard copies. These documents track assets, serial numbers, maintenance intervals, and test dates. Substation inspections are reported annually and components are required to be maintained and inspected at intervals specified by FPUC and/or NERC.

If a problem is found during inspections, a technician contacts the Manager of Electric Operations or the Manager of Technical Projects. E-mailed notifications are addressed to the Director of Electric Operations. Maintenance items found during substation inspections are repaired at the time of inspection or put on a maintenance list to be remedied as soon as possible. If a system or component failure is not repaired by the next maintenance cycle, FPUC management classifies it as an unresolved maintenance issue. The company requires documentation of the steps taken to address the issue.

5.3.3 Quality Assurance
FPUC management is responsible for scheduling and tracking maintenance and testing on transformers, circuit breakers, relays, batteries, and chargers at transmission substations. FPUC states that when a contractor performs work at a substation, a FPUC employee is present for security and to ensure the work is done safely. Prior to commencing work, a technician performs a walkthrough with the contractor. A FPUC employee is required to be present to oversee switching. FPUC employees undergo an internal certification process to ensure they are qualified to perform switching activities.

5.4 2016–2018 Hurricane Season Transmission Facility Damage
FPUC’s transmission system did not experience significant damage during the 2016–2018 storm seasons. The company’s service territory was affected by Hurricanes Hermine, Matthew, Irma, and Michael. During these storms, FPUC participated in the Southeastern Electric Exchange and exercised mutual assistance agreements with Florida municipalities, accessing resources nationwide.

FPUC states that after a named storm impacts the service territory, it initiates a forensic analysis of locations that meet reportable criteria. Although several named storms affected the company from 2016–2018, only one forensic analysis was performed, after Hurricane Michael. The
company states that its practice is to conduct a forensic analysis on all transmission and distribution poles that are leaning or unrepairable. The FPUC Forensic Team Leader, generally a full-time manager, coordinates overall forensic efforts, deploys groups, reviews observations, and reports the results. A third party consultant or teams from the Southeastern Electric Exchange collect storm data related to failed poles, damaged wires and equipment, and outage causes. These forms track pole age, wind grade, and height; previous inspections and repair work done on the pole; whether decay or deterioration existed; the location of breaks; leaning structures; equipment conditions; and whether the damage is part of a cascade.

If a transmission pole fails during normal business operations due to a mechanical issue or if a warranty is involved, FPUC may further investigate or involve the manufacturer to determine the cause of failure. If a transmission pole fails due to age, corrosion on metal structures or hardware, salt spray contamination, or wood rot, no further inspection is done. The company believes that with the inspection processes it has in place, wood transmission poles would not reach the point of failure due to wood rot. FPUC states that its wood poles typically fail due to vehicle impacts or falling trees.

5.4.1 Hurricane Michael Damage

Hurricane Michael made landfall on October 10, 2018, as a Category 5 hurricane with maximum sustained winds of 161 mph. All of FPUC’s 15,355 Northwest Division customers in Liberty, Calhoun, and Jackson counties lost service. Approximately 10 to 12 percent of FPUC’s system in the Northwest Division required a complete rebuild and the rest required repairs.

Since FPUC-owned transmission structures and substations are located in the Northeast Division, damage to transmission infrastructure was limited to Gulf interconnections serving FPUC customers. FPUC observed that several third-party transmission structures in its service territory had damaged cross-arms and insulators due to falling trees. FPUC contacted the third party’s control center for status updates on whether the transmission system was operational.

FPUC communicated with the Southeastern Electric Exchange Mutual Assistance Committee. Thirty-five FPUC employees from the Northwest Division and 50 employees from elsewhere in the company worked alongside 1,155 contract employees to restore power. FPUC leveraged its employees, contractors, and volunteers for line work, tree crews, and clean up. The substantial number of contract employees posed logistical challenges to FPUC involving staging sites and accommodations. After third-party transmission resources were restored by October 18, FPUC proceeded with customer restoration. Ninety-five percent of FPUC customers capable of receiving power were restored by November 1. However, nine percent of customers in the affected areas were unable to receive service due to significant property damage. Ultimately, FPUC experienced a permanent loss of approximately five percent of its customers.

Immediately after the storm, FPUC dispatched damage assessors to review feeders and provide information needed to plan repairs, such as materials needed. Line crews simultaneously worked to restore the electrical system. After the damage assessment, FPUC assigned contracted personnel to perform the forensic analysis on 88 distribution feeders where significant damage had occurred. The FPUC Forensic Team Leader selected the locations to be inspected and provided the contractor with maps and forms to gather data. FPUC used this data to determine that 98 percent of damaged poles surveyed were non-hardened and the causes of damage by
frequency were the cascade effect, trees, wind, and debris. The company observed that trees inside and outside road ROWs caused damage to distribution lines. FPUC summarized the forensic data in its reliability filing in March 2019.

5.4.2 Hurricane Irma Damage
Hurricane Irma made landfall in Florida on September 10, 2017, as a Category 4 storm. The company’s Northeast Division customers on Amelia Island were subject to a mandatory evacuation. The service territory experienced maximum sustained winds of 45–50 mph and gusts of 71 mph, resulting in outages to 16,036 customers in Nassau County. An additional 74 customers in Calhoun and Jackson counties lost service. The company received 48 distribution linemen and vegetation management resources through mutual assistance agreements. Restoration began on September 11 and all customers capable of receiving electrical service were restored by September 15.

A fence at a transmission substation was damaged by tree limbs and subsequently repaired. A visual inspection found that one 70-foot wood transmission pole was broken due to high winds. The pole received its eight-year wood pole inspection in 2013 and the inspection indicated no need for replacement. FPUC states that wood decay did not contribute to pole failure.

FPUC reported to the Commission that it repaired nine additional non-hardened transmission structures after Hurricane Irma. The company states it has no maintenance records for the repaired structures and notes that it was not consistent in documenting this information at the time. FPUC damage assessors reported that vegetation was the primary cause of storm-related outages.

5.4.3 Hurricane Matthew Damage
Hurricane Matthew affected the eastern coast including FPUC’s Northeast Division in October 2016. The hurricane resulted in outages to 15,693 customers in Nassau County. The company’s service territory experienced maximum sustained winds of 39 mph and gusts of 87 mph. Fernandina Beach experienced a peak storm surge of nearly ten feet. FPUC customers were subject to a mandatory evacuation of Amelia Island. The company requested mutual assistance aid including 40 distribution linemen. Restoration activities began on October 8 and all customers capable of accepting service were restored within two days.

Upon visual inspection, FPUC found that a wood transmission pole was damaged by high winds and a falling tree. This pole was later replaced. The company notes the pole was manufactured in 1968 with an unknown wind rating. Inspection records for this pole were determined to be current. The company states that wood decay did not cause the pole to fail. FPUC repaired four non-hardened transmission structures and one substation as a result of Matthew. Damage assessors identified vegetation as the primary cause of storm-related outages. However, the company states it does not have maintenance records for the repaired structures.
5.5 Commission Audit Staff Observation

Observation 1: FPUC will work towards replacing its remaining 112 wood transmission structures (out of 263 total transmission structures in its Northeast Division) with concrete structures over time as maintenance, inspection, and construction activities require new poles.

5.6 Company Comments

FPUC opted to provide no comments regarding Sections 5.1 through 5.5.
6.0 Gulf Power Company

Gulf Power Company (Gulf) serves approximately 463,000 Northwest Florida customers, with nearly 50 percent living within one mile of the coast or major body of water. As of January 1, 2019, Gulf became a subsidiary of NextEra Energy, Inc. (NextEra), and has begun to work with Florida Power and Light Company (FPL) on sharing best practices, consolidation of systems, and finding common solutions.

Gulf’s Transmission System consists of 1,670 miles of lines (58 miles of 46 kV, 1016 miles of 115 kV, and 595 miles of 230 KV), 4,817 wooden structures, 5,035 concrete structures, and 605 metal structures. The only non-overhead transmission lines on Gulf’s system are two underwater submarine crossings.

6.1 Transmission Structure Inspections

6.1.1 Types and Frequency of Inspections

Gulf’s Transmission Line Inspection Standards guide a program of ground line inspections, walking comprehensive inspections, and aerial inspections. Gulf contracts its ground line inspections but uses both company employees and contractors to perform comprehensive walking and aerial inspections. This inspection program has been a component of Gulf’s Storm Hardening Plan since 2007. The transmission structure inspection program is based on two alternating twelve-year cycles, which results in each structure being inspected at least every six years. Substations are inspected annually based on Gulf’s Substation Inspection Criteria. The Standard Transmission Operations and Maintenance Program (STOMP) application is used to schedule and track progress.

The Ground Inspection is a standalone inspection, and may be used as a follow-up to the Comprehensive Aerial Inspection or as an In-Service Inspection to verify operation. The objectives are:

- To thoroughly evaluate the reported problems and condition of the transmission facilities, inspect the transmission line, and record the associated abnormal situations and attributes.
- To conduct a visual ground inspection in compliance with the Southern Company Transmission Line Inspection Guidelines.

The objectives of the Comprehensive Walking Inspection are:

- To identify and record field problems and abnormal situations in Gulf’s Transmission Line Inspection System (TLIS).
- To identify wear and deterioration on structures and conductor hardware.
♦ To observe and assess rust damage to steel guys, grips, and shield wire to assist in prioritizing replacements.

♦ To climb selected structures when visual inspection shows an area of concern to determine the scope of the problem.

♦ To adhere to Southern Company Transmission Inspection Standards.

Routine aerial inspections are performed three times per year. This inspection is performed by a fixed wing plane. Typical issues identified in this inspection are vegetation growth, buildings being constructed on the right of way, leaning poles, broken insulators, etc. When potential issues are identified, they usually require ground follow up and assessment.

Gulf’s 2018 Wood Pole Inspection Program was designed to comply with Florida Public Service Commission Orders requiring an eight-year inspection cycle for distribution poles. As allowed, chromated copper arsenate poles less than 25 years in age and poles surrounded by concrete and asphalt are exempted from inspections. Gulf poles treated with Creosote, Penta, or chromated copper arsenate receive a visual inspection with sounding, boring and excavation as appropriate.

In 2018, a total of 28,070 transmission and distribution wooden poles were inspected with a rejection rate of 2.71 percent. Gulf completed the change-out of all poles identified as rejects from all inspections prior to 2018 and began changing out poles identified as rejects in the 2018 inspection.

6.1.2 Inspection Tracking and Scheduling
Gulf uses its STOMP application to manage both the transmission line and substation inspections. Each line segment on the transmission system and each substation is assigned an inspection cycle in the application. At the beginning of each year, an engineer creates work orders for each line segment and substation design rating that contains an inspection schedule for that given year. When the inspection and associated work have been completed, the work order is signed off by the local foreman and closed. STOMP automatically schedules the next inspection based on completion date.

STOMP contains line construction information including pole and cross-arm size and type. Gulf’s Transmission Line Maintenance System (TLMS) manages work orders, selecting lines due for inspection from STOMP and creating inspection work orders. This data is exported to Gulf’s TLIS field data input program. TLIS is GIS-based, allowing the field inspector to track and record the site and inspection data. The transition of Gulf’s GIS data to the NextEra Energy systems began in February of 2019, and is scheduled for completion at the end of 2020.

Gulf’s Transmission Line Department, headed by the Power Delivery Construction Manager, is responsible for transmission facilities and associated inspection and maintenance programs. Gulf transmission planning has been performed by Southern Company Services. However, future transmission planning services will be performed by FPL transmission planning.
Gulf employees that perform inspections meet periodically to review the transmission bulletins, the inspection process and expectations, and to discuss quality control items discovered during previous inspection cycles. Inspections performed by third-party contractors include periodic and random “spot checks” conducted in the field to ensure compliance with procedures and assist with findings or concerns.

### 6.1.3 Contractor Management

Gulf contractors are familiar with the Southern Company Transmission Line Inspection Standards program. A Gulf transmission line engineer schedules work with the contractors, designating the lines to be inspected, arranging necessary material, and tracking progress. Contractors provide daily communication to the line engineer, identifying the line and structures inspected and observed conditions requiring further analysis.

Quality control reviews for transmission line inspections are conducted as the Transmission Line Engineer imports inspection data into STOMP for work order completion. During this process, a quality check is performed to ensure that all required structures were inspected, and that the data is correct.

### 6.1.4 Internal Reporting

Gulf’s transmission department provides monthly metrics on key transmission indicators to senior management. These indicators include storm hardening project status, completed and remaining pole inspections, substation inspections, and wooden pole replacements. Monthly metrics on key transmission indicators are provided via dashboards to management. The monthly metrics are shared at the vice-president level and with the President.

SERC Reliability Corporation (SERC) completed an Operations & Planning Standards Compliance Audit of Gulf in March 2017. The team assessed compliance with the North American Electric Reliability Council (NERC) Reliability Standards, and evaluated 50 requirements within the 2017 Electric Reliability Organization Enterprise Compliance Monitoring and Enforcement Program. No findings were noted for the Reliability Standards and applicable Requirements in the scope of this engagement.

### 6.1.5 Wood Transmission Structure Replacement Program

Gulf currently has 4,817 wooden structures on its transmission system. Gulf’s 2019–2021 storm hardening plan states the following regarding wooden transmission structure replacement:

Based on data from Hurricane Michael and the overall performance of wooden structures on its transmission system, Gulf will begin a program to replace all wooden structures with concrete or steel structures in a systematic approach going forward. For the 2019–2021 Storm Hardening Plan, Gulf is proposing to spend $5-$12 million dollars on transmission hardening in 2019, and an estimated $14-$40 million during the final two years of this plan.

Gulf currently estimates that it will replace 100 poles in 2019 and 250 per year in 2020 and 2021. The actual number of poles replaced will vary based on several factors associated with the different lines and pole construction methods.
6.2 Transmission Vegetation Management

Gulf’s organization responsible for transmission vegetation management is the Forestry Services Department which reports to the Power Delivery Construction Organization. This group is made up of a Utility Arborist Supervisor who oversees two Utility Arborist Technicians. Gulf’s transmission vegetation management program incorporates Southern Company guidelines and procedures. Gulf states it plans vegetation management to comply with Federal and NESC requirements and utility best practices. In 2018, vegetation hazard removals were the focus of Gulf’s Transmission Vegetation Management (VM) programs.

6.2.1 Inspections and Trimming
The Transmission VM Program uses an Integrated Vegetation Management Approach which includes: cycle-based floor maintenance, a combination of line specific cycles and reliability-based management for ROW side maintenance, and non-routine maintenance identified during annual vegetation inspections.

NERC Standard FAC-003-4 guides trimming of vegetation located on transmission ROWs to minimize encroachments. Gulf’s practices have been developed to help ensure compliance with FAC-003-4 which applies to all transmission lines of 200 kV-plus. Gulf’s own Transmission Vegetation Management Program provides trimming standards for the 46 kV and 115 kV lines.

Gulf Vegetation Technicians perform 100 percent of 200 kV-plus ground inspections. A minimum vegetation clearance distance, with an additional buffer distance, is maintained to ensure compliance with vegetation-to-conductor clearance requirements. Rotary Wing Aerial vegetation management inspections are completed once each year on 100 percent of 200 kV-plus lines and 75 percent of lines below 200 kV.

Gulf starts ground inspections each spring once active growth is observed in the area. Floor maintenance includes mowing of 3,500 acres, and application of herbicide to 5,200 acres. Side maintenance work orders are assigned based on the vegetation conditions observed during routine vegetation management ground inspections by Gulf Arborists. Reliability-Based Management is completed on a “find and fix” basis. Ground floor vegetation is managed on a six-year cycle consisting of an initial mowing followed by two herbicide applications. Danger tree work is conducted throughout the year and is identified through the annual vegetation management inspection process.

6.2.2 Inspection Tracking and Scheduling
Vegetation management scheduling and tracking is managed through Gulf’s Transmission Vegetation Maintenance System. Inspections are automatically generated through this system for all 200 kV-plus lines annually.

The “Tree Gulf” program was continued throughout 2018 as a tool to proactively report and address problem vegetation conditions. “Tree Gulf” streamlines the internal reporting process and electronically produces work orders sent to Gulf Forestry Services. This tool enables Gulf employees, including non-field personnel, to report vegetation concerns through phone, radio, or email communication. Gulf’s arborists and technicians interface frequently with members of the
public. These meetings with community leaders, government officials, and military bases explain area vegetation management projects, Gulf construction projects, utility ROW maintenance, and storm preparation and recovery activities.

6.2.3 Contractor Management
Gulf utilizes contractors to perform all the physical aspects of vegetation management on the transmission system. Gulf Forestry Services personnel are responsible for all contract management, scheduling, inspection, quality assurance, and contractor production.

Though Gulf arborist technicians are responsible for vegetation management inspections on 200 kV-plus lines, contractors are utilized for inspecting lower voltage transmission lines. Gulf arborist technicians complete vegetation management inspections per NERC requirements. Lower-rated lines are inspected by contractors or Gulf’s forestry personnel. The Utility Arborist Supervisor and technicians perform work quality reviews of contractor maintenance activities for work quality and completion.

For 200 kV-plus lines, completion of work identified through the inspection is verified by a Gulf arborist technician. Spot checks are performed on lower voltage lines to verify completion and work quality. Gulf's arborists complete Quality Assurance reports on contractors working on the system.

6.2.4 Internal Reporting
Gulf Transmission Vegetation Management was audited by both SERC and the Southern Company in 2017. SERC’s Compliance Audit addressed Inherent Risk Assessment and Internal Control Evaluation. Southern Company’s Internal Audit covered Gulf’s Vegetation Management Program requirements, documentation to demonstrate compliance with NERC Standard FAC-003-4, and inspection and maintenance of transmission lines in accordance to FAC-003-4. Neither audit resulted in findings.

Gulf’s Transmission Vegetation Maintenance System provides an executive dashboard summary of all transmission vegetation management maintenance activity. The dashboard shows remaining and year-to-date progress of acres mowed, ROW cleared, NERC inspections, acres of herbicide applied, and miles of side trimming. Monthly scorecards are provided to senior management outlining year-to-date progress and expense for the various transmission vegetation maintenance activities.

6.3 Transmission Substation Inspections
Gulf operates 144 transmission and distribution substations. Of these, 37 are transmission substations, including five mobile substations. Mobile substations are used in existing substation yards during maintenance and as a temporary bridge during system or equipment interruptions.

6.3.1 Inspections
Gulf’s Transmission Substation Department oversees inspections and maintenance. All substation inspections and maintenance are performed by Gulf employees. A work order is
created to begin the inspection process and to document the inspection completion and closeout. Substation inspection activity may occur in conjunction with scoping and planning other work projects on site.

Gulf inspects all of its substations at least once annually. These inspections include visual inspection of all structures, buss work, switches and capacitor banks for defects. Results are entered in Gulf’s Substation Inspection Dashboard which measures progress made against remaining inspections for batteries, breakers, regulators, and transformers.

Over the next three years, Gulf plans to install real-time water level monitoring systems and communication equipment inside flood-prone company substations. Information from these monitoring devices will be used to evaluate substation conditions and will provide the ability to de-energize substations ahead of rising water to minimize damage impact.

Gulf’s Coastal Substation Risk Assessments are being reviewed for all substations following Hurricane Michael. As part of the process, a NOAA model is used to define the potential maximum storm surge heights and winds resulting from historical, hypothetical, or predicted hurricanes.

6.3.2 Inspection Tracking and Scheduling
Just as in line inspection tracking and scheduling, Gulf makes use of its STOMP application to manage substation inspections and tracking. Each substation is assigned an inspection cycle in the application. Early each year, an engineer creates a work order and inspection schedule for each substation. When the inspection and associated work have been completed, the work order is signed off by the local foreman and closed. The STOMP application automatically schedules the next inspection based on completion date.

6.3.3 Quality Assurance
Quality control reviews for substation inspections are conducted by the local foreman that reviews the inspection results and documented findings before the work order is closed. The local foreman provides a first-level quality review.

6.4 2016–2018 Hurricane Season Transmission Facility Damage
Gulf was severely impacted by Hurricane Michael as it made landfall in the Panama City area on October 10, 2018. Gulf experienced minimal damage to its transmission system and substation equipment as a result of hurricanes Hermine, Irma, and Nate in 2016 and 2017.

Gulf performs transmission facility post-storm forensic analysis through the use of helicopter and drone assessments on the impacted transmission system. Future forensic data will be collected using handheld computers to quantify damage, assess causes, determine needed repair components, determine vegetation management resource needs, and identify site access challenges. The information collected will be utilized to perform a forensic analysis containing an executive summary, description of the data collected, preliminary storm data, areas affected,
and the analysis results. Ground assessments may follow to verify reported damage and to identify additional damage not visible from aircraft.

### 6.4.1 Hurricane Michael Damage

Hurricane Michael was a very strong Category 5 storm with maximum sustained wind speeds of 161 miles per hour. Approximately 136,000 of Gulf’s 463,000 customers were out of service due to Hurricane Michael.

Gulf activated its storm center on October 9, 2018, and it remained activated until December 21, 2018, supporting restoration efforts in the area. Major restoration activities were completed in 13 days, with power restored to 99 percent of the customers that could take power.

As part of the Hurricane Michael restoration effort, Gulf Transmission’s storm response team collected forensic data from system damage. Aerial patrols by helicopters and drones captured the location and nature of each failure and provided the data for entry into the TLMS. Ground crews on the scene along with a construction inspector assessed damage and determined the cause of the failures. Gulf’s Transmission Engineering Department reviewed the findings of the field inspections and data, and is currently preparing a report to be used to determine possible changes in the future.

The damage to the transmission system was significant and required the efforts of many to remove broken trees and repair what the storm had destroyed. In total, 59 line segments were out of service during the storm causing outages at 45 transmission and distribution substations. More than 600 miles of transmission lines were significantly impacted, requiring repair and/or replacement of more than 100 miles of line, and repairs at about 30 substations. Gulf experienced 194 broken transmission structures, 104 additional structures with damaged hardware, and 108 leaning or twisted structures. Exhibit 6 shows Gulf’s Hurricane Michael storm damage to the 194 transmission structures.

<table>
<thead>
<tr>
<th>Structure</th>
<th>Wood 3-Pole</th>
<th>Wood Single Pole</th>
<th>Wood H-Frame</th>
<th>Concrete 3-Pole</th>
<th>Concrete Single Pole</th>
<th>Concrete H-Frame</th>
<th>Steel Tower</th>
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<td>18</td>
<td>0</td>
<td>0</td>
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<td>5</td>
<td>2</td>
<td>10</td>
</tr>
<tr>
<td>230 kV</td>
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<td>0</td>
<td>0</td>
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<tr>
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<td><strong>11</strong></td>
<td><strong>158</strong></td>
<td><strong>0</strong></td>
<td><strong>5</strong></td>
<td><strong>2</strong></td>
<td><strong>15</strong></td>
</tr>
</tbody>
</table>

*Exhibit 6 Source: Document Request Response DR-3.2*

In response to Commission audit staff’s request for forensics reports concerning damage which occurred during Hurricane Michael, Gulf stated:

> The intense winds from the storm caused catastrophic damage to the timber surrounding transmission corridors and road right-of-ways. This damaged timber, in turn, significantly impacted Gulf’s transmission lines. Approximately 40 percent of the transmission line damage documented during aerial patrols of the
system following landfall reported trees on conductors, shield wire or structures. Structure failures due to wind overloading were prevalent as well. An analysis of the impacted lines was performed by Gulf Power’s Transmission Line Department to compare their designed wind load rating to the estimated wind loads experienced during Hurricane Michael. This analysis revealed that for all lines and structures damaged, the estimated wind speeds were at or above the original design criteria of the transmission line. As vegetation impacted these fully wind loaded or overloaded structures and wires, widespread failures occurred. Gulf was not able to document any examples where deterioration caused structural failures. Instead, textbook examples of structural wind overloading were found across the transmission system.

Although Gulf’s response asserts that Gulf “was not able to document any examples where deterioration caused structural failures,” Gulf’s April 2, 2019 presentation to staff regarding Hurricane Michael damage stated that “Primary damage caused by wind resulting in broken, leaning repositioned, and uprooted trees.” This statement indicates that not all damage was caused by wind, but it was the principal cause.

Commission audit staff notes that Gulf’s forensic reports do not contain estimates of the specific wind speeds sustained at each damage site. Winds across Hurricane Michael’s path varied. As an example, in Gulf’s territory, maximum sustained winds ranged from 58 mph at Panama City Beach to 86 mph at Tyndall AFB, and peak gusts ranged from 75 mph at Panama City Beach to 139 mph at Tyndall AFB. A more detailed forensics report may have been warranted to determine secondary causes of failure, possibly rust, wood rot, or deficient maintenance procedures.

Gulf found that concrete poles fared much better than wood poles. The primary failure mode of concrete structures was foundation-related. In most cases, the soils surrounding the pole failed allowing the pole to lean or fall to the ground. Older concrete pole installations generally utilized an industry standard “10 percent plus 2” methodology meaning that the depth of embedment was set at 10 percent of the length of the pole plus an additional two feet. These poles were backfilled with native soil or in some cases concrete or stone. During Hurricane Michael the “10 percent plus 2” embedment has shown itself to be inadequate when structures are placed in marsh type environments or after receiving excess amounts of rain and Category 5 winds. Gulf’s line design philosophy has evolved over the years. Most recent concrete pole installations utilized engineered foundations and/or storm guys which result in stronger installations.

Storm guys proved effective on concrete poles in keeping the structures in position. On wooden poles, however, the addition of storm guys did not appear to prevent pole failure – the point of failure was typically moved up to the guy attachment location. According to Gulf, the fundamental limitation of wood pole construction of transmission lines was made apparent by Hurricane Michael. Widespread pole failures were experienced through the highest wind zones, regardless of the age and construction standard of poles.

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12 https://www.weather.gov/tae/michael_psh
Some steel lattice towers that were wind-loaded beyond their original design strength failed during Hurricane Michael. However, Gulf noted that its aluminum “Guyed Y” open-lattice structures supported by eight tensioned guy wires experienced no failures during Hurricane Michael.

### 6.4.2 Hurricane Nate Damage
Hurricane Nate made landfall on October 7, 2017, in Mississippi as a Category 1 hurricane. While Hurricane Nate did not make landfall in Florida, parts of Gulf’s service territory were impacted by the hurricane. Gulf experienced loss of service to 40,725 customers, or 9.06 percent of its customer base. No Gulf transmission structures or substations were in need of repair or replacement.

### 6.4.3 Hurricane Irma Damage
Hurricane Irma made landfall in Florida on September 10, 2017 as a Category 4 hurricane. Gulf experienced 10,732 outages or 2.39 percent of its customers. However, no transmission structures or substations were in need of repair or replacement.

### 6.5 Commission Audit Staff Observations

**Observation 1:** Gulf plans to proactively replace 350 of its 4,817 wooden transmission poles with concrete or steel structures over the period 2019–2021.

**Observation 2:** Gulf is launching a substation mitigation and strengthening initiative over the period 2019–2021.

**Observation 3:** Gulf will utilize a new post-storm forensic data collection, evaluation, and reporting system for storm damage data as part of its 2019–2021 Storm Hardening Plan.

**Observation 4:** Gulf believes that every failed transmission pole and structure during the 2017–2018 storms experienced beyond-design capability wind speeds, and that it was not able to document any examples where deterioration caused structural failures.

### 6.6 Company Comments

Gulf opted to provided no comments regarding Sections 6.1 through 6.5 above.
7.0 Tampa Electric Company

Tampa Electric Company (TEC), a subsidiary of Emera Inc., provides generation, transmission, and distribution services to 765,000 customers in Hillsborough, Pasco, Pinellas, and Polk counties. TEC’s transmission system contains approximately 25,062 structures; 1,328 circuit miles of overhead lines at 69 kV, 138 kV, and 230 kV; and 68 substations. Approximately 20 percent of transmission structures are wood and 79 percent are steel or concrete. Forty-five percent of transmission structures are located in an urban environment. Exhibit 7 lists transmission structures by material and voltage.

<table>
<thead>
<tr>
<th>Material</th>
<th>69 kV</th>
<th>138 kV</th>
<th>230 kV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Concrete</td>
<td>6,556</td>
<td>412</td>
<td>1,684</td>
</tr>
<tr>
<td>Steel</td>
<td>6,062</td>
<td>242</td>
<td>4,955</td>
</tr>
<tr>
<td>Wood</td>
<td>3,862</td>
<td>173</td>
<td>1,069</td>
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<tr>
<td>Aluminum</td>
<td>0</td>
<td>0</td>
<td>37</td>
</tr>
<tr>
<td>Fiber-Reinforced Polymer</td>
<td>8</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Iron</td>
<td>2</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>16,490</td>
<td>827</td>
<td>7,745</td>
</tr>
</tbody>
</table>

Exhibit 7

Generally, older transmission structures are wood, lattice aluminum H-frames, or lattice steel towers. Newer structures are made of pre-stressed spun concrete or tubular steel. The company has 205 steel lattice towers in its system.

Currently nine miles, or less than one percent of TEC’s transmission system, is underground. TEC is in the process of adding 0.91 miles of underground transmission, its first new underground transmission installation in over twenty years. This project will convert a portion of its 69 kV transmission circuit in Tampa Bay from overhead to underground.

7.1 Transmission Structure Inspection

In 2018, all scheduled ground line, above-ground, ground patrol, and aerial infrared inspections were completed per the Commission-approved plan. These activities included 1,028 wood structures inspected through the ground line inspection program and 3,031 structures reviewed in the above-ground inspection. In 2018, the company completed 207 transmission circuit inspections through ground patrols or infrared patrols.
7.1.1 Types and Frequency of Inspections

**Eight-Year Wood Pole Ground Line Inspections**

Ground line inspections are performed on transmission wood poles on an eight-year cycle. The contractor technician begins the inspection with a safety review of poles from ground level to pole top. This visual review can identify concerns such as slack guy wires, damaged equipment or hardware, excessive pole tilt, and inadequate clearances near energized equipment. The inspector also visually reviews insulators, guying, static wires, conductors, grounding, and cross-arms. The inspector either rejects the poles or subjects them to additional inspection. Chromated copper arsenate transmission poles less than 16 years old are subject only to the visual safety review.

The transmission wood poles that pass the safety review are sounded, bored, and excavated at least 18” below the ground line. The technician removes exterior decay, measures remaining pole strengths, and externally treats poles with a preservative. Poles are also internally treated if they have isolated voids and will remain in service.

The technician photographs inspection findings and remits a weekly report of poles inspected. The report identifies pole specifications, strength, damage to the pole or hardware, treatments, and other work completed. The contractor recommends whether a pole replacement should occur on an immediate or regular schedule. A wood pole is failed and replaced if pole strength decreases below 67 percent of designed capacity or the pole no longer meets NESC Grade B Construction requirements. Poles may also be replaced when there is significant compression damage or damage to the outer shell due to excessive climbing. Poles with decay, minimal holes, or split tops may remain operational if TEC determines that the structural integrity will not be compromised through the next inspection cycle. The TEC Operations Engineer is responsible for initiating pole replacements.

Previously, wood pole inspections included non-wood structures in the visual safety review. TEC believes this effort overlapped with other inspections. Since 2018, ground line inspections have only included wood structures.

**Annual Ground Patrol Inspections**

The annual ground patrol inspections are visual assessments of transmission circuits including all wood and non-wood structures. A TEC inspector visually reviews transmission structures and hardware including insulators, guying, switches, static wires, conductors, grounding, cross arms, and encroachments. Unlike ground line inspections, ground patrols do not include sounding, boring, excavation, or other investigative methods.

Ground patrol inspection results are tracked and prioritized by severity. Inspection ratings of P1 indicate there is a concern for public safety and the company places an immediate callout to address the problem. Inspection results of P2 do not cause immediate safety concerns but TEC creates a work order and assigns a crew with priority, generally within a week. For P3 inspection results, TEC enters the issue into the Transmission Maintenance database and plans a repair in the future. The company performs ground patrol inspections throughout the year.
Eight-Year Above-Ground Inspections

Above-ground inspections are also performed on all transmission structures over an eight-year cycle. The focus of this inspection is on the condition of the pole above the ground level. This inspection is more comprehensive than the annual ground patrol inspection and involves a detailed review of poles and equipment including switches, insulators, static wires, grounding, conductors, cross-arms, guying, other hardware, and vegetation encroachments. This inspection may be performed using drones, helicopters, bucket trucks, or climbers. Drones are used to reach structures that are not easily accessible by foot. TEC observes that with new drone technology, it can now simultaneously complete the above-ground and ground patrol inspections.

A TEC line patrolman performs the above-ground inspection using a tablet connected to the Transmission Inspection Application. The lineman takes pictures, emails the company, and reviews circuit completion. Although the inspection is currently done by TEC staff, the company states it may use internal or external resources in the future. TEC considers the above-ground inspections to be a check-up on the ground line wood pole inspections.

Annual Aerial Infrared Patrols

Aerial infrared patrols are conducted on the entire transmission system annually. A TEC employee and a contractor perform the inspection via helicopter when the system is at peak load. The inspection identifies hot spots, which are elevated thermal readings that can reveal connections, switches, and splices with substandard connections. Temperature readings indicate the severity of problems, which are ranked on a scale of I, II, and III. Critical issues (I) are the highest concern and are addressed immediately, while serious (II) and intermediate issues (III) are repaired within six to 12 months. The inspection may detect damaged poles and cross-arms. TEC staff monitors the inspection process, shares expertise with the contractor, and checks off circuits as work is completed. When problems are found, the Operations Engineer creates work requests and the repairs are coordinated by an internal planner as quickly as possible.

The aerial infrared patrol may be supplemented by drones. TEC observes that drones are fast, cost effective, and can reach areas that are difficult to access. The company owns several drones that have the capability to zoom in and photograph hardware. One drone is configured with a high resolution infrared camera. All drones are operated by internal staff certified by the Federal Aviation Administration.

Other Inspections

In addition to the cyclical inspections described above, other steps assess at-risk transmission structures and components. TEC states that it experienced hardware failures in the past and wanted to review older circuits. In 2018, the company performed a one-time, targeted inspection of static wires, which can fail due to corrosion and vandalism. Management states this inspection was very productive to the company. A contractor photographed and processed the data and TEC verified the results via drones. TEC tracks static wire repairs using an Excel database and the Transmission System Maintenance Dashboard. Static wires are currently inspected as part of regularly scheduled transmission inspections.

TEC notes that steel towers are particularly subject to corrosion. In 2016, the company hired a consultant to perform a one-time, confidential inspection of its 205 steel lattice transmission towers and associated cathodic protection. The contractor assessed environmental conditions
known to impact steel corrosion and visually identified 63 towers with pre-existing galvanic protection and 37 towers with pre-existing rectified cathodic protection. TEC states the remaining structures may have had cathodic protection such as anode beds not easily identified by a visual inspection; however, the contractor reviewed the adequacy of all cathodic protection by measuring its electrochemical potential.

After the inspection, TEC reinforced steel structures, repaired concrete foundations, and installed 205 additional anodes on 24 structures. As of 2019, all repairs have been completed with the exception of two towers undergoing engineering work. TEC coordinated with the contractor to inspect several difficult-to-access steel towers, including towers submerged in water, inside the fence at a power plant, or near an eagle’s nest. TEC states that based on the inspection results and remediation work, it believes all structures currently in service that require cathodic protection are adequately protected.

If transmission structures are difficult to access or in flood zones, TEC uses drones to inspect them. If the foundation or components are obstructed, TEC notes that excavations are typically required to uncover and assess conditions. Ground line inspection policies require the contractor to report inaccessible locations to TEC. If a pole cannot be inspected at the ground line inspection, TEC or the contractor make a later attempt to inspect the pole.

7.1.2 Inspection Tracking and Scheduling

TEC’s Electric Delivery Transmission Operations Department is responsible for transmission structure inspections and maintenance. The Manager of Transmission Operations supervises 51 TEC personnel and indirectly supervises 20 to 40 contractors. Other key members include the Operations Engineer and Senior Planner-Scheduler. This department implements transmission and maintenance inspection programs, generates reports for management, develops transmission goals, and prepares storm hardening filings for the Commission.

Compliance with transmission inspection policies and procedures is the responsibility of the Transmission Operations Engineer, who produces monthly reports for management. Commission audit staff reviewed transmission policies and procedures for the ground line inspection program, vegetation management contracts, documentation of transmission structure and substations inspections from 2016–2018, and storm hardening and reliability filings.

TEC’s Transmission Operations Department tracks transmission inspections through Microsoft Access, Excel, and a structured query language database. Transmission inspections may be tracked daily, weekly, monthly, or by circuit, depending on the inspection type. Transmission structure inspection results are monitored via the Transmission System Maintenance Dashboard. The company uses this tool to review performance and gather data for uses including Commission filings. TEC states that the dashboard improves awareness of failure resolution backlogs and is used to support funding of related activities.

The Transmission System Maintenance Dashboard has a visual interface and indexes pole failures, resolution status, and expenditures. Pole failures from ground line, above-ground, and ground patrol are catalogued by year. Infrared results are organized by year and work order resolution status. Pole replacements are tracked monthly and compared against annual targets.
and forecasts. Preventative blanket spending is tracked monthly and compared to targeted, forecasted, and historical spending.

The company uses a tool called the Transmission Inspection Application to perform ground patrol and above-ground inspections. This tool is accessed in the field via a tablet. The system incorporates a Microsoft Bing map and data from transmission structure records. Inspection data is uploaded by a transmission lineman and reviewed weekly by management. The company’s geographic information system serves as a database of transmission, distribution, and substation assets.

7.1.3 Contractor Management
TEC’s use of contractors to perform ground line and aerial infrared inspections, and other inspections creates a need for monitoring and oversight. The company monitors transmission inspections through weekly phone calls and verbal reports with contractors. Ground line inspection contractors are required to submit weekly inspection reports documenting activities and results. Also, TEC states contractors may be accompanied by an internal foreman daily to review workmanship issues found during the inspection process. A contracted company that does not perform within specifications may be dismissed, though performance enhancement would be a first course of action. Transmission ground line inspection policies require the contractor, pole inspectors, and pole treatment specialists to have specific levels of experience in their respective fields.

In 2019, the company implemented a quality control audit of transmission ground line inspections to verify contractor compliance with its service contract. TEC randomly selected and assessed 3.9 percent of the wood transmission structures inspected and compared its auditors’ observations with the reported inspection results. Approximately 94 percent of the transmission structures passed the audit criteria.

TEC performs informal quality control checks on ground line and aerial infrared inspections. The company selects ten or more transmission poles weekly for each ground line inspection contract crew and reviews the quality of the work with their supervisor. If the work is substandard, all of the inspections completed that week will be rejected and the contractor is required to take corrective actions at no cost to TEC. A TEC line patrolman conducts visual and/or thermographic inspections after aerial infrared patrols using a ground-mounted infrared camera to confirm inspection results and assess corrective actions. The above-ground inspection provides a quality cross-check on ground line inspections.

7.1.4 Internal Reporting
TEC updates management on transmission facilities inspections and maintenance through annual performance reviews, annual reliability reports, and three-year Storm Hardening Plans. The Transmission System Maintenance Dashboard is shared monthly with Transmission Department leaders and senior management. The company’s transmission group reviews data in-house, and monitors inspection results and pole replacement backlogs from ground line, ground patrol, and above-ground inspections. Inspection data from the Transmission Inspection Application is uploaded for review by management. The Transmission Operations Engineer produces a monthly internal report that includes all transmission structure inspections, which is reviewed by the Transmission Operations Manager.
**FRCC/SERC Audits**

In the past, TEC was audited every three years by the Florida Reliability Coordinating Council to verify NERC compliance. The next audit will be conducted by the Southeast Electric Reliability Council in 2020.

The most recent audit occurred July 2017 and included a review of TEC’s vegetation management program. In response to the audit, TEC updated its internal vegetation management procedures. The audit also reviewed compliance with PRC-005-6, which pertains to programs that maintain Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying that affect Bulk Electric System (BES) Reliability. The audit reviewed PRC-004-5, which focuses on identifying and correcting misoperations of protection systems for BES elements. After the audit, TEC updated its Misoperation Correction Action Plan.

The audit commended TEC for performing vegetation inspections twice annually, exceeding NERC requirements. The audit also commended TEC for labeling substation relays with the previous test dates.

**Insurance Risk Assessment**

Every three years, TEC is subject to a confidential insurance risk assessment on behalf of a company which offers property and liability coverage. The scope of the assessment includes substations, transmission, vegetation management, and related inspections. The suggestions are intended to assist the company with internal risk management decisions.

In considering the suggestions, TEC is reviewing and updating specific transmission inspection and maintenance practices. Although TEC retains electronic transmission line inspection results indefinitely, the company is reviewing records retention policies to ensure that at least one cycle of transmission inspections is kept and that paper and electronic records are consistent.

In 2019, TEC implemented a quality assurance audit for ground line inspections and is considering the benefit of incorporating standard timeframes to replace or repair transmission poles. In response to a third-party risk assessment, TEC is implementing an internal goal to replace transmission poles that fail ground line inspections using a five-year cycle, although permitting, accessibility, and outages may affect this goal.

**Benchmarking and Collaboration**

In five studies from 2016 to date, TEC has collaborated with various North American utilities and consultants to benchmark transmission and substation practices, expenditures, and reliability. The company notes it has gained insight on critical asset inspections and added new resources to inspect auto transformers and relays at transmission substations.

TEC participates in the North American Transmission Forum (NATF), which focuses on improving industry performance and transmission system reliability by exchanging information among its members. Thirty-seven TEC employees are engaged with NATF groups on topics including vegetation management practices, transmission, asset management, lines, reliability metrics, resiliency, and supply chain risk management.
7.1.5 Wood Transmission Structure Replacement Program

From the early 1990s onward, TEC’s Transmission Design Requirements and Guidelines have specified steel, concrete, or composite poles be used for new construction, line relocations, and wood pole maintenance replacements. The company’s 2019–2021 Storm Hardening Plan indicates it is prudent and cost effective to replace wood poles over time with concrete or steel through its inspection and maintenance program. Transmission wood poles are reviewed by several inspections, including eight-year ground line inspections. TEC does not truss or restore failed transmission structures, opting to replace them.

TEC considers hardened concrete and steel pole replacements to be nearly identical in strength and less prone to deterioration than other materials. Non-wood transmission structures used for new line construction, system rebuilding, or line relocations are required to meet Grade B Construction Standards from the National Electrical Safety Code. New 69 kV structures meet a 120 mph wind standard and new 138 kV and 230 kV structures meet a 133 mph wind standard. This 133 mph standard exceeds current wind loading requirements. TEC incorporated the standard when it commissioned the first 230 kV line in its territory and considers it to be a best practice for new 138 kV and 230 kV lines.

TEC’s 5,104 wood structures represent approximately 20 percent of all transmission structures in its system. The company’s timeline to replace failed wood poles is affected by economics, permit requirements, accessibility, outages, and ongoing road improvement projects. TEC prioritizes replacements based on the severity of degradation to the structure and the amount of time that has passed since the condition was found. TEC considers recommendations from the ground line inspection contractor to prioritize certain poles for replacement. Transmission management states there is no firm schedule to replace failed poles but the company aims to prevent growth in its backlog of pending replacements. TEC has an internal goal to change out transmission poles identified for replacement within five years.

Since 2016, TEC has replaced over 1,500 transmission structures with non-wood poles. The company observes that given recent pole failure data, it is difficult to estimate a timeline for all wood transmission structures to be replaced. TEC projects that it will replace 120 poles per year in 2019, 2020, and 2021. From 2009–2018, wood pole failures and replacements varied considerably year to year. Pole failures ranged from 21 to 735 (1 to 20 percent of poles reviewed) and replacements ranged from 155 to 940 structures. TEC observes that each cycle of inspections covers a large geographic area and the data may be influenced by the age of poles reviewed in specific years.

Despite annual variations, TEC’s wood pole failures and replacements have trended downward over the 2009–2018 period. The company is considering accelerating wood pole replacements in light of Section 366.96, Florida Statutes (F.S.), which will lead to the establishment of a hardening cost recovery process.
7.2 Transmission Vegetation Management

The key functions of vegetation management are maintaining transmission rights-of-way (ROWs), fulfilling proactive and reactive maintenance requests, and overseeing vegetation management contractors. TEC developed its current transmission vegetation management plan by analyzing past performance, cycles, and expenditures with a focus on improving reliability and cost effectiveness. The company controls vegetation through a multi-pronged approach incorporating trimming, mowing, applying herbicides, and working with customers and local communities.

TEC’s transmission vegetation management program is required to comply with ANSI A300 standards, National Electrical Safety Code standards, and FAC-003-4 Transmission Vegetation Management. In 2018, TEC trimmed 509 miles of overhead transmission and mowed 2,369 miles of ROW. Transmission ROW vegetation clearances are controlled to manage risks to overhead lines and structures. Clearances are measured from beneath or adjacent to the conductor to the edge of the easement. TEC’s recommended clearances for 69 kV lines are 15 feet, 138 kV lines are 25 feet, and 200 kV lines are 25 feet for roadside structures and 30 feet for off-road structures. The clearances are based on circuit voltage, the number of circuits in a corridor, easements, construction requirements, and data gathered through LIDAR surveys. These standards were updated in April 2017, and are documented in service agreements with third-party contractors.

7.2.1 Inspections and Trimming

TEC’s Transmission Field Specialist patrols 138 kV and 230 kV corridors twice yearly to document vegetation conditions. Concerns are prioritized and addressed in consultation with the TEC Line Clearance Arborist. Bulk lines of 138 kV and 230 kV are maintained on a two-year cycle and 69 kV lines are maintained on a three-year cycle. Maintenance includes manual, mechanical, biological, and chemical controls. The company uses mechanical, climbing, and bucket crews to trim vegetation rather than helicopters due to cost, vegetation density, and the locations being relatively accessible.

TEC works with customers to address trees outside the ROW, which can impact the transmission system. Under certain conditions, TEC observes that it is able to manage vegetation outside ROWs without prior authorization from the property owner. The company notes that easement stops, permitting delays, and local ordinances may complicate managing vegetation outside ROWs. The company observes it receives few reactive maintenance requests from customers per year.

7.2.2 Inspection Tracking and Scheduling

TEC monitors vegetation management assets and activities using internal system maintenance reports produced through Microsoft Excel. The company tracks information on transmission circuits, miles, vegetation, contractor hours, expenditures, and work completion dates. Proactive vegetation maintenance requests include data identifying the circuits, specific locations, and deadlines. Reactive trim requests from TEC customers are routed through the work management tool WorkPro. These requests include information about weekly routes, related tickets, and the
customers requesting the trimming. The company tracks transmission vegetation management through system maintenance reports utilizing Excel and WorkPro.

TEC aims to complete all transmission vegetation management within the first six months of the year though work may be completed in August or September.

Line clearance arborists and a contracted general foreman determine when to cut hazard trees and trim vegetation clearances based on when the circuit was last addressed, reliability data, and visual inspections of the circuit. Lines below 200 kV are inspected while vegetation management activities are in progress or thereafter, while lines above 200 kV are inspected per the requirements of FAC-003-4. This NERC standard uses a defense-in-depth strategy to limit vegetation near transmission ROWs to reduce the risk of vegetation problems resulting in cascading failures.

The TEC Line Clearance Department is responsible for scheduling and managing vegetation near transmission circuits, overseeing contractors, and reporting performance metrics. The Manager of Line Clearance and Construction Services provides leadership on vegetation management and is responsible for departmental operations and internal compliance. The Transmission Field Specialist patrols transmission circuits and works with the Line Clearance Arborist to determine contractor scheduling and prioritization.

**7.2.3 Contractor Management**
In 2018, TEC employed 20 contracted personnel to perform transmission tree trimming. Transmission vegetation management is performed by contractors except when TEC needs to secure an area, such as cases involving direct wire contacts during storm restoration. In these cases, TEC personnel may trim nearby vegetation. The company schedules a monthly meeting with contractors to assess activity, performance, and workplace safety.

Oversight of contractors is primarily outlined through contracted requirements for safety, compliance, scope, deadlines, records retention, status reports, and quality control. Prior training and/or certifications are required for certain TEC transmission managers and for a percentage of contracted transmission crew personnel. Contractors must participate in TEC’s performance and quality assurance meetings upon notice and submit weekly reports summarizing activities, circuit mileage, and timesheets. Contractors are subject to work process inspections by TEC and non-compliant work must be corrected within a defined period. TEC’s Line Clearance Arborist plans and monitors vegetation management activities, circuit completion, regulatory compliance, and reviews contractor invoices on a weekly basis. Contractors regularly remit data on inspections and vegetation thickness. Issues are followed up through work orders.

**7.2.4 Internal Reporting**
Internal vegetation management reports document costs, man hours, and percent of circuit completion. The information contained within these reports is to be reviewed weekly by TEC and third-party contractors and regularly reported to management to address program effectiveness, compliance, and funding levels. System maintenance reports in Excel and WorkPro track vegetation management activities.
## 7.3 Transmission Substation Inspections

As of 2019, TEC operates 68 transmission substations. Over time, the number of substations has changed due to new solar installations and the shutdown of mining sites. Nine solar substation sites are at various stages of development. Two of the sites were turned over by a contractor to TEC in April 2019 and will be subject to regular inspection intervals.

### 7.3.1 Inspections

TEC’s Electric Delivery Substation Operations Department is responsible for transmission substation inspections and maintenance including transmission substation construction, maintenance, and restoration activities, substation scheduling, and internal reporting. TEC inspects transmission substations quarterly. The Cascade asset management database generates a maintenance work order three months after each substation inspection is completed, initiating the next cycle. These inspections visually review substation equipment, grounding, and control buildings. TEC journeyman electricians perform the substation inspections, although the company has used contractors for specific tasks such as bushing replacements.

Transmission substation hardware including battery systems, protective relays, transformers, and associated components are subject to regular maintenance and testing. In 2018, TEC completed 152 transmission substation inspections, 404 protection relay tests, 661 battery system inspections, 58 transformer Doble tests, and 539 dissolved gas analyses of transformers or on-load tap changers. As part of its storm hardening efforts, the company has equipped certain substations with active flood monitoring, enabling it to de-energize a substation if water levels exceed certain limits.

### 7.3.2 Inspection Tracking and Scheduling

Substation inspection and maintenance is scheduled via Cascade, which the company uses to troubleshoot, track ongoing projects, and document problems found. If an issue is found, a work order will be created in Cascade and reviewed by the maintenance supervisor. Maintenance work is completed by a substation electrician or crew. In 2019, TEC completed and implemented a new dashboard for tracking substation operations. This dashboard documents equipment failures, transmission inspections, spare equipment, and budgets.

Substation activities are tracked daily through a report shared with seventeen managers and directors of the Substation Operations Department. This report summarizes events, potential problems involving substations and equipment, and action plans to address problems. A monthly substation report is reviewed by substation supervisors.

### 7.3.3 Quality Assurance

TEC substation supervisors review routine inspection reports and perform internal quality control checks. Substation supervisors randomly audit substation electricians’ inspection checklists to ensure that all inspection components are complete. Supervisors review a monthly inspection report generated using Cascade. A daily report and annual documentation of transmission substation inspections is reviewed.
TEC mobilizes forensic analysis contractors after a Category 1 or higher storm threatens its service territory. After a storm, one contractor gathers data on a sample of damaged structures and a second contractor performs a forensic analysis to understand the root causes of damage to TEC’s system.

To perform the analysis, TEC relies on a field asset database developed in 2007 and updated in 2018 by the forensic analysis contractor. The database tracks distribution and transmission facilities by location. This contractor patrols damage sites after a storm to collect information about poles, conductors, equipment, and hardware condition. The sample is based upon the scale of the damaged areas and the number of structures subject to storm-force winds.

TEC works with the second contractor to evaluate the data, prepare a report, and develop prevention strategies for future storms. These strategies may include updating specifications for engineering, equipment, and future construction.

### 7.4.1 Hurricane Irma Damage

Hurricane Irma impacted TEC’s service territory on September 10, 2017, with winds from 50 to 76 mph. Over 328,000 customers lost electrical service, mostly in Hillsborough County. Pasco, Pinellas, and Polk counties were also affected. TEC brought in approximately 3,400 mutual aid personnel during restoration including tree workers, damage assessors, and distribution line resources. Management notes that downed lines from the hurricane caused limited transmission substation outages. The company restored service to all customers in under nine days, with most receiving electricity by the end of September 18.

A forensic analysis contractor performed the analysis for Hurricane Irma using data provided by TEC and field data gathered by another contractor. The forensic analysis relied on a sample size of less than one percent of TEC’s transmission and distribution structures to yield a range of plus or minus 11.7 percent with a confidence interval of 99 percent. The forensic analysis was published in February 2018, and identified wind as the main cause of damage, particularly from debris and vegetation outside utility-owned ROWs outside of TEC’s control.

Within the sample data, the forensic report found no transmission damage aside from three leaning transmission structures and noted that leaning poles up to 30 degrees from the vertical axis could have existed prior to the storm. TEC replaced one hardened and nine non-hardened transmission structures and repaired two hardened and five non-hardened poles. Based on previous inspection records, TEC does not believe that wood rot caused any non-hardened poles to fail.

Of the ten transmission poles that failed and were replaced, nine were wood and one was concrete. The vintages of these poles ranged from 1959 to 1985. According to TEC, seven poles broke due to wind load and three washed out due to flooding. Among these, previous inspections found no deficiencies except for one pole submerged in water, which later washed out during the storm.
Of the seven transmission poles repaired after Irma, five were wood, one was concrete, and one was steel. During a 2015 inspection, one wood pole was observed to have some shell rot damage. Wind load damaged the insulators on the reject pole. TEC replaced the insulators and subsequently replaced this pole with a hardened structure. No previous structural inspection deficiencies had been noted for the remaining six poles. Four wood poles had broken insulators due to wind load. The concrete pole had loose anchors due to wind load and the steel pole had damaged insulators caused by undersized insulators, which TEC replaced.

7.4.2 Hurricane Matthew Damage
Hurricane Matthew followed a path along the eastern coast of Florida in October 2016, but did not make landfall in the state. Pinellas County experienced maximum sustained winds of 24 mph and gusts of 40 mph. Approximately 4,000 customers lost power. TEC did not request mutual aid and relied upon staff and contractors for restoration. The majority of customers were reconnected by the end of the day on October 7. The company reported no damage to transmission structures or substations. Since Hurricane Matthew’s wind speeds did not reach Category 1 in the service territory, the company did not initiate a forensic analysis.

7.4.3 Hurricane Hermine Damage
Hurricane Hermine made landfall on September 2, 2016, as a Category 1 storm. Both Hillsborough and Polk Counties were affected, with maximum sustained winds up to 37 mph and gusts up to 58 mph. Nearly 31,000 customers lost service. TEC requested 30 damage assessors, 250 linemen, and 50 tree trimmers through mutual aid. All customers were restored by September 3. TEC reported no repairs or replacements of transmission structures or substations. Wind speeds did not reach Category 1 in the company’s service territory thus no forensic analysis was done.

7.5 Commission Audit Staff Observation

Observation 1: TEC plans to proactively replace approximately 360 of its 5,104 wood transmission structures with concrete or steel over the period 2019–2021.

7.6 Company Comments

TEC opted to provide no comments regarding Sections 7.1 through 7.5 above.
Appendix 1
Order No. PSC-06-0351-PAA-EI, 10 Storm Preparedness Initiatives

By Order No. PSC-06-0351-PAA-EI, issued April 25, 2006 in Docket 060198-EI, the Commission ordered IOUs to inspect wooden poles every eight years to assure weakened ones are replaced, and to implement 10 Storm Preparedness Initiatives:

♦ Three-Year Vegetation Management Cycle for Distribution Circuits
♦ Audit of Joint-Use Attachment Agreements (shared use of poles with telecom)
♦ Six-Year Transmission Structure Inspection Program
♦ Hardening of Existing Transmission Structures
♦ Development of Transmission and Distribution Geographic Information System
♦ Collection of Post-Storm Data and Forensic Analysis
♦ Collection of Detailed Outage Data Differentiating Between the Reliability Performance of Overhead and Underground Systems
♦ Increased Utility Coordination with Local Governments
♦ Collaborative Research on Effects of Hurricane Winds and Storm Surge
♦ Development of Natural Disaster Preparedness and Recovery Program Plans

The Commission also ordered electric utilities to file updated storm hardening plans every three years, and began annual Hurricane Season Preparation Workshops, which allow the IOUs, Municipals, and Cooperatives to share individual hurricane season preparation activities. These practices continue today.

Three-Year Vegetation Management Cycle for Distribution Circuits

Utilities typically have two different vegetation management plans, one for transmission facilities and another for distribution facilities. In general, transmission vegetation management activity is more rigorous than distribution vegetation management. Transmission structures tend to be taller than distribution structures. Distribution structures are typically at or below tree heights. Also, the amount of tree clearing a utility is able to achieve within a transmission corridor is greater than the utility’s ability to clear trees within the proximity of its overhead distribution facilities. Thus, tree-related storm damages are more likely to occur on overhead distribution facilities than on transmission facilities. The Commission believes additional emphasis is needed to be placed on maintaining tree clearances from overhead distribution facilities to reduce the potential for vegetation-related storm damage.
Audit of Joint-Use Attachment Agreements
Each investor-owned electric utility was required to develop a plan for auditing joint-use agreements that includes pole strength assessments. These audits had to include both poles owned by the electric utility to which other utility attachments are made (telecommunications and cable) and poles not owned by the electric utility to which the electric utility has attached its electrical equipment. The location of each pole, the type and ownership of the facilities attached, and the age of the pole and the attachments to it had to be identified. Utilities had to verify that such attachments have been made pursuant to a current joint-use agreement. Stress calculations were required to be made to ensure that each joint-use pole is not overloaded or approaching overloading for instances not already addressed by Order No. PSC-06-0144-PAA-EI.

Six-Year Transmission Structure Inspection Program
Each investor-owned electric utility was required to develop a plan for fully inspecting all transmission towers and other transmission line supporting equipment such as insulators, guying, grounding, conductor splicing, cross-braces, cross-arms, bolts, etc. All substations, capacitor stations, relay stations, and switching stations are included in the transmission inspection plan because of the critical nature of these facilities.

The transmission inspection plan was required to be based on achieving at least a six-year inspection cycle. Each investor-owned electric utility had to propose a program methodology that is effective in assuring the utility is adequately prepared for future storms. All alternatives were required to be compared to a six-year inspection cycle methodology and had to be shown to be equivalent or better in terms of cost and reliability for purposes of preparing for future storms.

Hardening of Existing Transmission Structures
The 2006 Order required that each investor-owned electric utility develop a plan to upgrade and replace existing transmission structures. The plan had to include the scope of activity, any limiting factors, and the criteria used for selecting transmission structure upgrades and replacements.

Transmission and Distribution Geographic Information System
The Commission required each investor-owned electric utility to develop a transmission and distribution geographic information system program to maintain facility specific data such as location and performance data. The intent was for the utilities to have flexibility to propose a methodology that is efficient and cost effective in assuring that sufficiently detailed data is collected to conduct forensic reviews, assess the performance of underground systems relative to overhead systems, determine whether appropriate maintenance has been performed, and evaluate storm hardening options.

Post-Storm Data Collection and Forensic Analysis
Each investor-owned electric utility was required to develop a program that collects data for purposes of forensic analysis. A utility was allowed to integrate this initiative with its geographic information system activities as well as with its post-storm data collection activities. The Commission intent was for utilities to have the flexibility to propose a methodology that is efficient and cost effective in assuring the utility collects sufficiently detailed data to conduct forensic reviews and become better able to evaluate storm hardening options.
**Collection of Detailed Outage Data Differentiating Overhead and Underground Systems**

The 2006 Order required each investor-owned electric utility to develop a program to collect performance data that differentiates between overhead and underground facility performance. A utility was allowed to integrate this initiative with its geographic information system activities and also with its post-storm data collection activities. The Commission intended for utilities to have the flexibility to propose a methodology that is most efficient and cost effective in assuring the utility collects sufficiently detailed data to conduct forensic reviews differentiating between overhead and underground facility performance.

**Increased Utility Coordination with Local Governments**

Each investor-owned electric utility was required to develop a program to increase coordination with local governments. The intent of expanding any existing utility/government liaison program is to promote on-going dialogue on key issues with the goal of reaching some accommodation or agreement on how the utility and the governmental agency will work together to address mutual concerns and prioritize needs, considering the time and financial constraints associated with given actions. This would include discussing local issues such as undergrounding and tree trimming matters.

**Collaborative Research on Effects of Hurricane Winds and Storm Surge**

The 2006 Order required each investor-owned electric utility to establish a plan that increases collaborative research, establishes continuing collaboration, identifies objectives, promotes cost sharing, and funds necessary work. The investor-owned electric utilities were required to solicit participation from the municipal electric utilities and rural electric cooperative utilities in addition to available educational and research organizations.

**Natural Disaster Preparedness and Recovery Program**

Each investor-owned electric utility was required to develop a formal disaster preparedness and recovery plan that outlines its disaster recovery procedures. Each utility was required to maintain a current copy of its utility disaster plan with the Commission on a going-forward basis.
Appendix 2
FPSC Monitoring of Storm Hardening and Preparation Observations

**Storm Hardening Plans**
Each utility must file with the Commission for its approval a detailed storm hardening plan every three years. Each utility storm hardening plan must contain a detailed description of the construction standards, policies, practices, and procedures employed to enhance the reliability of overhead and underground electrical transmission and distribution facilities. Storm Hardening is further discussed in Section 4.3.

**Wood Pole Inspection Report**
As part of each IOUs’ storm hardening plan, the Wooden Pole Inspection Program requires each utility to inspect and assess the strength of all of its installed wooden poles over an eight-year period. IOUs also have wooden pole replacement programs in place where a select number of existing poles are replaced with hardened poles. The National Electrical Safety Code Extreme Wind Loading standards are used in designing replacement poles. IOU Pole Inspection Reports must be filed with the FPSC by March 1 of each year, and contain the following information:

1) A review of the methods the company used to determine NESC compliance for strength and structural integrity of the wood poles included in the previous year’s annual inspections, taking into account pole loadings where required;

2) An explanation of the inspected poles selection criteria, including, among other things, geographic location and the rationale for including each such selection criterion;

3) Summary data and results of the company’s previous year’s transmission and distribution wood pole inspections, addressing the strength, structural integrity, and loading requirements of the NESC (See Attachment B to this Order); and

4) The cause(s) of each pole failure for poles failing inspection, to the extent that such cause(s) can be discerned in the inspection. Also, the specific actions the company has taken or will take to correct each pole failure.

**Annual Hurricane Workshops**
No amount of preparation can eliminate outages in extreme weather events, so utility regulators work to reduce and shorten outages. In support of sharing individual hurricane preparation activities among IOUs, Municipals, and Cooperatives, the Commission has held annual Hurricane Season Preparation Workshops since 2006. These workshops provide an opportunity for electric utilities to discuss their storm preparation and restoration processes, coordination with local governments, and public outreach.

**Annual IOU Electric Storm Hardening and Distribution Reliability Reports**
The Commission requires all IOUs to file an annual update of their storm hardening initiatives on or before March 1 of each year covering the prior year as required by Order No. PSC-2006-0781-PAA-EI. All of the IOUs submit their annual update of storm hardening initiatives with the concurrent filing of their Annual Distribution Reliability Report with the PSC. This report includes updates of utilities’ hardening efforts to allow the Commission to monitor progress.
Additionally, each IOU updates its tariff as necessary to reflect the Commission requirement that the cost of conversion from overhead to underground, as well as the benefits of storm hardening, be incorporated into the Contributions-in-Aid-of-Construction calculation as outlined in Rules 25-6.0342 and 25-6.064, F.A.C.