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TECO’s responses to staff’s first set of interrogatories Nos. 1-6.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20220010-EI
STAFF'S FIRST SET OF INTERROGATORIES
INTERROGATORY NO. 1
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1. Please identify all documents that establish or memorialize any of the policies and practices the Company used during the 2021 period for program oversight, program deployment, program costs controls, and accounting for each of the following:

a. Distribution Lateral Undergrounding;

b. Transmission Asset Upgrades;

c. Substation Extreme Weather Hardening;

d. Transmission Access Enhancement;

e. Vegetation Management;

f. Infrastructure Inspections; and

g. Common Storm Protection Plan Activities and Costs.

A. Tampa Electric uses the following documents, provided below, to serve as the main guiding policies and practices the company follows in regard to program oversight, program deployment, program cost controls, and accounting for Storm Protection Plan ("SPP") costs that are sought for recovery through the Storm Protection Plan Cost Recovery Clause ("SPPCRC").

The Transmission Asset Upgrades, Vegetation Management, and Infrastructure Inspections SPP programs were required under the previous Electric Infrastructure Storm Hardening Rule, Rule No. 25-6.0342, Florida Administrative Code ("F.A.C.") which required each utility to file an updated Storm Hardening Plan every three years. Tampa Electric filed its initial 2007-2009 Storm Hardening Plan petition on May 7, 2007. Tampa Electric filed four additional three-year Storm Hardening Plans from 2010 through 2019 with each of these being approved by the Commission. Within each of these Storm Hardening Plans, the company was required to provide the deployment strategy that would be used to achieve the desired objectives of enhancing reliability and reducing restoration costs and outage times associated with extreme weather events. These three programs were transitioned into the company's initial 2020-2029 SPP with the following changes:

1. The Transmission Asset Upgrades program was changed to a proactive approach in which to change out the remaining transmission

wood pole population within the initial ten-year timeframe of the 2020-2029 SPP versus changing out wood poles upon inspection failure.

2. Vegetation Management was changed to include three additional initiatives: Supplemental Distribution Circuit Vegetation Management, Mid-cycle Distribution Vegetation Management, and 69 kV Vegetation Management Reclamation.
3. Inspection programs did not change

In addition to these changes, Tampa Electric received Commission approval to transition these three programs that were currently being recovered via base rates to recovery through the SPPCRC by adjusting base rates. These adjustments were approved in the company's 2020 Settlement Agreement that was approved by Order No. PSC-2020-0224-AS-EI, within Docket No. 20200145-EI. This Order also approved the company's initial 2020-2029 SPP and the 2020 for 2021 SPPCRC projection, which also contained the Distribution Lateral Undergrounding, Substation Extreme Weather Hardening, and Transmission Access Enhancements SPP programs.

Common Storm Protection Plan Activities and Costs, while not a separate program are costs that were contained in the company's initial 2020-2029 SPP. These costs follow the similar guidance for recovery through the SPPCRC in that, the costs must be new, must be incremental, must benefit all SPP programs and cannot be recovered simultaneously through base rates (avoiding double recovery).

In addition, for program oversight, program deployment, program costs controls, and accounting as it relates to capital expenditures, The company follows Tampa Electric's Capitalization Policy and Tampa Electric's Capital Play book. As nuances arise for SPPCRC related expenses that may not be covered in either of these two documents, the company team members will engage counterparts from Energy Delivery, Regulatory Affairs, Regulatory Accounting, Regulatory Plant Accounting and Business Planning for guidance. Those team members responsible for financial reviews will export information from the company's SAP system monthly (by program, funding project, activity, order number, etc.) and compare those results to the monthly forecast for each SPP program, project or activity. These team members will then collaborate with the Program Managers and other team members to help determine if actuals align with the projected spend and activity as well as identifying any causes for variances that may need to be addressed which may include the reclassification of expenses to other or Non-SPPCRC accounts.

In addition, for program oversight, program deployment, program costs controls, and accounting as it relates to O&M expenditures, those team members responsible for financial reviews will export information from the company's SAP system monthly (by funding project, activity, order number, etc.) and compare those results to the monthly forecast for each O&M SPP project or activity. These team members, similar to the review of capital costs, will then collaborate with the Program Managers and other team members to help determine if actuals align with the projected spend and activity as well as identifying any causes for variances that may need to be addressed which may include the reclassification of expenses to other or Non-SPPCRC accounts.

a. **Distribution Lateral Undergrounding:**
Section 366.96, Florida Statutes
Rule 25-6030, F.A.C.
Rule 25-6031, F.A.C.
Commission Order No. PSC-2020-0224-AS-EI

Tampa Electric is also providing the following four documents:
1. Guidance for charging to the SPPCRC
2. TEC Capitalization Policy
3. Tampa Electric Capital Play book
4. Tampa Electric's Initial SPP Prioritization Study

b. **Transmission Asset Upgrades:**
Rule 25-6.0342, F.A.C.
Section 366.96, Florida Statutes
Rule 25-6030, F.A.C.
Rule 25-6031, F.A.C.
Commission Order No. PSC-2020-0224-AS-EI

Tampa Electric is also providing the following six documents:
1. Guidance for charging to the SPPCRC (see Response No. 1a above)
2. TAU 2 How to Implement Transmission SPP
3. TAU 3 SPP TAU Implementation Flow Chart
4. TAU 4 Transmission Maintenance Pole Replacement Documentation
5. TEC Capitalization Policy (see Response No. 1a above)
6. Tampa Electric Capital Play book (see Response No. 1a above)

c. **Substation Extreme Weather Hardening:**

Section 366.96, Florida Statutes
Rule 25-6030, F.A.C.
Rule 25-6031, F.A.C.
Commission Order No. PSC-2020-0224-AS-EI

Tampa Electric is also providing the following four documents:

1. Guidance for charging to the SPPCRC (see Response No. 1a above)
2. TEC Capitalization Policy (see Response No. 1a above)
3. Tampa Electric Capital Play book (see Response No. 1a above)
4. Tampa Electric's 2021 Substation Study

d. **Transmission Access Enhancement:**
Section 366.96, Florida Statutes
Rule 25-6030, F.A.C.
Rule 25-6031, F.A.C.
Commission Order No. PSC-2020-0224-AS-EI

Tampa Electric has established policies and practices for its Transmission Access Enhancement Program. Contracts are the primary tools for oversight, deployment, and cost controls; Work Orders are the primary tools for accounting. Additionally, the company holds regular meetings with contractors to review Program progress. Tampa Electric is also providing the following three documents:

1. Guidance for charging to the SPPCRC (see Response No. 1a above)
2. TEC Capitalization Policy (see Response No. 1a above)
3. Tampa Electric Capital Play book (see Response No. 1a above)

e. **Vegetation Management:**
Rule 25-6.0342, F.A.C.
Section 366.96, Florida Statutes
Rule 25-6030, F.A.C.
Rule 25-6031, F.A.C.
Commission Order No. PSC-2020-0224-AS-EI

Tampa Electric has established oversight, deployment, controls, and accounting policies and practices for its Vegetation Management Program ("VMP"). Contracts are the primary tools for oversight and deployment. Cost controls and accounting are monitored via financial spreadsheets. Additionally, the company holds regular meetings with contractors to review VMP adherence and progress. Tampa Electric is also providing the following two documents:

1. Guidance for charging to the SPPCRC (see Response No. 1a above)
2. Tampa Electric's initial SPP Vegetation Management Study

f. **Infrastructure Inspections:**
Rule 25-6.0342, F.A.C.
Section 366.96, Florida Statutes
Rule 25-6030, F.A.C.
Rule 25-6031, F.A.C.
Commission Order No. PSC-2020-0224-AS-EI

Tampa Electric is also providing the following document:

1. Guidance for charging to the SPPCRC (see Response No. 1a above)

g **Common Storm Protection Plan Activities and Costs**: Tampa Electric uses the document titled, "Guidance for Charging to the SPPCRC" regarding what common activities and costs can be recovered through the SPPCRC. In addition, while not specifically documented, Common costs are those costs that are applicable SPP costs that are charged to the category as "Common" when these costs do not have the ability to be assigned to a specific SPP program. Because any new costs proposed to be included in the SPPCRC are highly scrutinized, these costs will be discussed between Tampa Electric's Energy Delivery and Regulatory Departments to ensure that the costs meet the requirements of the Commission's SPP and SPPCRC rules and will not create a situation of double recovery prior to the costs being included in the SPPCRC.

Guidance for Charging to the SPPCRC

(Storm Protection Plan Cost Recovery Clause)

Tracking costs for SPPCRC

- SPP Programs & Projects will have Funding Projects and Work Orders to track costs.
- PMO's (cost collectors that are used for capital and O&M) are the lowest level of detail where we can further compartmentalize work if needed.
- PMO's are also used for the SPP Common Program charges (internal O&M labor, legal fees, travel, etc.)
- SPP transactions will be tagged in Power Plan with the SPP class code, "SPP Clause."
- Cost Centers F262160 (clause) and F223460 (ED) were created for SPP.

If you have any questions about what Program, Project or PMO to charge, please reach out to Sarah Strom or Dave Plusquellic.

What costs are recoverable through SPPCRC?

CAPITAL*

- ✓ All SPP Capital project costs
- ✓ Internal labor charged to SPP Capital projects (includes A&G allocations)
- ✓ External Labor (i.e. contractors) hired for work on SPP Plan or Projects

O&M

- ✓ Incremental Labor (O&M):
  - New headcount for work on the SPP Plan or Projects
  - External Labor (i.e. contractors) hired for work on SPP Plan or Projects
- ✓ Incremental O&M – not included in base rates, such as:
  - Planned Vegetation Management (due to the company adjusting base rates to allow for it to flow through the clause)
  - Legal & consultant fees, specifically related to SPP or SPPCRC
  - Travel expenses to FPSC for meetings/hearings, specifically related to SPP or SPPCRC
  - Miscellaneous expenses related to supporting SPP projects (such as materials and supplies, outside services and advertising)
  - Specific computer assets needed to facilitate SPP programs

If you have any questions about what is recoverable through the SPPCRC, contact Mark Roche in Regulatory Affairs.

*** All charges to capital must follow the company's guidance on proper capital charging. If you need assistance to determine if a charge is capital or O&M, first contact Sarah Strom. If needed, additional capital charging guidance can be obtained by the Regulatory Plant Accounting department (David Avellan, Director).***

What costs are NOT recoverable through SPPCRC?

- ✗ Meals
- ✗ Unplanned Vegetation Management or Vegetation Management during restoration efforts
- ✗ O&M that is included in base rates (including non-incremental internal labor)
- ✗ Cost of Removal
- ✗ Unrecovered net book value of assets being removed
- ✗ Upfront cost of assets that would be repurposed to other areas of the company upon closing of the clause (i.e. – general computers, fleet vehicles, warehouse machinery)

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TEC CAPITALIZATION POLICY

DRAFT

Regulatory Plant Accounting

Last Revised: 5/6/2021

Proprietary and Confidential

Version 1

CONTENTS

EXECUTIVE SUMMARY

Identifying capital projects and determining which costs should be capitalized is a key component of our business. Tampa Electric Company (TEC) is responsible for ensuring compliance with capitalization requirements for electric utilities set forth by the Federal Energy Regulatory Commission (FERC), Florida Public Service Commission (FPSC), and Florida Administrative Code (FAC). Additionally, we must follow United States Generally Accepted Accounting Principles (GAAP).

The purpose of this policy is to summarize and simplify topics related to the capitalization of costs. This includes the eligibility of costs for capitalization, timing of capitalization, and associated dollar thresholds. The policy also describes which costs are explicitly considered operations and maintenance (O&M) expense, and are therefore not eligible for capitalization.

It is our intention that this policy will assist team members with capital decision making and summarize complex topics. However, this policy does not include every possible capitalization scenario and therefore should be treated as a guide. Readers should begin by reviewing the Responsibilities and General Guidelines. We have also included a Capital Decision Tree to assist readers in making specific capital decisions, step by step. Additional guidance should be sought from Regulatory Plant Accounting (RPA) as needed by submitting a Capital Decision Form, available on the Capital Policy SharePoint site.

This policy will be reviewed regularly by RPA and updates will be made as required due to changes to regulatory and GAAP guidance, new technologies, and the growth of our business.

RESPONSIBILITIES

Regulatory Plant Accounting: It is the responsibility of RPA to understand and interpret the regulations that address plant accounting, capitalization of costs, AFUDC, and depreciation. RPA is also responsible for maintaining the capitalization policy. RPA will ensure that Business Units understand the capitalization policy and training and assistance with interpretation of this policy will be provided as needed. RPA will have final approval of capital projects and is responsible for reviewing and monitoring capital projects to ensure the capitalization policy is being followed. RPA will ensure consistent application of the capitalization policy and provide guidance on capitalization matters as needed.

Operational Plant Accounting: It is the responsibility of Operational Plant Accounting, working with Business Planning and project managers, to ensure that projects are set up appropriately (including best estimates for work order estimated in-service and estimated completion dates), charges to capital projects are properly accounted for in accordance with this policy, work order statuses are updated throughout the project lifecycle and assets are put into service, completed, and unitized in a timely manner.

Business Planning / Engineering / Asset Management: It is the responsibility of Business Planning, Engineering, and Asset Management, working with Operational Plant Accounting, to ensure that projects are set up appropriately (including best estimates for work order estimated in-service and estimated completion dates), and charges to capital projects are properly accounted for in accordance with this policy. It is also the responsibility of these groups to identify potentially complex components of capital projects and non-traditional items that could potentially have a material impact on the financial statements. Examples of complex issues include, but are not limited to, land treatment, lease agreements, future asset retirement obligations, contract service agreements, etc. Such items require the sign-off of the Technical Accounting team.

Project Managers / Project Control: It is the responsibility of project managers, or anyone acting as or functioning as a project manager (such as project leads or distribution design technicians) to review transactions that are being charged to the capital project and ensure that charges are appropriate. Project managers should consult Business Planning, Operational Plant Accounting, and Regulatory Plant Accounting as needed. It is the project manager's responsibility to inform Business Planning or Operational Plant Accounting of any changes to a capital project estimate or status. In addition, project managers are responsible for notifying Business Planning or Operational Plant Accounting when assets are ready for their intended use to ensure capital projects are placed in-service and completed in a timely manner.

Anyone charging dollars to a capital project: It is the responsibility of anyone charging dollars to a capital project to ensure that the expenditure qualifies for capital treatment. When charging a capital project, it is the individual's responsibility to support the capital charge with sufficient explanation and proper documentation. Individuals should seek guidance from their project managers, Business Planning, Operational Plant Accounting, and / or RPA for capitalization policy guidance as needed.

GUIDELINES

GENERAL GUIDELINES

Retirement units are items of utility plant which, when placed into service, are capitalized and when removed from service, with or without replacement, are always retired. **The FPSC has issued a Retirement Unit listing that must be followed by Florida utilities**. Requests for new retirement units must be filed with and approved by the FPSC – *consult with RPA for guidance*.

Minor items are any part or element of plant that is not designated as a Retirement Unit but is a component part of a Retirement Unit (see Minor Items).

In general, the initial installation or full replacement of a retirement unit is considered capital. Minor Items that are included in the initial installation of a retirement unit, generally may be capitalized. However, Minor Items that are installed or replaced on their own are O&M.

RETIREMENT UNITS

A full listing of retirement units by FERC Account can be found on the Capital Policy SharePoint site.

Guidelines for **Retirement Units** per FAC 25-6.0142:

- **Installation:** Initial installation of a new retirement unit is considered capital and should be booked to the appropriate FERC plant account along with associated installation and labor costs (see Components of Construction Costs).
- **Replacement:** Replacement of a retirement unit with another Retirement Unit is considered capital and should be booked to the appropriate FERC plant account along with associated installation and labor costs (see Components of Construction Costs).
- **Removal / Retirement:** When a retirement unit is taken out of service or abandoned in place, the book cost should be credited to the appropriate FERC plant account, along with any associated cost of removal and gross salvage.
- **Relocation:** O&M

MINOR ITEMS

Guidelines for **Minor Items:**

- **Initial Installation with Retirement Unit:** On initial install of a retirement unit, minor items may typically be capitalized with the retirement unit.
- **Initial Installation without Retirement Unit:** When a new minor item(s) is being added to an existing major unit of plant the cost is considered O&M.
- **Replacement:** The replacement of a minor item independently of the retirement unit of which it is a part, the cost of the replacement is considered O&M.
- **Removal / Retirement:** If removing a Minor Item without replacement, no booking of the retirement is necessary.
- **Relocation:** O&M

SUBSTANTIAL BETTERMENTS

Minor additions installed subsequently to the initial installation of a retirement unit and / or replaced independently from the retirement unit may be capitalized if the item meets the requirements for a Substantial Betterment – that is, the minor addition is installed with the primary purpose of making the respective retirement unit of which they are a part of **more useful, efficient, of greater durability, or greater capacity**.

A capital decision form (which can be found on the Capitalization Policy SharePoint site) must be submitted to RPA to request substantial betterment treatment.

NEW RETIREMENT UNITS / SUBDIVISION OF RETIREMENT UNITS / NEW TECHNOLOGY

In the event that a new retirement unit is necessary due to new technology and / or a business need (e.g. Solar), the request should be submitted to RPA for review. New retirement units will be reviewed on an annual basis and filed with the FPSC with the Annual Status Report, as needed.

SPECIFIC TOPICS

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC)

Allowance for funds used during construction (AFUDC) is accrued on construction projects to capitalize financing costs of construction. AFUDC has two components: debt and equity. AFUDC debt is used to offset interest expense and AFUDC equity is booked to Other Income. **Prior to starting a project that may be AFUDC eligible, please consult with RPA.**

For Florida Electric utilities, in order to be eligible to earn AFUDC a construction project must:

- Have expenditures that exceed 0.4% of the sum of the total balance in accounts 101 Electric Plant In-Service and 106 Completed Construction not Classified at the time construction commences
- Have an expected construction timeline in excess of one year

The expenditure threshold is calculated by RPA and updated on the Capital Policy SharePoint site monthly. Please contact RPA for guidance on current and forecasted thresholds.

AFUDC shall be accrued on eligible projects starting with the first expenditure and as long as activities that are necessary to get the asset ready for its intended use are in progress. Activities shall include those prior to physical construction, such as the development of plans or the process of obtaining permits from governmental authorities. However, activities do not include preliminary survey and investigation activities (see Preliminary Survey Costs). *A utility may bundle related projects that achieve a specific outcome if it demonstrates that the total cost of the bundled projects excluding AFUDC is less than the total cost of the unbundled projects.*

AFUDC is calculated on a cumulative cash basis and accruals are not eligible for inclusion in AFUDC basis. AFUDC should not be accrued during a period of interrupted construction exceeding six months. AFUDC will stop being accrued in the month assets are ready to be and / or are placed in service. In the month the work order goes in-service, one half of calculated AFUDC is earned.

AFUDC shall not be accrued on the following:

- Retirement work in progress (RWIP) or Cost of Removal (COR)
- Preliminary survey and investigation
- Plant held for future use
- Accruals for invoices
- Accruals for property taxes
- Contract retentions
- Blanket projects
- Special projects less than 1 year in duration

For forecast purposes, project contingency is excluded from the AFUDC calculation.

ASSET TRANSFERS

At times, there is a need to transfer an asset and / or land from TEC to another company affiliate (for example, a transfer from TEC to Peoples Gas System). Before transfers between affiliates take place, all transactions shall be reviewed by RPA and Regulatory Affairs to ensure appropriate treatment.

COMPONENTS OF CONSTRUCTION COSTS

Based on FERC Electric Plant Instruction 3 below is a summary of what is considered components of construction cost and their proper classification. For further guidance, contact RPA.

CAPITAL COMPONENTS OF CONSTRUCTION COSTS

Components of Construction Costs:

1. Direct Costs – Costs directly related to the construction process that are necessary to get the asset in place and in working condition.
2. Indirect Costs (Overhead) – Costs necessary to get the asset in place and in working condition but are not directly identifiable with any one unit of property or project. These costs should be allocated proportionately across related projects (see Overhead).

Costs Typically Incurred During a Construction Project (which can be direct or indirect as defined above):

1. Contract work – amounts paid for work under contract by other companies/entities
2. Labor (Direct) – pay and expenses of employees engaged in construction activities, including fringe benefits.
3. Material and Supplies – includes the purchase price and all related taxes, cost of inspection, transportation costs, loading costs, and fabrication costs for materials that are necessary components of the units of property installed. Proper allowance shall be made for unused materials and supplies, materials recovered from temporary structures used for performing the work, and for discounts allowed and realized in the purchase of materials and supplies.
   - Materials and supplies for a capital project include:
     - Materials issued from a company storeroom
     - Materials drop-shipped directly from the vendor
     - Materials purchased used a Purchasing Card (P-card)
     - Pre-staged materials
     - Emergency spares
4. Transportation – includes costs of transporting employees, equipment, and materials and supplies. General vehicle charges may be allocated to a construction project if used directly for such purposes.
5. Special Machine Service – the costs of labor and fringe benefits, materials and supplies, depreciation, and other expenses incurred in the operation, use, and maintenance of special machines (such as ditchers, pile drivers, etc.). Also includes rental, maintenance, operation, and use expenditures for the special machines belonging to other entities.
6. Shop service – includes the proportion of the expense of the shop department assignable to construction work except that the cost of fabricated materials from the utility's shop shall be included in materials and supplies
7. Protection – includes costs related to protecting company property during construction work, such as incremental security, fire prevention, casualty prevention, protecting against damage to the property of others, cost of apprehending and prosecuting incendiaries, and fees paid to municipalities.
8. Injuries and damages – expenses or losses related to construction work due to injuries to persons, damages to property of others, and investigations pertaining to such.

9. Privileges and permits – include payments for and expenses incurred in securing temporary permits in connections with construction work. This would also include any payments made for the right to use private or public property for construction. This does not include rents, franchise fees or consents.
10. Rents – amounts paid for the use of construction quarters and office space solely occupied by construction forces.
11. Engineering and supervision – includes only the portion of the pay and expenses of engineers, surveyors, draftsmen, inspectors, superintendents and their assistants applicable to construction work.
12. General administration capitalized – includes the portion of the pay and expenses of general officers and administrative and general expenses applicable to construction work only. (See A&G).
13. Engineering services – includes the amounts paid to other companies, firms, or individuals engaged to plan, design, prepare estimates, supervise, inspect, or give general advice and assistance in connection with construction work.
14. Insurance – insurance premiums paid for the protection against losses or damages in connection with construction (fire or casualty).
15. Legal costs – includes the general legal expenditures incurred in connection with construction and the related court and legal costs, other than legal expenses included in protection (item 7) and injuries and damages (item 8).
16. Property Taxes – only applicable to the construction of a new power plant. Includes property taxes during original construction phase.
17. Allowance for Funds Used During Construction (AFUDC) – (see AFUDC)
18. Earnings and expenses – Revenues received for power produced by generating plants during the construction period (used by utility or sold). Expenses include costs of operating the power plant associated with the received revenues.
19. Training – includes costs incurred to train employees during the construction process if it is necessary that employees be trained to operate and maintain plant facilities or systems that are being constructed and these facilities or systems are 1) not conventional and 2) new to the company's operations. Once the asset is placed in-service, subsequent training costs are charged to O&M. – *Prior approval by RPA must be obtained to capitalize training costs.*
20. Studies – includes costs mandated by regulatory bodies for safety and environmental studies relative to plant under construction.
21. Asset retirement obligations – the costs recognized as a result of asset retirement obligations incurred during the construction and testing of utility plant.

OVERHEAD

All overhead construction costs such as engineering supervision, general office salaries and expenses, construction engineering and supervision by third parties, law expenses, insurance, injuries and damages, pension and taxes **are considered capital** and shall be charged directly to construction projects.

Team members should charge identifiable time dedicated to work on capital constructions projects directly to the project through manual time entry or an overhead allocation.

ADMINISTRATIVE & GENERAL (A&G) COSTS

Administrative and General (A&G) expenses are expenditures related to the day-to-day operations of our business and are not directly related to generation and distribution activities. A portion of A&G expenditures are capitalized based on an accounting estimate as determined by management. The FPSC permits the capitalization of A&G, and the company follows this regulatory guidance based on ASC 980.

The concept of capitalizing A&G expense is based on the recognition that some of the charges posted in A&G expense accounts result from activities related to preparing assets for service (activities related to the construction, acquisition, and / or installation of property, plant and equipment).

Departments that charge labor to A&G accounts are:

- Legal
- Insurance
- Security
- Treasury
- Human Resources
- Community Relations
- Safety
- Claims
- Real Estate
- Information Technology
- Tax
- Regulatory Affairs
- Business Development & Strategy
- Risk Management
- Facility Services
- Procurement
- Finance
- Governmental Affairs

Examples of capital-related activities performed by employees in these departments that charge labor to A&G are:

- Legal department efforts related to research, negotiation and execution of permits, rights-of-way, easements, contracts, and other agreements that facilitate the acquisition and construction of land and equipment
- Real estate department efforts related to locate, assess, and acquire land
- Insurance department efforts related to construction sites and equipment

Team members belonging to the departments listed above that are assigned to work on capital projects should direct charge to the project through manual time entry or an overheard allocation (see Overhead).

OPERATIONS AND MAINTENANCE (O&M) COMPONENTS OF CONSTRUCTION COSTS

Costs that do not qualify for capitalization and should be charged to the appropriate O&M account include, but are not limited to, the following:

- Installing, replacing or removing a Minor Item.
- Inspecting, testing, and reporting on condition of plant specifically to determine the need for repair, replacements, rearrangements, and changes and inspecting and testing the adequacy of repairs that have been made.
- Work performed specifically for preventing failure, restoring serviceability or maintaining the original life of asset
- Consultants' fees and expenses, except as required for design or construction of a unit of property.
- Repairing or restoring the condition of property (but not replacing complete major unit of plants)
- Removing dangers or hazards surrounding property.
- Restoring and maintaining service.
- Routine work involving preventing, inspecting, locating and clearing trouble.
- Rearranging and relocating property not retired, including the net cost of installing, maintaining, and removing temporary facilities to prevent service interruptions.
- Routine cleaning of buildings and grounds.
- Routine patrolling and testing, including cleaning of manholes, ducts, etc.
- Inspecting and testing of meters, regulators, etc.
- Setting or removing meters in the distribution system.
- Training employees on maintenance work. Also, general training such as continuing education
- Tests for efficiency of equipment operations
- Preparing instructions for operations and/or maintenance
- Preparing, reviewing, or analyzing budgets, estimates, operating results or drawings related to operation or maintenance.
- Reviewing, formulating, or establishing processes, organizational setup or routines of departments.
- Environmental charges except when the environmental solution can be unitized as a major unit of plant (ex: piece of equipment to reduce emissions).
- Free standing desks, chairs, tables etc. are considered individual items and are charged to the appropriate O&M account unless the dollar guidelines for the FERC category are met (see Dollar Thresholds).
- Re-paving
- Re-carpeting
- Re-painting
- Industry, civic, and association dues as well as professional engineering fees and subscriptions.
- Advertising and public relations expenses.
- Meals and travel costs related to any of the above activities.

CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAC)

Contributions in aid of construction (CIAC) are amounts received by the company as a contribution towards the cost of building or extending existing facilities into a new service area or other service changes. CIAC is treated as a reduction of utility plant construction costs. This treatment is consistent with FERC guidelines.

Sometimes advances may be received from developers, which may be refunded once the development meets certain milestones. These amounts are retained if the milestones are not met in a specified amount of time. Advances should be recorded as a liability until refunded or the milestone period lapses. If the milestone period lapses, the amounts are credited to the appropriate plant account, reducing the related plant balance.

CRADLE-TO-GRAVE ACCOUNTING

The Florida Administrative Code and FERC allows for the pre-capitalization, or "cradle-to-grave" accounting for items in the following accounts:

- 368 – Line transformers
- 370 – Meters

TEC follows this treatment for meter and transformer purchases. With this treatment, the costs of the items are capitalized upon purchase by charging to the appropriate plant account, whether actually in-service or held in reserve. Additionally, the cost for refurbishing these items shall be charged to the appropriate expense accounts (such as meter repair).

DEFERRED DEBITS

For Major Utilities such as TEC, Account 186 – Miscellaneous deferred debits shall include all debits not accounted for elsewhere, such as miscellaneous work in progress, and unusual or unextraordinary expenses, not included in other accounts, which are in the process being amortized and items for which the proper final disposition is uncertain. Since Tampa Electric is a Major utility, this account **shall not include costs for preliminary surveys and investigations** (see Preliminary Survey Costs).

DOLLAR THRESHOLDS

The use of dollar thresholds is isolated and limited to general plant (including computers) and software.

TEC dollar thresholds have been established as follows:

- General Plant such as office furniture, communication equipment, miscellaneous equipment, etc. (FERC Accounts 389 – 399) - $1,000 minimum
  - Computers are evaluated against the threshold as a full set:
    - Desktop – Includes PC, monitor, mouse, keyboard
    - Laptop – Includes Laptop, docking station, monitor, mouse, keyboard
- Software (FERC Account 303) – $50,000 (see Software section).

LAND AND LAND RIGHTS

The guidance below is meant to be a general guide for the accounting treatment of land. However, there may be unique circumstances or timing that leads to different treatment. Please contact RPA for guidance on specific land purchases, leases or transfers.

Treatment of Land for Non-AFUDC Eligible Projects:

When land is purchased for a project that is **not** AFUDC eligible (see *Treatment of Land for AFUDC Eligible Projects* below), it shall be accounted for using the following guidelines:

- If construction is planned to start before calendar year-end, land will be booked directly to Plant In-Service (Account 106/101).
- If construction is not planned to start before calendar year end, land will be booked to Property Held for Future Use (105) then transferred to Plant In-Service (106/101) when construction commences.

Treatment of Land for AFUDC Eligible Projects:

Land related to an AFUDC eligible project (see AFUDC) is only eligible to earn AFUDC if it was purchased specifically for new generation construction. Otherwise, the guidelines stated above for land related to non-AFUDC eligible projects apply.

Once land is deemed eligible to earn AFUDC, it shall be accounted for using the following guidelines:

- If construction is planned to start within 60 days of purchase, land will be booked to Construction Work in Progress (107).
- If construction is planned to start past 60 days from purchase, land will be booked to Property Held for Future Use (105) then transferred to Construction Work in Progress (107) when construction commences.
- AFUDC will begin accruing once construction commences.
- When a large tract of land is acquired, AFUDC shall only be earned on the portion of the land for which construction activities are underway.
- Land will stay in Construction Work in Progress (107) while construction activities are in progress.
- Once the Generation Assets have reached Commercial Operation Date, the land will be placed in-service and booked to Plant In-Service (106/101).
- AFUDC will be transferred to the Generation Assets once in-service, so that the amounts are included in the depreciable asset base.

Land Purchased as an Option

When land is being evaluated as a potential option for future construction projects prior to a signed contract on the land, related charges shall be placed in account Misc. Deferred Debits (186). The associated funding project should be assigned a generic Major Location with no Asset Location. No work orders shall be created until there is a signed contract on the land, in which then a specific Major Locations / Asset Locations should be assigned. *

** Please contact RPA to request the creation of new Major / Asset Locations, as these must be approved by the Master Data Maintenance (MDM) team. In addition, the new Major / Asset location structure must be added to the Workman tree, which will be coordinated by RPA once the necessary MDM approvals are obtained.*

Clearing and Grading

Costs incurred in connection with first clearing and grading of land and rights-of-way and damage costs associated with the construction and installation of new assets are to be charged to the construction project and shall **not** be included in the accounts for land and land rights and rights-of-way. Such costs shall be included with the appropriate utility plant account. Subsequent clearing and grading costs, after the first instance, are O&M.

Land Sales

Gain or loss on the sale of land is the difference between the amount received from the sale of land or land right, less commissions and other costs related to the sale, and the book cost of such land or rights. When land and an attached building / structure are sold, sales proceeds need to be allocated between the land and the existing structure(s). Please consult with RPA and Real Estate for further guidance on Land Sales and appropriate accounting treatment of gains / losses.

Sale of Resources

The net profit from the sale of timber, wood, sand, gravel and other resources or other property acquired with the right-of-way or other lands shall be credited to the appropriate utility plant account to which related. Please consult with RPA and Accounts Receivable Miscellaneous (ARM) team for further guidance.

Land Leases

All lease agreements are to be reviewed by Technical Accounting in order to ensure proper accounting treatment.

Capital Decision Form

For further questions related to the purchase and capitalization of land, please fill out a Capital Decision Form which can be found on the Capital Policy SharePoint site.

LEASES

All capital projects with a potential lease component, including land leases, should be reviewed by Technical Accounting to ensure appropriate treatment.

PRELIMINARY SURVEY COSTS

Account 183 – Preliminary survey and investigation charges shall be used for all costs incurred for preliminary surveys, plans, investigations etc. made for the purpose of determining feasibility of utility projects under contemplation. This account shall also include costs of studies and analyses mandated by regulatory bodies related to plant in-service. Records supporting entries to account 183 shall be kept as supporting documentation.

Preliminary Survey Costs Related to Construction Projects:

If construction results, account 183 shall be credited for study costs directly attributable to the new plant construction and charged to the appropriate plant account. Study costs not directly attributable to the new construction should be credited to the 183 account and charged to the appropriate O&M account. For costs that are commonly incurred regardless of the option chosen, the costs shall be allocated equally amongst all the options.

Preliminary Survey Costs Related to the Purchase of Land:

Preliminary surveys and studies to identify land for an appropriate site location shall be charged to account 183 – Preliminary survey and investigation. If the study results in the purchase of land, the account 183 shall be credited for the associated study costs. If development of the land for its intended use begins immediately, study costs shall be charged to 107 – Construction Work in Progress. If the land will be held for future development, study costs shall be charged to account 105 – Plant Held for Future Use. If there is no plan for the use of the land as "utility plant", study costs shall be charged to account 121 – Non-utility property. If the land being assessed is ultimately not purchased, survey costs shall be credited to the 183 account and then charged to the appropriate O&M account.

Prior to setting up projects for account 183, consult with RPA on appropriate treatment.

For a step-by-step guide to determining treatment of preliminary survey costs, see the Preliminary Survey Costs Decision Tree located in the Appendix.

PUNCH LIST

Punch List – A punch list is a listing of engineering and construction items that were intended to be completed during the original project scope but remain to be completed in order to bring the plant or plant system into compliance with the design criteria or contractual obligation. In order for punch list items to be included within the original project scope, the criteria below should be met.

Major Projects

- Contractual – identified and documented per the contract scope for punch list items or as an addendum
- If no punch list item timeline exists per the contract, items must be identified within 3 months of the project in-service date

All Other Projects

- Contractual, as defined above
- If no punch list item timeline exists per the contract, items must be identified as of the project in-service date

Work identified subsequent to the punch list cutoff outlined above shall be evaluated as a stand-alone project.

SOFTWARE

Software eligible for capitalization is classified as internal use software – software that is acquired, internally developed, or modified solely to meet the entity's internal needs, with no plans to market the software externally.

(Note: Hosted software arrangements / Cloud Computing Contracts (CCA) have specific considerations – see Hosted Software).

Both of the following must be true prior to capitalization of software costs:

1. The preliminary project stage has been completed
2. Feasibility has been established and management authorization has been obtained

Additionally, a threshold of **$50,000** shall be used for the capitalization of software project costs.

Below are examples of typical tasks per project stage, and the appropriate capital treatment. **Prior to capitalizing any costs, the project must be past the preliminary stage.**

Stage	Examples	Classification
Preliminary	- Defining general project objectives and performance requirements - Outlining major processes, general data flow, and system requirements - Evaluation of alternatives - Demonstrations by vendors - Select a consultant / vendor	O&M
Development	- Coding and configuration of software - Interface development - Installation of hardware - Testing and parallel processing - Maintenance fees incurred during development	Capital
Cutover/ Go-Live / Post Implementation	- Training costs past project in-service date - Maintenance fees incurred past in-service date - Hyper-care	O&M

Additionally, the below costs are not eligible for capitalization **regardless of the project stage:**

- Manual data conversion costs (see clarifications in matrix on next page)
- Re-engineering of processes and change management
- Implementation of existing software already in-service in one area of the company to another

Capitalization of software costs stops when the following occurs:

- Software is substantially complete and ready for its intended use and all substantial testing has been completed. This is considered the end of the application development stage and the software shall be placed in-service at this point.
- If it is determined that it is no longer probable that the software will be completed and placed in-service, all costs incurred will be written off to O&M.

SOFTWARE COSTS MATRIX

Project Stage	Activity	O&M	Capital
Preliminary	Prepare RFP	X	
	Assess current state	X	
	Re-engineering of business process	X	
	Process redesign for baseline software	X	
	Restructure workforce	X	
	Evaluation and selection of alternatives / feasibility studies	X	
	R&D assessments	X	
	Selection of consultant(s)	X	
	Rental costs for facilities for project team	X	
	Software development	X	
Development	Design of chosen approach		X
	Purchase of software		X
	Incremental purchases directly related to the project or project team		X
	Software configuration		X
	Coding of software / modifications		X
	Coding of new interfaces		X
	Reconnecting of existing interfaces		X
	Purchase of hardware		X
	Installation of hardware		X
	Testing / Parallel Testing		X
	Data conversion - Developing conversion software		X
	Data conversion - Running data conversion programs	X	
	Data conversion - Cleaning up bad data	X	
	Technical training on developing or installing product	**Depends – See *Training***	
	Creation of system documentation / job aids / manuals		X
	Organizational change management	X	
	Training the trainer / Training end users	**Depends – See *Training***	
Cutover/ Go-Live / Post Implementation	Software Maintenance	X	
	Training	X	
	Application Maintenance	X	
	On-going support (unless addressing defects identified prior to go-live)	X	

Multiple-Element Software Arrangements:

For internal-use software purchased from a third-party, the purchase price may include multiple elements, such as training, maintenance fees, data conversion costs, rights to future upgrades and enhancements, etc. **Costs should be allocated based on objective evidence of fair value of the elements in the contract, not necessarily on prices stated within the contract for each element.** For example, for a contract in which the vendor includes a certain number of "free" training hours in the purchase price, a fair value should be assigned to the training hours and the respective amount assigned should be allocated to O&M. Costs for each element should be given the appropriate capital or O&M treatment based on the guidance within this policy.

Training:

Capitalization of training costs related to new software will be evaluated on a case-by-case basis. Training costs that may be eligible for capitalization are only eligible if they occur during the development stage and prior to the software in-service date.

Requests for evaluation of training costs must be submitted through a Capital Decision Form which can be found on the Capital Policy SharePoint Site prior to the capitalization of such costs.

UPGRADES & ENHANCEMENTS

Upgrades and enhancements are modifications to existing internal use software that result in additional functionality – modifications to enable software to perform tasks that it was previously incapable of performing. Upgrades and enhancements normally require new software specifications and may also require a change to all or part of the existing software specifications. *Upgrades and enhancements which solely provide a new look or different presentation of information are not considered additional functionality and are not eligible for capitalization.*

Upgrades and enhancements must meet the requirements for new internal use software and all guidelines stated above for eligibility for capitalization of costs shall be applicable.

HOSTED SOFTWARE / CLOUD COMPUTING ARRANGEMENTS (CCA)

Hosted software solutions or Cloud Computing Arrangements (CCA) are arrangements where the applications are hosted on servers that reside outside the company at a vendor or other third-party location. In these arrangements, the end user (TEC) does not take possession of the software; rather, the software application resides on the vendor's or a third party's hardware, and the end user accesses and uses the software on an as-needed basis over the Internet or via a dedicated line.

Accounting for arrangements that are considered licensed assets:

Per ASC 350-40, CCA arrangements that are considered licensed assets may be capitalized as internal-use software when **both** of the following criteria are met:

1. The customer has the contractual right to take possession of the software at any time during the hosting period without significant penalty, defined as:
   - The ability to take delivery of the software without incurring significant cost
   - The ability to use the software separately without a significant decrease in utility or value

2. It is feasible for the customer to either run the software on its own hardware or contract with another party unrelated to the vendor to host the software

If these two criteria are met, costs related to the CCA may be treated the same as internal-use software and the guidance within this policy applies.

Accounting for arrangements that are considered a service contract:

If the two criteria above are not met, the arrangement is considered a service contract. Per ASU 2018-15 – *Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract*, implementation costs should follow the existing internal-use software guidance to determine which costs are eligible for capitalization. Implementation costs will be capitalized or expensed depending on the nature of the costs and the project stage during which they are incurred. The general guidelines are as follows:

- Activities to develop or obtain software that allow for access to or conversion of old data by new systems are capitalizable
- Activities related to coding and testing during the application development stage are capitalizable
- Data conversion activities are expensed as incurred. The process of data conversion from an old system to a new one may include purging or cleansing existing data, reconciling the data in the old and new systems, creating new or additional data, and converting old data to the new system.
- **Hosting fees are O&M.**

Accounting Treatment for Service Contracts:

While the eligibility for capitalization follows similar guidance as internal-use software under FPSC rules and CCA licensed contracts, the classification of capitalizable costs related to a CCA service contract vary from that of internal-use software and CCA licensed contracts. Under US GAAP, capitalizable costs associated with a service contract should be recorded as an Other Asset (rather than an intangible asset) with amortization recognized as O&M over the life of the service contract (rather than as depreciation and amortization).

FERC has issued guidance on Docket Number A120-1-000 such that capitalized implementation costs associated with cloud computing arrangements should be recorded as a utility plant asset, consistent with the account requirements for internal-use software. Capitalized implementation costs should be recorded in FERC account 303 (misc. intangible plant), provided these costs are not specifically provided for in other utility plant accounts. These costs should be amortized consistent with requirements of the utility plant accounts in which they are recorded. Amortization of capitalized cloud computing costs recorded as intangible plant utility should be recorded in FERC account 404 (amortization of limited-term electric plan).

Prior to entering into a hosted software arrangement, consult with Technical Accounting for a detailed review of the contract and guidance on which components of the costs are to be capitalized.

SPARES

CAPITAL SPARES

A supply of essential spare parts and auxiliary equipment are held in reserve in order to meet future needs. These items shall be classified as Capital Spares and the associated costs capitalized through Account 107 Construction Works in Progress and recorded in the appropriate utility plant account through Account 101 Plant in-service for depreciation purposes when all of the following conditions are met:

- The item is a retirement unit
- The item costs $50,000 or more
- The item has a long lead-time and is not available locally on a dependable, timely basis or is of custom manufacture for a specific piece of equipment
- The item is vital to the continued operation of the facility or the continuity of service, not for routine or periodic replacement

Items that do not meet all of the above criteria that are not purchased for a specific project should be charged to inventory through Account 154 – Plant materials and supplies.

Items that should not be classified as Capital Spares:

- Items ordered in quantity
- Parts acquired to fulfill material needs during outages where preventative and corrective maintenance is performed
- Items requisitioned from stock when performing routine replacement or maintenance work

For further guidance on treatment of capital spares, please contact RPA.

REPAIRABLE SPARES

Repairable spares are retirement units that upon replacement are sent to a vendor for refurbishment. The refurbished items are returned to the company in "like-new" condition and placed back into inventory.

The process of removing a retirement unit to be sent for refurbishment and subsequently replacing the item with a new retirement unit from inventory results in both an addition (107) for the new retirement unit and a retirement / cost of removal (108) for removing the old unit. One capital work order with two separate tasks, one to account for the addition of the new retirement unit and one to account for the cost to remove the old unit shall be created. A separate work order shall be created to account for the O&M costs associated with the repair / refurbishment of the old unit.

Example Demonstrating Accounting Treatment:

It is determined that a widget with a book cost of $50,000 is no longer operating at full capacity and must be replaced (the widget is considered a retirement unit). The widget is removed from operations with a labor cost of $5,000.

A replacement widget valued at $50,000 is issued from inventory and installed at a labor cost of $5,000 and A&G overhead allocation of $1,000.

The old widget is sent to a vendor for refurbishment for a cost of $20,000 and is returned to the company three months later in certified "like-new" condition. The refurbished widget is placed in inventory.

Capital WO Task 1 – Addition
Capital WO Task 2 – Retirement
O&M WO for Refurbishment

	Capital		Inventory		O&M		Cash	
Retirement Issued to WO	50,000			50,000				
Allocation and A&G	1,000					1,000		
Labor to Install	5,000							5,000
Labor to Remove	5,000							5,000
Return Retirement Unit to Stores		50,000	50,000					
Repair Retirement Unit					20,000			20,000
Impact	$11,000		$0		$19,000		($30,000)	

WARRANTY

This section covers warranties for tangible assets. For software related warranty purchases see Software.

Warranty purchases should be considered one of two types:

- **Assurance-type Warranty** – the entity providing the warranty will fix or replace a good or service if the original good or service was faulty. Indicators of this type of warranty include:
    - Replacement of the same type of item originally purchased
    - Repair faulty item to the same condition as purchased
    - A service obligation does not exist for the seller as part of the warranty. Separate service contracts should be expensed

  Assurance-type warranties should be treated as **capital** when purchased, whether received as part of the purchase of the asset or purchased separately. When assets are replaced, unless there is a substantial betterment or replacement of an older asset with new technology, the asset being replaced will remain on the books at its original cost, rather than the old asset being retired and the new asset being recognized at its cost. Unreimbursed costs incurred to replace the asset should be expensed to O&M.

- **Service-type Warranty** – provides customer with a service that is incremental to the assurance that the good or service will meet expectations as agreed upon in the contract. Indicators of this type of warranty include:
    - An option to purchase a separate warranty
    - Longer coverage period (extended warranty)
    - A specific obligation exists by the seller other than replacement or repair of the original item

  Service-type contracts should be typically be treated as **O&M** when purchased or received.

Warranty costs should be allocated to capital and O&M appropriately as applicable, using the guidance above. For further guidance of treatment of warranties please contact RPA.

WORK ORDER STATUS REQUIREMENTS - IN-SERVICE, COMPLETION & UNITIZATION

In order for capital dollars to be classified and forecasted appropriately, work order statuses must be updated consistently and timely in PowerPlan. It is the responsibility of those overseeing capital projects to communicate to Business Planning or Plant Accounting when the work order is ready to be placed in the below statuses. It is the responsibility of Plant Accounting to update work order statuses timely and accurately once the information is received.

Start of Capitalization: Capitalization of work order charges starts with the first expenditure and continues as long as activities, that are necessary to get the asset ready for its intended use, are in progress. Activities shall include those prior to physical construction, such as the development of plans or the process of obtaining permits.

Note: Pre-engineering work can be capitalized before construction commences, once a retirement unit installation or replacement has been identified. However, inspection costs to determine a repair versus replacement are considered O&M.

In-Service Date: The asset in-service date is the earliest of the date the asset becomes ready for service, becomes used and useful, or begins generating revenue.

Once an asset is ready to be placed in-service, the Engineer, Project Manager, or other person responsible for obtaining or overseeing the completion of the asset should notify Business Planning or Plant Accounting and provide the following:

- Associated work order number
- Asset in-service date
- Asset location
- Estimated project completion date (see Completion Date below); and
- Dollar estimate at the 300-plant account level

Entering the in-service date changes work order status from "open" to "in-service".

When an asset is placed in-service, the estimated project completion date should be updated accordingly, typically set at 3 months for most projects, and within 6 – 12 months for larger projects. Once an asset is placed in service, the asset balance is transferred from account 107 – Construction Work in Progress to account 106 – Construction Completed but not Classified, and the asset begins depreciating.

Completion Date: The actual work order completion date is the date all costs have been recorded to a project, usually within 3 months (6 – 12 months for larger projects) after the in-service date. The Engineer, Project Manager, or other person responsible overseeing the completion of the asset should contact Business Planning or Plant Accounting and provide the completion date.

Additionally, the final as-built that lists asset details at the retirement unit level should be provided at the same time as the completion date with the following information:

- Associated work order number
- Asset in-service date
- Asset location
- Estimated project completion date (see Completion Date below); and
- Dollar estimate at the 300-plant account level

Entering a completion date changes the work order status from "in-service" to "completed".

Unitization: Once the work order has an updated final as-built and the completion date has been entered, it is ready for unitization. In order for the asset to be unitized, a final as-built listing asset details at the retirement unit level must be submitted to Operational Plant Accounting. Once submitted, Operational Plant Accounting will unitize the asset as part of the month-end close process. *The work order status will change from "complete" to "unitized". This creates a pending transaction that will need to be approved and posted.*

Posted to CPR: Once the pending unitization transaction is approved and posted, the work order status will change to *"posted to CPR"*

Summary of work orders statuses and the corresponding GL account classification for capital dollars:

Work Order Status	GL Account
Open	107 – Construction Work in Progress (CWIP)
In Service	106 – Construction Completed but Not Classified (CCNC)
Complete	106 – Construction Completed but Not Classified (CCNC)
Unitized	106 – Construction Completed but Not Classified (CCNC)
Posted to CPR	101 – Utility Plant In Service

APPENDIX

CONTACTS

This policy is maintained by RPA. For further guidance or more information please reference the below contacts.

Regulatory Plant Accounting

Guidance on Capitalization Topics / Capital Decisions:

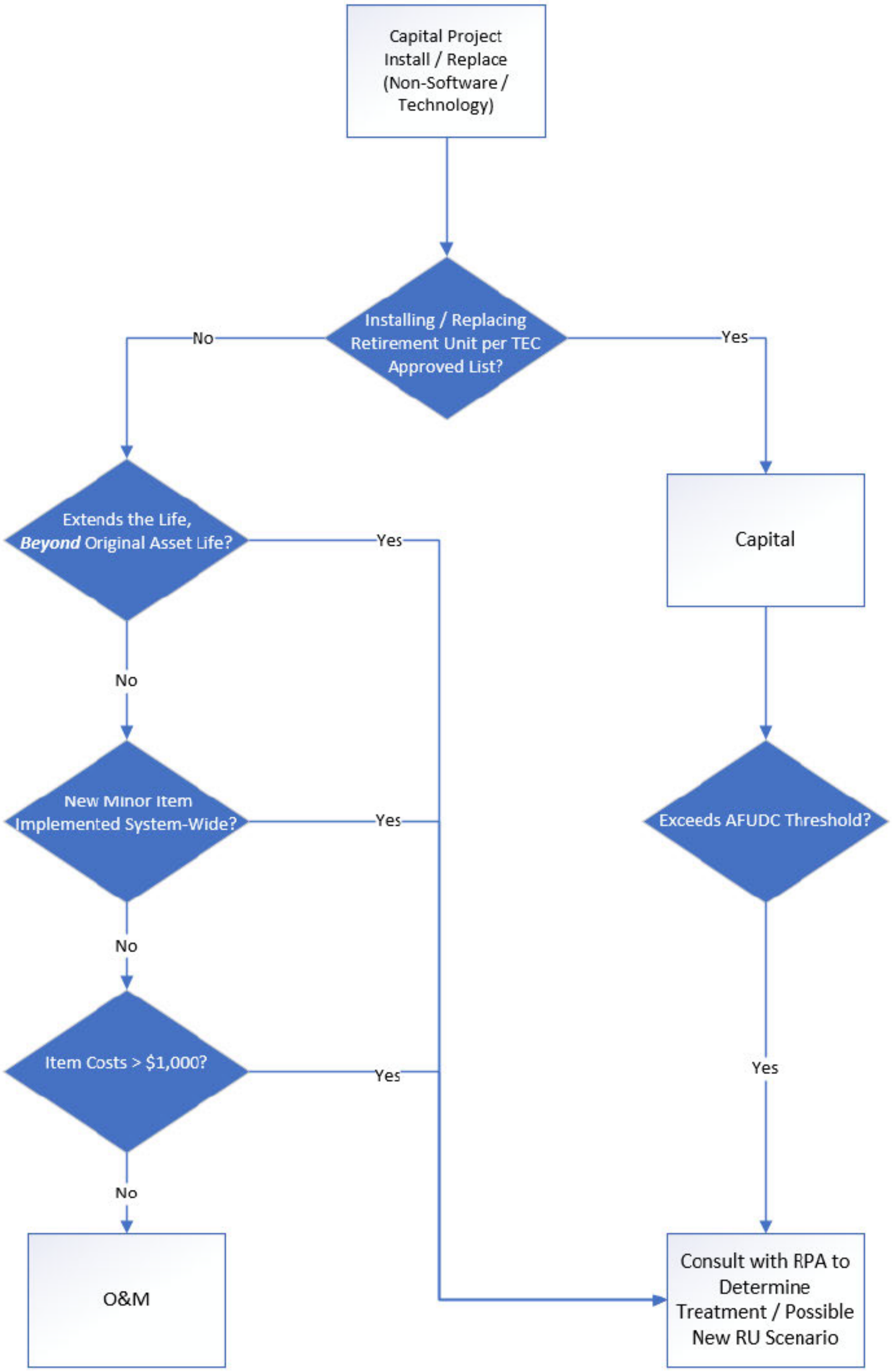
David Avellan, Director Regulatory Plant & Tax Accounting
Anthony Trask, Accounting Systems Manager
Sharon Tracy, Supervisor Plant Accounting
Mary Hensley, Senior Business Planning Analyst
Dana Braden, Coordinator Plant Accounting

Technical Accounting

Questions related to complex accounting topics (such as leases, contracts, cloud computing, ARO, etc.):

Jacob Diazgranados, Director Financial Reporting
Dana Moronese, Technical Accounting Manager

CAPITAL DECISION TREE



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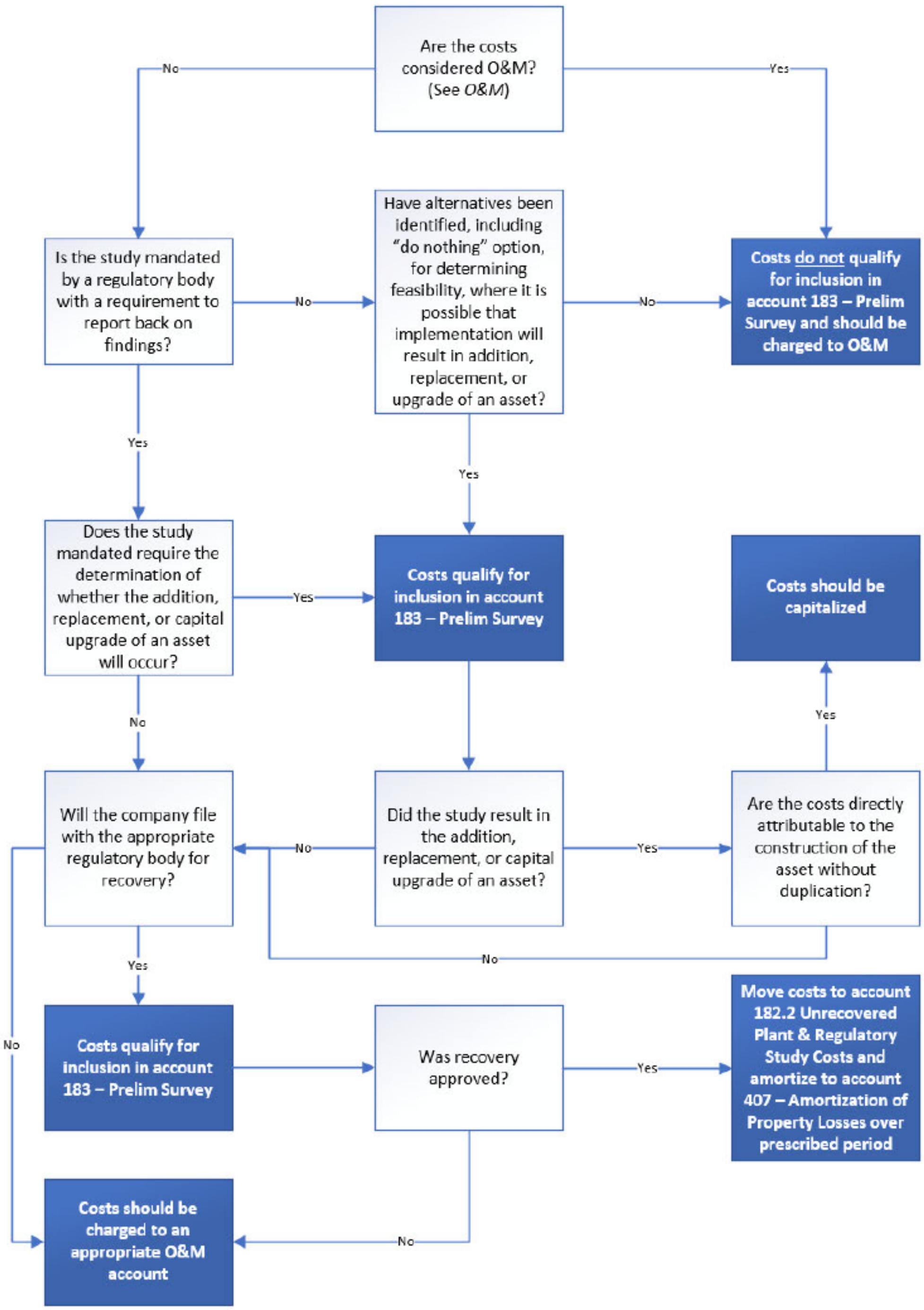
PRELIMINARY SURVEY COSTS DECISION TREE



CONSTRUCTION PROJECT MATRIX

Type of Cost	Additional Clarification	Capitalization Policy Reference	Classification
Labor – Direct			
Admin Support	Dedicated resources or directly assignable time to a construction project.	- *Components of Construction Cost* - *Overhead*	Capital
Business Process Improvement Documentation		- *O&M*	O&M
Contract Labor Vendor Management Fees / Contracting Services Management	If related to the construction project.	- *Components of Construction Cost* - *Overhead*	Capital
Design and Engineering		- *Components of Construction Cost* - *Overhead*	Capital
Drawing Updates		- *Components of Construction Cost*	Capital
Engineering Licenses / Dues / Professional Certifications	Periodic renewals of professional certifications or association memberships.	- *O&M*	O&M
Business / Financial Services		- *Components of Construction Cost* - *Overhead*	Capital
General Training	Training not specific to equipment providing new functionality for the company.	- *O&M*	O&M
Installation	Costs to install new asset, also includes relocation of existing equipment that is required in order to install new asset.	- *Components of Construction Cost*	Capital
Janitorial	Only for services needed as a direct result of construction project.	- *Components of Construction Cost*	Capital
Land Surveying and Clearing		- *Land and Land Rights*	Capital
Permanent Operations Staff	Operation employees hired to operate the new generation prior to in-service date, if required to be granted an operating license.	- *Components of Construction Cost*	Capital
Procedure Documentation	As a result of new equipment or equipment new to location.	- *Components of Construction Cost*	Capital
Project Planning and Management	Capitalize the amount that is reasonably determined to contribute to the chosen alternative. If project will not continue, expense.	- *Components of Construction Cost* - *Overhead* - FERC Account 183 Description	Capital

Project Specific Training	Specific to construction of new equipment that provides new functionality to the company.	- *Components of Construction Cost*	Capital
Qualifications Verification	For new personnel assignable to the construction project, including certification and training.	- *Components of Construction Cost*	Capital
Removal / Decontamination	If specific to the construction project.	- *General Guidelines*	Capital
Studies	Capitalize the amount that is reasonably determined to contribute to the chosen alternative. If project will not continue, expense.	- *Preliminary Survey Costs*	Capital
Testing Pre-Installation	Not applicable if testing solely to determining the timing of replacement.	- *Components of Construction Cost*	Capital
Materials			
Construction Specific Signage	If specific to the construction project.	- *Components of Construction Cost*	Capital
Consumables (e.g. lightbulbs)	If used during the installation or construction of the asset. Subsequent replacements are not capital.	- *Components of Construction Cost*	Capital
Direct Parts and Components		- *Components of Construction Cost*	Capital
Freight / Transportation / Shipping		- *Components of Construction Cost*	Capital
Office Equipment / Computers / Software	When dedicated to the construction project.	- *Components of Construction Cost*	Capital
Safety Equipment	When required and dedicated to the construction project.	- *Components of Construction Cost*	Capital
Small Tools	When consumed on the job and no longer useful after job completion	- *Components of Construction Cost*	Capital
Software for / as part of Components	If part of component and no alternative exists, capital. Otherwise, evaluate using Software policy.	- *Software*	Capital
Test Materials / Equipment		- *Components of Construction Cost*	Capital
Other			
Equipment Rental		- *Components of Construction Cost*	Capital
General Meetings	Department meetings where various topics are discussed, including travel and expenses associated with such meetings	- *O&M*	O&M
Injuries / Damages		- *Components of Construction Cost*	Capital
Insurance		- *Components of Construction Cost*	Capital

Inventory / Spare Parts	Purchased during construction for use on the project	- *Capital Spares*	Capital
Maintenance		- *O&M*	O&M
Per diem	**Related to direct construction project work, otherwise O&M**	- *Components of Construction Cost*	Capital
Postage	Related to shipping of items directly related to the construction project, such as engineering plans or supplies	- *Materials and Supplies*	Capital
Project-specific Meetings	Discussing details on specific capital project status or plans	- *Components of Construction Cost*	Capital
Property Taxes	Specific to new generation only	- *Components of Construction Cost*	Capital
Public / Community Relations	Costs associated with coordinating and planning a public meeting to educate the community and provide positive community relations for the company but add no value to the asset.	- *O&M*	O&M
Punch List	List of engineering and construction items that remain to be completed to bring the plant or plant systems into compliance with design criteria	- *Punch List*	Capital
Recognition Awards (e.g. gift certificates, meals, etc.)	For achievement based awards specific to the construction project for achieving project milestones	- *Components of Construction Cost*	Capital
Regulatory Fees	If specific to the construction project	- *Components of Construction Cost*	Capital
Required Public Workshops	Cost associated with coordinating and planning public workshops. Required workshops from a regulatory group to obtain license or permits.	- *Components of Construction Cost*	Capital
Scaffolding (Labor, Material / Rentals)	If specific to the construction project	- *Components of Construction Cost*	Capital
Supporting Infrastructure	Construct or Donate roads, hospitals, equipment, or other infrastructure required by regulatory agency but will not be owned by the company	Contact RPA for guidance	O&M
Temporary Facilities	If related to direct construction work	- *Components of Construction Cost*	Capital
Temporary Power		- *Components of Construction Cost*	Capital
Travel	Related to direct construction project work	- *Components of Construction Cost*	Capital
Warranty	Beyond punch list items.	- *Warranty*	O&M
Waste Processing	Waste disposal fees specific to the construction project	- *Components of Construction Cost*	Capital
Water / Working Meals	**Related to direct construction project work, otherwise O&M**	- *Components of Construction Cost*	Capital
Workforce Development	Providing sponsorship to education facility to train employees	- *O&M*	O&M

TAMPA ELECTRIC CAPITAL PLAY BOOK

Version 2 – Updated 4/15/2021

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

Table of content

1. Purpose and Scope of the Document

The purpose of this document is to provide guidance for the Capital Investment Program ("CIP") process for Tampa Electric Company ("TEC"). The guidelines outlined below have been approved by the Executive Team and are to be adhered to when developing capital plans and initiating projects.

These guidelines will assist those involved, at any level in the CIP process at TEC to achieve success with project planning, development, quality, cost, monitoring and closeout.

These guidelines address the issues most often incurred and present a standard approach to all capital funded projects. They apply to all construction, capital improvements, major equipment purchases and other special projects.

These guidelines establish a standard approach to:

1. Capital planning and budgeting
2. The review and evaluation criteria
3. Controlling and reporting
4. Closing projects

2. Acronyms & Terms

a. **AFUDC** - Allowance for Funds Used During Construction is accrued on construction projects to capitalize financing costs of construction. AFUDC has two components: debt and equity. AFUDC debt is used to offset interest expense and AFUDC equity is booked to Other Income.

b. **Capital Investment** – Includes the purchase and/or replacement of a retirement unit investment greater than $1,000 that has a useful life of greater than one year. A technology project investment must be $50,000 or greater. This includes, but not limited to:

   - Distribution / transmission lines and associated equipment
   - New facilities / building improvements

- System infrastructures (such as security, fire prevention, utilities)
- New and replacement equipment, major upgrades, technology and mobile equipment / vehicles

c. **CIP** – Capital Investment Program

d. **CIR** – Capital Improvement Requisition is used by Energy Supply. The CIR is a set of summaries and estimate forms used for projects less than $200,000. It defines project cost, description, justification and benefits.

e. **CLT** – The Capital Leadership Team reviews projects greater than $5 million and makes the determination if the project should be approved to move forward. The approval from the CLT is related to the advancement of the project, not of the spending. The projects still have to be routed for authorization to spend through the PowerPlan capital management system.

f. **CWIP** – Construction Work in Progress

g. **ECRC** - The Environmental Cost Recovery Clause is the mechanism established by rule by the Florida Public Service Commission (FPSC), that allows utilities to recover prudent expenditures, including a return on investment of costs associated with an environmental compliance activity through the Environmental Cost Recovery Factor

h. **FERC -** The Federal Energy Regulatory Commission is the United States federal agency with jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, and oil pipeline rates. One of the top priorities of FERC is administering accounting and financial reporting regulations and regulating companies.

i. **NERC –** North American Electric Reliability Corporation

j. **NOI –** Net Operating Income is Regulated Operating Income minus Regulated Operating Expenses.

k. **PCR –** Project Change Request

l. **PEG** – The Project Economics Guide is used by Energy Supply. This spreadsheet tool can be used for calculating project economics, as required. (See Appendix 2)

m. **PIF –** The Project Initiation Form is used by Energy Supply. This form is used to initiate a project which gives a general overview of expectations and scope and authorizes a specific amount of funding for project planning efforts prior to project authorization. The PIF is approved before project planning is initiated. Electric Delivery utilizes their Initial Authorization Form for the same purpose.
n. **PSTEW –** The Planning Substation Transmission Estimating Workbook is used by Electric Delivery. This complex Excel workbook performs project cost estimation for stand alone, large projects.
o. **RB -** Rate Base - The value of property and net assets on which a utility is permitted to earn a reasonable return, in accordance with the FPSC.
p. **ROE –** Return on Equity - Net Operating Income (NOI)/Rate Base (RB)
q. **ROI –** Return on Investment for TEC is a separate return mechanism outside of the Regulated ROE equation that establishes a fixed return on Clause related investments.
r. **RPA –** Regulatory Plant Accounting
s. **SPP** -Storm Protection Plan submitted to the FPSC, outlines the Company's 10-year plan to promote the overhead hardening of electrical transmission and distribution facilities, the undergrounding of lines and the vegetation management and transmission/distribution inspection program.
t. **SPPCRC** – Storm Protection Plan Cost Recovery Clause

3. Roles and Responsibilities

a. **The Finance group** is responsible for Capital consolidation and reporting to the Tampa Electric Executive Team, the Board of Directors, Emera, the FPSC, FERC and other governmental entities.

    1. **Business Planning** is responsible for coordinating the development of the annual and 5-year capital Plans. They are also responsible for the oversight of monthly/quarterly reforecasts

and reporting monthly results to all Functional areas. Business Planning also plays a role in the close out process related to updating the PowerPlan capital management system budget module with actuals in preparation for entering forecast/budget estimates.

2. **The Regulatory Plant Accounting (RPA)** group addresses capital vs O&M budget decisions and maintains the Capitalization Policy, which is saved on the Finance SharePoint for capital decision making reference. Capital Decision forms are submitted to RPA when additional capitalization guidance is needed. This form is also found on the Finance SharePoint site.

b. **Functional Business Areas** are responsible for managing their projects from initiation to completion including specific planning for project development. They are responsible for communicating to Business Planning when projects are in service, and complete and any significant changes to projects that impact the spend profile and potential earning of AFUDC.

4. Investment Categories

a. **Growth:** Growth projects are significant investment projects that span multiple years and have total expenditures greater than 0.5% of the sum of assets (FERC accounts 101 and 106). As of March 2020, that value is $49M or greater. These projects are typically part of the company's strategic, financial and/or operational vision. This defines an AFUDC eligible project which is excluded from Rate Base as it is constructed. Components of a project may not be eligible for AFUDC and included in Rate Base but will still be reported as growth. An example of this would be the Meter portion of the AMI project.

b. **Sustaining:** Sustaining projects are investments that are necessary for a business to maintain reliable operations or meet day to day obligations to customers, safety or compliance. This includes the replacement and refurbishment of assets.

It can also include expansion projects that do not meet the growth criteria above. It is important to note that all capital investments that do not receive AFUDC or Clause treatment are still included in Rate Base as constructed because CWIP is a component of Rate Base. Sustaining capital projects do not benefit from the attention, resources, and rigor often given to growth capital projects.

Below are various types of sustaining spending.

1. Blanket Funding Projects - Reoccurring projects, used to procure routine, frequently used assets (poles, meters, pad mount transformers, etc.) or to facilitate routine work that cannot be specifically identified at the time of budget preparation. The purpose of the blanket is to provide flexibility to respond to business needs. Each blanket funding project work order (subproject) must fall below an approved amount otherwise a separate stand-alone (non-blanket) funding project should be created. Those amounts differ for functional areas:
   i. Energy Supply - $250,000
   ii. Electric Delivery – $250,000 – certain programs are exempt
   iii. Other areas $100,000

   Note: New blanket projects require approval from COO

2. Stand-alone Projects – All other non-blanket capital type projects are discreet, stand-alone projects that are well defined, and meet the specific capital requirements as noted above. These individual projects are justified and approved individually.
3. Carry Over Projects - Projects from the previous budget year that were originally scheduled to be completed in that year but, due to unforeseen issues and or a result of a business decision, have spending carrying over to the current year. There also may be

times when the project is completed on time, however trailing charges carry over to the current year. They are included in the current forecasts. They may not have been identified at budget time. These projects need to be communicated to Business Planning and Finance in the November/December timeframe to evaluate annual impacts on the Company's Financial Objectives.

4. Retirement Only Projects - Capital projects that are for retirement purposes only. Typically called dismantlement projects. These projects will be entered into PowerPlan using a Dismantlement Funding Project Type. The approval levels and process are the same as for investment projects. This capital spending activity impacts Rate Base just like all other sustaining capital spending.

5. Clause Projects – Projects/Programs that have been approved by the FPSC and have their own recovery mechanism and ROI paid for by the customer. Because these projects have their own ROI mechanism these investments are not included in Rate Base. Currently, TEC has two types of Clause capital project categories.
    a. **ECRC** – Environmental projects within Energy Supply. These projects are set up with a TEC Capital Grouping class code in PowerPlan. This class code is assigned to the work orders. Only Additions/Install Work Orders are eligible for ECRC recovery. Labor costs charged to these projects are excluded.
    b. **SPPCRC** – Storm Protection projects within Electric Delivery. These projects are assigned the Funding Project class code RPA Project Group and called SPP Clause. Only incremental labor can be charged to this project. Does not include cost of removal.

5. Capital Planning

The focus of the capital planning process is to determine an organization's long-term investment in assets to ensure a high degree of reliability for customers. Capital budget decisions can impact the O&M budget process and vice versa. The capital plan impacts the Income Statement through depreciation expense, maintenance expense, property tax and interest expense. On the Cash Flow Statement, it impacts the Investing section and drives necessary funding decisions and timing of those decisions. Finally, capital planning impacts a key metric the company and its investors monitor, the ROE. As capital investments are made that do not earn AFUDC or are not included in a Cost Recovery Clause they enter into Rate Base which is the denominator in the ROE equation. The more capital investments made, the more downward pressure made on ROE. Therefore, the timing of Rate Base growth has to be carefully maintained/balanced with NOI earnings (Net Operating Income) to achieve a reasonable return. In some cases, as investments are made on behalf of customers, rate base growth may out pace NOI and therefore rate cases are necessary to help balance this equation.

Development of a capital plan is intended to ensure that decision makers are aware of proposed future spending requirements, the expected benefits to both customers and the organization and the impacts and or risk of not making the investment. The capital planning process will result in a prioritized list of projects for the current fiscal year capital budget and the five-year capital plan.

These guidelines provide a standard methodology for identification of investment priorities across a diverse portfolio of capital assets and outlines the methods and requirements for the various planning activities.

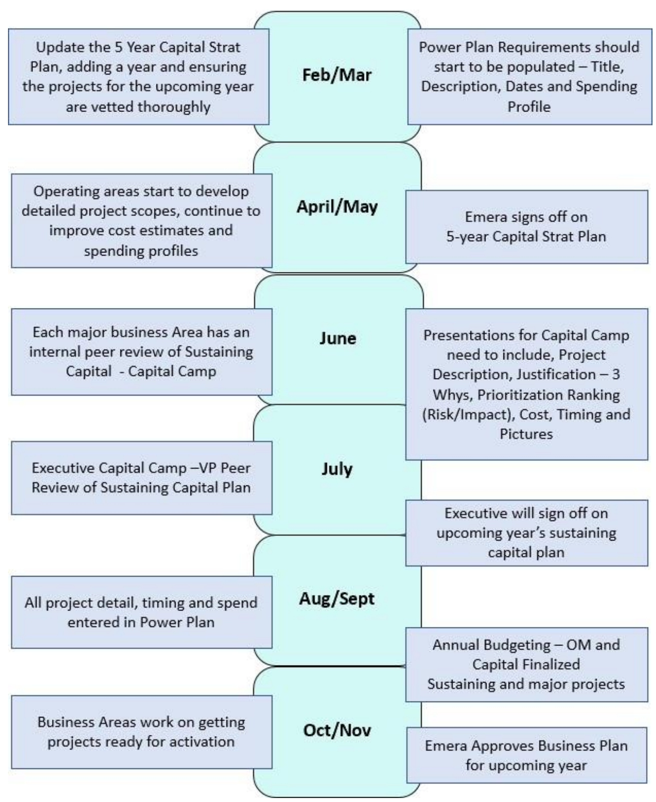
a. Timeline

The capital planning process is an annual process that is comprised of a number of sequential steps. The process starts in February, with a review and update of the STRAT plan (5-year plan) and ends in October/November with the final approval of the annual capital plan. Actual dates are communicated annually.

Each year the annual capital plan is developed to align with the long-term strategic objectives, and the annual operating plans, planned maintenance outages and O&M budgets. The approval of the capital plan does not authorize the commencement of spending on the individual projects. Each capital project initiation must follow Administration Policy 2.11 to obtain the necessary approvals to proceed.

The following illustration represents the major milestones during the annual process to update the CIP. This process is coordinated by the Finance Department.

Capital Planning Calendar



6. STRAT - 5 Year Planning

The initial phase of capital planning is the review and updating of the 5 Year STRAT plan. This involves compiling the proposed capital projects and operating expenditures for the upcoming year and the five subsequent years. The plan is updated annually to reflect new and better data, as well as any new proposed projects. It is a critical element in the long-term financial planning of the business. Projects identified will demonstrate a major and/or measurable contribution to the Corporate goals and objectives. The plan will be developed based off of sound asset management principles, projected customer requirements and strategic growth opportunities while aligning with the priorities of the corporate strategy.

The process will begin with each functional area reviewing their capital project lists from the prior year's STRAT plan, including the spend profile, timing and priority. Each business area will review, update and add their capital requirements based on highest priority.

The process allows for business areas to provide a brief outline of the project objectives, the initial priorities and a review with major stakeholders. The projects are reviewed for future impact on financials with an emphasis on the next year's proposal.

The review and final approval of the STRAT goes through various reviews with final Emera approval in April/May of each year – see Figure 1

7. Annual Planning

After the finalization of the STRAT plan the functional areas begin to finetune the details required to support a project in the annual budget. The projects identified in the first year of the STRAT plan are the foundation of the annual plan. Some reprioritization may occur, but significant change to the plan would undermine the purpose of the STRAT capital planning effort. The annual capital plan requires more detail, improved cost estimate and collaborative review of priorities.

The capital planning process is intended to ensure that the projects are clearly defined, and enough information is available to develop the scope, a reliable cost estimate and schedule prior to proceeding further in the capital planning process.

The reliability of cost estimating is measured by Confidence Level (CL). The below chart provides the Estimate Description and Probable Accuracy for each CL:

CONFIDENCE LEVEL (CL)	ESTIMATE DESCRIPTION (Phase of estimating cycle and typical estimate headings)	PROBABLE ACCURACY (Typical accuracy range and contingency - 90% confidence that actual $ will fall within)
CL1	FINAL DESIGN ESTIMATE (also full detail, release, fallout, tender, bottoms-up, detailed)	-5% to +5% before contingency Typical contingency = 3% - 5%
CL2	DEFINITIVE (also detailed, control, or forced detail, definitive)	-5% to +15% before contingency Typical contingency = 5% - 10%
CL3	OFFICE ESTIMATE also budget, scope, sanction, semi-detailed, authorization, preliminary)	-10% to +20% before contingency Typical contingency = 8% - 12%
CL4	FACTOR ESTIMATE (also conceptual, top-down, evaluation, study, favored, predesign study)	-20% to +30% before contingency Typical contingency = 10% - 20%
CL5	ORDER OF MAGNITUDE (also ROM, ball-park, rule-of-thumb, WAG, seat-of the-pants, questimate)	-30% to +50% before contingency Typical contingency = 15% - 40%

The Capital plan will include those projects which are essential for health and safety objectives, environmental / regulatory compliance, asset / customer reliability, economic or efficiency improvements and those which are required to provide service to a given area and/or mitigate known risks. Projects which serve to improve customer reliability are evaluated based on the probability factors related to performance targets (SAIDI, SAIFI, CAIDI). Economic initiatives are evaluated based on their economic and performance ranking (return on investment / net present value). The annual capital plan can be constrained by a number of factors including the ability to effectively execute within the available time and resources, pace of customer (load) growth, the maintenance cycle of the generating facilities and company cash flow.

Electric Delivery, Energy Supply, IT and Customer Experience have a peer review of projects prior to the submission of the annual budget that is often referred to as "Capital Camp". This same type of review is done with the Executive Team to ensure the company is spending the right money, in the right place and at the right time. This also provides the Leadership Teams from all areas of the business insight to the plan, opportunity to critique investment plans, level of priority being assigned and ultimately the team's buy in and support of the annual plan and how it supports corporate priorities.

8. <u>Capital Project Review Procedure</u>

Review procedures differ for Growth Projects and Sustaining Capital

a. **Growth / Major Projects**

   <u>Conceptual Capital Review as required</u> – Major Project concepts can come about in different ways such as the result of Corporate Strategic initiatives or Resource Planning. The concept is then presented to the Decision Board by the Sponsoring officer to determine if the project should move forward. The information reviewed includes description of the project, the objectives, the strategic alignment, timeline, risk and financial assessments.

b. **Sustaining Capital**:

   a. <u>Executive Capital Camp</u>

      The objective of Capital Camp is to review proposed projects, consider financial and non-financial implications, evaluate risk and probability, prioritize and identify early on any proposals that should not proceed, or may require revisions or changes in timing or scope. The goal is to ensure the most impactful projects are approved for the annual budget.

      Each functional area presents their proposed capital projects at Capital Camp. Typical aspects examined during this initial screening are project description, justification, priority, and cost estimate. (See Appendix 3)

Each project being proposed for the annual budget at Capital Camp must present the following details:

b. **Project Description** - Provide a short narrative which describes the project, the objective, and the benefit to the business.

c. **Justification**: The project justification must answer the following questions:

1. Why should we do the project?
    a. This should be clear and concise, citing customer requirements, safety needs, regulatory obligation, replacement, life cycle, etc.
    b. Reference studies, inspections, condition assessments, maintenance history or criticality.
    c. Multiple benefits – condition, safety risk, heat rate, reliability, production, financial
2. Why do the project now?
    a. Risk of failure and associated production impacts
    b. Resource or timing optimization
    c. Economic Value (maintenance costs/efficiencies)
3. Why do the project this way?
    a. Scope choices
    b. Design choices
    c. Other options that were considered

The Justification fields in PowerPlan must be updated for these projects. This will allow for the timely printing of the Justification forms to document projects making it into the budget (See Appendix 4).

9. Ranking Criteria

In order to compare projects of differing scale and purpose, a priority scoring system is used. The Risk Matrix (Appendix 1) will be used to rank capital proposals. Each proposal will be reviewed by the Business Unit's key stakeholders and assigned a priority ranking based on placement in the ranking matrix. Criticality and condition values are typically influenced by one predominant factor and ranked accordingly. These include (Health and Safety, Environment, Equipment Reliability, Equipment Reliability, Customer Reliability, and Business Sustainability).

The four colors of the ranking matrix are a visual representation of the likelihood of a capital project being completed. A project within the red ranking is considered a high priority and should be completed. Projects within the orange and yellow rankings represent projects that carry a higher risk than the projects in the green ranking. While the colors provide a visual illustration of risk, the ranking numbers are the focus of the ranking process. A lower ranking suggests a lower level of risk and urgency, but not always a lower level of priority. There may be factors such as timing of an outage that may move projects.

10. Economic Analysis

Projects greater than $1 million require an economic evaluation regardless if it is Growth or Sustaining unless otherwise approved by a sponsoring officer. The analysis will calculate and compare the revenue requirement by comparing alternatives. There are two options available at TEC. Energy Supply uses a model referred to as PEG (Production Economics Guide). This method is tailored to look at the impact projects will have on unit performance. Other areas of the business are able to contact the Director of Strategic & Financial Analysis who can assist with models on the financial impact projects will have on the business.

11. PowerPlan Requirements

As the information is gathered, each functional area will input information in TEC's capital management system, PowerPlan. PowerPlan is a multi-faceted application that, from a capital planning perspective, assists in accurately capturing capital budgets/forecasts, calculates AFUDC, depreciation and tax and unitizes assets to the books. In order to do this effectively, the requirements must be entered correctly.

a. Requirements for creating an individual Funding Project within PowerPlan for STRAT plan
    a. Project Title/Short Description
    b. Funding Project Type
    c. Department cost center responsible for project
    d. Major location
    e. Asset location
    f. Dates: Start, in service and completion dates.
    g. Estimated funding requirements and timing of spend
    h. AFUCD eligibility

b. Requirements within PowerPlan for the annual plan include the above and information to update the Justification tab within the system
    a. Project Scope Description
    b. Justification Criteria
    c. Objective – Why Do this Project?
    d. Alternatives Discussed – Why Do it this Way?
    e. Risk Review – Why do it Now?
    f. Need for CLT or board approvals
    g. Updated dates: Start, in service and completion dates.
    h. Updated Estimated Funding requirement with detail and timing of spend
    i. AFUCD eligibility
    j. A&G allocation

12. Approvals

It must be appreciated that a Capital Plan is simply a plan and that the projects, the scope of work, the scheduling and cost estimates can and will change over time. It is only when a funding project approval routing in PowerPlan is complete that it becomes an active project. Until a project is approved it must be considered as only a planned project.

All appropriate project approvals are required prior to spending or committing funds or overspending previously approved funds. Approvals are required at various phases of a project.

a. Conceptual Approval for Major/Growth projects. When a strategic opportunity has been identified and determined to be a viable prospect, the sponsoring officer will present to the Decision Board a proposal of concept. The review is intended to provide the Decision Board with the description, the strategic rational, timeline, risk and high-level financial impact. Approval given at this stage provides the team with permission to develop a detailed project plan and determine the most cost-effective way to achieve expected results to submit for spending approval.
b. Budget Approval – The annual budget is an approval of the budget as a program and is approved by Emera, normally in October or November of each year. Following the notification that the budget has been approved, the functional areas begin initiating authorization to spend on the Funding Projects.
c. Funding Project Approval: All project approvals are required prior to spending

Threshold	Approval Level
Up to $100K	Manager
Up to $500K	Director

Up to $2M	Vice President
Up to $5M	Sr. Vice President
Up to $10M	COO
Up to $20M	CEO/President
Greater than $20M	Board of Directors

d. Preliminary Engineering Approval- This approval is typically $50 thousand or less on projects that require engineering, design or business case development. Charges related to construction or material are not included in the scope of this approval. Approval amount can be greater than $50 thousand depending on the magnitude of the project. Approver needs to be aware that if this project is not viable, the costs will be transferred (reclassed) to O&M expense.

The charges for preliminary engineering is not to be confused with the those charged to study account 183. The study account 183 is used to capture enough information to determine if a project is feasible. Preliminary engineering approval occurs after a project has been deemed viable.

e. Unforeseen & Unbudgeted (U&U): There may be times when extraordinary circumstances and/or changing priorities necessitate a project be completed that has not been included in the current fiscal year budget. Typically, these projects are greater than $250 thousand, (not covered by blankets) that develop throughout the year. These projects were not included in the current year's capital budget and cannot wait until the next year's budget process.
U&U requires a review of funding options with the functional area leadership who will provide the sponsoring officer with written notification outlining how they will manage the U&U spending within their approved budget. Vice President level approval must be obtained prior to spending and the review of funding options can happen at the next monthly meeting of the functional area

leadership or sooner upon request, if the project is time sensitive. If the funding cannot be managed within the approved budget, COO approval is required in order to proceed with the project. Once the funding option is determined the project will be submitted for authorization and follow the same approval process as other funding projects. The funding project will be assigned the PowerPlan RPA CapEx Classification class code U&U.

f. PCR – Project Change Request is intended to request additional approval prior to incurring expenditures above the original approved amount. A PCR is required in the following two instances:
   i. Project cost estimates are tracking at an increase of 10 percent from the original approved amount and do not exceed $250 thousand for projects over $2.5 million.
   ii. Project cost estimates that result in the total project costs exceeding the prior approval authority level as outlined in policy 2.11

Once the Annual capital budget has been approved, functional areas are authorized to begin project implementation.

All approvals are processed within the PowerPlan system. With each approval routing, a clear description of the project and/or the reason for the overrun is explained within the Justification Field.

13. Monitoring/Tracking: Projects are monitored at various levels throughout the course of the year. Results and forecasts reporting are done monthly.

a. Results Reporting – After the monthly close out process is complete, Business Planning produces reports at various levels of detail for the functional areas and Executives. These reports typically identify result variances for the month and year to date compared to the budget, Q1F or Q3F. Subsequent to this, the ELT meets together and reviews the Financials, including key metrics such as NI, CFO, CapEx and ROE.

b. Forecast Reporting – Monthly forecasts are required for all major projects that are AFUDC eligible. All other projects are required to forecast quarterly.

Business Planning provides functional business areas with a monthly summary of all capital spend against the approved budget and previous forecasts at the funding project level to compare fluctuation of spending throughout the year. Additional reporting is also done as requested by the functional areas.
The ELT meets on the forecast monthly and reviews the Financials, including key metrics like NI, CFO, CapEx and ROE.

c. Quarterly Reporting – Q1F and Q3F presentations are submitted to Emera

Major project owners are responsible to monitor the project spending on a monthly basis. It is important to keep in mind that high profile projects often require more extensive reporting of activity compared to the more routine capital projects. Each major project has a monthly meeting with the ELT to review progress, spending, milestones, scope changes, etc.
Project spend must not exceed the approved amount. An alert is in place within PowerPlan that will notify the project owner when project spend is within 10 percent of approved amount.

d. Project Status Tracking – It is not just important to monitor project spend, it is also important to track the project status. As part of their regular processes, RPA produces a few reports to ensure the in service and complete dates reflected in PowerPlan are in line with actual project timelines.

i. Monitoring project in-service dates is critical due to the potential impacts to AFUDC, depreciation and tax calculations. RPA provides a monthly report showing work order estimated in-service and completion dates for the current month. These dates are reviewed by Business Planning and project owners to determine if the dates are appropriate or need to be changed. Changes are then made in PowerPlan.

ii. A Late In Service report is run monthly to capture open work orders with estimated in service dates in the past. These results are sent to Business Planning and project owners for corrections.

iii. An Idle report is produced that identifies projects with estimated in service dates in the future, but have not incurred charges for a period of time. This report recognizes projects that are possibly stalled or should already have been placed in service. An email is sent to Business Planning and project owners inquiring about the project status and if any changes are needed within PowerPlan.

14. **Closing:** The finalization of a project should happen within six months of the project going in service. When projects are complete, actions are taken to finalize project activities and ensure proper project closeout. See Appendix 5 for the Project Closeout Checklist that must be completed during project closeout.

1898 & Co.
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Storm Protection Plan Resilience Benefits Report

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

Tampa Electric Company

TEC SPP Resilience Benefits Report
Project No. 121429

Revision 0
4/10/2020

TAMPA ELECTRIC COMPANY
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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
AHI	Asset Health Index
ANL	Argonne National Laboratory
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
C&I	Commercial & Industrial
CMI	Customer Minutes Interrupted
DOE	Department of Energy
FLISR	Fault Location, Isolation, Service Restoration
GIS	Geographic Information System
ICE	Interruption Cost Estimator
IEEE	Institute of Electrical and Electronics Engineers
LOF	Likelihood of Failure
MED	Major Event Day
NARCU	National Association of Regulatory Utility Commissioners
NASC	National Electric Safety Code
NIAC	National Infrastructure Advisory Council
NOAA	National Oceanic and Atmospheric Administration
NPV	Net Present Value
OMS	Outage Management System
PNNL	Pacific Northwest National Laboratory's
POF	Probability of Failure
ROW	Right-of-Way

Abbreviation	Term/Phrase/Name
SIM	Storm Impact Model
SLOSH	Sea, Land, and Overland Surges from Hurricanes
SPP	Storm Protection Plan
T&D	Transmission and Distribution
TEC	Tampa Electric Company

1.0 EXECUTIVE SUMMARY

Tampa Electric Company (TEC) engaged the services of 1898 & Co, the advisory and technology consulting arm of Burns & McDonnell, to assist with the development of the 10-year Storm Protection Plan required by Florida Statute 366.96, also known as Senate Bill 796. In collaboration, TEC and 1898 & Co. utilized a resilience-based planning approach to identify hardening projects and prioritize investment in the Transmission and Distribution (T&D) system utilizing a Storm Resilience Model. The Storm Resilience Model evaluates each hardening project's ability to reduce the magnitude and/or duration of disruptive storm events. Key objectives for the Storm Resilience Model are:

1. Calculate the customer benefit of hardening projects through reduced utility restoration costs and impacts to customers
2. Prioritize hardening projects with the highest resilience benefit per dollar invested into the system
3. Establish an overall investment level that maximizes customers benefit while not exceeding TEC technical execution constraints

While the resilience benefit is significant and is the focus of this report, it is not the only benefit of TEC's Storm Protection Plan. Additional benefits are described and quantified elsewhere in TEC's Plan. The Resilience Model employs a data-driven decision-making methodology utilizing robust and sophisticated algorithms to calculate the resilience benefit of hardening projects in terms of the range of reduced restoration costs and Customer Minutes Interrupted (CMI). The hardening projects provide resilience benefit from several perspectives. Some of the hardening projects eliminate storm-based outages all together, some reduce the number of customers impacted (CI), and others decrease the duration of storm-related outages. This report shows only the reduction in CMI, which accounts for both types of benefits. However, there is a strong relationship between reduction in CMI and reduction in CI.

Resilience-based prioritization facilitates the identification of the hardening projects that provide the most benefit. Prioritizing and optimizing investments in the system helps provide confidence that the overall investment level is appropriate and that customers will get the most value for the level of investment.

This report outlines project prioritization and benefits calculations for the following TEC storm hardening programs:

- Distribution Lateral Undergrounding
- Transmission Asset Upgrades
- Substation Extreme Weather Hardening
- Distribution Overhead Feeder Hardening
- Transmission Access Enhancements

The other programs within TEC's Storm Protection Plan, Vegetation Management, Infrastructure Inspections, and Distribution Pole Replacements, are not evaluated or included in this report. Their benefits and prioritization are described in other parts of TEC's Storm Protection Plan. Similarly, their benefits are described in other portions of TEC's Storm Protection Plan.

1.1 Resilience Based Planning Approach

Figure 1-1 provides an overview of the Storm Resilience Model. The model employs a resilience-based planning approach to calculate the benefits of reducing storm restoration costs, CI, and CMI. Each of the different components are reviewed in further detail in Sections 3.0, 4.0, 5.0, and 6.0.

The Major Storm Events Database contains 13 unique storm types with a range of probabilities and impacts to create a total database of 99 different unique storm scenarios. The storm scenarios range from a Category 3 or greater direct hit from the Gulf of Mexico to a Category 1 or 2 partial hit over Florida, to a tropical storm. Section 3.0 provides additional details on the 99 different storm scenarios.

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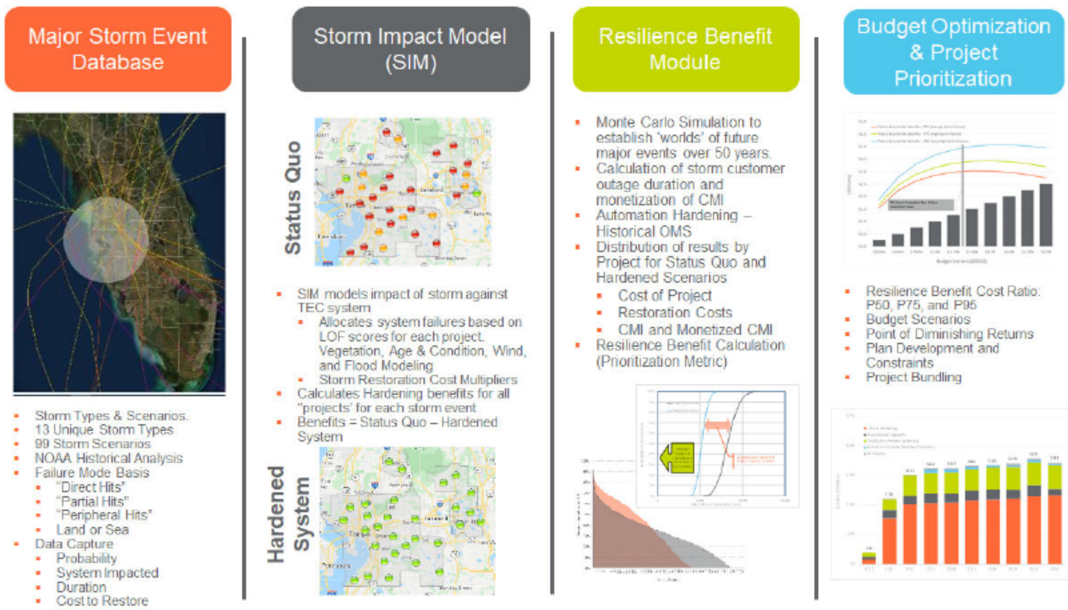
Figure 1-1: Storm Resilience Model Overview



Each storm scenario is then modeled within the Storm Impact Model to identify which parts of the system are most likely to fail given each type of storm. The Likelihood of Failure (LOF) is based on the vegetation density around each conductor asset, the age and condition of the asset base, and the applicable wind zone for the asset's location. The Resilience Model is comprehensive in that it evaluates nearly all TEC's T&D system. Table 1-1 provides an overview of the potential project count for each of the programs.

Table 1-1: Potential Projects Considered

Program	Project Count
Distribution Lateral Undergrounding	18,560
Transmission Asset Upgrades	131
Substation Extreme Weather Hardening	59
Distribution Overhead Feeder Hardening	1,613
Transmission Access Enhancements	96
Total	20,459

The Storm Impact Model also estimates the restoration costs and CMI for each of the projects in Table 1-1 above for each storm scenario. For purposes of this report, the term "project" refers to a collection of assets. Assets are typically organized from a customer impact perspective, see Section 2.2. Finally, the Storm Impact Model calculates the benefit in decreased restoration costs and CMI if that project is hardened per TEC's hardening standards. The CMI benefit is monetized using the DOE's Interruption Cost Estimator (ICE) for project prioritization purposes.

The Resilience Benefit Calculation utilizes stochastic modeling, or Monte Carlo simulation, to select a storm scenario for each of the 13 storm types for 1,000 iterations. This produces 1,000 different future storm worlds and the expected range of benefit values depending on the different probabilities and impact ranges to the TEC system. The probability of each storm scenario is multiplied by the benefits calculated for each project from the Storm Impact Model to provide a resilience-weighted benefit for each project in dollars. Feeder Automation Hardening projects are evaluated based on historical outages and the expected decrease in historical outages if automation had been in place.

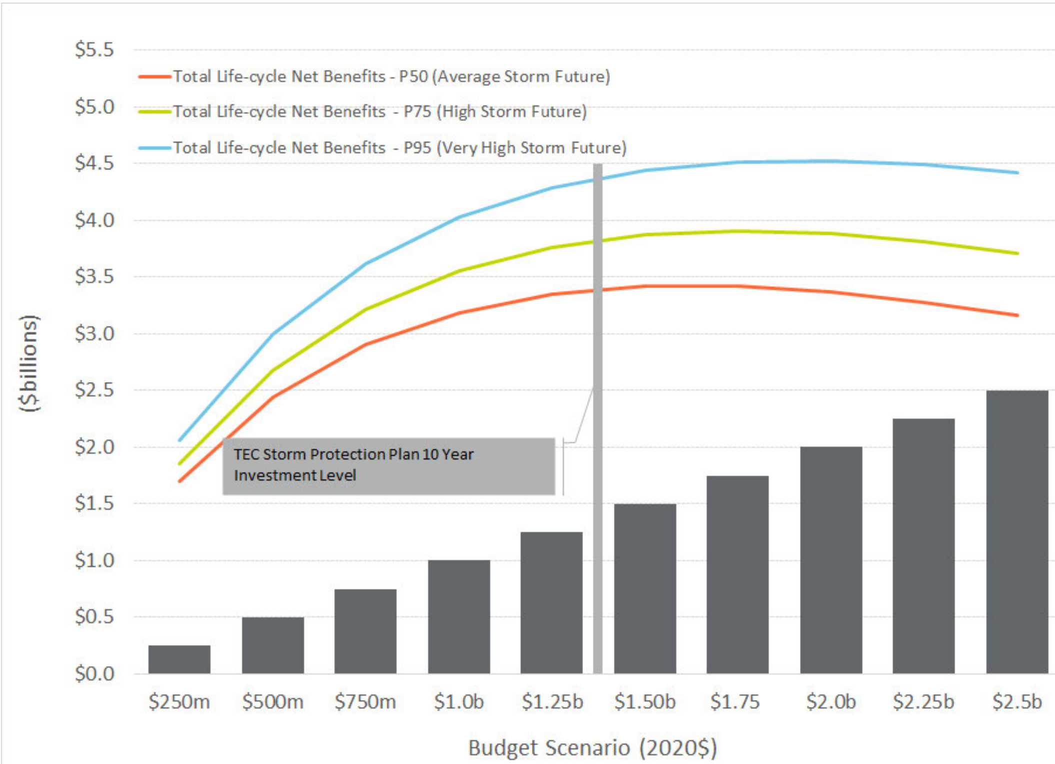
The Project Scheduling and Budget Optimization model prioritizes the projects based on the highest resilience benefit cost ratio. It also performs a budget optimization over a range of budget levels to identify the point of diminishing returns.

The model prioritizes each project based on the sum of the restoration cost benefit and monetized CMI benefit divided by the project cost. This is done for the range of potential benefit values to create the resilience benefit cost ratio. The model also incorporates TEC's technical and operational constraints in scheduling the projects such as contractor capacity and scheduling planned transmission outages. Using the Resilience Benefit Calculation and Project Scheduling and Budget Optimization model, the Storm Resilience Model calculates the net benefit in terms of reduced restoration costs and CMI for the 10-year investment profile.

1.2 Results & Conclusions

TEC and 1898 & Co. utilized a resilience-based planning approach to establish an overall budget level and identify and prioritize resilience investment in the T&D system. Figure 1-2 shows the results of the budget optimization analysis. Given the total level of potential investment, the budget optimization analysis was performed in $250 million increments up to $2.5 billion. The figure shows the total life-cycle gross NPV benefit for each budget scenario for P50, P75, and P95. P50 to P65 levels represent a future world in which storm frequency and impact are close to average, P70 to P85 level represent a future world where storms are more frequent and intense, and P90 and P95 levels represent a future world where storm frequency and impacts are all high.

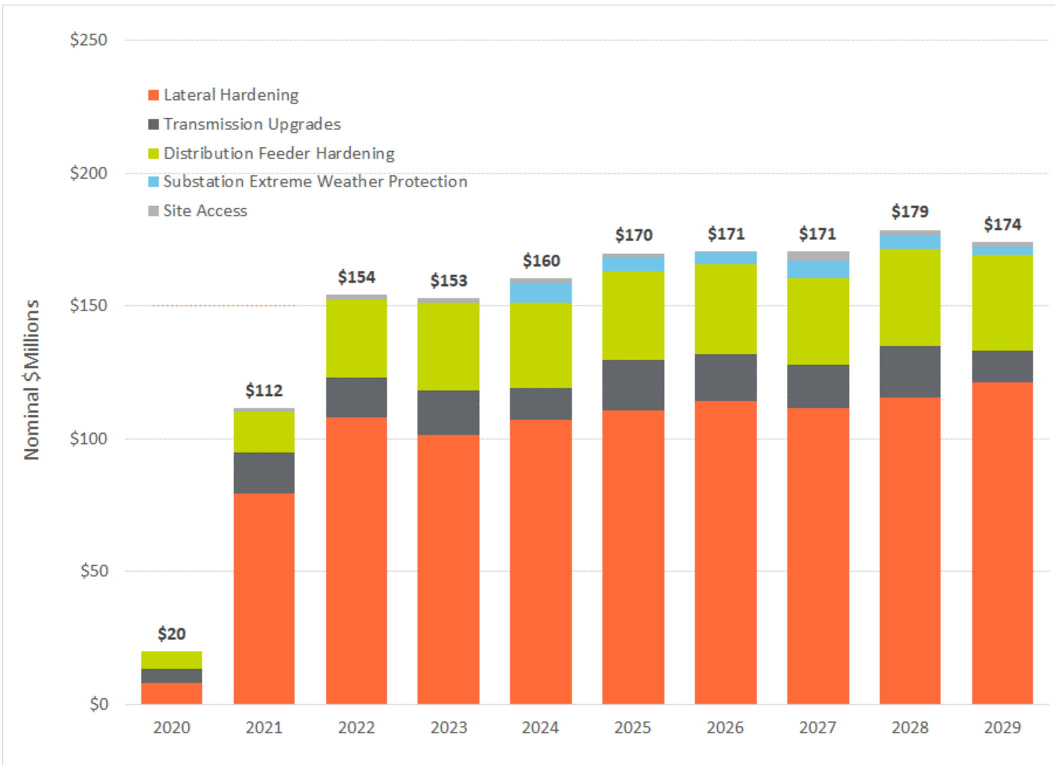
Figure 1-2: Budget Optimization Results



The figure shows significantly increasing levels of net benefit from the $250 million to $1.5 billion budget scenarios with the benefit level flattening from $1.5 billion to $2.0 billion and decreasing from $2.0 billion to $2.5 billion. The figure also shows the total investment level in 2020 dollars for the TEC Storm Protection Plan. The TEC overall investment level is right before the point of diminishing returns, which demonstrates that TEC's plan has an appropriate level of investment over the next 10 years capturing the hardening projects that provide the most value to customers.

Figure 1-3 shows the Storm Protection Plan investment profile. The table includes the buildup by program to the total. The investment capital costs are in nominal dollars, the dollars of that day. The overall plan investment level is approximately $1.46 billion. Lateral undergrounding makes up most of the total, accounting for 66.8 percent of the total investment. Feeder Hardening is second accounting for 19.8 percent. Transmission upgrades make up approximately 10.2 percent of the total with substations and transmission site access making up 2.2 percent and 1.0 percent, respectively. The plan includes a few months of investment in 2020 and a ramp-up period to levelized investment (in real terms) in 2022.

Figure 1-3: Storm Protection Plan Investment Profile

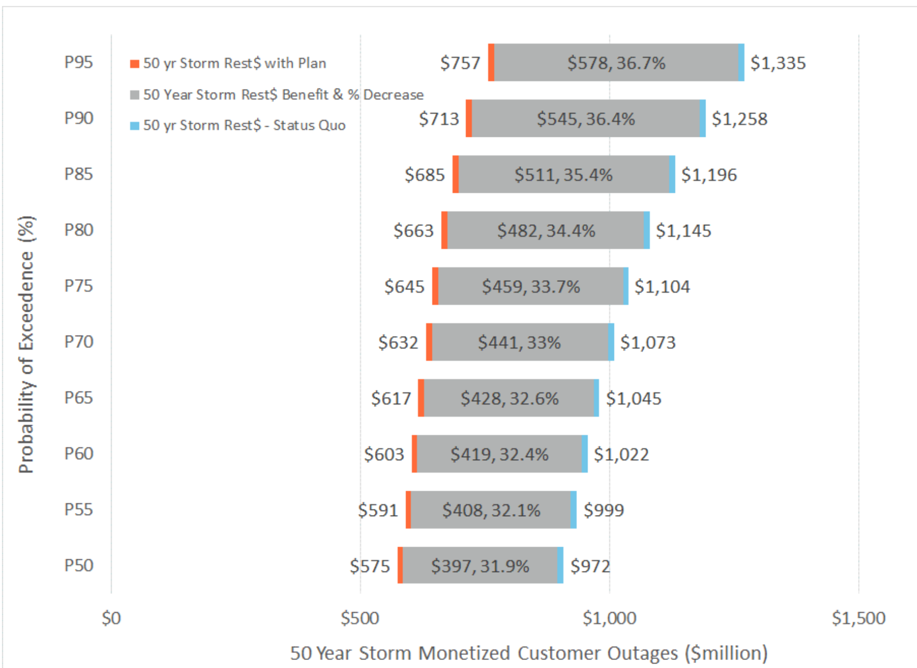


Customer benefits are calculated in terms of the:

1. Reduction in the Storm Restoration Costs
2. Reduction in the number of customers impacted and the duration of the overall outage, calculated as CMI

Figure 1-4 shows the range in restoration cost reduction at various probability of exceedance levels. To reiterate, the P50 to P65 level represents a future world in which storm frequency and impact are close to average, the P70 to P85 levels represent a future world where storms are more frequent and intense, and the P90 and P95 levels represent a future world where storm frequency and impacts are all high.

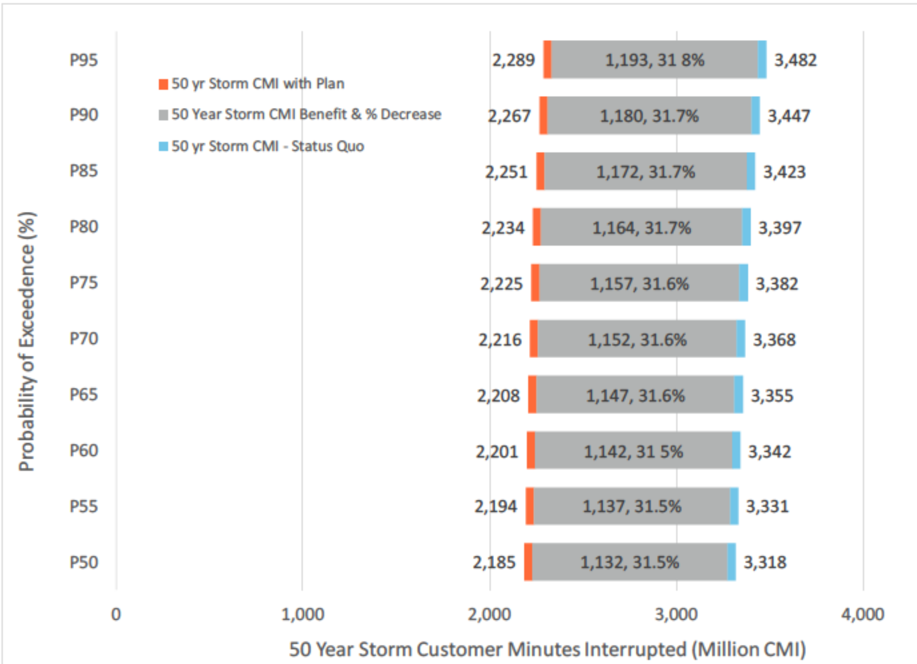
Figure 1-4: Storm Protection Plan Restoration Cost Benefit



The figure shows that the 50-year NPV of future storm restoration costs in a Status Quo scenario from a resilience perspective is $970 million to $1,340 million. With the Storm Protection Plan, the restoration costs decrease by approximately 32 to 37 percent. The decrease in restoration costs is approximately $400 to $580 million. From an NPV perspective, the restoration cost benefit is approximately 36 to 53 percent of the Storm Protection Plan Investment Level. In other words, the reduction in restoration costs pay for 36 to 53 percent of the total invested capital costs.

Figure 1-5 shows the range in CMI reduction at various probability of exceedance levels. The figure shows relative consistency in benefit level across the P-values with approximately 32 percent decrease in the storm CMI over the next 50 years.

Figure 1-5: Storm Protection Plan Customer Benefit



The following include the conclusions of TEC's Storm Protection plan evaluated within the Storm Resilience Model:

- The overall investment level of $1.46 billion for TEC's Storm Protection Plan is reasonable and provides customers with maximum benefits. The budget optimization analysis (see Figure 1-2) shows the investment level is right before the point of diminishing returns.
- TEC's Storm Protection Plan results in a reduction in storm restoration costs of approximately 32 to 37 percent. In relation to the plan's capital investment, the restoration costs savings range from 36 to 53 percent depending on future storm frequency and impacts.
- The customer minutes interrupted decrease by approximately 32 percent over the next 50 years. This decrease includes eliminating outages all together, reducing the number of customers interrupted, and decreasing the length of the outage time.
- The cost (Investment – Restoration Cost Benefit) to purchase the reduction in storm customer minutes interrupted is in the range of $0.61 to $0.82 per minute. This is below outage costs from the DOE ICE Calculator and lower than typical 'willingness to pay' customer surveys.

- TEC's mix of hardening investment strikes a balance between investment in the substations and transmission system targeted mainly at increasing resilience for the high impact / low probability events and investment in the distribution system, which is impacted by all ranges of event types.
- The hardening investment will provide additional 'blue sky' benefits to customers not factored into this report.

2.0 INTRODUCTION

Hurricanes have inflicted significant damage to Florida in recent years and parts of the state face years of recovery. One of the most important things Florida can do to prepare for the next major storm is to make the electric grid more resilient. When the grid can better withstand the impacts of storms, everyone benefits. Florida businesses and families save money because they can get back on their feet more quickly[1]. Florida Statute 366.96 allows for the comprehensive planning and front-end investment necessary to protect Florida's power supply. It also allows utilities to design integrated programs to address all phases of resilience which, in turn, will reduce storm-related restoration costs and outage times.

This document outlines the approach to

1. Calculate the benefit of hardening projects through reduced utility restoration costs and impacts to customers
2. Prioritize hardening projects with the highest resilience benefit per dollar invested into the system
3. Establish an overall investment level that maximizes customers' benefit while not exceeding TEC technical execution constraints

The resilience-based approach is an integrated data driven decision-making strategy comparing various storm hardening projects on a normalized and consistent basis. This approach takes an integrated asset management perspective, a bottom-up approach starting at the asset level. Each asset is evaluated for its likelihood of failure in a storm event. Additionally, the consequence of failure is also evaluated at the asset level in terms of the restoration costs and CMI. Assets are rolled up to hardening projects and hardening projects are then rolled up to programs. Each project only hardens the assets that provide the most benefit to customers and that align with TEC's design standards.

This report outlines project prioritization and benefits calculations for the following TEC storm hardening programs:

- Distribution Lateral Undergrounding
- Transmission Asset Upgrades

[1] State Rep. Randy Fine and State Sen. Joe Gruters, Sun Sentinel, May 2019

- Substation Extreme Weather Hardening
- Distribution Overhead Feeder Hardening
- Transmission Access Enhancements

The other programs within TEC's Storm Protection Plan, Vegetation Management, Infrastructure Inspections, and Distribution Pole Upgrades, are not evaluated or included in this report. Their benefits and prioritization are described in other parts of TEC's Storm Protection Plan. Similarly, their benefits are described in other portions of TEC's Storm Protection Plan.

The following sections outline the foundation and background necessary to understand the rest of this report. These sections include a review of:

- Topic of resilience
- Resilience as the project assessment approach
- TEC asset base evaluated for resilience measures
- Resilience-based planning approach
- Resilience Investment Business Case Results

2.1 Resilience as the Benefits Assessment

Resilience has many faces. It looks different to different people and organizations depending on their challenges and focus. Is it more important to avoid an event from disrupting your business or is it more important to recover quickly? Both are important and TEC's approach considers both of these questions and more.

Resilience has been defined differently by many organizations. In a 2013 paper, the National Association of Regulatory Utility Commissioners (NARUC) paraphrased its own definition of resilience in a manner that is simple and easy to understand.

> *"it's the gear, the people and the way the people operate the gear immediately before, during and after a bad day that keeps everything going and minimizes the scale and duration of any interruptions."*

Before that, the National Infrastructure Advisory Council (NIAC) provided a definition that is often quoted, and which includes elements used in many other definitions. It states that resilience is

> *"The ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event."*

The NIAC definition includes a system's ability to absorb and adapt. These important characteristics were also used by Argonne National Laboratory (ANL) in its work on state and social resilience and were incorporated into Pacific Northwest National Laboratory's (PNNL) work on the resilience impacts of transactive energy systems. The ANL approach can be used to break resilience into four phases that also align with NARUC's elegantly simple description. The difference is that ANL explicitly includes the ability of the system to recognize and mitigate potential failures before they happen. These four phases are described below.

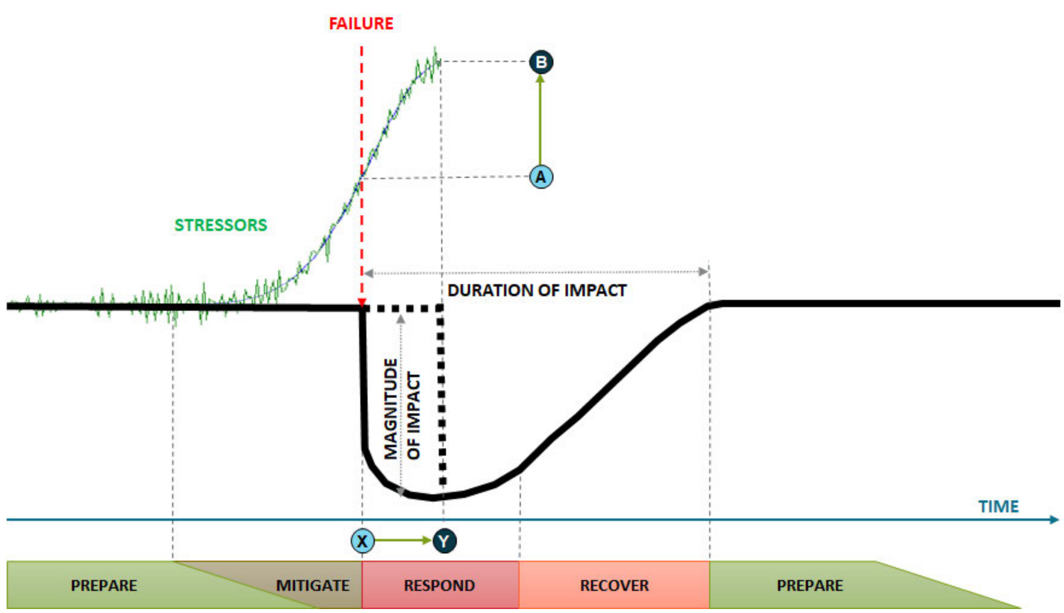
- Prepare (Before)
  The grid is running normally but the system is preparing for potential disruptions.
- Mitigate (Before)
  The grid resists and absorbs the event until, if unsuccessful, the event causes a disruption. During this time the precursors are normally detectable.
- Respond (During)
  The grid responds to the immediate and cascading impacts of the event. The system is in a state of flux and fixes are being made while new impacts are felt. This stage is largely reactionary (even if using prepared actions).
- Recover (After)
  The state of flux is over, and the grid is stabilized at low functionality. Enough is known about the current and desired (normal) states to create and initiate a plan to restore normal operations.

This is depicted graphically in Figure 2-1. The green line represents an underlying issue that is stressing the grid, and which increases in magnitude until it reaches a point where it impacts the operation of the grid and causes an outage. The origin of the stress may be electrical due to a failing component, or external due to storms or other events. The black line shows the status of the entire system or parts of the system (e.g. transmission circuits). The "pit" depicted after the event occurs represents the impact on a system in terms of the magnitude of impact (vertical) and the duration (horizontal). For utilities this can be measured after the event and is used by the Institute of Electrical and Electronics Engineers

(IEEE) 1366 to calculate reliability metrics. If TEC is able to detect the strain on the grid caused by these stresses then it increases the opportunity to act before a failure occurs, thus reducing or avoiding the impact of the subsequent event.

Figure 2-1 represents a conceptual view of resilience. It can be used to depict a specific transmission line or the whole transmission system. If the figure is used to represent a specific line, it represents the impact of the event on that line. If the figure is used to represent the impact on the whole TEC system, it represents the aggregated impacts of the event (storm) and the multiple outages that may result from it. Note that whether this is a specific or overall depiction of resilience there is no quantification of time. Time increases from left to right but due to the nature of events that may occur there are no timescales used.

Figure 2-1: Phases of Resilience



For example, hardening of the overhead transmission system is targeted at the “prepare” phase. Mitigation depends on the ability to detect developing issues and includes the capability to detect stresses on the grid by monitoring it. Responding to an event as it is impacting the grid depends on the ability to make informed decisions, to deploy crews rapidly to the right place at the right time, and for the grid to adapt to the stresses through reconfiguration. Recovery depends on coordinated activity and good planning.

In Figure 2-1, the level of strain on the grid caused by the early effects of an event that could cause asset failure is represented by 'A'. As an example, this might be a wooden transmission pole, with failure occurring at time 'X'. In this example suppose a steel monopole was used to replace the wood pole transmission structure. The monopole might succumb to failure at higher strain levels depicted by 'B' and would result in later failure at time 'Y'.

For the line where this occurred, this illustrates how hardening did not prevent failure but delayed it and shortened the outage duration. If it takes more work to erect a new monopole it might increase recovery time for a specific line, yet if less steel monopoles failed relative to the number of wood poles that would have failed, there would be less to replace and the overall system outage time and recovery time would be reduced. Fewer asset failures means that more crews will be able to work on the assets that do fail, which can have a multiplying effect on outage reduction time.

The Storm Resilience Model evaluates the phases of resilience for storms on both the entire system and at the sub-system level (substations, transmission circuit, site access, feeder, and lateral). Section 2.3 provides additional detail on this evaluation approach.

2.2 Evaluated System for Resilience Investment

The Storm Resilience Model (described in more detail in Section 2.3) is comprehensive in that it evaluates nearly all of TEC's T&D system. Table 2-1 shows the asset types and counts included in the Storm Resilience Model.

Table 2-1: TEC Asset Base Modeled

Asset Type	Units	Value
Distribution Circuits	**[count]**	**668**
Feeder Poles	[count]	35,200
Lateral Poles	[count]	122,500
Feeder OH Primary	[miles]	2,200
Lateral OH Primary	[miles]	3,800
Transmission Circuits	**[count]**	**207**
Wood Poles	[count]	3,800
Steel / Concrete / Lattice Structures	[count]	17,700
Conductor	[miles]	1,300
Substations	**[count]**	**255**
Site Access	**[count]**	**96**
Roads	[count]	70
Bridges	[count]	26

All of the assets are strategically grouped into potential hardening projects, and only the assets that require hardening are included in the projects. For distribution projects, assets were grouped by their most upstream protection device, which was either a breaker, a recloser, trip savers, or a fuse. This approach focuses on reducing customer outages. The objective is to harden each asset that could fail and result in a customer outage. Since only one asset needs to fail downstream of a protection device to cause a customer outage, failure to harden all the necessary assets still leaves weak links that could potentially fail in a storm. Rolling assets into projects at the protection device level allows for hardening of all weak links in the circuit and for capturing the full benefit for customers.

For lateral projects, those with a fuse or trip saver protection device, the preferred hardening approach is to underground the overhead circuits. Since the main cause of storm related outages, especially for weakened structures, is the wind blowing vegetation into conductor, causing structure failures, undergrounding lateral lines provides full storm hardening benefits. While rebuilding overhead laterals to a stronger design standard (i.e. bigger and stronger poles and wires) would provide some resilience benefit, it would not solve the vegetation issues, since the high wind speeds can blow tree limbs from outside the trim zone into the conductor.

For distribution feeder projects, those with a recloser or breaker protection device, the preferred hardening approach is to rebuild to a storm resilient overhead design standard and add automation hardening. Assets in these projects include older wood poles and those with a ‘poor’ condition rating. Additionally, poles with a class that is not better than ‘2’ were also included in these projects. The combination of the physical hardening and automation hardening provides significant resilience benefit for feeders. The physical hardening addresses the weakened infrastructure storm failure component. While the vegetation outside the trim zone as still a concern, most distribution feeders are built along main streets where vegetation densities outside the trim zone are typically less than compared to laterals. Further, the feeder automation hardening allows for automated switching to perform ‘self-healing’ functions to mitigate vegetation outside trim zone and other types of outages. The combination of the physical and automation hardening provide a balanced resilience strategy for feeders. It should be noted that this balanced strategy with automation hardening is not available for laterals. As such, undergrounding is preferred approach for lateral hardening and overhead physical hardening combined with automation hardening is the preferred approach for feeders.

At the transmission circuit level, wood poles were identified for hardening by replacing with non-wood materials like steel, spun concrete, and composites. These materials have consistent internal strength while wood poles can vary widely and are more likely to fail. Transmission wood poles were grouped at the circuit level into projects.

TEC identified 96 separate transmission access, road, and bridge projects based on field inspection of the system.

TEC performed detailed storm surge modeling using the Sea, Land, and Overland Surges from Hurricanes (SLOSH) model. The SLOSH model identified 59 substations with a flood risk, depending on the hurricane category.

Table 2-2 contains a list of potential hardening projects based on the methodology outlined above. As seen below, there are a significant number of potential hardening projects, over 20,000. The following sections outline the approach to selecting the hardening projects that provide the most value to customers from a restoration cost and CMI decrease perspective.

Table 2-2: Potential Hardening Projects Considered

Program	Project Count
Distribution Lateral Undergrounding	18,560
Transmission Asset Upgrades	131
Substation Extreme Weather Hardening	59
Distribution Overhead Feeder Hardening	1,613
Transmission Access Enhancements	96
Total	20,459

2.3 Resilience Planning Approach Overview

The resilience-based planning approach calculates the benefit of storm hardening projects from a customer perspective. This approach calculates the resilience benefit at the asset, project, and program level within the Storm Resilience Model. The results of the Storm Resilience Model are a:

1. Reduction in the Storm Restoration Costs
2. Reduction in the number of customers impacted and the duration of the overall outage, calculated as CMI

Figure 2-2 provides an overview of the resilience planning approach to calculate the customer benefit, restoration cost reduction and CMI reduction of hardening projects and prioritization of the projects.

2.3.1 Major Storms Event Database

Since the magnitude of the restoration cost decrease and CMI decrease is dependent on the frequency and magnitude of future major storm events, the Storm Resilience Model starts with the 'universe' of major storm events that could impact TEC's service territory, the Major Events Storms Database.

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STAFF'S FIRST SET OF INTERROGATORIES
INTERROGATORY NO. 1a (part 4)
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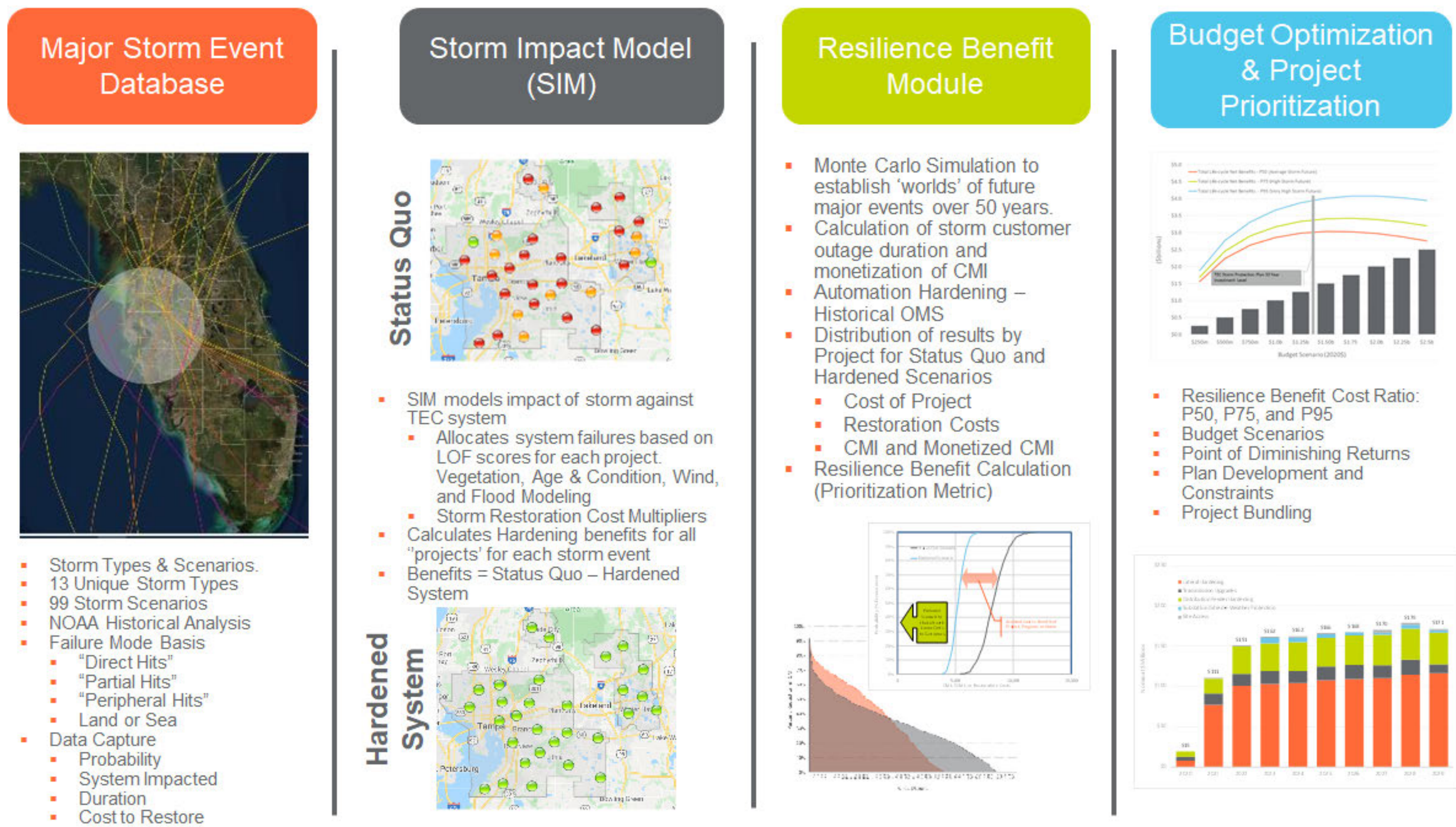
Figure 2-2: Resilience Planning Approach Overview



The Major Storms Event Database describes the stressor that causes system failure. The database also provides the high-level impact to the system of the storm stressor. The major events database includes the following:

- Storm Type
- Probability of a storm occurring
- Restoration Costs
- Percentage of the system impacted
- Duration of the storm

The major storm events database includes 13 unique storm types. The storm types include the various hurricane categories and direction they come from (hurricane impacts from the Gulf side are much different than from the Florida side). Each storm type has a range of probabilities and impacts. With the various combinations (high probability with lower consequence and low probability with high consequence, etc.) the Major Storms Event Database includes 99 different storm scenarios. Section 3.0 provides additional detail on the Major Storms Event Database.

2.3.2 Storm Impact Model

Each storm scenario is then modeled within the Storm Impact Model to identify which parts of the system are most likely to fail given each type of storm. The Storm Impact Model calculates the restoration costs and customers impacted by system failures for both the Status Quo and Hardened Scenarios. The Storm Impact Model identifies the damaged portions of the system by modeling the elements that cause failures in the TEC asset base.

For circuits, the main cause of failure is wind blowing vegetation onto conductor causing conductor or structures to fail. If structures (i.e. wood poles) have any deterioration, for example rot, they are more susceptible to failure. The Storm Impact Model calculates a storm LOF score for each asset based on a combination of the vegetation rating, age and condition rating, and wind zone rating. The vegetation rating factor is based on the vegetation density around the conductor. The age and condition rating utilize expected remaining life curves with the asset's 'effective' age, determined using condition data. The wind zone rating is based on the wind zone that the asset is located within. The Storm Impact Model includes a framework that normalizes the three ratings with each other to develop one overall storm LOF score for all circuit assets. The project level scores are equal to the sum of the asset scores normalized for length. The project level scores are then used to rank each project against each other to identify the likely lateral, backbone, or transmission circuit to fail for each storm type. The model estimates the weighted storm LOF based on the asset level scoring.

The model determines which substations are likely to flood during various storm types based on the flood modeling analysis. That analysis provides the flood level, meaning feet of water above the site elevation, for various storm types.

Each transmission site access project provides access to one or more transmission circuits. If a major storm event causes a transmission outage and the access location is also impacted, it can take longer to restore the system. The Storm Impact Model uses each transmission circuit's storm LOF to estimate the LOF of each site access during a storm. For instance, if site access 'A' is needed to gain access to Circuit '1' and '4', the storm likelihood for site access 'A' equals the storm likelihood of failure for Circuit '1' and '4' combined.

Once the Storm Impact model identifies the portions of the system that are damaged and caused an outage for a specific storm, it then calculates the restoration costs to rebuild the system to provide service. The restoration costs are based on the multipliers for storm replacement over the planned replacement costs using TEC labor and procured materials only. The restoration cost multipliers are based on historical storm events and the expected outside labor and expedited material cost needed to restore the system.

Similarly, the Storm Impact Model calculates the CMI for each project. Since circuit projects are organized by protection device, the customer counts and customer types are known for each asset in the Storm Impact Model. The time it will take to restore each protection device, or project, is calculated based on the expected storm duration and the hierarchy of restoration activities. This restoration time is then multiplied by the known customer count to calculate the CMI. The CMI benefit is monetized using DOE's ICE Calculator for project prioritization purposes.

Finally, the Storm Impact Model then calculates the reductions in project storm LOF, restoration costs, and CMI for each hardening project. The output of the Storm Impact Model is the project LOF, CMI, monetized CMI, and restoration costs for each of the 99 storms for both the Status Quo and Hardened scenarios.

2.3.3 Resilience Benefit Calculation

The Resilience Benefit Calculation utilizes stochastic modeling, or Monte Carlo simulation, to select a storm scenario for each of the 13 storm types for 1,000 iterations. This produces 1,000 different future "storm worlds" and the expected range of benefit values depending on the different probabilities and impact ranges to the TEC system. The probability of each storm scenario is multiplied by the benefits calculated for each project from the Storm Impact Model to provide a resilience-weighted benefit for each project in dollars. Feeder Automation Hardening projects are evaluated based on historical outages and the expected decrease in historical outages if automation had been in place.

2.3.4 Project Scheduling and Budget Optimization

The Project Scheduling and Budget Optimization model prioritizes the projects based on the highest ratio of resilience benefit to cost. It also performs a budget optimization simulation to identify the point of diminishing returns for hardening investments for the 10 year period and portions of the system evaluated.

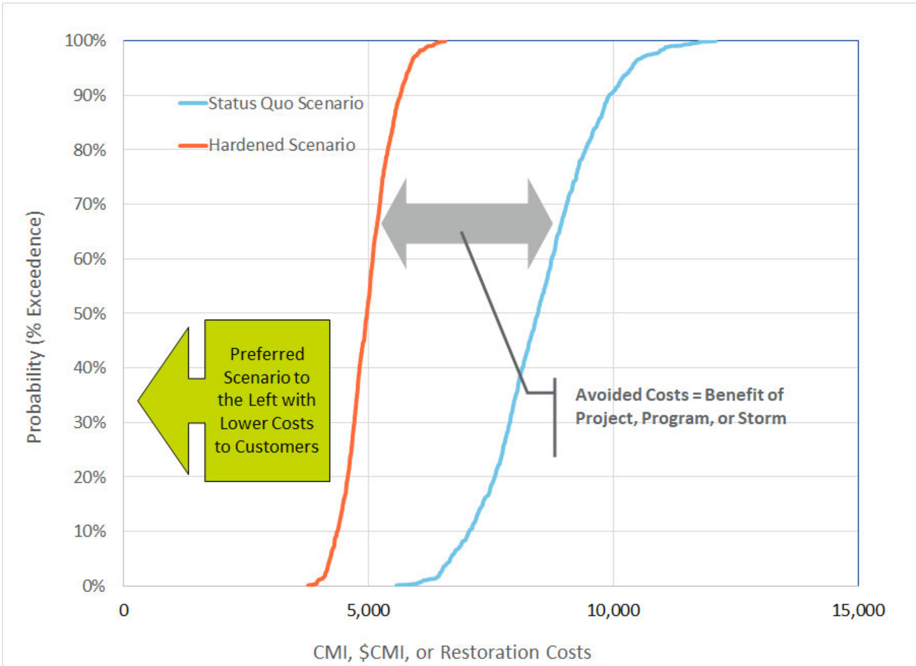
The model prioritizes each project based on the sum of the restoration cost benefit and monetized CMI benefit divided by the project cost. This calculation is performed for the range of potential benefit values to create the resilience benefit cost ratio. The model also incorporates TEC's technical and operational constraints in scheduling the projects such as contractor capacity and scheduling transmission planned outages. Using the Resilience Benefit Calculation and project scheduling model, the Storm Resilience Model calculates the net benefit in terms of reduced restoration costs and CMI for the 10-year investment profile.

Budget optimization is performed by running the model over a wide range of budget scenarios. Each budget scenario calculates the range in reduction of restoration costs and CMI. The budget optimization calculates the point where incremental hardening investments result in diminishing returns in customer benefit.

2.4 S-Curves and Resilience Benefit

The results of the 1,000 iterations are graphed in a cumulative density function, also known as an 'S-Curve'. In layman's terms, the thousand results are sorted from lowest to highest (cumulative ascending) and then charted. Figure 2-3 shows an illustrative example of the 1,000 iteration simulation results for the 'Status Quo' and Hardened Scenarios.

Figure 2-3: Status Quo and Hardened Results Distribution Example

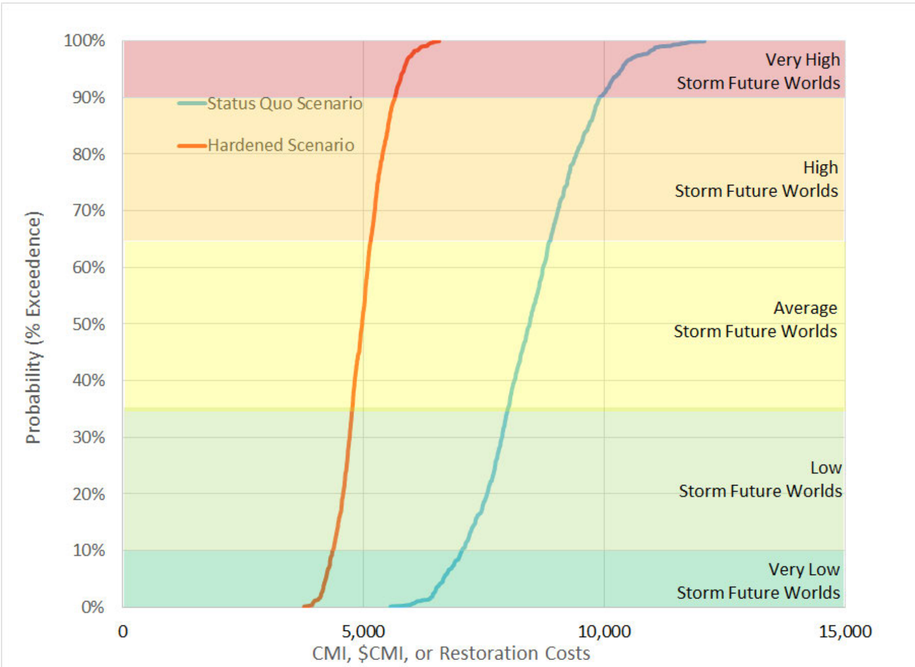


The horizontal axis shows the storm cost in terms of CMI, monetized CMI, or restoration costs. The values in the figure are illustrative. The vertical axis shows the percent exceedance values. For the Hardened Scenario, the chart shows a value of 5,000 at the 40-percentile level. This means there is a 40 percent confidence that the Hardened Scenario will have a value of 5,000 or less. Each of the probability levels is often referred to as the P-value. In this case the P40 (40 percentile) has a value of 5,000 for the Hardened Scenario.

Since the figure shows the overall cost (in minutes or dollars) to customers, the preferred scenario is the S-Curve further to the left. The gap or delta between the two curves is the overall benefit.

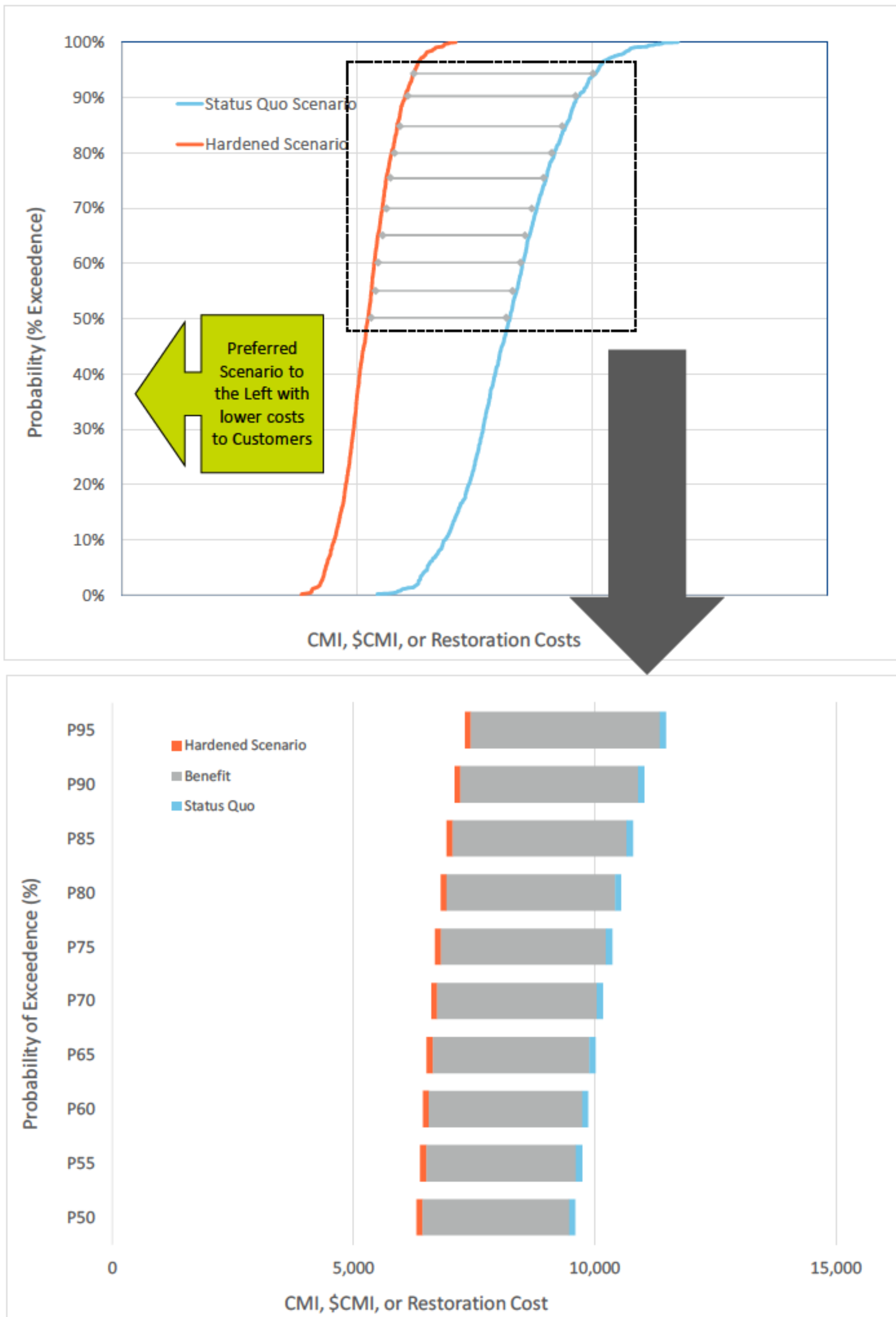
The S-Curves typically have a linear slope between the P10 and P90 values with ‘tails’ on either side. The tails show the extremes of the scenarios. The slope of the line shows the variability in results. The steeper the slope (i.e. vertical) the less range in the result. The more horizontal the slope the wider the range and variability in the results. Figure 2-4 provides additional guidance on understanding the S-Curves and the kind of future storm worlds they represent.

Figure 2-4: S-Curves and Future Storms



For the storm resilience evaluation, the top portion of the S-curves is the focus as it includes the average to very high storm futures, this is referred to as the resilience portion of the curve. Rather than show the entire S-curve, the results in the report will show specific P-values to highlight the gap between the 'Status Quo' and Hardened Scenarios. Additionally, highlighting the specific P-values can be more intuitive. Figure 2-5 illustrates this concept of looking at the top part of the S-curves and showing the P-values. Section 7.0 includes results figures similar to the second figure in Figure 2-5 below.

Figure 2-5: S-Curves and Resilience Focus



3.0 MAJOR STORMS EVENT DATABASE

The first main component of the Storm Resilience Model is the Major Storms Event Database. The database describes the phases of resilience, Figure 2-1, for the TEC high-level system perspective for a range of storm stressors. This section describes the data sources and approach used to develop the database. Since the benefits of hardening projects are directly related to the frequency and impact of major storm events, the resilience-based planning approach starts with developing the range of storm types that could impact TEC's service territory. The impact of major storm events to the TEC system is dependent on following:

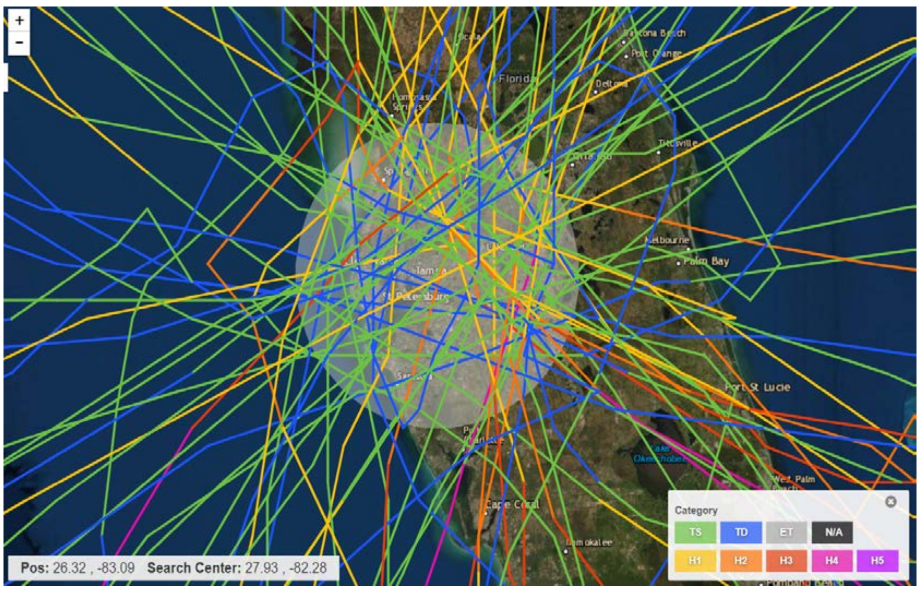
- Wind speeds of the storm (i.e. category of storm). Higher wind speeds means more trees and tree limbs from inside and outside of the tree trim zone on the conductor. The additional weight and forces on the conductor cause pole or tower failures. At high enough wind speeds, the wind speed alone can cause a structure failure.
- Direction that it comes from (Gulf or Florida). Storms from the Gulf could bring storm surge and associated flooding. Additionally, the counter-clockwise storm band rotation include different level of energy (i.e. wind speed) if they have been over land for a period of time.
- Eye Distance from TEC's territory. Storms that directly hit Tampa are impactful since the entire service territory effectively gets hit twice by the storm bands. Additionally, the total duration of the event is longer. For more distant storms, only a few storm bands may hit the TEC service territory.

The major storms event database includes the range of storm stressors that would cause an outage(s) to the TEC system based on the three main contributing factors above. The database includes both the probability of the storm stressor, impact in terms of restoration costs and duration, and impact with respect to which parts of the TEC system fail. The following sections provide additional analysis and commentary on how these assumptions were developed for the storms event database.

3.1 Analysis of NOAA Major Storm Events

The National Oceanic and Atmospheric Administration (NOAA) includes a database of major storm events over 167 years, beginning in 1852. This database was mined to evaluate the different types and frequency of major storms to impact the TEC service territory. Figure 3-1 provides an example screen shot from NOAA's storms database. It shows all the events, including path and category, to come within 50 miles of TEC's service territory center.

Figure 3-1: NOAA Example Output – 50 Mile Radius



Source: https://coast.noaa.gov/hurricanes/

This database was mined for all major event types up to 150 miles from TEC service territory center. The 150-mile radius was selected since many hurricanes can have diameters of 300 miles where some of the hurricane storm bands impact a significant portion of the TEC service territory. Additionally, the database was mined for the category of the storm as it hit the TEC service territory. The analysis of NOAA's database was done for the following types of storm categories:

- 'Direct Hits' – 50 Mile Radius from the Gulf and Florida directions. The max wind speeds hit all or significant portions of TEC service territory twice, once from the front end and again on the back end of the storm. Additionally, the wind speeds cause all the assets and vegetation to move in one direction as the storm comes in and in the opposite direction as it moves out. This double exposure to the system causes significant system failures.
- 'Partial Hits' – 51 to 100 Mile Radius. At this radius, the storm bands hit a significant portion of the TEC service territory. Wind speeds are typically at their highest at the outer edge of the storm bands. The storm passes through the territory once, so to speak, minimizing damage

relative to a 'direct hit'. For large category storms, the 'Partial Hit' could still cause more damage than a 'Direct Hit' small storm.

- 'Peripheral Hits' – 101 to 150 Mile Radius. Since hurricanes can be 300 miles wide in diameter, some of the storm bands can hit a fairly large portion of the system even if the main body of the storm misses the service area.

Table 3-1 includes the summary results from the NOAA database of storms to hit or nearly hit the TEC service territory since 1852.

Table 3-1: Historical Storm Summary

Event Type	Direct Hits Gulf	Direct Hits Florida	Direct Hits Total	Partial Hits	Peripheral Hits	Total
Cat 5	0	0	0	0	0	0
Cat 4	0	1	1	0	1	2
Cat 3	0	1	1	5	4	10
Cat 2	4	1	5	2	8	15
Cat 1	6	6	12	14	8	34
Tropical Storm	11	20	31	29	28	88
Tropical Depression	10	8	18	17	NA	35
Total	31	37	68	67	49	184

Table 3-1 shows a total of 184 storms to hit the Tampa area since 1852. A total of 68 were direct hits within 50 miles, 67 were partial hits in the 51 to 100-mile radius, and 49 were peripheral hits in the 101 to 150 mile radius. The table also shows very few category 4 and above events, 2 out of 184, with one 'Direct Hit'. While there are 10 Category 3 types storms, only 1 is a 'Direct Hit'. Nearly 20 percent of the events are Category 1 Hurricanes. Almost two thirds of the events are Tropical Storms or Tropical Depressions. For direct hits, the results show approximately 46 percent of the events come from the Gulf of Mexico while the other 54 percent come over Florida. The direction the storm comes from has significant impact on the overall damage to TEC's system. Based on these results and the various quantities by event type, the following 13 unique storm types serves as the foundation for the Major Storms Event Database:

1. Category 3 and Above 'Direct Hit' from the Gulf
2. Category 1 & 2 'Direct Hit' over Florida
3. Category 1 & 2 'Direct Hit' from the Gulf
4. Tropical Storm 'Direct Hit'
5. Tropical Depression 'Direct Hit'
6. Localized Event 'Direct Hit'
7. Category 3 and Above 'Partial Hit'
8. Category 1 & 2 'Partial Hit'
9. Tropical Storm 'Partial Hit'
10. Tropical Depression 'Partial Hit'
11. Category 3 and Above 'Peripheral Hit'
12. Category 1 & 2 'Peripheral Hit'
13. Tropical Storm 'Peripheral Hit'

Each of these storm types serve as a stressor on the system that causes an outage and damage. The next three subsections provide a historical analysis of storm events that impacted TEC's Service Territory to provide information on the probability of each of the 13 storm types.

3.1.2 Direct Hits (50 Miles)

Figure 3-2 provides a historical view of the number of major storm events to hit the TEC service territory over the last 167 years. The figure shows 6 different storm types. Figure 3-3 converts the storm data in Figure 3-2 to show the total storm count for a 100-year rolling average starting with the period 1852 to 1951. Review of the two figures shows there have been no Category 3 or above hurricanes to hit the TEC service territory from the Florida side.

Figure 3-2: "Direct Hits" (50 Miles) Over Time[2]

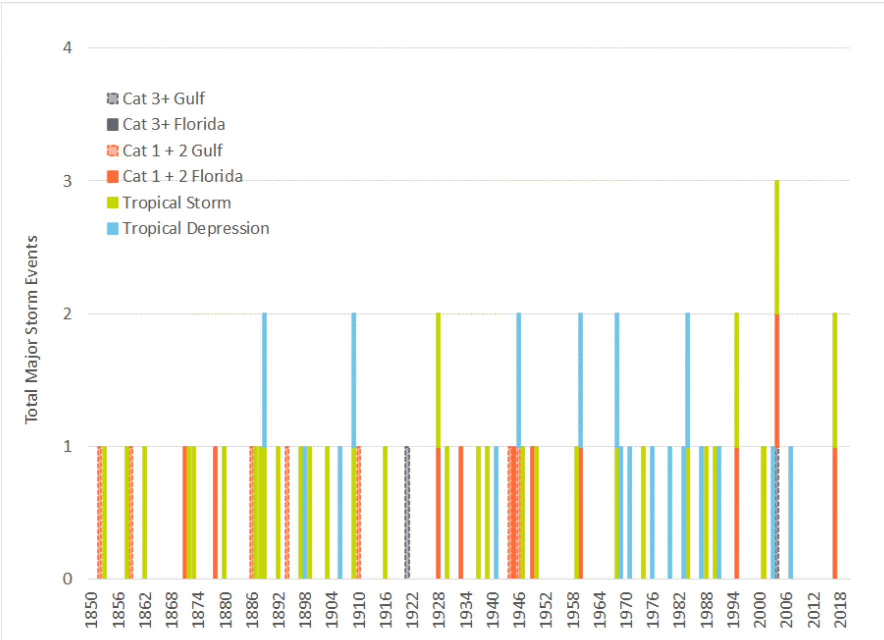


Figure 3-3 shows an average of approximately 40 storms for each rolling 100-year period from 1951 to 2019. The rolling 100-year average results show a stability to the number of 'Direct Hits' over the time horizon. The figure shows a relative stability in the number of Category 1 and above storms over the period. Even though there is relative stability in the 40-storm average for the 100-year rolling average time horizon, the figure shows a decrease in the number of tropical storms with a corresponding increase in the number of tropical depressions. Figure 3-4 converts the totals for each 100-year period in Figure 3-3 to probabilities by dividing by 100.

[2] Source: https://coast.noaa.gov/hurricanes/ with analysis by 1898 & Co.

Figure 3-3: "Direct Hits" (50 Miles) 100 Year Rolling Average[3]

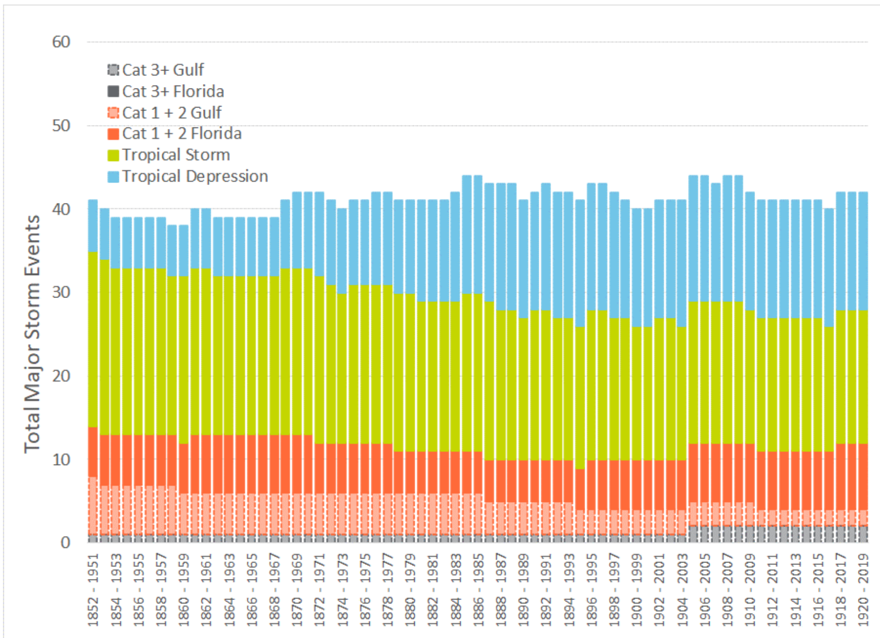
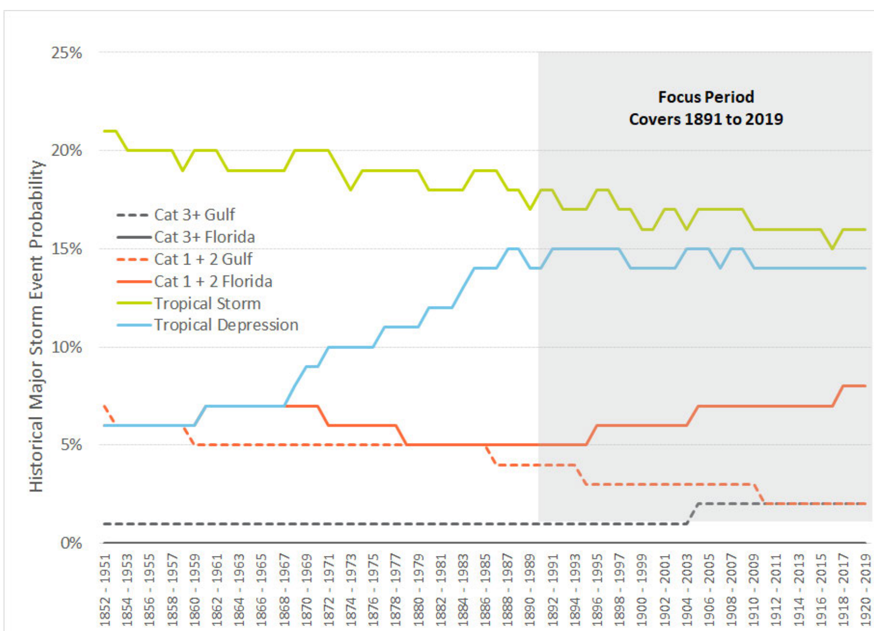


Figure 3-4: "Direct Hits" (50 Miles) 100 Year Rolling Probability[3]



[3] See Footnote 2

The figure shows a low historical probability for Category 3 and above events from the Gulf of 1 to 2 percent. Additionally, there has been a decrease in the probability of Category 1 and 2 storms from the Gulf with a corresponding increase in the number coming from the Florida side. The story is similar for Tropical Storms and Tropical Depressions. The number of Tropical Storms shows a steady relative decline with a significant increase in probability of Tropical Storms until 1990 and stabilizes thereafter. As the figure shows, the probabilities of failure show a relative stability for the 100-year rolling average probabilities from 1990 to 2019, which encompasses thirty 100-year periods. Given the recent stability over this period these probability ranges were utilized in the Major Storms Event Database.

3.1.3 Partial Hits (51 to 100 Miles)

Figure 3-5 provides a historical view of the number of major storm events that have partially hit the TEC service territory over the last 167 years. A storm is classified as a partial hit if the eye passes between 51 and 100 miles from TEC's service territory. The figure shows 4 different storm types. Figure 3-6 converts the storm data in Figure 3-5 to show the total storm count for a 100-year rolling average starting with the period 1852 to 1951. The 100-year rolling average of storm events for partial hits follows a similar profile to that of direct hits, but it does show that Category 3 storms have hit TEC's service territory within a 51 to 100-mile radius throughout the rolling average windows in the analysis. This illustrates that there is a real possibility that TEC's service territory will be impacted by a Category 3 or higher hurricane each year.

Figure 3-5: "Partial Hits" (51 to 100 Miles)[4]

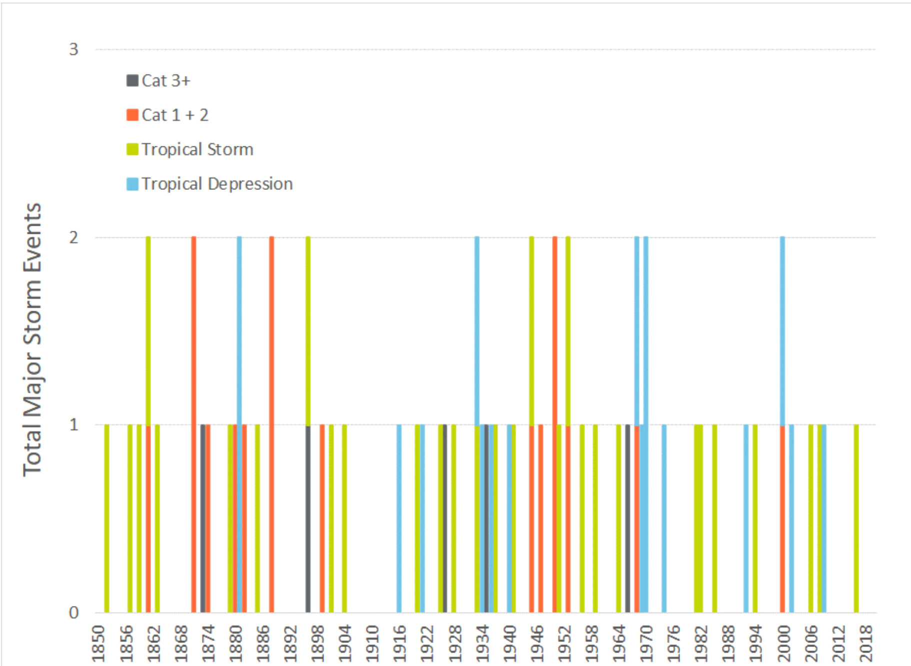


Figure 3-5 shows an average storm count of approximately 42 for each rolling 100-year period from 1951 to 2019. The rolling 100-year average results show a stability to the number of 'Partial Hits' over the time horizon. The figure shows a slight decline in the number of Category 1 and 2 storms over the period. As the overall storm count has remained stable, the slight decline in Category 1 and 2 storms was inversely mirrored by an increase in tropical depression counts.

Figure 3-7 converts the totals for each 100-year period in Figure 3-6 to probabilities by dividing by 100. This figure further illustrates the change in storm type distributions as Category 1 and 2 storms gave way to tropical depressions. The reason for the shift is unknown, but it is possible that this change is due to increases in data accuracy or recording procedures over time.

[4] See Footnote 2

Figure 3-6: "Partial Hits" (51 to 100 Miles) 100 Year Rolling Average[5]

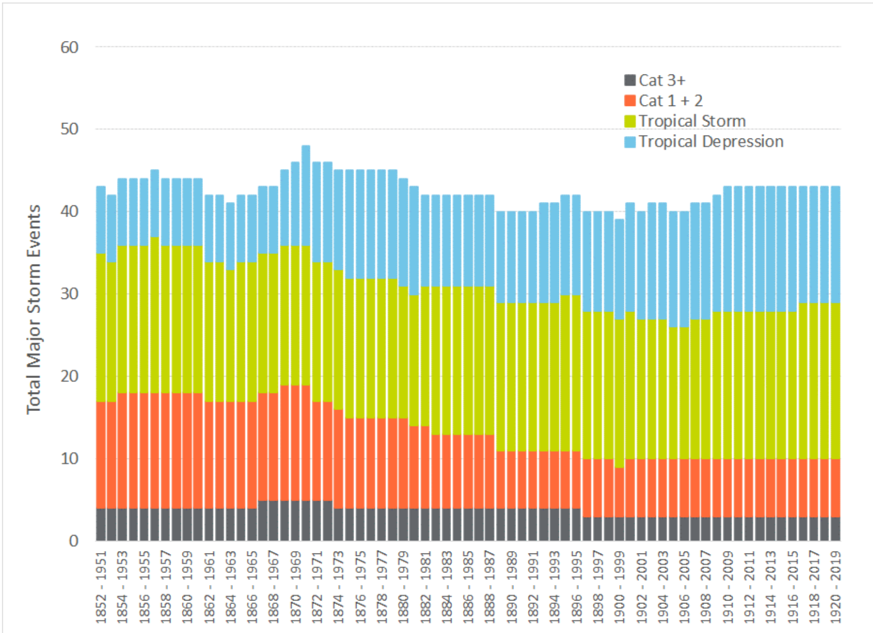
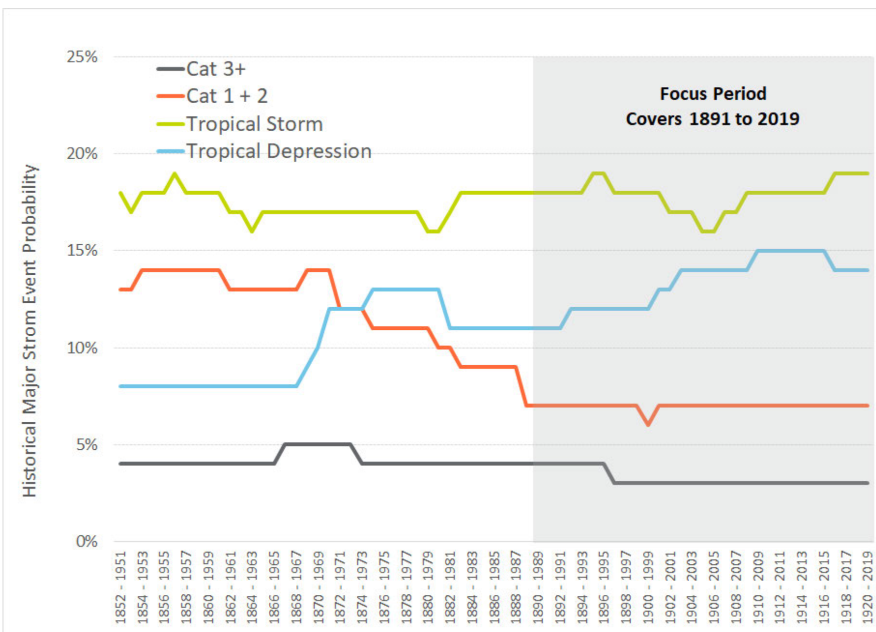


Figure 3-7: "Partial Hits" (51 to 100 Miles) 100 Yr. Rolling Probability[5]

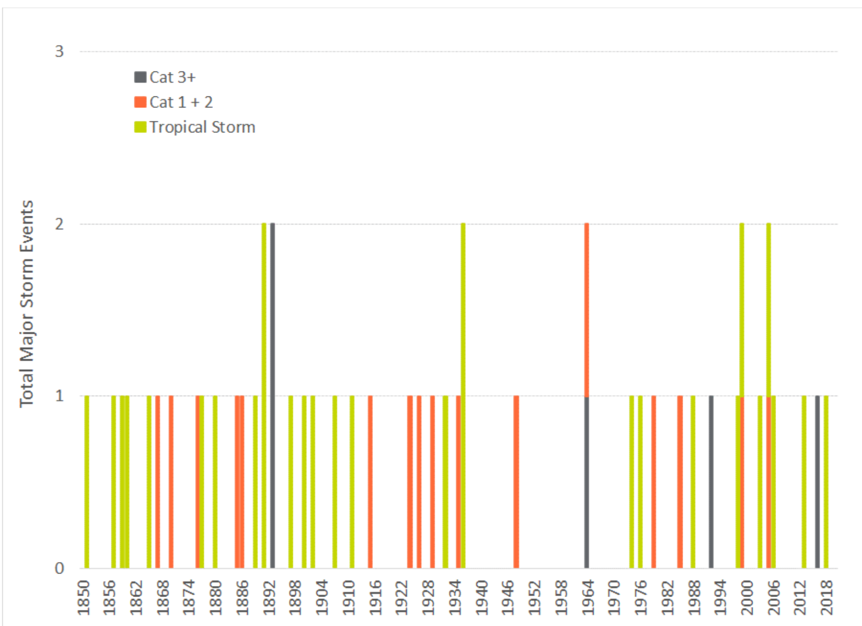


[5] See Footnote 2

3.1.4 Peripheral Hits (101 to 150 Miles)

Figure 3-8 provides a historical view of the number of major storm events that have hit TEC's service territory in the periphery over the last 167 years. A storm is classified as a partial hit if the eye passes between 101 and 150 miles from TEC's service territory. Since tropical depressions within this range may not be large enough to impact TEC's service territory, the figure only includes Tropical Storms, Category 1 and 2 storms, and Category 3 and higher storms. Figure 3-9 converts the storm data in Figure 3-8 to show the total storm count for a 100-year rolling average starting with the period 1852 to 1951.

Figure 3-8: "Peripheral Hits" (101 to 150 Miles)[6]



The 100-year rolling average of storm events for peripheral hits shows a slight decline from 30 to 25 storms, mostly driven by a decline in Tropical Storms.

Figure 3-10 converts the totals for each 100-year period in Figure 3-9 by dividing by 100. This figure further illustrates the decline in probability of Tropical Storms over the analysis period.

[6] See Footnote 2

Figure 3-9: "Peripheral Hits" (51 to 100 Miles) 100 Yr. Rolling Avg.[7]

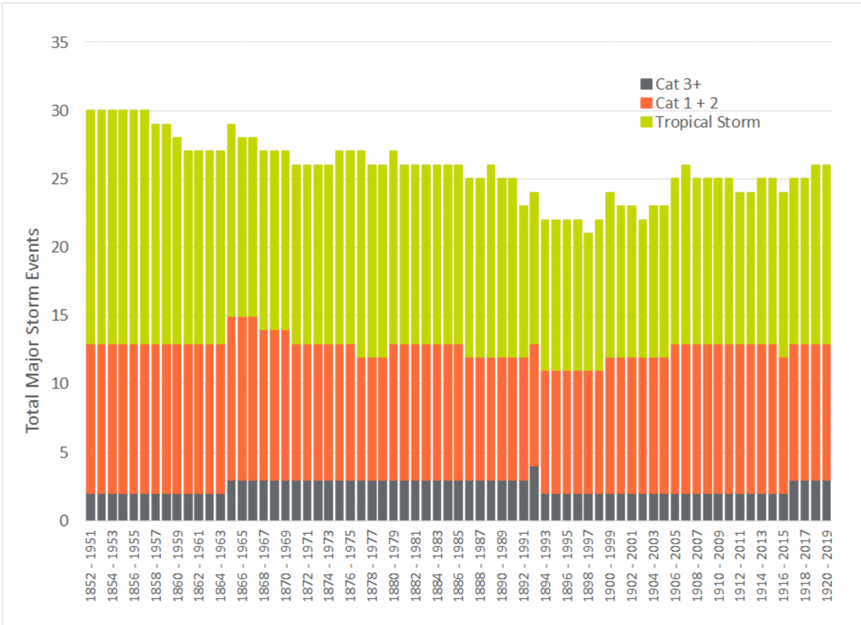
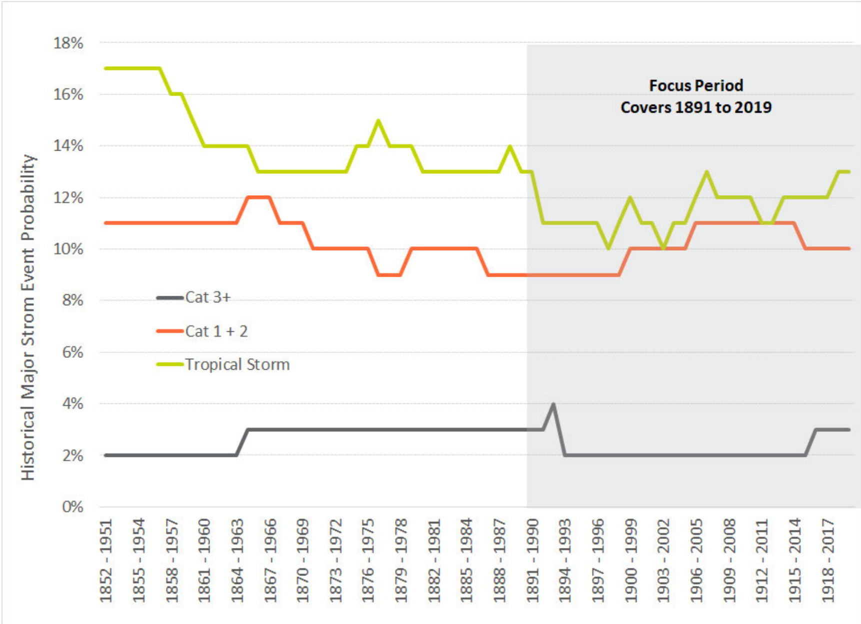


Figure 3-10: "Peripheral Hits" (51 to 100 Miles) 100 Yr. Rolling Probability[7]



[7] See Footnote 2

3.2 Major Storms in the Future

Section 3.1 reviewed the historical major events to hit the TEC service territory over the last 167 years. It is unclear whether climate change is affecting or will affect the frequency or severity of major storm events in the future. Research into this question reveals that there is no statistical evidence to support a higher frequency of major storm activity. The World Meteorological Organization provided the following comment:

> "Though there is evidence both for and against the existence of a detectable anthropogenic signal in the tropical cyclone climate record to date, no firm conclusion can be made on this point. However, research shows that there is evidence that the magnitude of the events are and will continue to increase."

Given this research, the Major Storm Event Database utilizes the historical probabilities for future storm probability. The impact of the events is discussed in the next section.

3.3 Major Storms Impact

Table 3-2 shows the damages cost of recent major storms to hit the Southeast United States. The table shows that the costs of these major events is significant.

Table 3-2: Recent Major Event Damages Cost

Storm Name	Category	Year	Damages (2018 $Billions)
Michael	5	2018	$25
Irma	4	2017	$51
Matthew	5	2016	$10
Wilma	3	2005	$10
Dennis	3	2005	$3
Jeanne	3	2004	$9
Ivan	3	2004	$19
Frances	2	2004	$12
Charley	4	2004	$19

The costs shown in the table are all damage costs to society and are based on insurance claims. The utility restoration costs are one element of this total. The TEC storm reports provide information on the restoration costs of historical events to hit the TEC service territory. Figure 3-11 provides a summary of the storm report for Hurricane Irma in 2017. It cost TEC approximately $100 million and restoration took slightly more than 7 days. Table 3-3 provides a summary of other recent TEC storm reports.

Figure 3-11: Hurricane Irma Impact to TEC Service Territory[8]

Storm Name: Irma

Year: 2017

TEC Cost: ~$100 million

Category: 1 over Florida

Radius: 50 Miles

Outage Duration: 7 Days

System Impact:
15 T-Lines
200 Circuits
55% of Customers

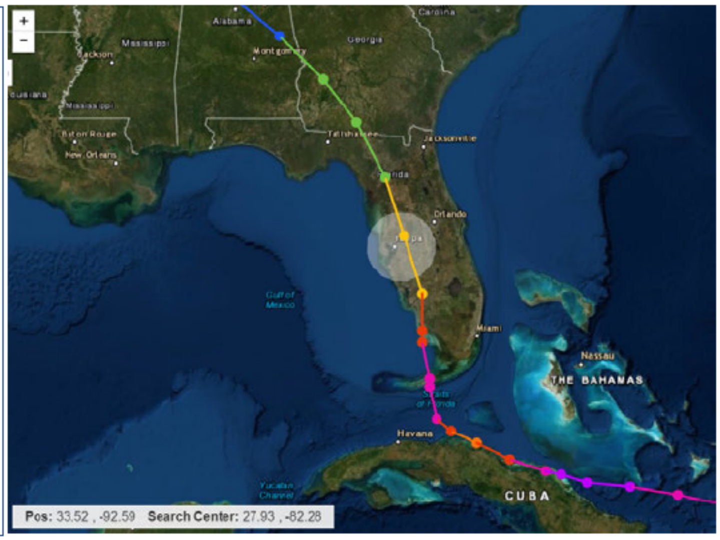


Table 3-3: Storm Report Summary

Storm Name	Category	Year	Damages (2018 $Millions)
Irma	1	2017	$102
Matthew	3	2016	$1
Hermine	1	2016	$6
Colin	TS	2016	$3

3.4 Major Storms Database

TEC and 1898 & Co collaborated in developing the Major Storm Events Database. The database utilizes the results of the NOAA analysis to identify 13 unique storm types. With the range of storm probabilities, the range in cost for each unique storm type, and the range in system impact, the 13 unique storm types are represented by 99 different storm events. Table 3-4 provides a summary of the Major Storms Event Database. The table includes the ranges of probabilities, restoration costs, impact to the system, and duration. Each of the 99 storm events are then modeled within the Storm Impact Model described more in the next section.

[8] See Footnote 2

Table 3-4: Storm Event Database

Storm Type No	Scenario Name	Annual Probability	Restoration Costs (Millions)	System Impact (Laterals)	Total Duration (Days)
1	Cat 3+ Direct Hit - Gulf	1.0% - 2.0%	$300 - $1,200	60% - 70%	17.4 - 34.5
2	Cat 1 & 2 Direct Hit – Florida	5% - 8%	$75 - $150	35% - 55%	6.0 - 8.8
3	Cat 1 & 2 Direct Hit – Gulf	2% - 4%	$150 - $300	45% - 60%	8.7 - 12.9
4	TS Direct Hit	16.5%	$25 - $75	12.5% - 31.3%	2.6 - 5.3
5	TD Direct Hit	14.5%	$5 - $15	6.3% - 15.6%	2.0 - 3.6
6	Localized Event Direct Hit	50.0%	$0.5 - $1.5	1.3% - 3.1%	0.3 - 0.6
7	Cat 3+ Partial Hit	3% - 4%	$90 - $180	36% - 48%	6.4 - 9.2
8	Cat 1 & 2 Partial Hit	7.0%	$15 - $90	8.5% - 28%	2.3 - 6.9
9	TS Partial Hit	17% - 18%	$11 - $30	8% - 15%	2.0 - 3.6
10	TD Partial Hit	12% - 15%	$0.4 - $3.0	2% - 3.8%	1.5 - 2.7
11	Cat 3+ Peripheral Hit	2% - 3%	$0.8 - $ 21.4	1.2% - 14.1%	1.0 - 3.0
12	Cat 1 & 2 Peripheral Hit	10% - 11%	$0.6 - $8.6	0.9% - 6.5%	0.9 - 2.3
13	TS Peripheral Hit	11% - 12%	$0.5 - $3.8	0.7% - 3.4%	0.9 - 1.3

4.0 STORM IMPACT MODEL

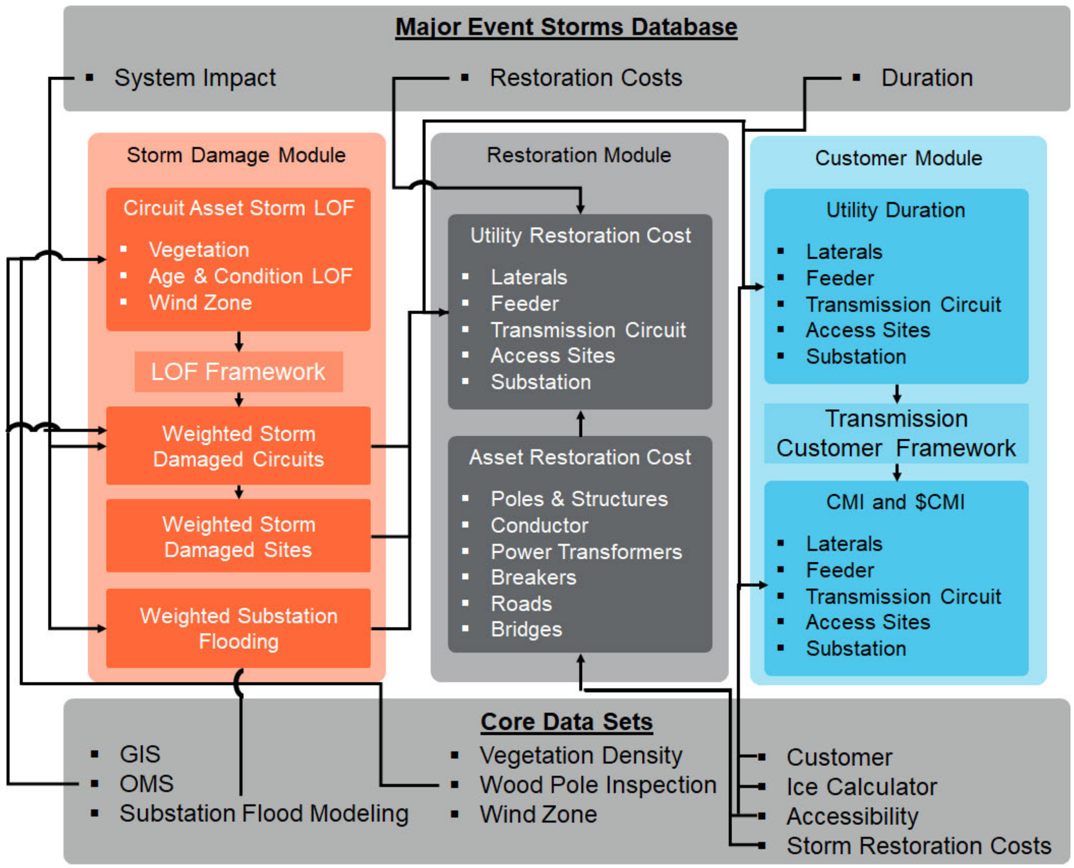
The second major component of the Storm Resilience Model is the Storm Impact Model. Whereas the Major Storms Event Database describes the phases of resilience, Figure 2-1, for the TEC high-level system perspective for each storm stressor, the Storm Impact Model goes a layer deeper and develops the phases of resilience for each potential hardening project on the TEC T&D system for each storm stressor scenario.

The Storm Impact Model models the impact to the system of any type of major storm event. Specifically, it identifies, from a weighted perspective, the particular laterals, feeders, transmission lines, access sites, and substations that fail for each type of storm in the Major Storms Event Database. The model also estimates the restoration costs associated with the specific sub-system failures and calculates the impact to customers in terms of CMI. Finally, the Storm Impact Model models each storm event for both a Status Quo and Hardened scenario. The Hardened scenario assumes the assets that make up each project have been hardened. The Storm Impact Model then calculates the benefit of each hardening project from a reduced restoration cost and CMI perspective.

The Storm Impact Model utilizes a robust and sophisticated set of data and algorithms to model the benefits of each hardening project for each storm scenario. This section of the report outlines the core data, algorithms, and frameworks that are part of the Storm Impact Model. It outlines a very granular level of analysis of the TEC System. This granular level of data and analysis allows for the Storm Resilience Model to accurately calculate the ratio of resilience benefit to cost resulting in more efficient hardening investment. This also provides confidence that investments are targeted to the portions of the system that provide the most value for customers.

Figure 4-1 provides an overview of the Storm Impact Model architecture. The following sections describe in more detail each of the core modules in more detail.

Figure 4-1: Storm Impact Model Overview



4.1 Core Data Sets and Algorithms

As discussed above, the resilience-based approach and methodology is data driven. This section outlines the core data sets and base algorithms employed within the Storm Impact Model. TEC's data systems include a connectivity model that allows for the linkage of the three foundational data sets used in the Storm Impact Model – the Geographical Information System (GIS), the Outage Management System (OMS), and Customer Information.

4.1.1 Geographical Information System

The Geographic Information System (GIS) serves as the first of three foundational data sets for the Storm Impact Model. The GIS provides the list of assets in TEC's system and how they are connected to each other. Since the resilience-based approach is fundamentally an asset management bottom-up based methodology, it starts with the asset data, then rolls all the assets up to projects, and all projects up to programs, and finally the programs up to the Storm Protection Plan.

In alignment with this methodology, TEC utilized the connectivity in their GIS model to link each distribution voltage asset up to a lateral (fuse protection device) or feeder (breaker or recloser protection device). This provides a granular evaluation of the distribution system that allows projects to be created to target only portions of a circuit for resilience investment. Through this approach, TEC and 1898 & Co. were able to use the asset level information from Table 4-1 and convert it to the project level summaries in Table 4-2. It is important to note that each asset in Table 4-1 is tied to one of the projects listed in Table 4-2, which provides a bottom-up analysis.

Table 4-1: TEC Asset Base

Asset Type	Units	Value
Distribution Circuits	**[count]**	**668**
Feeder Poles	[count]	58,700
Lateral Poles	[count]	122,500
Feeder OH Primary	[miles]	2,200
Lateral OH Primary	[miles]	3,800
Transmission Circuits	**[count]**	**207**
Wood Poles	[count]	5,000
Steel / Concrete / Lattice Structures	[count]	20,400
Conductor	[miles]	1,300
Substations	[count]	**255**

Table 4-2: Projects Created from TEC Data Systems

Program	Project Count
Distribution Lateral Undergrounding	18,560
Transmission Asset Upgrades	131
Substation Extreme Weather Hardening	59
Distribution Overhead Feeder Hardening	916
Total	19,666

4.1.2 Outage Management System

The second foundational data set is the OMS. The OMS includes detailed outage information by cause code for each protection device over the last 19 years. The Storm Impact Model utilized this information to understand the historical storm related outages for the various distribution laterals and feeders on the system to include Major Event Days (MED), vegetation, lightening, and storm-based outages. The

OMS served as the link between customer class information and the GIS to provide the Storm Impact Model with the information necessary to understand how many customers and what type of customers would be without service for each project. The OMS data also served as the foundation for calculating benefits for feeder automation projects. This is discussed in more detail in Section 5.4.

4.1.3 Customer Type Data

TEC provided customer count and type information that featured connectivity to the GIS and OMS. This allowed the Storm Impact Model to directly link the number and type of customers impacted to each project and the project's assets. For example, the Storm Impact Model 'knows' that if pole 'Y' fails, fuse '1' will operate causing XX customers to be without service. The model also knows what type of customers are served by each asset; residential, small or large commercial, small or large industrial, and priority customers. This customer information is included for every distribution asset in TEC system. The customer information is used within the Storm Impact Model to calculate the CMI (customers affected * outage duration) for each storm for each lateral or feeder project. Table 4-3 below shows the count of customers by class from TEC's service territory that have been linked to assets in the Storm Impact Model.

Table 4-3: Customer Counts by Type

Customer Type	Customer Count
Residential	695,000
Small Commercial and Industrial	71,100
Large Commercial and Industrial	16,300
Total	782,400

4.1.4 Vegetation Density Algorithm

The vegetation density for each overhead conductor is a core data set for identifying and prioritizing resilience investment for the circuit assets since vegetation blowing into conductor is the primary failure mode for major storm event for TEC. The Storm Impact Model calculates the vegetation density around each transmission and distribution overhead conductor. The Storm Impact Model utilizes tree canopy data to calculate the percentage of vegetation for 100 feet by 100 feet grids across the entire TEC system. The 100 square foot grid size is indicative of the vegetation density on the system from a major storm perspective. For each span of conductor (approximately 240,000) a vegetation density is assigned based on the grid the conductor goes through. This information is used within the LOF framework to identify the portions of the system mostly likely to have an outage for each type of storm.

Figure 4-2 and Figure 4-3 show the range of vegetation density for OH Primary and Transmission Conductor, respectively. The figures rank the conductors from highest to lowest level of vegetation density. As shown in the figures, approximately 30 to 35 percent of the conductor spans (not weighted by length) for OH Primary and Transmission Conductor have near zero tree canopy coverage, while approximately 65 to 70 percent have some level of coverage all the way up to 100 percent coverage.

Figure 4-2: Vegetation Density on TEC Primary Conductor

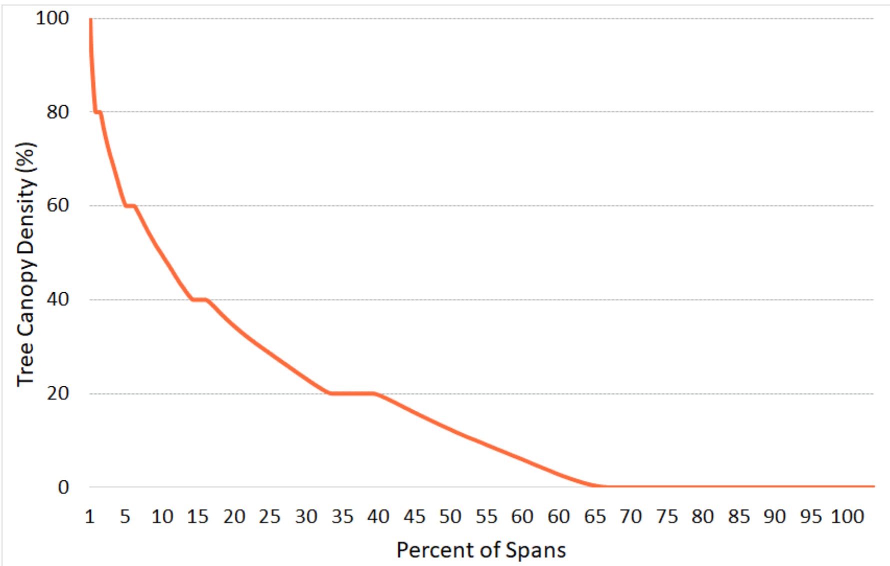
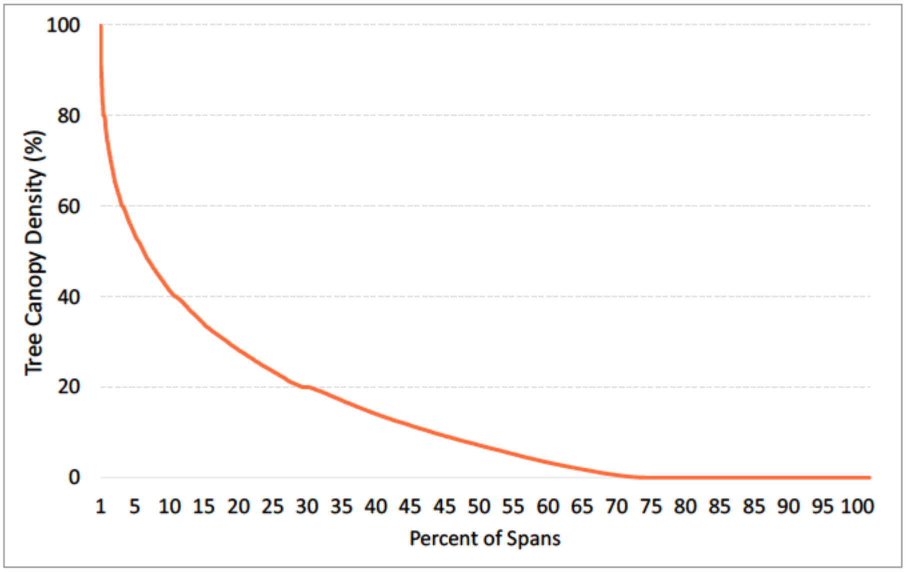


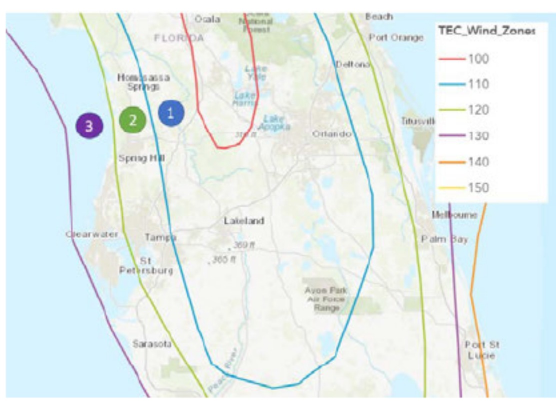
Figure 4-3: Vegetation Density on TEC Transmission Conductor



4.1.5 Wood Pole Inspection Data

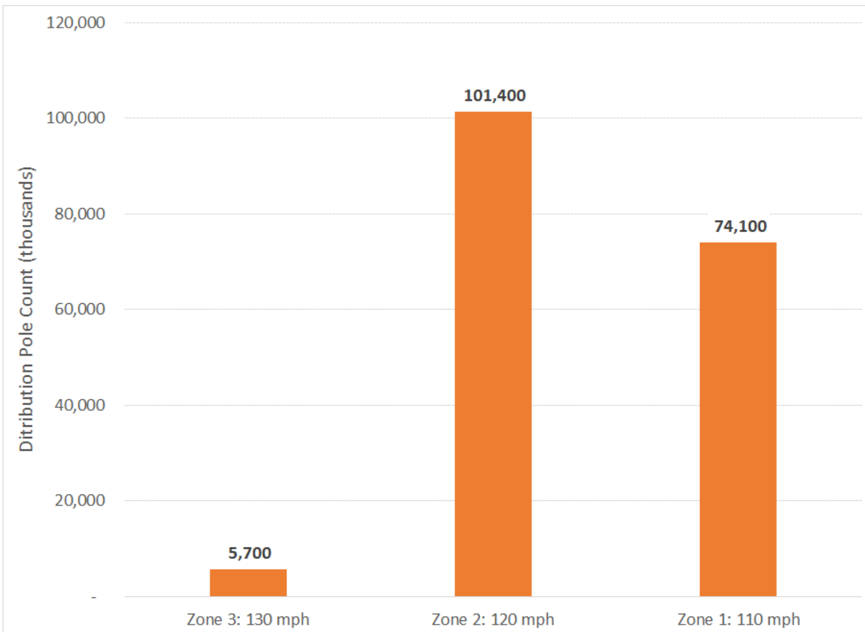
A compromised, or semi-comprised, pole will fail at lower dynamic load levels then poles with their original design strength. The Storm Impact Model utilizes wood pole inspection data within 1898 & Co.'s asset health algorithm to calculate an Asset Health Index (AHI) and 'effective' age for each pole. Section 4.2.2 outlines the approach for using the 'effective' age for assets to calculate the age and condition based LOF.

4.1.6 Wind Zone



A third driver of storm-based failure is the asset's location with respect to wind speeds. Wind zones have been created across the United States for infrastructure design purposes. The National Electric Safety Code (NESC) provides wind and ice loading zones. The zones show that wind speeds are typically are higher closer to the coast and lower the further inland as shown in the adjacent figure. The Storm Impact Model utilizes the provided wind zone data from the public records and the asset geospatial location from GIS to designate the appropriate wind zone. Figure 4-4 shows distribution of assets within each wind zone. As shown in the figure, most of the poles are in the 120 mph and 110 mph zones, while a smaller percentage are in the 130 mph zone near the coast.

Figure 4-4: Pole Wind Zone Distribution



4.1.7 Accessibility

The accessibility of an asset has a tremendous impact on the duration of the outage and the cost to restore that part of the system. Rear lot poles take much longer to restore and cost more to restore than front lot poles. To take differences in accessibility into account, the Storm Impact Model performs a geospatial analysis of each structure against a data set of roads. Structures within a certain distance of the road were designated as having roadside access, others were designated as in the deep right-of-way (ROW). This designation was used to calculate restoration and hardening project costs in the Storm Impact Model. Approximately 60 percent of the T&D system has some kind of road access while the remainder, approximately 40 percent, is in the deep right-of-way.

4.1.8 ICE Calculator

To monetize the cost of a storm outage, the Storm Impact Model and Resilience Benefit Calculation utilize the ICE Calculator. The ICE Calculator is an electric reliability planning tool developed by Freeman, Sullivan & Co. and Lawrence Berkeley National Laboratory. This tool is designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements in the United States. The ICE Calculator was funded by the Office of Electricity Delivery and Energy Reliability at the U.S. Department of Energy (DOE).

The Storm Impact Model includes the estimated storm interruption costs for residential, small commercial and industrial (C&I), and large C&I customers. The calculator was extrapolated for the longer outage durations from storm outages. The extrapolation includes diminishing costs as the storm duration extends. These estimates for outage cost for each customer are multiplied by the specific customer count and expected duration for each storm for each project to calculate the monetized CMI at the project level. The avoided monetized CMI and restoration cost benefit are used for prioritization of projects.

4.1.9 Substation Flood Modeling

TEC performed detailed storm surge modeling using the Sea, Land, and Overland Surges from Hurricanes (SLOSH) model. The SLOSH models perform simulations to estimate surge heights above ground elevation for various storm types. The simulations are based on historical, hypothetical, and predicted hurricanes. The model uses a set of physics equations applied to the specific location shoreline, Tampa in this case, incorporating the unique bay and river configurations, water depths, bridges, roads, levees and other physical features to establish surge height. These results are simulated several thousand times to develop the Maximum of the Maximum Envelope of Water, the worst-case scenario for each storm category. The SLOSH model results were overlaid with the location of TEC’s 255 substations to estimate the height of above the ground elevation for storm surge. The SLOSH model identified 59 substations with flooding risk depending on the hurricane category.

4.2 Weighted Storm Likelihood of Failure Module

The Weighted Storm LOF Module of the Storm Impact Model identifies the parts of the system that are likely to fail given the specific storm loaded from the Major Storms Event Database. The module is grounded in the primary failure mode of the asset base; storm surge and associated flooding for substations and wind, asset condition, and vegetation for circuit assets.

4.2.1 Substation Storm Likelihood of Failure

The main driver of substation failures during major storm events is flooding. The Major Storms Event Database designates the number of substations expected to have minor and major flooding for each of the 99 storm scenarios. Only the storm scenarios with hurricanes coming from the Gulf of Mexico provide the necessary condition for storm surge that would cause substation flooding.

To identify which substations would be the likely to experience flooding, the Storm Impact Model uses the substation flood modeling described in Section 4.1.9. This model provides the estimated feet of flooding above site elevation assuming the maximum of maximum approach, a worst of the worst-case scenario. Because of this extreme worst-case scenario, the results could not be used for a typical hurricane category to hit the TEC service territory. The flood modeling has flood height data for all 5 hurricane category types. The Storm Impact Model uses the flooding height values as likelihood scores to identify the substation Probability of Failure (POF) for each storm event in the Major Storms Event Database.

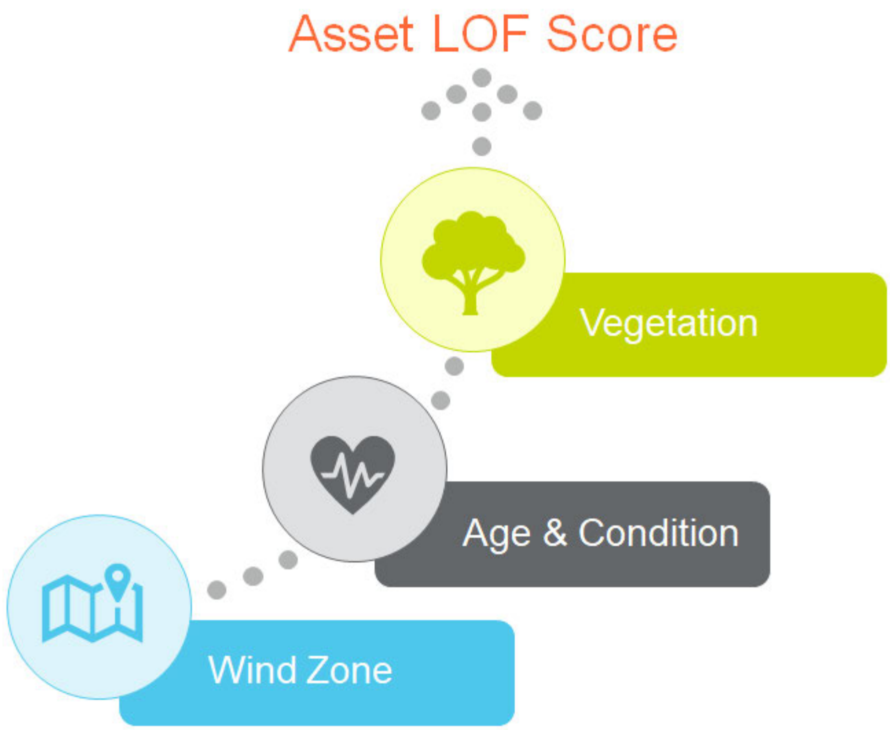
4.2.2 Circuits Storm Likelihood of Failure

The main driver of circuit failures during storms is wind blowing vegetation (and other debris) into conductor. The conductor is weighted down. The additional weight, when combined with the wind loading, causes the structures holding up the conductor to fail. Typically, the vegetation touching the conductor triggers the protection device to operate, however, the enhanced loading on the poles causes asset failures that are costly to repair both in terms of restoration costs and in CMI. The storm LOF of an overhead distribution asset is a function of the vegetation around it, the age and condition of the asset, and the applicable wind zone (coastal zones see higher wind speeds).

Figure 4-5 depicts the framework used to calculate the storm LOF score for each circuit asset on TEC's T&D system. Assets included within the framework are: wood poles, steel poles, concrete poles, lattice towers, overhead primary, and overhead transmission conductor. The framework does not use weightings, rather it is normalized across each of the scoring criteria.

For the vegetation LOF scores, the Storm Impact Model uses the vegetation density of each overhead primary and transmission conductor normalized for length. Section 4.1.4 outlines the approach to estimate the vegetation density for approximately 240,000 primary and transmission conductors. Each primary and transmission conductor is one span from structure to structure. The vegetation density, normalized for length, is used in the LOF framework to calculate an LOF score for vegetation. Overall, the vegetation score contributes on average 60 to 80 percent of system LOF depending on the storm scenario.

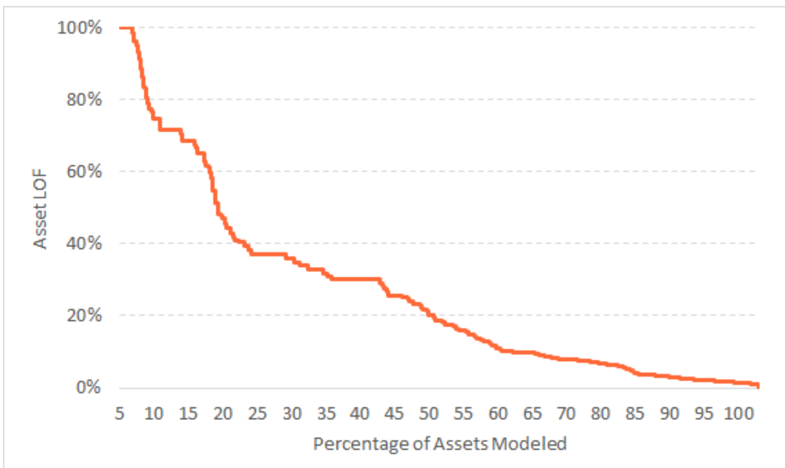
Figure 4-5: Storm LOF Framework for Circuit Assets



The Storm Impact Model utilizes 1898 & Co.'s asset management solution, Capital Asset Planning Solution (CAPS), to estimate the age and condition based LOF for each wood pole, metal structure, overhead primary, and transmission conductor. 1898 & Co.'s CAPS utilizes industry standard survivor curves with an asset class expected average service life and the asset's 'effective' age (or calendar age if condition data is not available) to estimate the age and condition based LOF over the next 10 years. Condition data for wood poles was used to factor in any rot or impacts to the pole's ground-line circumference. Section 4.1.5 outlines the wood pole inspection data used in the 'effective' age calculations.

Figure 4-6 shows the age and condition LOF distribution of the T&D infrastructure asset base. The age and condition based LOF scores were used in the storm LOF framework to calculate storm LOF scores for each asset. Overall, the age and condition score contribute on average 20 to 30 percent of system LOF depending on the storm scenario.

Figure 4-6: Age & Condition LOF Distribution



The wind zone criteria use the wind zone designation data from Section 4.1.6 inside the asset LOF framework to develop the LOF scores. Overall, the wind zone contributes on average 5 to 10 percent of system LOF depending on the storm scenario.

The Storm Impact Model uses the sum of the three criteria (vegetation, age & condition, and wind zone) to calculate the total storm LOF for each asset. The assets are then totaled up to the project level, providing a granular understanding of the LOF for each project. The Storm Impact Model uses the storm LOF scores to identify the circuit project POF for each storm event in the Major Storms Event Database.

4.2.3 Site Access Storm Likelihood of Failure

The site access dataset includes a hierarchy of the impacted circuits. Using this hierarchy, each site access LOF equals the total of the circuits it provides access to. Section 4.2.2, above, provides the details on how the circuit LOF is calculated.

4.3 Project & Asset Reactive Storm Restoration

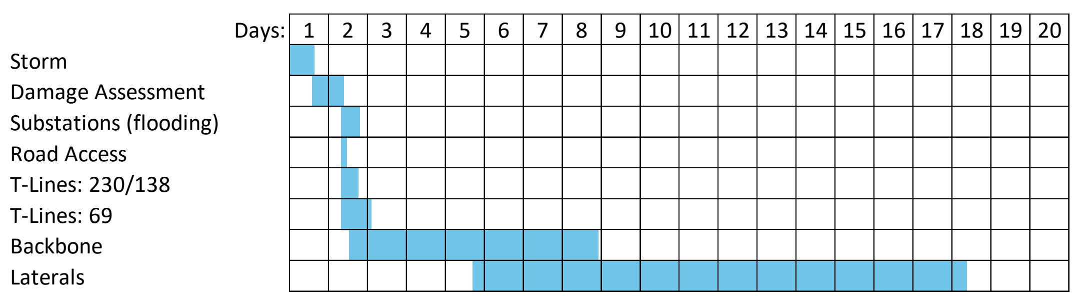
The Storm Impact Model estimates the cost to repair assets from a storm-based failure. Storm restoration costs were calculated for every asset in the Storm Protection Model including wood poles, overhead primary, transmission structures (steel, concrete, and lattice), transmission conductors, power transformers, and breakers. The costs were based on storm restoration costs multipliers above planned replacement costs. The multipliers were in the 1.4 to 4.0 range. These multipliers were developed by TEC and 1898 & Co. collaboratively. They are based on the expected inventory constraints and foreign labor resources needed for the various asset types and storms. Substation restoration costs include storm costs for minor and major flooding events. For minor flooding events, the substation equipment can be used in the short term to restore power flow after cleaning, but the equipment needs to be replaced within 1 year. For major flooding, the substation equipment cannot be restored and must all be replaced. Restoration costs for site access projects were developed by TEC and provided to 1898 & Co.

For each storm event, the restoration costs at the asset level are aggregated up the project level and then weighted based on the project LOF (Section 4.2) and the overall restoration costs for the storm event outlined in the Major Event Storms Database.

4.4 Duration and Customer Impact

The Storm Impact Model calculates the duration to restore each project in the Status Quo Scenario. The assumptions for major asset class outage duration are outlined in the Major Event Storms Database. Figure 4-7 provides an example duration profile for the Category 3 and above storm event.

Figure 4-7: Example Storm Duration Profile



The project specific duration is based on percent complete vs percent time curves for each major asset class. The projects are ranked by metrics that are similar to those TEC uses to prioritize storm restoration activity, such as priority customers. Specific project durations are calculated based on completion vs time curves. For example, using the example from the figure above, a lateral project may have a relatively high priority (i.e. customer count is high with more critical customers). That lateral would be restored by day 7 of the profile above. However, the lowest ranked laterals will have project durations in the 16 to 17-day range.

The project duration is then multiplied by the number of affected customers for each project (see Section 4.1.3) to calculate the CMI for each project. It should be noted that the Storm Impact Model assumes feeder automation has been installed on each circuit so that the affected number of customers is 400, the target for each hardening protection zone. This is a conservative assumption so that no double counting of benefits occurs.

Some of the storm scenarios include significant outages to the transmission system. The percentage of the system impacted is so high that the designed resilience (looping) of the system is lost for a short period of time, which in turn causes mass customer outages across the system from the transmission system. The Storm Impact Model allocates customer outages from these events to the various parts of the TEC transmission system based on transmission system operating capacity and overall importance to the Bulk Electric System (BES).

Finally, the CMI for each project for each storm event is monetized using the ICE Calculator. Section 4.1.8 provides additional detail on the ICE Calculator. The monetization is performed for each type of customer; residential, small C&I, large C&I, and the various priority customers. The monetization of CMI is calculated for project prioritization purposes as discussed below in Section 5.0.

4.5 'Status Quo' and Hardening Scenarios

The Storm Impact Model calculates the storm restoration costs and CMI for the 'Status Quo' and Hardening Scenarios for each project by each of the 99 storm events. The delta between the two scenarios is the benefit for each project. This is calculated for each storm event based on the change to the core assumptions (vegetation density, age & condition, wind zone, flood level, restoration costs, duration, and customers impacted) for each project.

The output from the Storm Impact Model is a project by project probability-weighted estimate of annual storm restoration costs, annual CMI, and annual monetized CMI for both the 'Status Quo' and Hardened Scenarios for all 99 major storm scenarios. The following section describes the methodology utilized to model all 99 major storms and calculate the resilience benefit of each project.

5.0 RESILIENCE NET BENEFIT CALCULATION MODULE

The Resilience Benefit Calculation Module of the Storm Resilience Model uses the annual benefit results of the Storm Impact Model and the estimated project costs to calculate the net benefits for each project. Since the benefits for each project are dependent on the type and frequency of major storm activity, the Resilience Benefit Module utilizes stochastic modeling, or Monte Carlo Simulation, to randomly select a thousand future worlds of major storm events to calculate the range of both 'Status Quo' and Hardened restoration costs and CMI. The benefit calculation is performed over a 50-year time horizon, matching the expected life of hardening projects.

The feeder automation hardening project resilience benefit calculation employs a different methodology given the nature of the project and the data available to calculate benefits. The Outage Management System (OMS) includes 19 years of historical data. The resilience benefit is based on the expected decrease in impacted customers if the automation had been in place.

The following sections provide additional detail on the project costs, Monte Carlo Simulation, and feeder automation.

5.1 Economic Assumptions

The resilience net benefit calculation includes the following economic assumptions:

- Period: 50 years – most of the hardening infrastructure will have an average service life of 50 or more years
- Escalation Rate: 2 percent
- Discount Rate: 6 percent

5.2 Project Cost

Project costs were estimated for the over 20,000 projects in the Storm Resilience Model. Some of the project costs were provided by TEC while others were estimated using the data within the Storm Resilience Model to estimate scope (asset counts and lengths) that was then multiplied by unit cost estimates to calculate the project costs. The following sub-sections outline the approach to calculate project costs for each of the programs.

5.2.1 Distribution Lateral Undergrounding Project Costs

For each project, the GIS (see Section 4.1.1) and Accessibility algorithm (see Section 4.1.7) were leveraged to estimate:

- Miles of overhead conductor for 1, 2, and 3 phase laterals
- Number of overhead line transformers, including number of phases, that need to be converted to pad mounted transformers
- Number of meters connected through the secondary via overhead line.

Each of these values creates the scope for each of the projects. TEC provided unit costs estimates, which are multiplied by the scope activity (asset counts and lengths) to calculate the project cost. The unit cost estimates are based on supplier information and previous undergrounding projects.

5.2.2 Transmission Asset Upgrades Project Costs

The Transmission Asset Upgrades program project costs are based on the number of wood poles by class, type (H-Frame vs monopole), and circuit voltage. TEC provided unit cost estimates for each type of pole to be replaced. The project costs equal the number wood poles on the circuit multiplied by the unit replacement costs.

5.2.3 Substation Extreme Weather Hardening Project Costs

The project costs for the Substation Extreme Weather Hardening program are based on the perimeter of each substation multiplied by the unit cost per foot to install storm surge walls. The costs per foot vary by the required height of the wall. The substation wall height is based off the needed height to mitigate the flooding from the SLOSH model results.

5.2.4 Distribution Overhead Feeder Hardening Project Costs

The distribution overhead feeder hardening project costs are based on the number of wood poles that don't meet current design standards for storm hardening and the cost to include automation. TEC provided unit replacement costs based on the accessibility of the pole as well as the average cost to add automation to each circuit.

5.2.5 Transmission Access Enhancements

TEC provided all the project costs for the Transmission Access Enhancements. The cost estimates were based on the length of the bridge or road. Those lengths were developed using geospatial solutions using TEC's GIS for each problem area.

5.3 Resilience-weighted Life-Cycle Benefit

The benefits of storm hardening projects are highly dependent on the frequency, intensity, and location of future major storm events over the next 50 years. Each storm type (e.g. Category 1 from the Gulf) has a range of potential probabilities and consequences. For this reason, the Storm Resilience Model employs stochastic modeling, or Monte Carlo Simulation. Monte Carlo Simulation is a random sampling methodology.

In the context of the Storm Resilience Model, the Monte Carlo simulator selects the major storm events to impact the TEC service territory over the next 50 years from the Major Storms Event Database (Section 3.0). That database outlines the 'universe' of storm event types that could impact the TEC service territory. The database includes 13 unique storm types with 99 different storm events when factoring in the range of probabilities and impacts. The database is based on a historical analysis of major storms to come within 150 miles of the TEC service territory over the last 167 years.

Table 5-1 shows the selection of storm events for each storm type for the first 7 iterations and iteration 1,000. The selected 13 storm events for each iteration represent the future world of storms to impact the TEC service territory over the next 50 years. Each storm has a different frequency and impact to the TEC system. The Monte Carlo Simulation is performed over 1,000 iterations creating a 1,000 of these future storm 'worlds'.

Each project's CMI, monetized CMI, and restoration costs are calculated for the 13 storm events for each iteration for both the 'Status Quo' and Hardened Scenarios over a 50-year time horizon. The difference between the 'Status Quo' and Hardened Scenarios is the benefit of the project for that storm event. The sum of the benefits for all 13 storm events for each iteration equals the total benefits for the project. The CMI, monetized CMI, and restoration costs are then weighted by the probability of the storm event to calculate the storm resilience-weighted life-cycle benefit.

Table 5-1: Monte Carlo Simulation Storm Event Selection

Storm Type No	Scenario Name	Storm Event - Iteration								
		1	2	3	4	5	6	7	...	1000
1	Cat 3+ Direct Hit - Gulf	5	6	5	2	3	6	1	...	3
2	Cat 1 & 2 Direct Hit – Florida	13	16	11	11	8	17	12	...	17
3	Cat 1 & 2 Direct Hit – Gulf	20	24	20	19	19	20	23	...	20
4	TS Direct Hit	28	29	29	30	29	29	30	...	29
5	TD Direct Hit	31	32	31	32	33	31	33	...	31
6	Localized Event Direct Hit	36	35	34	35	36	34	35	...	34
7	Cat 3+ Partial Hit	39	39	39	39	40	37	37	...	41
8	Cat 1 & 2 Partial Hit	43	45	46	43	43	48	45	...	43
9	TS Partial Hit	50	52	52	52	50	54	52	...	50
10	TD Partial Hit	62	61	56	58	61	59	59	...	62
11	Cat 3+ Peripheral Hit	74	72	72	72	71	70	72	...	70
12	Cat 1 & 2 Peripheral Hit	82	87	87	76	79	84	81	...	82
13	TS Peripheral Hit	99	92	98	90	92	93	95	...	88

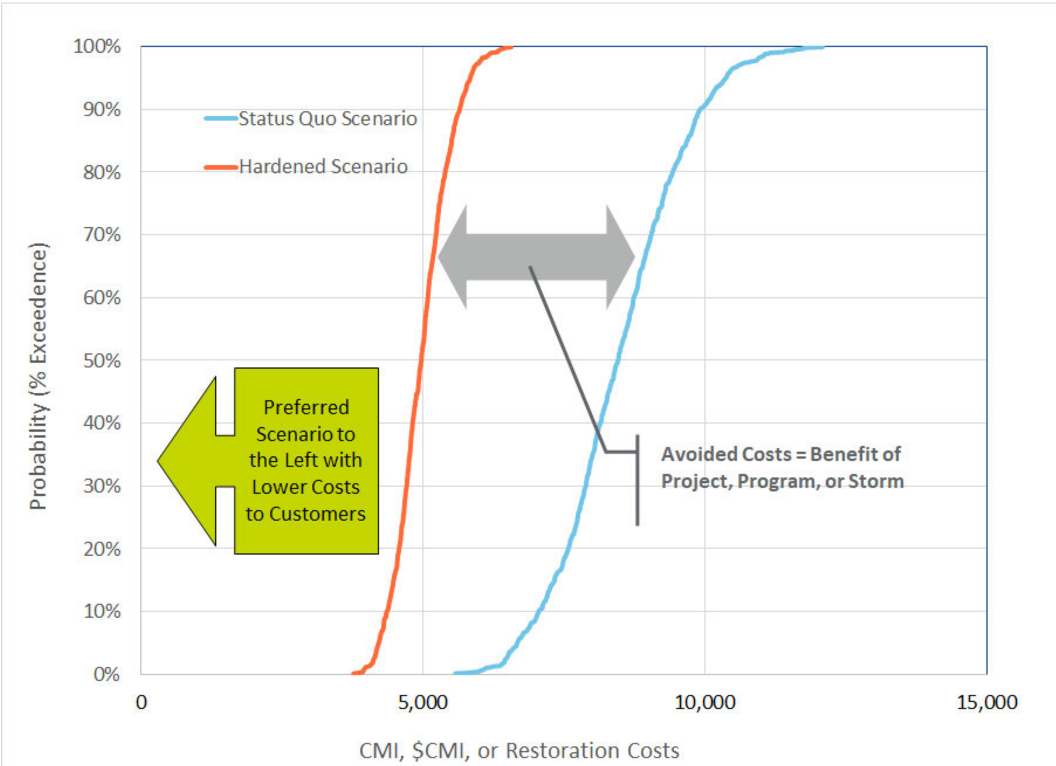
Table 5-2 provides an example calculation of storm resilience weighted CMI, monetized CMI, and restoration costs for both the 'Status Quo' and Hardened Scenarios. Each of the values is weighted by the probability of the event from the storms database over the 50-year time horizon. The monetized CMI and restoration cost show the NPV of the 50-year storm probability adjusted cash flows. The delta between the 'Status Quo' and Hardened scenarios is the benefits of the project for the first iteration. The example shows that the project is not impacted by small or peripheral storms. This calculation is repeated for all 1,000 iterations for the over 20,000 projects in the Storm Resilience Model.

Table 5-2: Project CMI and Restoration Cost Example – Iteration 1

Storm Type No	Scenario Name	Status Quo			Hardened		
		CMI	$CMI	Rest$	CMI	$CMI	Rest$
1	Cat 3+ Direct Hit – Gulf	64,910	$606,664	$132,303	41,947	$392,045	$0
2	Cat 1 & 2 Direct Hit – Florida	26,001	$377,198	$38,694	16,803	$243,757	$0
3	Cat 1 & 2 Direct Hit – Gulf	22,228	$305,395	$38,078	14,364	$197,356	$0
4	TS Direct Hit	26,587	$471,815	$53,821	17,072	$302,952	$43,127
5	TD Direct Hit	9,612	$150,651	$9,619	6,172	$96,733	$7,708
6	Localized Event Direct Hit	1,282	$27,601	$4,858	823	$17,723	$3,893
7	Cat 3+ Partial Hit	5,975	$86,440	$12,779	3,862	$55,860	$0
8	Cat 1 & 2 Partial Hit	3,575	$58,056	$14,771	2,310	$37,517	$0
9	TS Partial Hit	1,077	$27,788	$6,303	691	$17,843	$5,051
10	TD Partial Hit	$0	$0	$0	$0	$0	$0
11	Cat 3+ Peripheral Hit	$0	$0	$0	$0	$0	$0
12	Cat 1 & 2 Peripheral Hit	$0	$0	$0	$0	$0	$0
13	TS Peripheral Hit	$0	$0	$0	$0	$0	$0
	Total	161,246	$2,111,610	$311,225	104,043	$1,361,786	$59,779

The results of the 1,000 iterations are graphed in a cumulative density function, also known as an 'S-Curve'. Figure 5-1 shows an illustrative example of the 1,000 iteration simulation results for the 'Status Quo' and Hardened Scenarios. The resilience benefit of the project, program, or plan is the gap between the S-curves for the top part of the curve. Section 2.4 describes this in further detail.

Figure 5-1: Status Quo and Hardened Results Distribution Example



5.4 Feeder Automation Benefits Calculation

As part of the Storm Protection Plan, TEC intends to include feeder automation to allow for automatic switching during storm events. The design standard is to limit outages to impact a maximum of 400 customers. While many of the other Storm Protection Programs provide resilience benefit by mitigating outages from the beginning, feeder automation projects provide resilience benefit by decreasing the impact of a storm event, the 'pit' of the resilience conceptual model described in Figure 2-2 above.

The resilience benefit for feeder automation was estimated using historical Major Event Day (MED) outage data from the OMS (see Section 4.1.2). TEC has outage records going back 19 years. The analysis assumes that future MED outages for the next 50 years will be similar to the last 19 years.

The outage records document all outages by protection device. The system includes customer relationship information for each protection device to calculate the number of customers impacted if a device operates. The OMS records the start and end times for each outage. The information from the

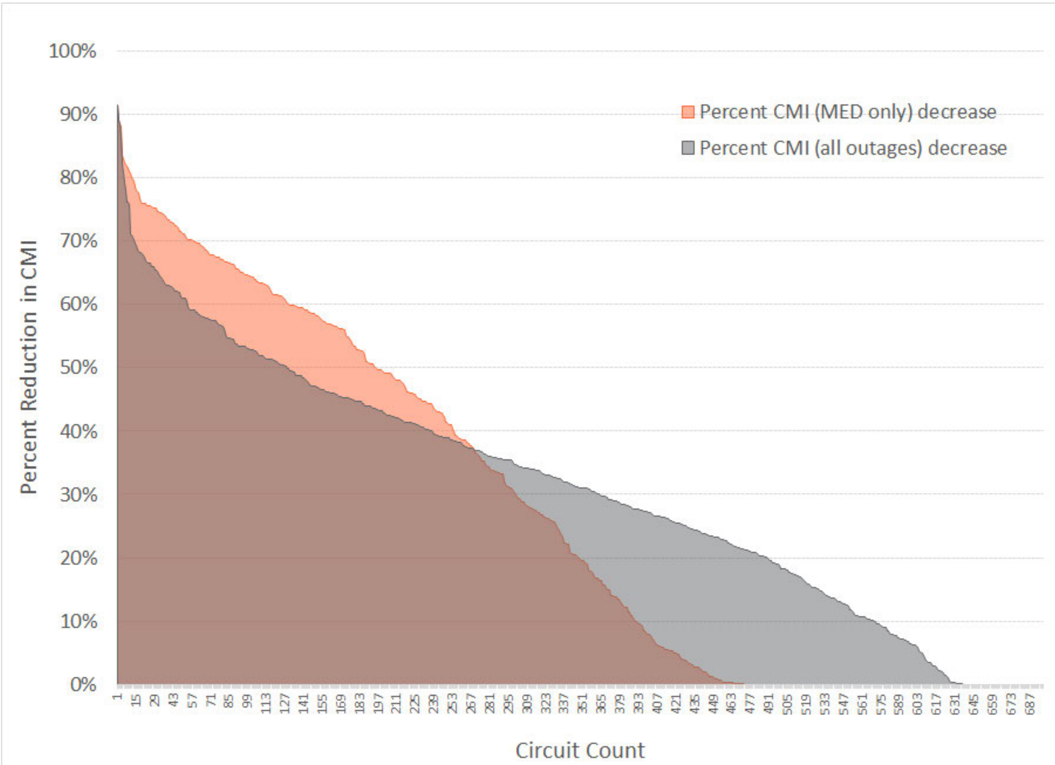
OMS is used to calculate reliability metrics for reporting purposes. The OMS also includes designations for MED, which are days during which a significant part of the system is impacted by a major event. These are typically major storms. MED is often referred to as 'grey-sky' days as opposed to non-MED which is referenced as 'blue-sky' days.

For the resilience benefit calculation, the Storm Resilience Model re-calculates the number of customers impacted by an outage, assuming that feeder automation had been in place. For example, a historical outage may have included a down pole from a storm event, causing the substation breaker to lock out and resulting in a four-hour outage for 1,500 customers, or 360,000 CMI. The Storm Resilience Model re-calculates the outages as 400 customers without power for four hours, or 96,000 CMI. That example provides a reduction in CMI of over 70 percent. The Storm Resilience Model extrapolates the 19 years of benefit calculation to 50 years to match the time horizon of the other projects.

The feeder automation projects include a range of investment types including reclosers, poles, re-conductering, adding tie lines, and substation upgrades to handle the load transfer. TEC provided the itemized costs for feeder automation for projects installed in years 2020 and 2021, and expected average feeder costs for years 2022 through 2029.

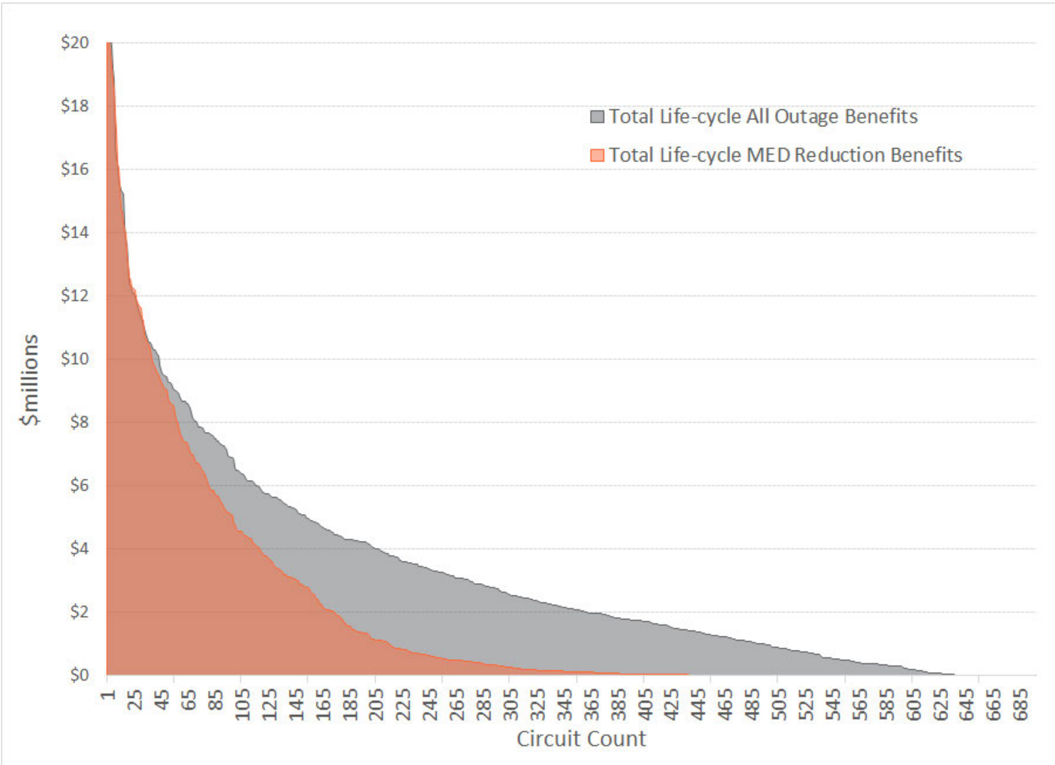
Figure 5-2 shows the percent decrease in CMI using this approach for all circuits. The figure is ranked from highest to lowest from left to right. The figure also includes the benefits to all outages. The figure shows a wide range of decreased CMI percentages with nearly 40 percent of circuits resulting in a 40 percent or more decrease in MED CMI. Additionally, the figure shows that approximately two thirds of the circuits would decrease MED CMI.

Figure 5-2: Automation Hardening Percent CMI Decrease



The resilience benefit calculation also monetized the CMI decrease using the ICE Calculator (Section 4.1.8). Figure 5-3 shows the percent decrease in monetized CMI for each circuit. The CMI was monetized and discounted over the 50-year time horizon to calculate the NPV. The NPV calculation assumed a replacement of the reclosers in year 25; the rest of the feeder automation investment has an expected life of 50 years or more. The monetization and discounted cash flow methodology was performed for project prioritization purposes.

Figure 5-3: Automation Hardening Monetization of CMI Decrease



6.0 BUDGET OPTIMIZATION AND PROJECT SELECTION

The Storm Resilience Model models consistently models the benefits of all potential hardening projects for an 'apples to apples' comparison. Sections 3.0, 4.0, and 5.0 described the approach and methodology to calculate the resilience benefit for the over 20,000 projects. Resilience benefit values include:

- CMI 50-year Benefit
- Restoration Cost 50-year NPV Benefit
- Life-cycle 50 year NPV gross Benefit (monetized CMI benefit + restoration cost benefit)
- Life-cycle 50 year NPV net Benefit (monetized CMI benefit + restoration cost benefit – project costs)

Each of these values includes a distribution of results from the 1,000 iterations. For ease of understanding and in alignment with the resilience base strategy, the approach focuses on the P50 and above values, specifically considering:

- P50 – Average Storm Future
- P75 – High Storm Future
- P95 – Extreme Storm Future

The following sections discuss the prioritization metric, budget optimization, and approach to developing the Storm Protection Plan.

6.1 Prioritization Metric - Benefit Cost Ratio

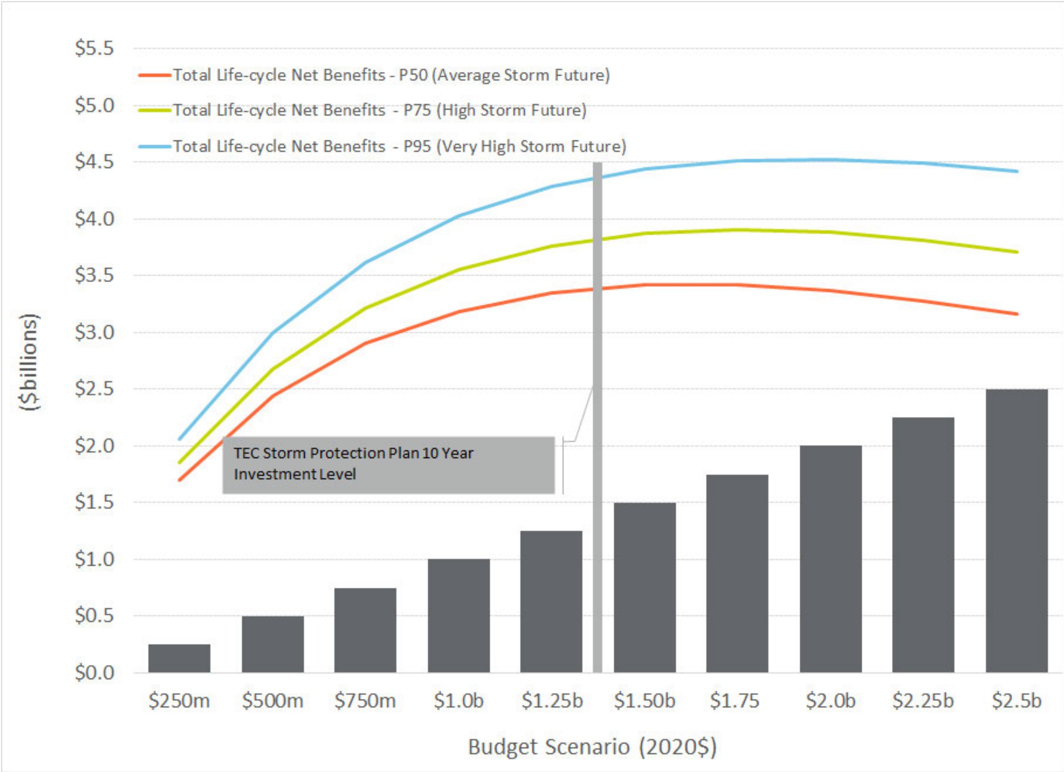
With all the projects being evaluated on a consistent basis, they can all be ranked against each other and compared. The Storm Resilience Model ranks all the projects based on their benefit cost ratio using the life-cycle 50 year NPV gross benefit value listed above. The ranking is performed for each of the P-values listed above (P50, P75, and P95) as well as a weighted value.

Performing prioritization for the four benefit cost ratios is important since each project has a different slope in their benefits from P50 to P95. For instance, many of the lateral undergrounding projects have the same benefit at P50 as they do at P95. Alternatively, many of the transmission asset hardening projects are minorly beneficial at P50 but have significant benefits at P75 and even more at P95. TEC and 1898 & Co. settled on a weighting on the three values for the base prioritization metric, however, investment allocations are adjusted for some of the programs where benefits are small at P50 but significant at P75 and P95.

6.2 Budget Optimization

The Storm Resilience Model performs project prioritization across a range of budget levels to identify the appropriate level of resilience investment. The goal is to identify where 'low hanging' resilience investment exists and where the point of diminishing returns occurs. Given the total level of potential investment the budget optimization analysis was performed in $250 million increments up to $2.5 billion. Figure 6-1 shows the results of the budget optimization analysis. The figure shows the total life-cycle gross NPV benefit for each budget scenario for P50, P75, and P95.

Figure 6-1: Budget Optimization Results



The figure shows significantly increasing levels of net benefit from the $250 million to $1.5 billion with the benefit level flattening from $1.5 billion to $2.0 billion and decreasing from $2.0 billion to $2.5 billion. The figure also shows the total investment level in 2020 dollars for the TEC Storm Protection

Plan. The TEC overall investment level is right before the point of diminishing returns showing that TEC's plan has an appropriate level of investment capturing the hardening projects that provide the most value to customers.

6.3 Storm Protection Plan Project Prioritization

In developing TEC's Storm Protection Plan, TEC and 1898 & Co. used the Storm Resilience Model as a tool for developing the overall budget level and the budget levels for each category. It is important to note that the Storm Resilience Model is only a tool to enable more informed decision making. While the Storm Resilience Model employs a data-driven decision-making approach with robust set of algorithms at a granular asset and project level, it is limited by the availability and quality of assumptions. In developing the TEC Storm Protection plan project identification and schedule, the TEC and 1898 & Co team factored in the following:

- Resilience benefit cost ratio including the weighted, P50, P75, and P95 values.
- Internal and external resources available to execute investment by program and by year.
- Lead time for engineering, procurement, and construction
- Transmission outage and other agency coordination.
- Asset bundling into projects for work efficiencies.
- Project coordination (i.e. project A before project B, project Y and project Z at the same time).

7.0 RESULTS & CONCLUSIONS

TEC and 1898 & Co. utilized a resilience-based planning approach to identify and prioritize resilience investment in the T&D system. This section presents the costs and benefits of TEC's Storm Protection Plan. Customer benefits are shown in terms of the:

1. Decrease in the Storm Restoration Costs
2. Decrease in the customers impacted and the duration of the overall outage, calculated as CMI

7.1 Storm Protection Plan

This section includes the program capital investment and resilience benefit results for TEC's Storm Protection Plan.

7.1.1 Investment Profile

Table 7-1 shows the Storm Protection Plan investment profile. The table includes the buildup by program to the total. The investment capital costs are in nominal dollars, the dollars of that day. The overall plan is approximately $1.46 billion. Lateral undergrounding makes up most of the total, accounting for 66.8 percent of the total investment. Feeder Hardening is second, accounting for 19.8 percent. Transmission upgrades make up approximately 10.2 percent of the total, with substations and site access making up 2.2 percent and 1.0 percent, respectively. The plan includes a few months of investment in 2020 and a ramp-up period to levelized investment (in real terms) in 2022.

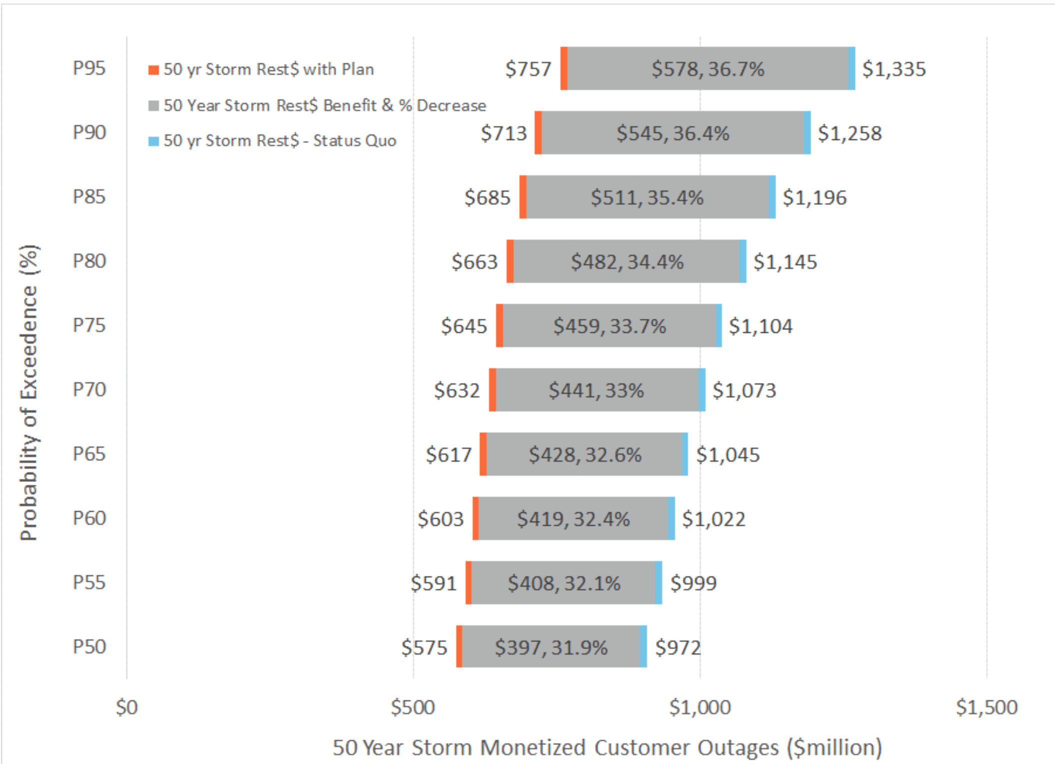
Table 7-1: Storm Protection Plan Investment Profile by Program (Nominal $000)

Year	Lateral Undergrounding	Transmission Asset Upgrades	Substation Hardening	Feeder Hardening	Transmission Site Access	Total
2020	$8,000	$5,600	$0	$6,200	$0	$19,700
2021	$79,500	$15,200	$0	$15,400	$1,400	$111,500
2022	$108,100	$15,000	$0	$29,600	$1,500	$154,200
2023	$101,400	$16,500	$0	$33,400	$1,600	$152,900
2024	$107,000	$11,900	$7,300	$32,500	$1,700	$160,400
2025	$110,800	$19,000	$5,500	$33,200	$1,300	$169,900
2026	$114,000	$17,700	$4,700	$33,800	$400	$170,600
2027	$111,400	$16,300	$6,700	$32,800	$3,300	$170,500
2028	$115,500	$19,600	$5,200	$36,400	$2,000	$178,700
2029	$121,100	$12,100	$2,900	$36,300	$1,700	$174,000
Total	$976,800	$148,900	$32,400	$289,600	$14,800	$1,462,500

7.1.2 Restoration Cost Reduction

Figure 7-1 shows the range in restoration cost reduction at various probability of exceedance levels. As a refresher, the P50 to P65 level represents a future world in which storm frequency and impact are close to average, the P70 to P85 level represents a future world where storms are more frequent and intense, and the P90 and P95 levels represent a future world where storm frequency and impact are all high.

Figure 7-1: Storm Protection Plan Restoration Cost Benefit

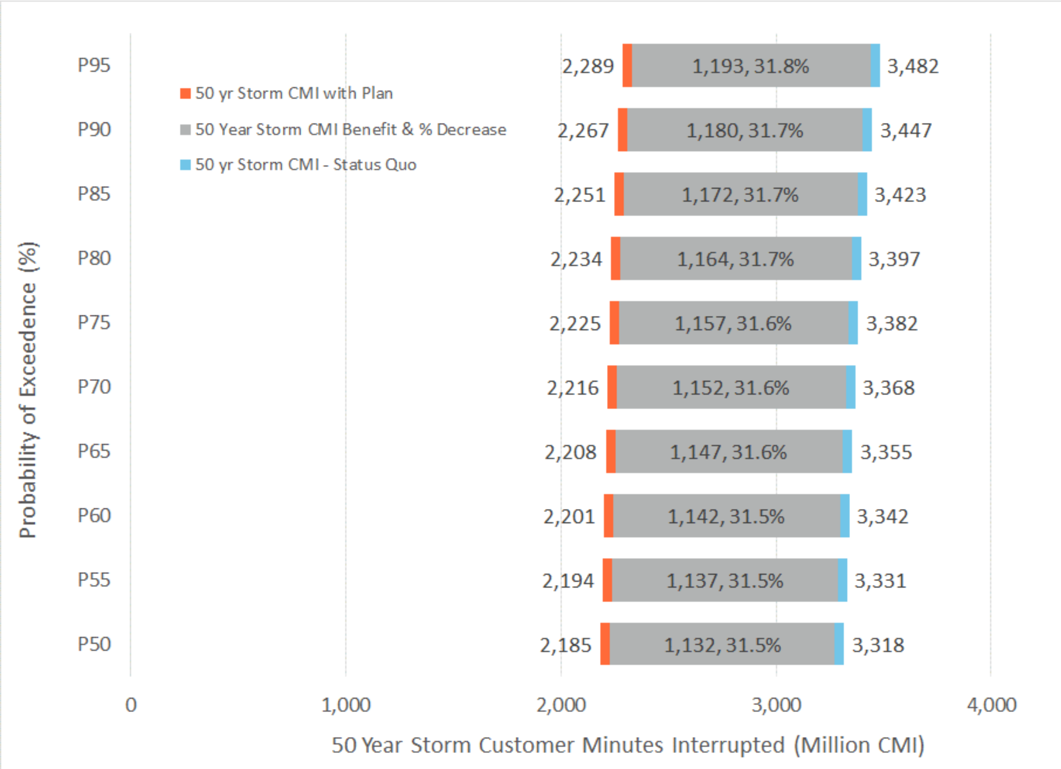


The figure shows that the 50 NPV of future storm restoration costs in a Status Quo scenario from a resilience perspective is $970 million to $1,340 million. With the Storm Protection Plan, the costs decrease by approximately 32 to 37 percent. The decrease in restoration costs is approximately $400 to $580 million. From an NPV perspective, the restoration costs decrease benefit is approximately 36 to 53 percent of the project costs.

7.1.3 Customer Benefit

Figure 7-2 shows the range in CMI reduction at various probability of exceedance levels. The figure shows relative consistency in benefit level across the P-values with approximately 32 percent decrease in the storm CMI over the next 50 years.

Figure 7-2: Storm Protection Plan Customer Benefit



7.2 Program Investment Profile Details

Table 7-3, Table 7-4, Table 7-5, and Table 7-6 show annual investment for the five programs evaluated in the Storm Resilience Model. The tables also show the counts associated with the investment level. For Table 7-3 the total count of circuits being worked on each year is shown. Several circuits are worked on over multiple years. The plan includes upgrading assets on 131 different circuits.

Table 7-2: Distribution Lateral Undergrounding Investment Profile

Year 1	Lateral Count	Miles	Nominal Cost ($000)
2020	24	10	$8,000
2021	281	101	$79,500
2022	316	119	$108,100
2023	308	105	$101,400
2024	286	124	$107,000
2025	283	106	$110,800
2026	286	118	$114,000
2027	318	146	$111,400
2028	298	126	$115,500
2029	282	152	$121,100
Total	2,682	1,107	$976,800

Table 7-3: Transmission Asset Upgrades Investment Profile

Year 1	Circuits Worked On	Nominal Cost ($000)
2020	21	$5,600
2021	35	$15,200
2022	28	$15,000
2023	15	$16,500
2024	15	$11,900
2025	6	$19,000
2026	7	$17,700
2027	10	$16,300
2028	13	$19,600
2029	20	$12,100
Total	NA	$148,900

Table 7-4: Substation Extreme Weather Hardening Investment Profile

Year	Count	Nominal Cost ($000)
2020	0	$0
2021	0	$0
2022	0	$0
2023	0	$0
2024	1	$7,300
2025	2	$5,500
2026	2	$4,700
2027	4	$6,700
2028	1	$5,200
2029	1	$2,900
Total	11	$32,400

Table 7-5: Distribution Overhead Feeder Hardening Investment Profile

Year	Feeder Count	Nominal Cost ($000)
2020	5	$6,200
2021	18	$15,400
2022	13	$29,600
2023	41	$33,400
2024	43	$32,500
2025	40	$33,200
2026	45	$33,800
2027	40	$32,800
2028	59	$36,400
2029	53	$36,300
Total	357	$289,600

Table 7-6: Transmission Access Enhancements Investment Profile

Year	Count	Nominal Cost ($000)
2020	0	$0
2021	8	$1,400
2022	6	$1,500
2023	5	$1,600
2024	4	$1,700
2025	4	$1,300
2026	1	$400
2027	3	$3,300
2028	3	$2,000
2029	3	$1,700
Total	37	$14,800

7.3 Program Benefits

Table 7-7 shows the restoration cost and CMI benefit for each of the programs. The ranges include the P50 to P95 values. Figure 7-3 shows each program's percentage of the total benefits compared to the program's percentage of the total capital investment. The figure shows the benefit values for both restoration cost and CMI.

Table 7-7: Program Benefit Levels

Program	Restoration Cost Percent Decrease	Storm CMI Percent Decrease
Distribution Lateral Undergrounding	~33%	~44%
Transmission Asset Upgrades	~90%	~13%
Substation Extreme Weather Hardening	70% to 80%	50% - 65%
Distribution Feeder Hardening	38% to 42%	30%
Transmission Access Enhancements	10%	~74%

Figure 7-3: Program Benefits vs. Capital Investment

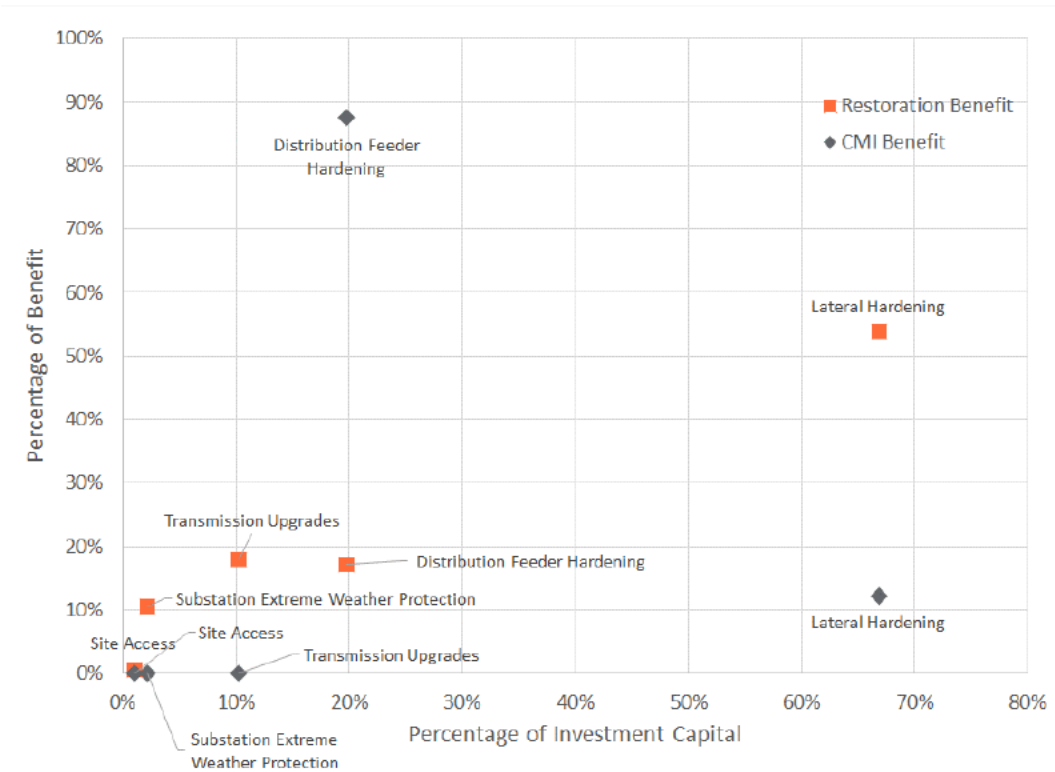


Table 7-7 and Figure 7-3 shows

- Distribution Feeder Hardening and Lateral Undergrounding account for 87 percent of the total capital investment, nearly all the CMI benefit, and approximately 71 percent of the restoration benefit.

- The Distribution Lateral Undergrounding program decreases the storm related CMI and restoration costs for the asset base by approximately 44 and 33 percent, respectively. Additionally, the program accounts for approximately 67 percent of the total plan's invested capital, approximately 54 percent of the plan's restoration benefit, and approximately 12 percent of the plan's CMI benefit. The low overall CMI reduction relative to the total reduction is because of the high decrease from the Feeder Hardening program, specifically feeder automation.
- The Distribution Feeder Hardening program contributes approximately 87 percent of the CMI benefit of the plan, mainly from feeder automation based on the historical 'grey sky' days.
- While Transmission Assets, Substation, and Access programs achieve fairly high percentages in decreasing CMI, their total contribution to CMI reduction for the plan is low (less than 1 percent).
- Substation Hardening accounts for over 10.5 percent of the restoration benefit of the plan while only accounting for approximately 2.2 percent of the capital investment. The cost to restore flooded substations is extremely high.

7.4 Conclusions

The following include the conclusions of TEC's Storm Protection plan evaluated within the Storm Resilience Model:

- The overall investment level of $1.46 billion for TEC's Storm Protection Plan is reasonable and provides customers with maximum benefits. The budget optimization analysis (see Figure 6-1) shows the investment level is right before the point of diminishing returns.
- TEC's Storm Protection Plan results in a reduction in storm restoration costs of approximately 32 to 37 percent. In relation to the plan's capital investment, the restoration costs savings range from 36 to 53 percent depending on future storm frequency and impacts.
- The customer minutes interrupted decrease by approximately 32 percent over the next 50 years. This decrease includes eliminating outages all together, reducing the number of customers interrupted, and decreasing the length of the outage time.
- The cost (Investment – Restoration Cost Benefit) to purchase the reduction in storm customer minutes interrupted is in the range of $0.61 to $0.82 per minute. This is below outage costs from the DOE ICE Calculator and lower than typical 'willingness to pay' customer surveys.

- TEC's mix of hardening investment strikes a balance between investment in the substations and transmission system targeted mainly at increasing resilience for the high impact / low probability events and investment in the distribution system, which is impacted by all ranges of event types.
- The hardening investment will provide additional 'blue sky' benefits to customers not factored into this report.

9400 Ward Parkway
Kansas City, MO

816-605-7800
1898andCo.com

Tampa Electric's Storm Protection Plan Transmission Asset Upgrade Implementation

For Existing and New Work Request

1 ALLOWABLE POLES

For Transmission Poles to go to the SPP and to the Clause, the poles will be one of the following:

1. Included as part of a Transmission Asset Upgrade Project
2. Failed poles that are replaced with the inspection that identified the failure being after April 10, 2020
3. Any backlog pole that is awaiting replacement that is along the line segment of a Transmission Asset Project

Poles that go to the clause should be counted towards the SHP, in addition - those poles that are replaced from the backlog should also be counted separately for reporting.

2 EXISTING WORK

2.1 ENGINEERING NOT STARTED WITH CONTRACTOR

Placed on Hold

2.2 IN ENGINEERING WITH CONTRACTOR

2.2.1 Design

All Maintenance Items shall be removed from Pole Replacement work request. Separate work request should be generated for Capital Maintenance items with Add-on Maintenance Items when applicable. Maintenance Items not captured on a work request can be billed at the Bad Target rate.

2.2.2 Invoicing

TRC Engineering Services charge numbers for engineering currently in progress on 4/13/2020 but won't be completed, submitted for approval, or billed (unit rate/pole) until the end of April and some in May 2020:

- Charge anything with PRE-02665 to B2248650 (69kV)
- Charge anything with PRE-02831 to B2213545 (138kV)
- Charge anything with PRE-02830 to B2248660 (230kV)

We should finish out that work under existing funding since it would be tough to carve it up at this point.

Financials will be changed over to SPP funding at a later time, prior to construction.

2.3 PRE FUNDING WORK REQUEST WITHOUT EXISTING CHARGES

Reuse existing Work Request/s. After verifying in SAP (IW33) that there is no cost posted to the Work Request, overwrite financials with SPP Project Specific Work Order number by circuit. Additional surrounding pole replacements can be added to the Work Request as appropriate.

Data collection will be completed to verify no changes to the field conditions or attachments have been made since the original design.

The existing PLS CADD design can be utilized and incorporated into the SPP Circuit model where appropriate. The design must be verified or updated to meet our current design methodology.

If any design conflicts or CU issues are existing in GIS, it recommended to discard job edits to prevent issues pushing to WorkPro later.

2.4 PRE FUNDING WORK REQUEST WITH EXISTING CHARGES

3 FUTURE WORK

3.1 FIELD VERIFICATION

Each circuit assigned shall be field verified from beginning to end to identify all wood poles associated with the circuit. Specifically, be on the lookout for:

- Stub poles supporting transmission facilities but not associated to the circuit in GIS
- Transmission wire that deadends on a wood structure inside the substation
- Tree trim requirements for pole replacements

A marked-up circuit map identifying all wood poles and tree trim required will be submitted back to TECO for review before proceeding. Provide photos of added poles and tree trim locations.

Field verification by the engineering contractor will be billed at an hourly rate and invoiced in the month work was performed.

Field Verification Circuit Maps, titled "Circuit ##### - Fielded", and associated photos will be stored:

Transmission Engineering Share Drive > Transmission > Projects > 1 Active > Maintenance > Circuit Folder > Create "SPP Field Verification" Folder

3.2 WORK REQUEST GENERATION

Work Request will be generated with SPP funding project numbers by circuit. Each work request number needs to be logged with Transmission Operations SPP Engineer.

Field Verification Circuit Maps will be utilized to group work for the generation of Work Request, titled "Circuit ##### - Fielded – WR Markup".

3.2.1 Transmission Pole Replacement Work Request

- Initiate > Work Request
- General Tab, Required Fields:
  - Contact Name: Kaylene Pelsh
  - Tel: 813-635-1724
  - Organization: TECO
  - St Nm: Circuit Number 'space' Street Name & Cross Street if applicable
  - County: County
  - Work Type: Designed
  - Job Type: TPMN69-G, TPMN138-G, or TPMN230-G
  - Description: SPP TAU - # Poles Ckt #
    - 35-character count limit due to SAP
  - Required Date: Construction Start date
  - Start Date: Construction Start date
  - Priority: 6 – requested by Procurement group to identify SPP material request
  - Crew HQ: TRA (F225100)
  - Dist: TRA
  - Assigned To: FYMOM
  - Click Create button

- Financials Tab
  - Overwrite Financials with SPP Project Specific Work Order number by Circuit
  - Update Finance Crew HQ to SPP
- References Tab
  - Enter Project: SPP-TAU
- Circuit # Tab
  - Add Transmission Circuit number to Network Level 3
- Requirements Tab
  - Complete 110 – Acquire Proper Charge # requirement

3.2.2 Associated Work Request

- Distribution Overhead Transfers
  - Work Type: Designed
  - Job Type: OLI-G (OH Maintenance Replace/Repair-NO Dist Poles)
  - Description: SPP TAU – Dist Trsfr WR #(Reference Trans WR)
    - 35-character count limit due to SAP
  - Priority: 6
  - Crew HQ: TRAENG (F224000)
- Distribution Primary Underground
  - Work Type: Designed
  - Job Type: ULI-G (UG Maintenance Replace/Repair-GIS)
  - Description: SPP TAU – DIST PRI UG WR #(Reference Trans WR)
    - 35-character count limit due to SAP
  - Priority: 6
  - Crew HQ: XXXOSC (XXX is the 3 letter of the service area)
- Distribution Primary Conduit Transfers
  - Work Type: Designed
  - Job Type: ULI-G (UG Maintenance Replace/Repair-GIS)
  - Description: SPP TAU – PRI COND TRSFR WR #(Reference Trans WR)
    - 35-character count limit due to SAP
  - Priority: 6
  - Crew HQ: XXXOSC (XXX is the 3 letter of the service area)
- Grounding
  - Work Type: Non Designed
  - Job Type: TGRND (Transmission Grounding)
  - Description: SPP TAU – GROUNDING WR #(Reference Trans WR)
    - 35-character count limit due to SAP
  - Crew HQ: TRAOSC
- Site Restoration
  - Work Type: Non Designed
  - Job Type: LBRTSK (Labor Task)
  - Job Code: TRSITE (Transmission Site Restoration)
  - Description: SPP TAU – SITE RESTOR WR #(Reference Trans WR)
    - 35-character count limit due to SAP
  - Crew HQ: TRAOSC
- Pole Haul In
  - Work Type: Non Designed

  - Job Type: LBRTSK (Labor Task)
  - Job Code: POLPUL (Pole Pull and Haul In)
  - Description: SPP TAU – POLE PULL WR #(Reference Trans WR)
    - 35-character count limit due to SAP
  - Priority: 6
  - Crew HQ: TRA (F223460)
  - Dist: TRAOSC (F225100)

3.2.3 Incorporating Existing Pole Replacement Work Request

3.3 Tree Trim Notification

Line Clearance will need 6-8 weeks lead time to plan and complete work.

Field Verification Circuit Maps that were utilized to group work for the generation of Work Request will again be utilized to notify Line Clearance of tree trim locations. Due to illegible grid numbers on the maps, a table with the grid numbers needs to be added.

<u>All</u> SPP Work Request will be assigned to LCTRA for review even if no tree trim locations were identified on the Field Verification Circuit Maps.

On the Transmission Pole Replacement Work Request, add the following:

- Requirements Tab
  - Add 248 Tree Trim Required and assign to LCTRA
    - Add pertinent Requirement Note:
      - SPP CIRCUIT, PRINT ATTACHED
      - SPP CIRCUIT, PLEASE VERIFY NO TREE TRIM REQUIRED, PRINT ATTACHED
- Documents Tab
  - Attach Field Verification Circuit Map with tree trim and Work Request number identified, titled “Circuit ##### Tree Trim – SPP WR #######”

3.4 Data Collection

Do not incorporate existing double-pole distribution transfer found in the field during data collection on Transmission SPP Work Request. Only underbuilt distribution transfer on existing wood poles supporting transmission facilities can be included in SPP funding.

3.5 Engineering

When multiple wood poles in a line are designated for replacement, the engineer should try to maximize the height of new pole installation without going over 74’ above ground.

3.6 Material Ordering

Remnant materials to be identified and used up

The following labor CUs must be added to the Work Request using action codes Transfer/Maintenance:

Transmission	# of Men	# of Hours	TRANS_LMN CU Quantity Calculation
3-phase Tangent Trunnion & OHGW	2	1	4
3-phase Tangent Suspension & OHGW	2	1	4
3-phase Deadend Bolted & OHGW	2	3	12
3-phase Deadend Compression & OHGW	2	4	16

Distribution	# of Men	# of Hours	LMN CU Quantity Calculation
1 Tangent wire (primary/neutral/secondary)	1	0.5	1
1 Deadend wire (primary/neutral/secondary)	1	1	2

3.7 Construction Print

Include pole stock number and insulator stock number on print.

3.8 SPP TAU Contractor Report

Populate *SPP TAU Contractor Report* excel file tabs:

- STR WORKING
  - Header Information (green boxes)
  - Install Section
    - Str #
    - Grid #
    - New Spec
    - Stk #
    - Embed (ft), if non-standard
    - Backfill Type – Rock
  - Removal Section
    - Str #
    - Grid #
    - Current Spec
    - Stk #
- STRUCTURES
  - Snip-it, Copy, and Paste Construction Order Header
  - Delete any unnecessary rows
- Engineering Unit Sheet
  - Paste Unit Sheet for WR into excel report
- Construction Unit Sheet
  - Dill hole (ft) = pole embed + 2
    - Obtain hole dia. from Structure tab
  - Backfill = Rock (aka. #57 stone)
    - Obtain qty. from Structure tab
  - Install Pole Type
    - Add qty. for install pole
  - Install Framing Type

        - Add qty. for framing type
    - Install Insulator
        - not typically used unless deviation from SPEC
    - Install Guying qty. when applicable
        - Add qty. when applicable
    - Install Wire
        - not typically used
    - Miscellaneous Installation
        - Add qty. for Drive (3) ground rods = 1 per pole
        - Add qty. for Damper
    - Transfer Existing Facilities
        - Add qty. for Phase Conductor
        - Add qty. for Static/OPGW
        - Add qty. for Jumper, if applicable
    - Remove Pole Type
        - Add qty. for removal pole
    - Remove Framing Type
        - Add qty. for framing type
    - Remove Insulator
        - not typically used unless deviation from SPEC
    - Remove Guying
        - Add qty. when applicable
    - Remove Wire
        - not typically used
    - Miscellaneous Removal
        - not typically used
- Outage Request Form
    - Auto-populates, print for work package
- Grounding
    - Auto-populates, print for work package
- Pole Changeout Sheet
    - Auto-populates, print for work package

3.9 WORK REQUEST PACKAGING

- Transmission Work Request Folder
    - Print and Staple Transmission WRGI to front of folder
    - Write (in Black Sharpie) Transmission WR # on the top tab of folder
    - To contain 4 stapled packages:
        - (1) – Transmission Planner (highlight on WRGI)
            - General Information (Transmission) [8x11]
            - Construction Order [8x11]
            - Construction Print [11x17]
        - (1) – TECO Line Supervisor (highlight)
            - General Information (Transmission) [8x11]
            - Construction Order [8x11]
            - Joint Use Form (if applicable) [8x11]

            - Construction Print [11x17]
            - Structure Report [11x17]
            - Updated SPECs/New SPECs [8x11]
        - (1) – Contractor Line Supervisor (highlight)
            - Outage Request Form (paper clipped)
            - General Information (Transmission) [8x11]
            - Construction Order [8x11]
            - Joint Use Form (if applicable) [8x11]
            - Construction Print [11x17]
            - Structure Report [11x17]
            - Updated SPECs/New SPECs [8x11]
        - (1) – Crew Leader (highlight)
            - General Information (Transmission) [8x11]
            - Construction Order [8x11]
            - Joint Use Form (if applicable) [8x11]
            - Construction Print [11x17]
            - Structure Report [11x17]
            - Updated SPECs/New SPECs [8x11]
            - Pole Photos [8x11]
            - Grounding Report [8x11]
            - Pole Change Out Sheet (per structure) [8x11]
- Distribution Work Request Folder (Seperate by OH and UG work)
    - Print and Staple WRGI to front of folder
    - Write (in Black Sharpie) Distribution WR # on the top tab of folder
    - To contain 3 stapled packages:
        - (3) – TECO Line Supervisor, Contractor Line Supervisor, Crew Leader
            - General Information [8x11]
            - Construction Order [8x11]
            - Joint Use Form (if applicable) [8x11]
            - Construction print [11x17]
            - Pole Change Out Sheet (per structure) [8x11]

Work Request Packages to be delivered on a weekly basis.

3.10 INVOICING

All invoicing for SPP projects must be separate from any other invoiced work.

SPP invoices must be saved (location TBD)

3.11 CLOSE OUT

- Transmission System Inspection Program Database
    - Check for existing inspection issues for subject pole
    - Add new line item for SPP Pole Replacement:
        - Circuit
        - WR

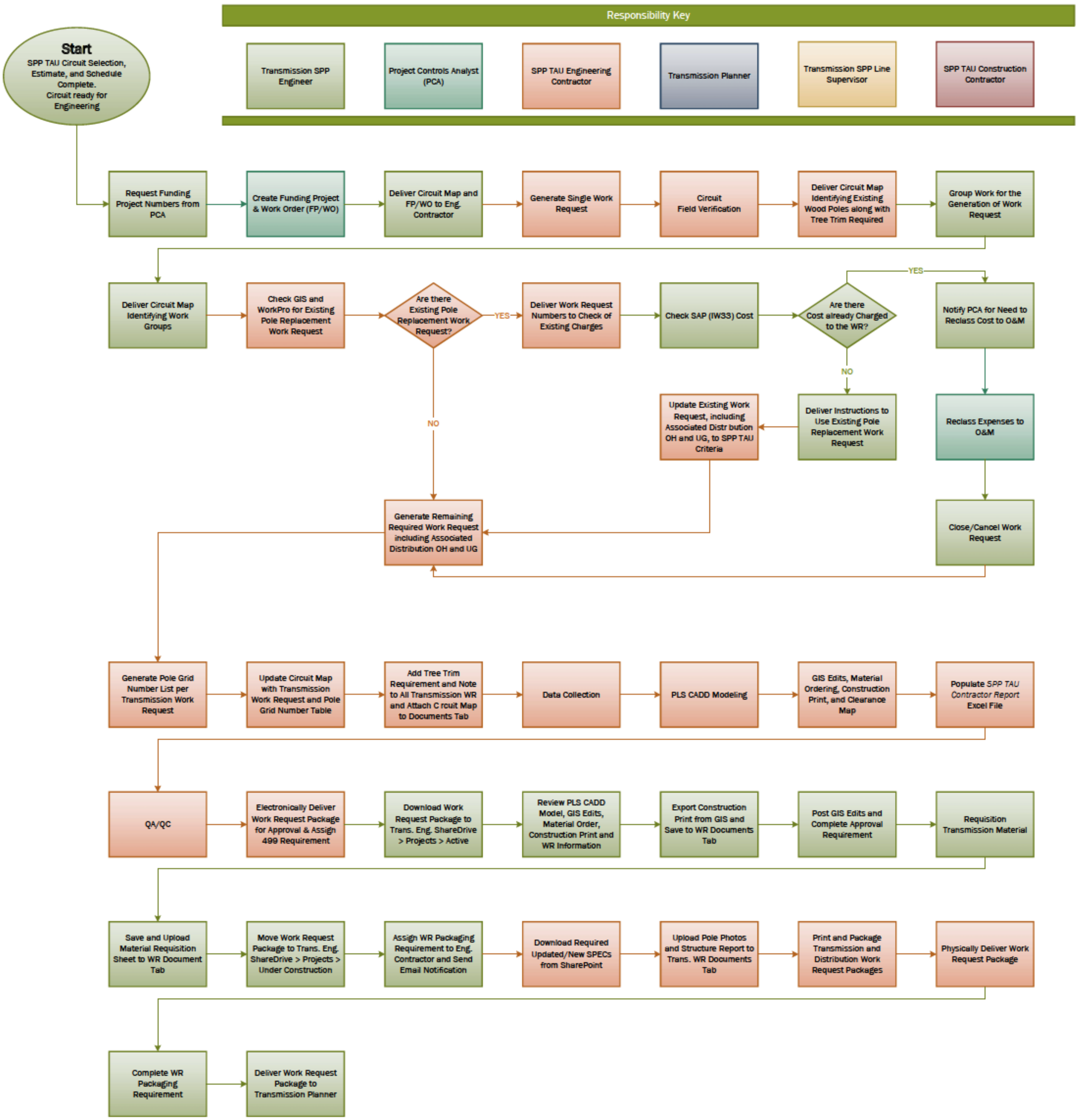
- SPP ☑
- Completion: date from WR print
- Crew
- Engineer
- X Grid
- Y Grid
- Asset Tag
- Memo Date: Approx. engineering start date
- Company: TEC
- Inspection Type: Hardening
- Structure Type: Wood
- Structure Height
- Pole(s) Replace: Yes – OR- Pole(s) Removal: Yes
- Comments: TAU SPP Circuit
  - Optional: 1 of 2 pole structure

Change Log:

4/15/2021 Update Crew HQ from SPP to reflect warehouse changes because of new warehouse creation for SPP. Change work assigned to FYMOM. Update financial tab to reflect SPP Finance crew HQ. Remove 870 completion from process and planner will complete and requisition materials. Robert Tyler Updates in RED. Update

TAMPA ELECTRIC COMPANY
DOCKET NO. 20220010-EI
STAFF'S FIRST SET OF INTERROGATORIES
INTERROGATORY NO. 1b (part 2)
PAGE 1 OF 1
FILED: MAY 16, 2022

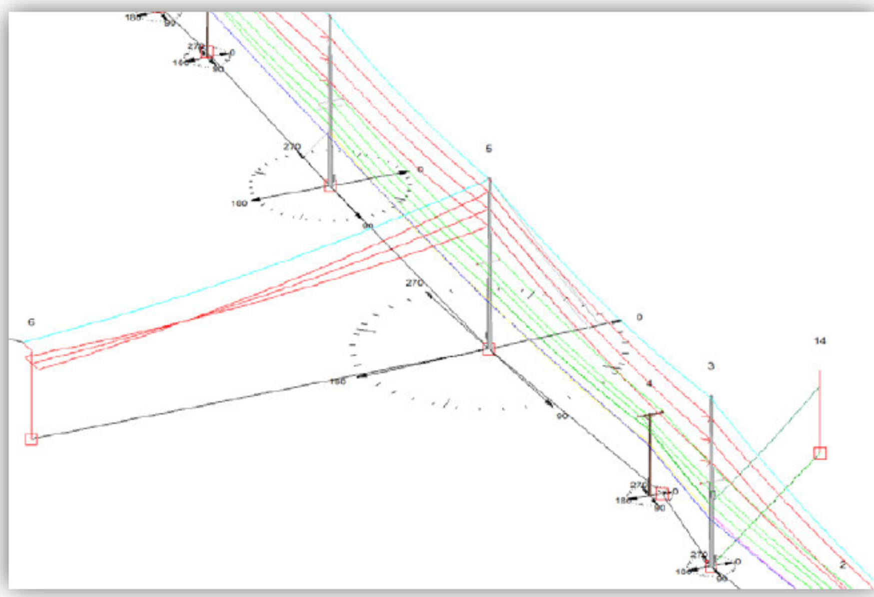
Storm Protection Plan (SPP) Transmission Asset Upgrade (TAU) Program
Implementation Flow Chart



TRANSMISSION MAINTENANCE POLE REPLACEMENT DOCUMENTATION

INCLUDING ENGINEERING FOR DISTRIBUTION UNDERBUILT

CONTENTS



WORK REQUEST

SETUP

- All Work Request
  - Financials:
    - 69kV – PRE-02665
    - 138kV – PRE-02831
    - 230kV – PRE-02830
  - Address for Transmission WR: Circuit Number 'space' Street Name (St Nm line only)
    - Ie. 66001 Main St & Jackson Rd
    - Fill in County information
  - Date Required: 4 months out
  - Organization: TECO

- Transmission Work
  - WR Type: Designed
  - Job Code: N/A
  - Job Type:
    - TMAIN69-G for 69kV
    - TMAIN138-G for 138kV
    - TMAINT-G for 230kV
  - Crew HQ: TRA
  - Dist: TRA

- Distribution Overhead Work
  - WR Type: Design
  - Job Type: OLI-G
  - Job Code: N/A
  - Crew HQ: TRAOSC
  - Dist: 'ServiceArea'

- Distribution Underground Conduit
  - WR Type: Design
  - Job Type: ULI-G
  - Job Code: N/A
  - Crew HQ: TRAOSC
  - Dist: 'ServiceArea'OSC

- Distribution Underground Primary Cable
  - WR Type: Design
  - Job Type: ULI-G
  - Job Code: N/A
  - Crew HQ: TRAOSC
  - Dist: 'ServiceArea'

- Distribution Underground Service
  - WR Type: Non Design
  - Job Type: URSV
  - Job Code: UGS-1
  - Crew HQ: TRAOSC
  - Dist: 'ServiceArea'

TAMPA ELECTRIC COMPANY
DOCKET NO. 20220010-EI
STAFF'S FIRST SET OF INTERROGATORIES
INTERROGATORY NO. 1b (part 3)
PAGE 3 OF 6
FILED: MAY 16, 2022

REQUIREMENTS

Rqmt	Description	Action Required By:	Timeframe	Update Status to:	Assign Responsible	Work Queue
110	Acquire proper Charge #	Field Tech	After financials are verified	Complete		
199	Field Visit Required	Field Tech	After field visit	Complete		
220	Coordinate w/ TRANS / DIST	Field Tech		Not Required		
248	Tree Trim Required	Field Tech	Add if required	Required	LCTRA	Check
260	Easement Required	Field Tech	Typically not required	Not Required	Delete DYTEC	Un-check
270	Stake job in field	Field Tech	Typically not required	Not Required	Delete DYTEC	Un-check
329	Is a MOT/RoW Permit Required?	Field Tech	After permit info is added	Complete		
350	DESIGN FACILITIES COLLECTED	Automatic	After material push from GIS	Complete		
399	Drafting / WR Packaging	Approver	After approval	Required	Admin	Check
		Admin	After packaging completed	Complete		
409	Add Circuit Number to WR	Field Tech	After circuit number added	Complete		
498	DESIGN DISAPPROVED - REWORK	Approver	Add if design is disapproved	Required	Field Tech	Check
		Field Tech	After rework, re-assign 499	Complete		
499	WORK APPROVED	Field Tech	To submit for approval	Required	Approver	Check
		Approver	After review	Complete		
510	Notify One-call	Planner		Complete		
520	Pole Haul Out	Field Tech		Not Required		
531	Field visit required prior to constr.	Line Super.		Complete		
540	Notify flaggers	Planner		Complete		
560	Pre-Arranged Outage required	Planner		Complete		
570	MATERIALS REQUISITIONED	Planner		Complete		
598	Planner Approval	Planner		Complete		
599	WORK SCHEDULED	Planner		Complete		
699	WORK COMPLETED					
777	Grounding					
778	Pole Haul In					
799	Reconciliation Finalized					
899	WORK REQUEST CLOSED					

FAMILY TREE

- Work Required: Transmission
  - **Parent Transmission WR**
  - Launch to GIS

- Work Required: Transmission and Distribution OH
  - **Parent Distribution OH WR**
  - Launch to GIS
    - **Associated 211 Transmission WR**

- Work Required: Transmission, and Distribution OH and UG Primary
  - **Parent Distribution UG Cable WR**
  - Launch to GIS
    - **Associated 211 Distribution UG Conduit WR**
      - **Associated 211 Distribution OH WR**
        - **Associated 211 Transmission WR**
        - *Will not be able to push material to work request from GIS*

- Work Required: Transmission, and Distribution OH and UG Service
  - **Parent Distribution UG Service WR***
  - Launch to GIS
    - **Associated 211 Distribution OH WR**
      - **Associated 211 Transmission WR**

- Work Required: Transmission, and Distribution OH, UG Primary, and UG Service
  - **Parent Distribution UG Cable WR**
  - Launch to GIS
    - **Associated 211 Distribution UG Conduit WR**
    - **Distribution UG Service WR***
      - **Associated 211 Distribution OH WR**
      - Associated to both UG Conduit and UG Service WR
        - **Associated 211 Transmission WR**
        - *Will not be able to push material to work request from GIS*

**Only create UG Service WR if handhole needs to be cut in for commercial service. Do not create a work request if the only work required is for service riser to be transferred, just include note on print for crew to transfer.*

GIS

- For Transmission Pole and Material:
    - Replace Feature on Transmission Pole
    - Add Compatible Unit
    - Pole Embedment
    - Transmission Specification Number
    - Silver Tag
    - Refresh Legacy Grid Number (on Install Pole Only)
    - Structure Circuit
    - Add Joint Use CUs to Ancillary tab if applicable
- For Distribution Underbuilt Material:
    - Install new Pole feature close to transmission pole
        - Do NOT own anything to this pole
    - Translate state to Proposed Removed
    - Update Legacy Grid Number to match Updated Transmission pole number
    - CU = Pole_Dummy
    - Pole Use: Stub
    - Add all Distribution CUs (Install and Remove) to the Ancillary CU tab

CONSTRUCTION PRINTS

- Work Area
- Key
- Work Request Number and Work Description (in Red)
- Circuit Number and Clearance Points (in Black)
- Notes
- Street Names and Center Line Distances
- Wire Labels and Distances including Lead Lengths
- Primary Phasing (Distribution Only)
- Pole Location Numbers (in Blue)
- Pole Label:

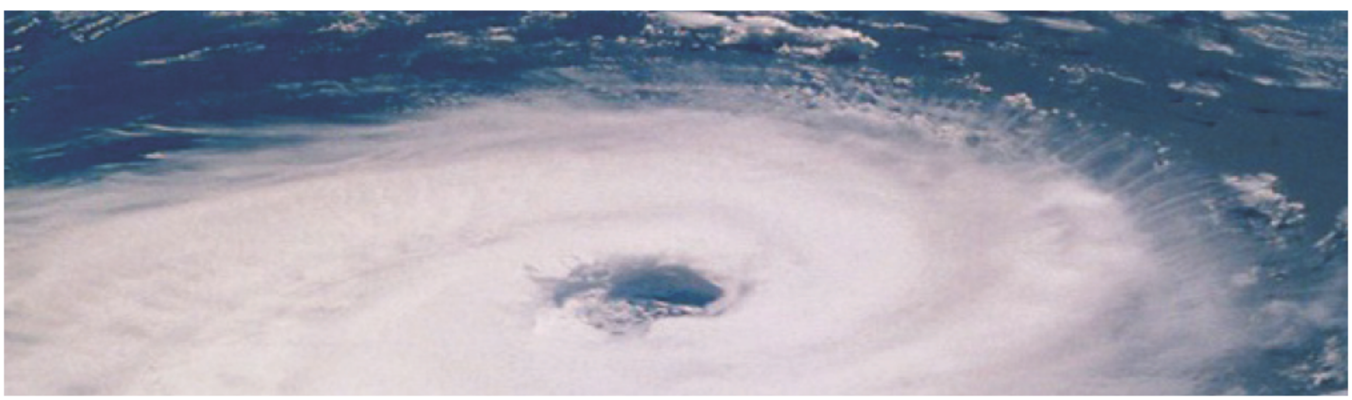
Transmission		**Distribution**	
Install	Remove	Install	Remove
Legacy Grid Number	Legacy Grid Number	SPEC #	SPEC #
Silver Tag Number	Pole Size	Equipment with Phase	Equipment with Phase
Pole Size	SPEC #	Legacy Grid Number	Legacy Grid Number
Embed Depth	Angle if applicable	Silver Tag Number	Silver Tag Number
SPEC #		Pole Size	Pole Size
Joint Use		Joint Use	Joint Use

PRINTING AND PACKAGING

- WorkPro
    - Clearance Points in Extra Info (From One Line Diagram)
    - Transmission and Distribution Circuit Numbers
    - MOT in Reference Tab
    - Permit information added
    - 248 Tree Trim Requirement on Transmission WR if applicable
    - Save a copy of print to Documents tab
    - Add the following to Comments Tab of Transmission WR:
        - Transmission Planner
        - Line Supervisor
        - Crew Leader

FILE SUBMISSION

- Submit one zipped folder per Work Request family. Supporting documentation to include:
    - PLS CADD bak file
    - Field collection notes
    - Filed collection photos
    - Construction Print
- Zipped folder naming convention:
    - Transmission Work Request Number (Circuit Number)
        - Ie. 2141532 (66001)



SUBSTATION HARDENING STUDY

Prepared by: HDR Engineering, Inc

August 27, 2021

HDR

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

Contents

EXECUTIVE SUMMARY

The Tampa Electric Company (TECO) system spans multiple counties in Florida covering a diverse area consisting of rural, urban, coastal, and inland communities. A significant part of the customer load that TECO serves, and the location of TECO's headquarters, is in Hillsborough County, Florida. This transmission network is in the Tampa Bay vicinity in low-elevation areas near the Gulf Coast. These substations are a mix of Transmission and Distribution Substations that serve as switching stations to distribute large generation resources, such as the Big Bend Substation or Gannon Substation, and distribution substations serving dense populations, such as the Manhattan Substation in south Tampa. These substations have been built and operated for many years and have served the Tampa community well. When originally developed, the substations were carefully located in geographic areas based on elevation above sea-level, proximity to customer load and access to transmission lines for interconnection to the main grid.

Over the past several years, concerns have grown over storm surge related to extreme weather events such as hurricanes or tropical storms. These concerns, coupled with rising sea levels, have drawn attention by TECO to 24 substations in Hillsborough County. In March of 2021, TECO solicited engineering firms to perform a Substation Extreme Weather Hardening Study (Substation Hardening Study) for these substations. HDR Engineering, Inc. (HDR) was selected to perform the study and began work in April of 2021.

Nine hardening projects are recommended as a result of this Substation Hardening Study.

Substation Project	Cost
Hookers Point - Re-grade Substation and Install New Control House, Autotransformer and Power Transformer	$7,600,000
South Gibsonton - Install Elevated Control House and Regrade North End of Substation	$3,100,000
Jackson Rd - Install Elevated Control House and New SPCC System for Autotransformer	$2,800,000
Estuary - Replace 69 kV Circuit Breaker and Elevate Relay and Control Enclosure	$900,000
El Prado - Rebuild Substation with Open-air Distribution Circuit Breakers	$5,000,000
Skyway - Replace 13.8 kV Circuit Breakers and Elevate Control House	$3,500,000
Desal - Elevate Control Enclosure	$700,000
MacDill - Install New SPCC Systems for Power Transformers	$700,000
Maritime - Replace 13.8 kV Circuit Breakers, Install New Transformers and Elevate Control House	$4,500,000
Total	**$28,800,000**

The substation hardening projects have an estimated cost of $28.8MM. The three (3) transmission projects at Hookers Point, South Gibsonton and Jackson will improve grid stability by maintaining the tie points between 230, 138, and 69 kV systems during a storm surge event. The six (6) distribution projects will improve reliability of service, including service to critical load, during storm surge events.

1.0 Introduction

This report outlines the study approach that HDR took in developing projects to harden the substations mentioned above against storm surge events. It outlines the data collected, based on both desktop studies and from field visits, the approach to developing scorecards to prioritize the substation susceptibility to storm surge flooding, and detailed information on the eight substation projects developed to strengthen the grid against extreme weather events.

The 24 substations included in this Substation Hardening Study are:

1. Big Bend 230 kV
2. Big Bend Solar 69 kV
3. Cypress Street 69 kV
4. Desal 69 kV
5. El Prado 69 kV
6. Estuary 69 kV
7. First Street 69 kv
8. Gannon 230 kV, 230/138 kV, 230/69 kV
9. Harbour Island 69 kv
10. Hookers Point 138/69 kV
11. Interbay 69 kV
12. Jackson Road 230/69 kV
13. MacDill 69 kV
14. Manhattan 69 kV
15. Maritime 69 kV
16. McKay Bay Cogen 69 kV
17. Meadow Park 69 kV
18. Miller Mac 69 kV
19. Millpoint 69 kV
20. Port Sutton 69 kV
21. Rocky Creek 69 kV
22. Skyway 69 kV
23. South Gibsonton 230/69 kV
24. Twelfth Avenue 69 kV

2.0 Study Approach

HDR Inc. conducted the Substation Hardening Study in three phases – Discovery, Evaluation and Recommendation. Each phase is described in the following subsections.

2.1 DISCOVERY PHASE

After being awarded the project from TECO, HDR began the process of collecting data to be used in the Substation Hardening Study. This data collection took place in the form of desktop studies, site visits in the field and the creation of a Geospatial Information Systems (GIS) database.

2.1.1 Desktop Studies

During the Discovery Phase, HDR collected data to be used in the Substation Hardening analysis. This included desktop studies and site visits to each of the 24 substations identified by TECO. The desktop studies were focused on gathering environmental existing conditions for the substations. This includes the following:

- FEMA 100- and 500-yr floodplain maps
- Evacuation Zone Categories
- Existing Wetlands within or adjacent to the substations
- Hydric soil presence

Floodplain maps

The industry standard for defining a high flood hazard area is the "100-year flood zone," which is a flood that has a 1 percent chance of occurring in a given year. This is the standard used by the Federal Emergency Management Agency (FEMA) to identify hazard areas for the National Flood Insurance Program. FEMA also identifies areas of minimal flood hazard (500-year flood zone), which is a flood that has a 0.2 percent chance of occurring in a given year.

The substation locations were overlayed upon the YEAR FEMA 100- and 500-yr floodplain maps to identify whether the substation is located within a flood hazard area. The FEMA map for each substation are located in the Appendices of this report.

Evacuation Zone Categories

Hillsborough County and the Tampa Bay Regional Council have identified evacuation zones based on potential storm tide heights and wind speed during a hurricane. The evacuation zones range from Zone A to Zone E and the potential storm tide heights vary dependent on the hurricane category, ranging from a Category 1 which can cause wind speeds of 74 to 95 miles per hour (mph) ranging to a Category 5 with wind speeds of 157 mph or greater. For example, Zone A area can experience potential storm tide heights ranging from up to 11 feet, during a Category 1 hurricane, and up to 38 feet during a Category 5 hurricane. The evacuation zone for each substation location was identified to understand potential storm tide heights during a hurricane.

Wetlands

Wetlands and other surface waters mapped by the U.S. Fish and Wildlife Service (USFWS) National Wetland Inventory (NWI) Wetland Mapper were reviewed to determine if they have been previously mapped within the substation area and adjacent to the substation area. These areas are seasonally saturated or permanently flooded and therefore can give an indication on the hydric and drainage conditions of the soil.

Hydric Soil Presence

A hydric soil is a soil that is saturated, flooded or ponded long enough during the growing season to develop anaerobic conditions in the upper part of the soil profile that favor the growth and regeneration of hydrophytic vegetation (USDA - SCS, 1991). The United States Department of Agriculture (USDA) Natural Resources Conservation Service (NRCS) Web Soil Survey was reviewed for near surface soil information at each substation location. The general soil types within the substation area were reviewed including hydric classification and depth to water table to have an indication of whether the substation was prone to flooding due to the near surface soil conditions.

Substation Elements

Another desktop study focused on the electric grid configuration of the substations. TECO provided HDR with the following information for each of the 24 substations.

- Single and Electrical (S&E) One Line Diagrams
- Substation Electrical Layouts
- Relaying and Control One Lines
- Property Boundaries

This information was used to identify whether the substation was used for Transmission or Distribution, the amount of generation connected (megawatts or MW), whether bulk power was connected, the number of transmission circuits connected, and the voltage level served from the substation (>100 kilovolt or kV). The data received from TECO was parsed out and saved to individual substation folders on a SharePoint drive created by HDR. This data was collected for use in the Evaluation phase for Grid Stability impact. When bulk power or multiple transmission circuits are removed from the electric grid quickly due to an outage, the system frequency can be negatively impacted and may deviate from 60 hertz (Hz). For this reason, substations with Bulk Power connected (Gannon and Big Bend 230 kV Substations) were treated with a higher level of criticality in the scorecard process during the Evaluation Phase.

Also noted in this desktop study was whether an autotransformer (230/138 or 138/69 kV) was located in the substation. This information was used to identify substations with long lead-time equipment that could impact the amount of time a substation is out of service after a storm surge event.

The last set of data collected in the desktop study concerned customer service information. This included the number of direct customers served, the number of distribution circuits at each substation, the peak load (Million Volt-Amps or MVA) and whether critical load is served from the substation.

2.1.2 Site Visits

Another critical part of the Discovery Phase was performing site visits to each of the 24 substations. Over the course of three days, an HDR senior electrical engineer and environmental engineer visited the substations along with a TECO representative. Ahead of each site visit, HDR created a substation site visit checklist with items to observe and information to be collected at each site.

The existing environmental and substation element observations made at each site were:

- Signs of recent flooding (Yes/No)?
- Substation elevation – elevated, low, or flat?
- Space to elevate control house (Y/N)?
- Relay panel condition (Old, new, or mixed)?
- Space to install berm outside substation (Y/N)?
- Space to elevate other equipment (Y/N)?
- Gopher tortoise burrows observed (Y/N)?
- Areas with standing water observed (Y/N)?
- Areas with vegetation (other than grass) observed (Y/N)?

These existing conditions were gathered to assess the substation existing environmental conditions and to develop hardening projects. Existing environmental conditions, such as whether the substation has signs of flooding and standing water and existing vegetation (i.e., water lines on the control houses, wet soils, puddles and wetlands) provided additional information on the water/soil regime and drainage conditions of the substation area and potential permitting needs for future hardening projects. The existence of Gopher tortoise burrows can also result in potential environmental restrictions and permitting needs for future hardening projects. By hardening, HDR is referring to physical design changes to the substations so they are less susceptible to damage from storm surge flooding. Industry accepted methods of substation hardening include elevating control houses to avoid flooding in storm-surge events and installing berms (temporary or permanent) to keep storm-surge flooding at bay. During the site visits, HDR staff took note of the substation layout, ownership area, and surrounding area to develop feasible hardening projects during the Recommendation Phase.

At each site visit, the HDR engineers took photographs of the substation, the equipment, and surrounding areas. These photos were taken for later references in the Evaluation and Recommendation phases of the project. This data was uploaded to the substation folders on the SharePoint drive as well as the Environmental Systems Research Institute (ESRI) Field Maps application that was developed (see section below for details).

2.1.3 ESRI Field Maps

As detailed above, a significant amount of data was collected – through both desktop studies and site visits. The SharePoint site served as a collection point and helped organize the information by substation. However, for this study, HDR needed the ability to analyze the substations geographically with overlays of information such as floodplain data and topography. To accomplish this task, the HDR engineering team worked with its GIS group to create a dashboard on ESRI Field Maps application. The first step was to enter the address of each of the 24 substations into the web-based platform. Using the mobile application during site visits, the engineering team was able to document representative assets for each individual piece of equipment such as control house, transformers, and circuit breakers. Each asset was tagged with GIS coordinates and notes from the field regarding equipment height above ground and condition were recorded. As photos of each asset were taken, including nameplates, those photos were tagged to the individual asset in the ESRI Field Maps application.

With substation assets captured and loaded into the ESRI Field Maps application, HDR was able to analyze each one in relation to floodplains and storm surge zones during the Evaluation Phase and recommend substation hardening projects during the Recommendation Phase.

2.2 EVALUATION PHASE

After the Discovery Phase was completed and HDR had sufficient information collected for each substation, the study entered the Evaluation Phase. The key part of this phase was the creation of a scorecard tool to prioritize the substations and rank them based on several criteria. Two primary elements for the scorecard included probability and impact, and secondary elements included weighting. The goal was to rank and score the 24 substations based on their criticality. ISO standards define criticality as a measure of the importance of an asset to the delivery of the organization's objectives.

The business objectives used in the scoring included:

- Grid Stability / Capacity – ability of the interconnected grid to provide adequate power and balance supply and demand
- Reliability / Availability – duration of time the system is out and not providing power to customers
- Customer Service – the number of customers and amount of load impacted by an outage
- Cost – the cost of restoring the system after it is damaged
- Safety – risk of injury, disability or death of an employee or member of the public
- Environmental – risk of not meeting environmental stewardship objectives or regulations

Input factors were used as the basis for measuring the impact on these objectives. The factors and objectives were then quantified and weighted to determine an overall criticality score for each substation.

2.2.1 Input Data

Input factors measured were based on observations made during the substation inspections. The following factors were used relative to each business objective:

Grid Stability / Capacity
- Generation connected
- Bulk Power connected
- Number of transmission circuits
- Load size >100kV

Reliability
- Hydric soil
- Signs of flooding
- Observed water
- Past flooding
- Material lead time / autotransformer

Customer Service
- Number of direct-served customers
- Number of distribution circuits
- Peak load (MVA)
- Critical Load

Cost
- Asset book value (based on age)
- Repair/replace cost factors due to autotransformers
- Repair/replace cost factors due to switchgear
- Replacement power costs

Safety
- Control house for shelter
- Evacuation zone category

Environmental
- Adjacent wetlands
- Gopher tortoise burrows
- HAZMAT

2.2.2 Scoring Levels

Input factors were scored using five levels reflecting impact to the business objectives:

1 = Negligible impact
2 = Minor impact
3 = Moderate impact
4 = Major impact
5 = Extreme impact

Impact level scores were assigned as follows:

Grid Stability / Capacity

- Generation connected:
  - 1 = 0
  - 2 = 25 MW
  - 3 = 500 MW
  - 4 = 1,000 MW
  - 5 = Greater than 1,000 MW
- Bulk Power connected
  - 1 = No
  - 4 = Yes
- Number of transmission circuits
  - 1 = 0
  - 2 = 1
  - 3 = 5
  - 4 = 10
  - 5 = More than 10
- Load size >100kV (Yes/No)
  - 1 = No
  - 4 = Yes

Reliability

- Hydric soil
  - 1 = No
  - 2 = 0 inches or unlisted
  - 3 = 3 inches
- Signs of flooding
  - 1 = No
  - 3 = Yes
- Observed water
  - 1 = No
  - 2 = Puddles
  - 3 = Yes
- Past flooding
  - 1 = No
  - 3 = Yes
- Material lead time / autotransformer
  - 1 = No
  - 3 = Yes

Customer Service

- Number of direct-served customers
  - 1 = None
  - 2 = 2,000
  - 3 = 6,000
  - 4 = 8,000
  - 5 = 10,000 or more
- Number of distribution circuits
  - 1 = None
  - 2 = 2
  - 3 = 4
  - 4 = 6
  - 5 = 8 or more
- Peak load (MVA)
  - 1 = 0
  - 2 = 20 MVA
  - 3 = 30 MVA
  - 4 = 40 MVA
  - 5 = 50 MVA or more
- Critical Load (Yes/No)
  - 1 = No
  - 3 = Yes
  - 5 = Port Load

Cost

- Asset book value / age
  - 1 = Old (i.e., fully depreciated)
  - 3 = Mixed (i.e., mid-life)
  - 5 = New
- Repair/replace cost factors due to autotransformers
  - 1 = No
  - 3 = Yes
- Repair/replace cost factors due to switchgear
  - 1 = No
  - 3 = Yes
- Replacement power costs
  - 1 = 0
  - 2 = 25 MW
  - 3 = 500 MW
  - 4 = 1,000 MW
  - 5 = Greater than 1,000 MW

Safety

- Control house
  - 1 = Yes
  - 2 = No

- Evacuation zone category
  - 2 = B
  - 3 = A

Environmental

- Adjacent wetlands
  - 1 = No
  - 3 = Yes

- Gopher tortoise burrows
  - 1 = No
  - 2 = Inconclusive
  - 3 = Yes

- HAZMAT (Yes/No)
  - 1 = No
  - 4 = Yes

2.2.3 Scoring

Impact level scores were then weighted, in consultation with TECO, and weighted-average total scores were calculated for each factor and the overall criticality score. The following weightings were used:

Grid Stability / Capacity – weighted at 40% of overall score

- Generation connected – weighted at 40%
- Bulk Power connected – weighted at 30%
- Number of transmission circuits – weighted at 20%
- Load size >100kV – weighted at 10%

Reliability – weighted at 20% of overall score

- Hydric soil – weighted at 25%
- Signs of flooding – weighted at 15%
- Observed water – weighted at 15%
- Past flooding – weighted at 30%
- Material lead time / autotransformer – weighted at 25%

Customer Service – weighted at 10% of overall score

- Number of direct-served customers – weighted at 25%
- Number of distribution circuits – weighted at 25%
- Peak load (MVA) – weighted at 25%
- Critical Load – weighted at 25%

Cost – weighted at 10% of overall score

- Asset book value / age – weighted at 50%
- Repair/replace cost factors due to autotransformers – weighted at 15%
- Repair/replace cost factors due to switchgear – weighted at 15%
- Replacement power costs – weighted at 20%

Safety – weighted at 10% of overall score

- Control house for shelter – weighted at 80%
- Evacuation zone category – weighted at 20%

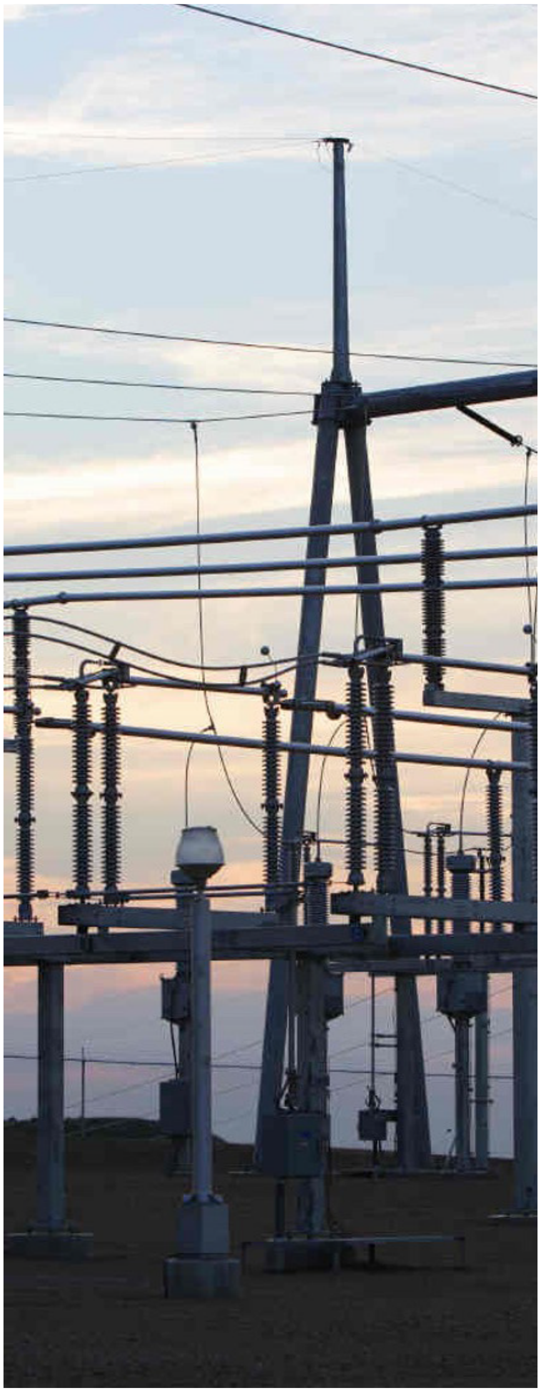
Environmental – weighted at 10% of overall score

Adjacent wetlands – weighted at 40%

- Gopher tortoise burrows – weighted at 20%
- HAZMAT – weighted at 40%

Weighting Chart

Generation Connected (40%)	Grid Stability (40%)	Consequence Score (100%)
Bulk Power Connected (30%)		
Number of Transmission Circuits (20%)		
Load Size > 100kV (10%)		
Hydric Soil (25%)	Reliability / Outage Duration (20%)	
Signs of Flooding (15%)		
Observed Water (15%)		
Past Flooding (20%)		
Material Lead Time (25%)		
# of Direct Served Customers (25%)	Customer Service (10%)	
# of Distribution Circuits (25%)		
Peak Load MVA (25%)		
Critical Load (25%)		
Book Value / Asset Age (50%)	Cost (10%)	
Cost Factor / Autotransformer (15%)		
Cost Factor / Switchgear (15%)		
Replacement Power Costs (20%)		
Control House (80%)	Safety (10%)	
Evacuation Zone Category (20%)		
Adjacent Wetlands (40%)	Environmental (10%)	
Gopher / Tortoise Burrows (20%)		
HAZMAT (40%)		



2.2.4 Scoring Results

Based on the scores and weightings described above, overall criticality scores and rankings for each substation were determined as shown in the chart on page 09. The blue bars show the criticality scores for each substation on Y-axis to the left. The red line shows the cumulative scores using the Y-axis on the right. For example, as shown by the green lines, 50% of the scores are due to the 10 left-most substations while the remaining 50% is due to the 14 substations to the right.

2.3 RECOMMENDATION PHASE

After the scorecard was developed, HDR reviewed the results and identified substations that were susceptible to storm surge flooding. Special attention was paid to substations where outages could impact grid stability or reliability of service and posed safety and environmental risks. For these substations HDR developed hardening projects to mitigate the risks and improve the resiliency of the substation in the event of storm surge flooding. On each scorecard substations were identified that scored high (to the left side of the charts) on the risk rankings. Hardening projects were developed to reduce those risks and drive their score down, bringing them to the right of the scorecards and in line with the other lower-risk substations.

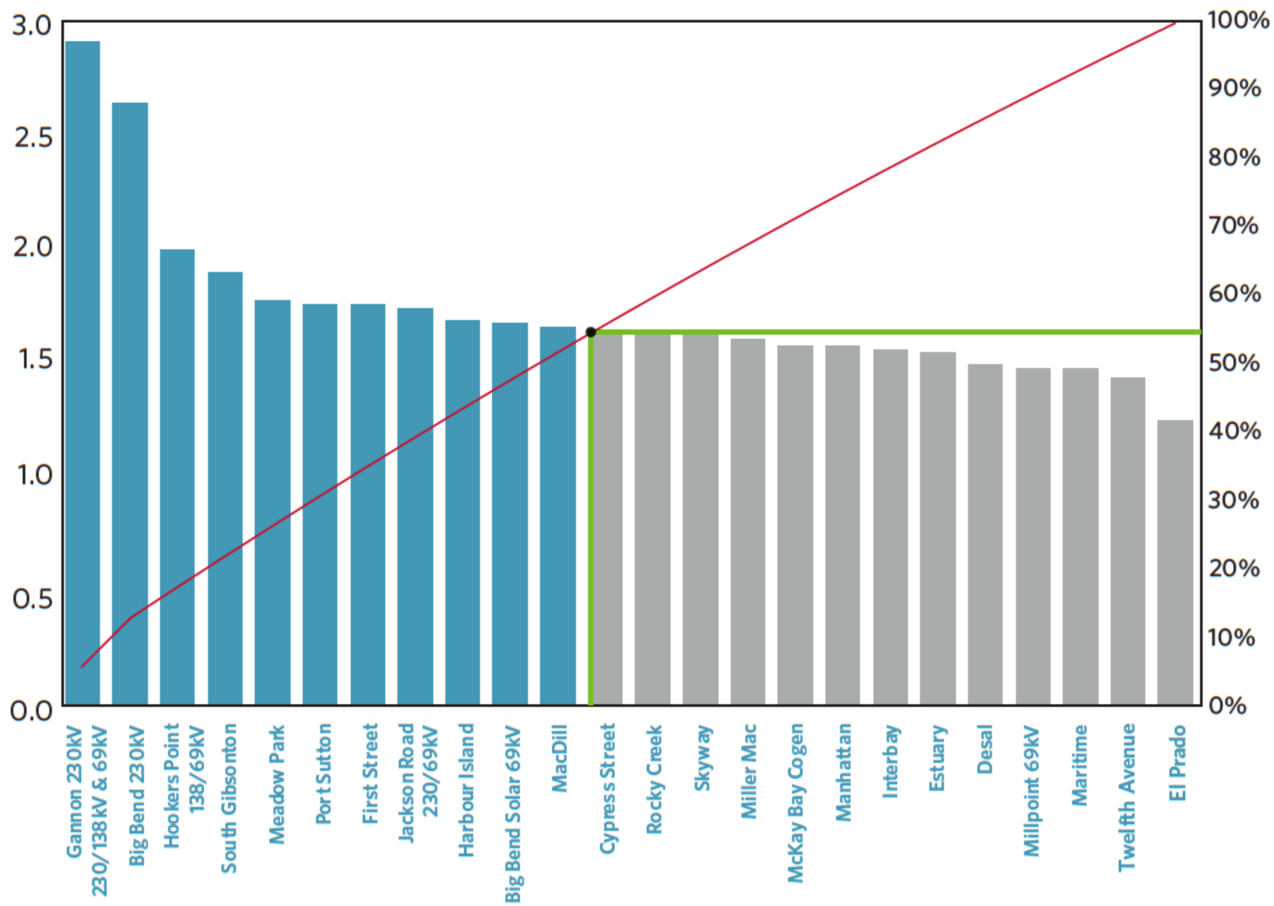
As the substation hardening projects were developed, budgetary cost estimates were created for each. These costs were turnkey – including equipment, construction, testing and commissioning. These costs were then used in a cost benefit analysis to justify the hardening project and its effectiveness in improving grid resiliency at the same time as being cost effective.

The projects developed in the Recommendation Phase are presented in Section 4.0 – Substation Hardening Projects.

3.0 Study Results - Scorecards

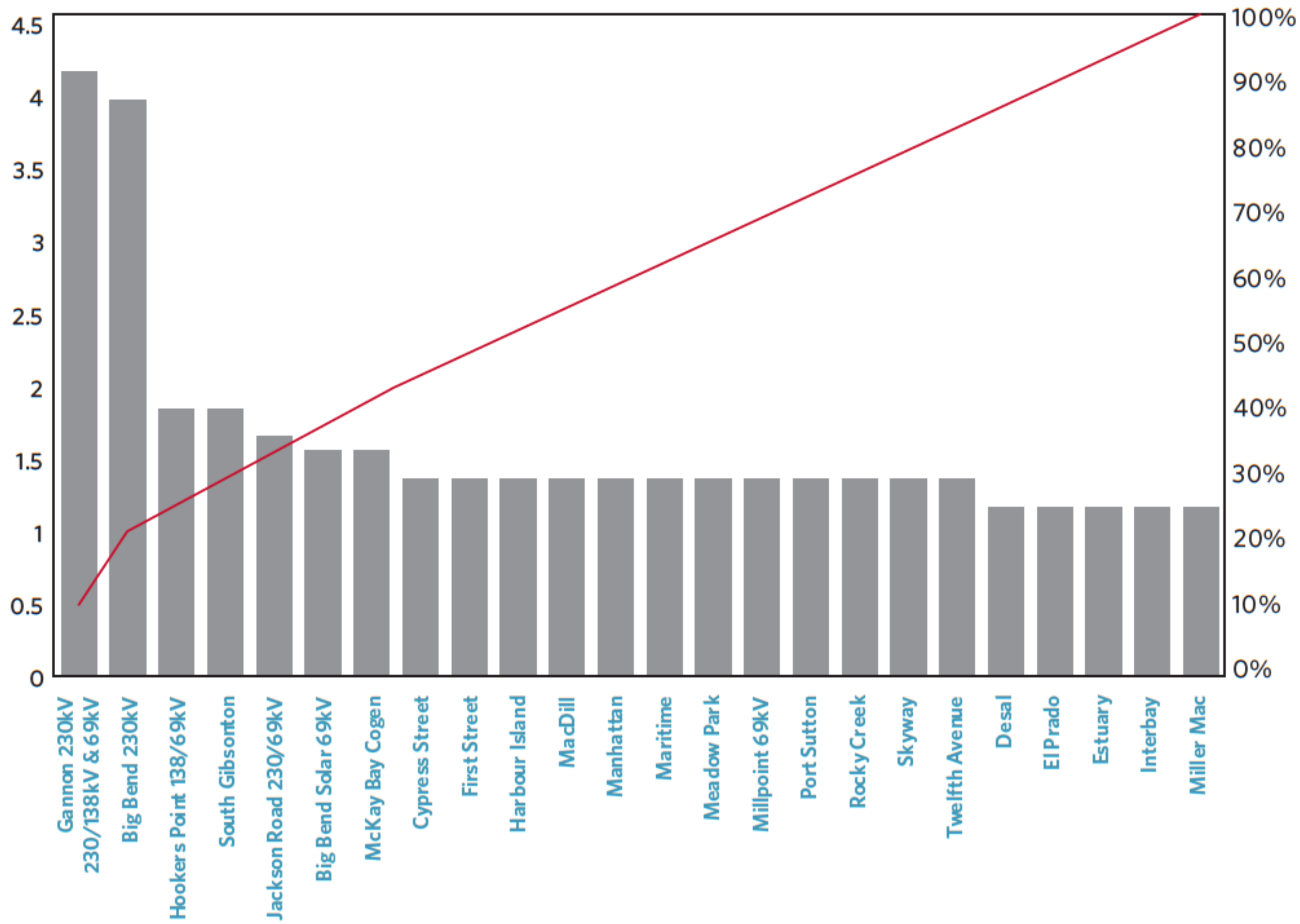
3.1 OVERALL SCORES

The Pareto chart below shows the consequence scores for each substation using the Y-axis on the left. The red line shows the cumulative scores using the Y-axis on the right. As shown by the two green lines, the 11 substations shown in blue to the left of the green vertical line account for approximately 55% of the overall consequence scores (based on the green horizontal line).



3.2 GRID STABILITY/CAPACITY

The component scores and rankings that made up the overall score are shown in the charts below and on the following pages:



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3.3 RELIABILITY

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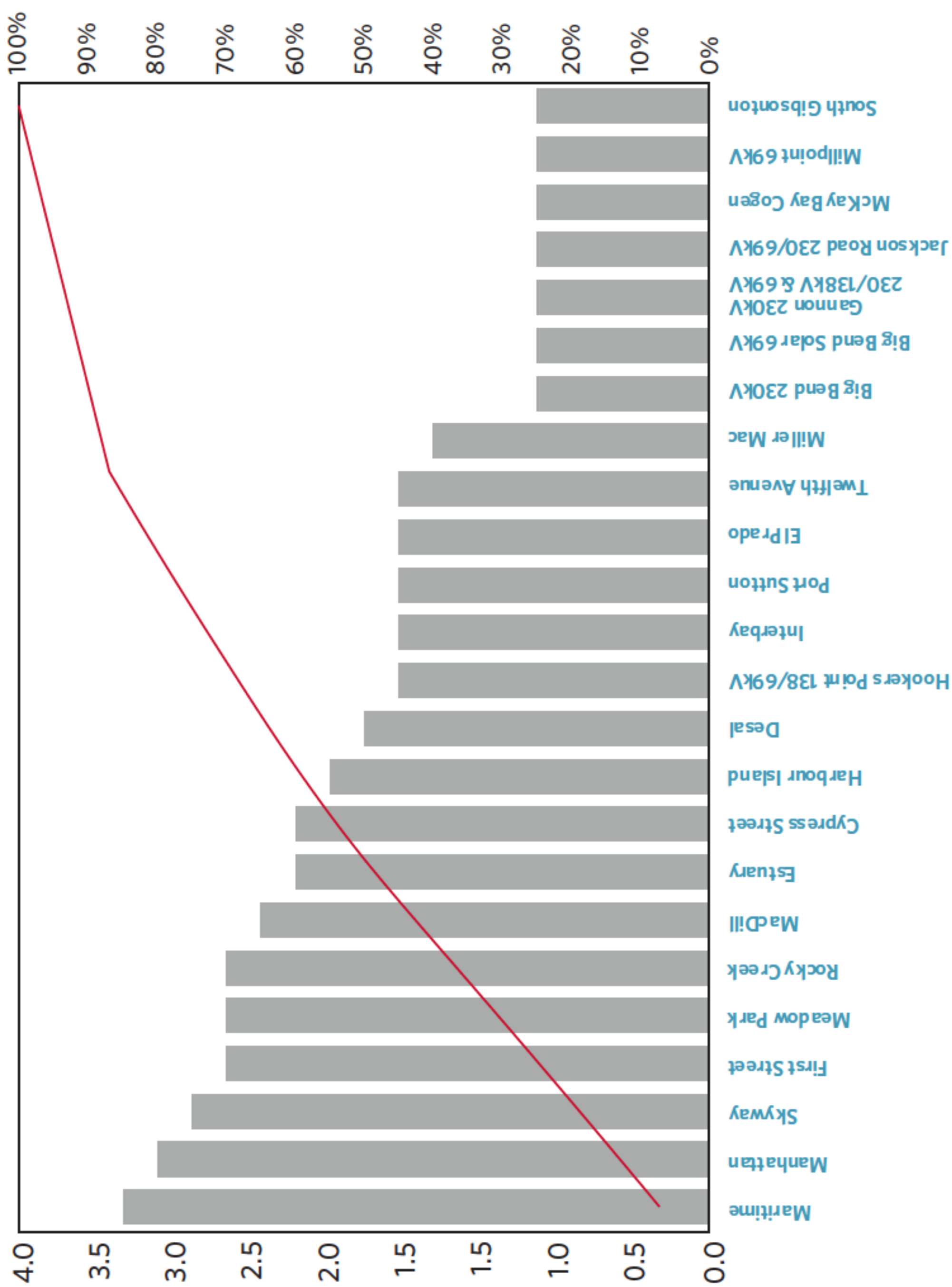
3.4 CUSTOMER SERVICE



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3.5 COST

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3.6 SAFETY

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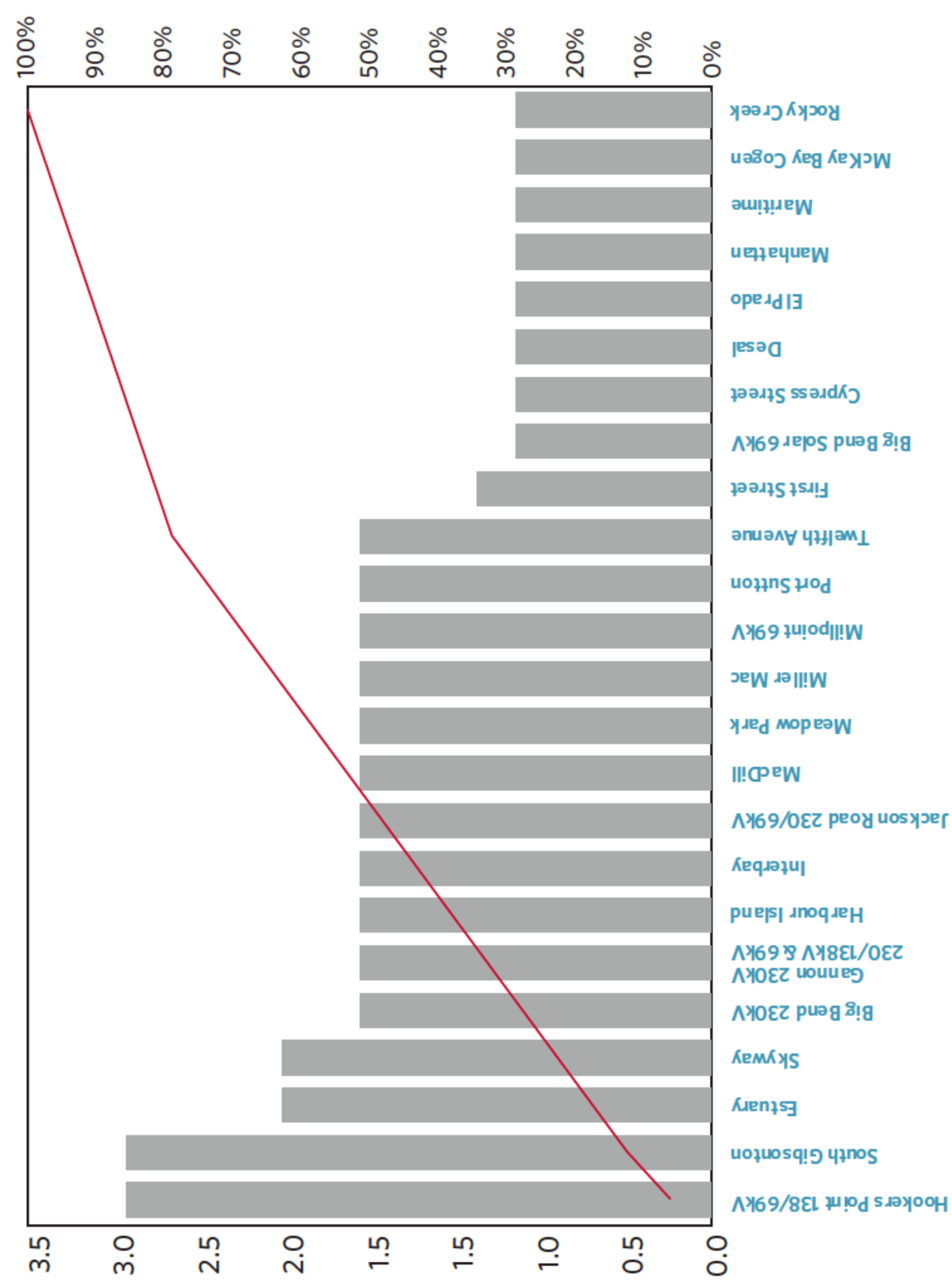
3.7 ENVIRONMENTAL



4.0 Substation Hardening Projects

Based on the data collected in the Discovery Phase and scorecards developed in Evaluation Phase, eight (8) projects were developed to harden TECO substations against extreme weather events. Three projects at transmission substation aim to improve grid stability and five were developed to improve customer service, cost, safety, and environmental impacts of losing the substations due to flooding from storm surge.

The Big Bend 230 kV and Gannon 230/138 and 69 kV Substations scored very high in the overall consequence and Grid Stability scorecards. This is due to the large amount of generation connected to these substations and the number of transmission lines that terminate at the facility. Both substations are fairly hardened against extreme weather in their current state. Each substation has new equipment, the circuit breakers and control houses are elevated, and the substation grading is elevated around the substations. For this reason, no projects were developed to improve Big Bend and Gannon, and the project development was focused on Hookers Point, Gibsonton and Jackson Rd transmission substations.

Of the 16 distribution substations, 10 were not found to be susceptible to storm surge flooding. These substations had new and/or elevated equipment and favorable substation grading and were located on an elevated property with grading away from the substations. For these reasons no hardening projects were developed at these substations and the focus was put on the remaining six distribution substations – Estuary, El Prado, Skyway, Desal, MacDill and Maritime.

The following table shows the substation hardening projects along with the total estimated costs for each. These costs are budgetary estimates (+/- 25% accuracy). They include equipment, engineering, permitting, construction, project management, testing and commissioning costs.

Substation Project	Cost
Hookers Point - Re-grade Substation and Install New Control House, Autotransformer and Power Transformer	$7,600,000
South Gibsonton - Install Elevated Control House and Regrade North End of Substation	$3,100,000
Jackson Rd - Install Elevated Control House and New SPCC System for Autotransformer	$2,800,000
Estuary - Replace 69 kV Circuit Breaker and Elevate Relay and Control Enclosure	$900,000
El Prado - Rebuild Substation with Open-air Distribution Circuit Breakers	$5,000,000
Skyway - Replace 13.8 kV Circuit Breakers and Elevate Control House	$3,500,000
Desal - Elevate Control Enclosure	$700,000
MacDill - Install New SPCC Systems for Power Transformers	$700,000
Maritime - Replace 13.8 kV Circuit Breakers, Install New Transformers and Elevate Control House	$4,500,000
Total	**$28,800,000**

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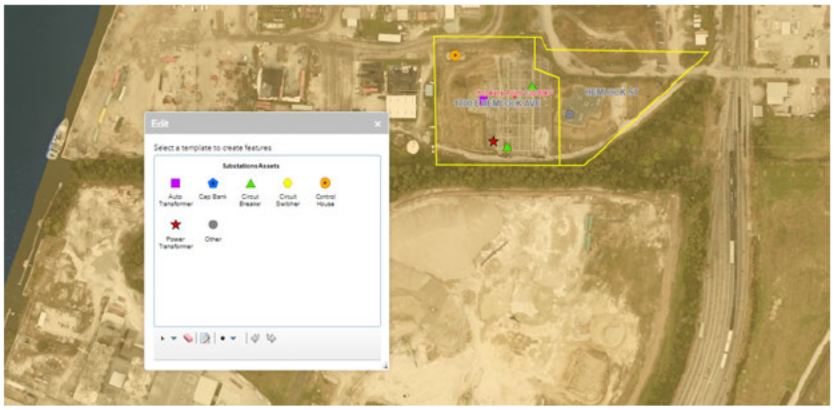


4.1 PROJECT 1

Hookers Point 138/69 kV Substation

Re-grade Substation and Install New Control House, Autotransformer and Power Transformer

Hookers Point is a 138/69 kV Substation with a 168 MVA autotransformer and seven (7) transmission circuits that terminate in the switchyard. Also installed at this substation is a power transformer that serves critical south load. The substation sits in the FEMA 100-yr floodplain and is located ~900 ft from a canal/drainage feature discharging into Tampa Bay.

Hookers Point is a critical substation because it ties the 138 and 69 kV systems together. If this substation flooded due to storm surge, the autotransformer may trip offline and the seven 69 kV circuit breakers may operate, taking those transmission lines out-of-service. This could happen due to flood waters around the equipment, or the control house flooding and the relays operate due to the flood waters.

The autotransformer, power transformer and control house all sit in a low-lying area on the west side of the substation. There is a ~3 ft embankment that splits the substation and to the east, on higher elevation sits the 69 kV switchyard. Three of the 69 kV circuit breakers are very old, oil-filled circuit breakers that sit close to the ground.

HDR recommends decommissioning and removing the autotransformer, power transformer and control house and elevating the west side of the switchyard to match the elevation of the main switchyard. Once the grading is complete, install a new 138/69 kV autotransformer with a 3' SPCC wall and a new power transformer to serve the customer load. HDR also recommends replacing the three older 69 kV breakers with gas insulated circuit breakers with on elevated structures, per the current TECO standard design.

This project will greatly reduce the likelihood of flooding in a storm surge event and will improve grid stability by making this critical 138/69 kV Substation more resilient.

Project Cost Estimate

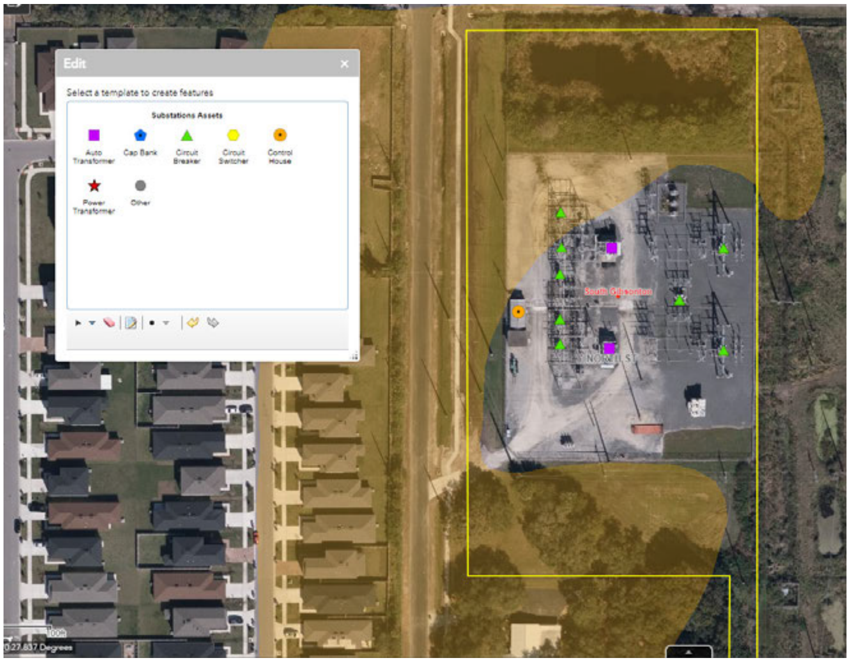
In the table below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the Hookers Point project.

Cost Benefit

The Hookers Point project is a large capital project and so the benefit to Tampa Electric and its customers should be great enough to justify that cost. The $7.6MM cost is justified by the improvements to grid stability by hardening this critical substation and maintaining the 138/69 kV tie point during flood events due to storm surge. If this substation is lost due to an outage, it may impact the service to 69 kV substations downstream and create voltage or frequency issues at those facilities.

This project improves the Grid Stability and Reliability score of Hookers Point and moves the substation to the right-hand side of both scorecards (page 10 and 11) into an acceptable range.

Hookers Point 138/69 kV Substation		
RE-GRADE SUBSTATION AND INSTALL NEW CONTROL HOUSE, AUTOTRANSFORMER AND POWER TRANSFORMER		
Item	**Equipment**	**Engineering, Permitting, Construction, Project Management, Testing and Commissioning**
Re-grade Substation	$250,000	$430,000
Elevated Control House	$2,000,000	$320,000
138/69 kV Autotransformer	$2,700,000	$320,000
69/13 kV Transformer	$900,000	$220,000
3 qty 69 kV Circuit Breakers	$300,000	$160,000
	$6,150,000	$1,450,000
Total	**$7,600,000**	



4.2 PROJECT 2

South Gibsonton 230/69 kV Substation

Install New Control House on Elevated Platform and Regrade North End of Substation

South Gibsonton is a 230/69 kV Substation with two (2) 224 MVA autotransformers and eight (8) transmission circuits that terminate in the switchyard. The substation partially sits in the FEMA 100-yr floodplain and is located ~1.5 mi from the Tampa Bay.

South Gibsonton is a critical substation because it ties the 230 and 69 kV systems together. If this substation flooded due to storm surge, the autotransformers may trip offline and the eight circuit breakers may operate, taking those transmission lines out-of-service. This could happen due to flood waters around the equipment, or the control house flooding and the relays operate due to the flood waters.

The control house at South Gibsonton sits at ground level. HDR recommends installing a new control house on an elevated platform or concrete slab. Currently control house is located underneath incoming transmission lines. There is available property, shown in the yellow boxed area in the image above, that could be cleared, and the new control house installed.

During the site visit HDR received feedback from the operations manager onsite that flooding has occurred in the past from the small body of water to the north of the substation. HDR recommends re-grading the north end of the South Gibsonton Substation and establishing a detention pond where the existing body of water is and possibly extending it into the transmission Right-of-Way to the east of the substation. This improvement to the grading and water detention may help storm surge flooding recede more quickly out of the substation and harden the substation.

HDR also recommends replacing the oil-filled 69 kV Circuit Breaker to mitigate the environmental impact due to storm surge flooding.

Project Cost Estimate
In the table below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the South Gibsonton project.

Cost Benefit
The South Gibsonton project is a large capital project and so the benefit to Tampa Electric and its customers should be great enough to justify that cost. The $3.1MM cost is justified by the improvements to grid stability by hardening this critical substation and maintaining the 230/69 kV tie point during flood events due to storm surge. If this substation is lost due to an outage, it may impact the service to 69 kV substations downstream and create voltage or frequency on the 230 kV bulk system.

This project improves the Grid Stability and Reliability score of South Gibsonton and moves the substation to the right-hand side of both scorecards (page 10 and 11) into an acceptable range.

South Gibsonton 230/69 kV Substation		
INSTALL ELEVATED CONTROL HOUSE AND REGRADE NORTH END OF SUBSTATION		
Item	Equipment	Engineering, Permitting, Construction, Project Management, Testing and Commissioning
Elevated Control House	$2,000,000	$320,000
Re-grade North End of Substation	$150,000	$480,000
69 kV Circuit Breaker	$100,000	$50,000
	$2,250,000	$850,000
Total	$3,100,000	

4.3 PROJECT 3

Jackson Rd 230/69 kV Substation

Install New Control House on Elevated Platform and Install New SPCC Systems for Autotransformer

Jackson Rd is a 230/69 kV Substation with one 224 MVA autotransformers and five (5) transmission circuits that terminate in the switchyard. The substation partially sits in the FEMA 100-yr floodplain and is located ~1.5 mi from the Tampa Bay. This substation has had flood events in the past due to the creek to the north flooding.

Jackson Rd is a critical substation because it ties the 230 and 69 kV systems together. If this substation flooded due to storm surge, the autotransformer may trip offline and the seven circuit breakers may operate, taking those transmission lines out-of-service. This could happen due to flood waters around the equipment, or the control house flooding and the relays operate due to the flood waters.

The control house at Jackson Rd sits at ground level. HDR recommends installing a new control house on an elevated platform or concrete slab. There is space at the south end of the substation for this modification to be made.

HDR also recommends updating the SPCC system for the 230/69 kV Autotransformer to include a 3 ft concrete wall, like other designs on the TECO system. The 3 ft wall may protect the autotransformer in a flood event related to storm surge. This is especially important due to long lead-times for autotransformers. This modification has a twofold benefit of hardening the substation and improving environmental protection.

HDR also recommends replacing the oil-filled 69 kV Circuit Breaker to mitigate the environmental impact due to storm surge flooding.

Project Cost Estimate

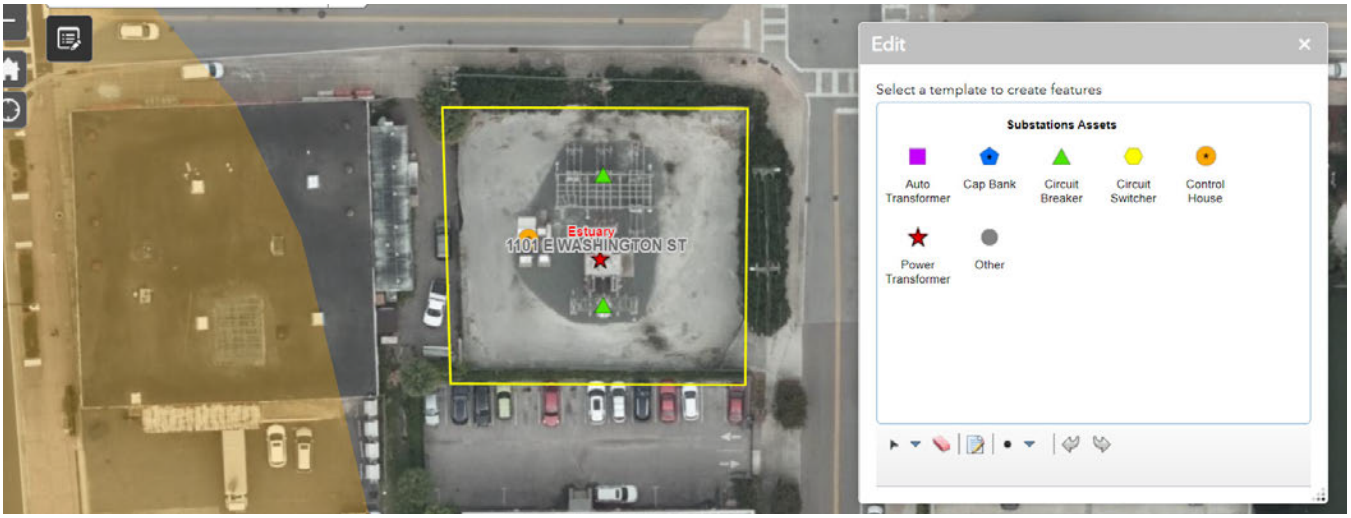
In the table below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the Jackson Rd project.

Cost Benefit

The Jackson Rd project is a large capital project and so the benefit to Tampa Electric and its customers should be great enough to justify that cost. The $2.8MM cost is justified by the improvements to grid stability by hardening this critical substation and maintaining the 230/69 kV tie point during flood events due to storm surge. If this substation is lost due to an outage, it may impact the service to 69 kV substations downstream and create voltage or frequency on the 230 kV bulk system.

This project improves the Grid Stability and Reliability score of Jackson Rd and moves the substation to the right-hand side of both scorecards (page 10 and 11) into an acceptable range.

Jackson Rd 230/69 kV Substation		
INSTALL ELEVATED CONTROL HOUSE AND NEW SPCC SYSTEM FOR AUTOTRANSFORMER ITEM		
Item	**Equipment**	**Engineering, Permitting, Construction, Project Management, Testing and Commissioning**
Elevated Control House	$2,000,000	$320,000
New SPPC System for Auto	$100,000	$255,000
13 kV Circuit Breaker	$75,000	$50,000
	$2,175,000	$625,000
Total	**$2,800,000**	



4.4 PROJECT 4

Estuary 69 kV Substation

Replace 69 kV Circuit Breaker and Elevate Relay and Control Enclosure

The Estuary 69 kV Substation located near downtown Tampa and serves critical downtown load. It sits just outside the FEMA 100-yr floodplain but is located ¼ mile from a canal discharging into Tampa Bay.

This substation has a power transformer, an old 69 kV oil-filled circuit breaker and four (4) distribution circuits. The 69 kV breaker is an older design that its low to the ground. The control cabinets inside the substation are not elevated and sit low to the ground as well.

To harden the Estuary 69 kV Substation against flooding in a storm surge event, HDR recommends replacing the oil-filled 69 kV circuit breaker with a gas insulated breaker that is elevated per the TECO standard design.

HDR also recommends elevating the control cabinets like other substations. The distribution circuit breakers have older electromechanical relays and would benefit from being upgraded to SEL relays.

This substation project would increase the reliability of service to the downtown area during a storm surge event that brings flooding to the area.

Project Cost Estimate

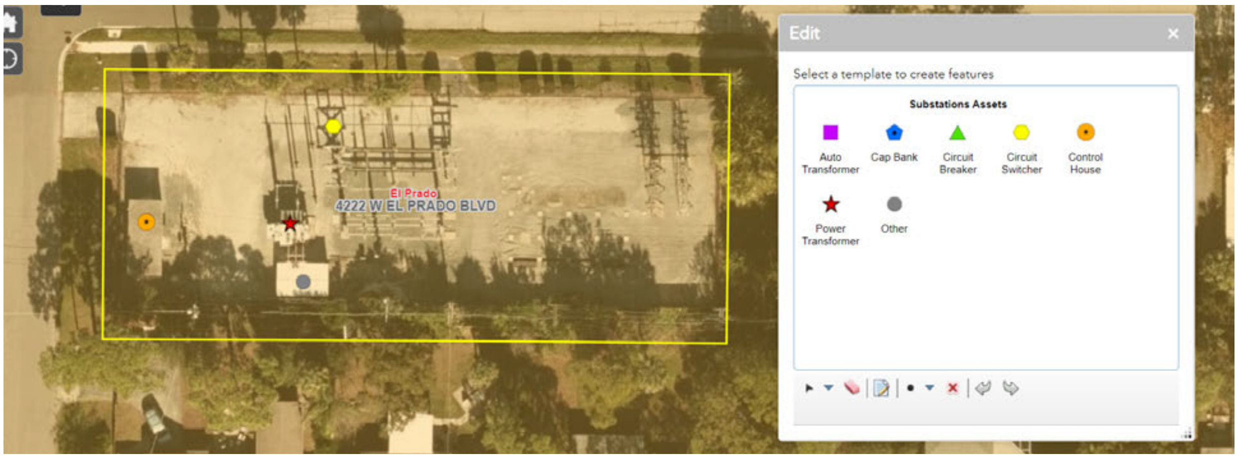
In the table below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the Estuary project.

Cost Benefit

The Estuary project is a smaller capital project at $900,000 and will improve the reliability of service to TECO customers in the area, including critical downtown load. It also improves the environmental safety of the substation by removing an older 69 kV oil-filled circuit breaker and replacing it with a gas-insulted unit. The cost of replacing the circuit breaker and elevating the control enclosure at the Estuary 69 kV Substation is beneficial due to the increase in reliability and environmental safety improvements.

This project improves the Customer Service, Safety and Environmental scores of Estuary and moves the substation to the right-hand side of both scorecards into an acceptable range.

Estuary 69 kV Substation		
REPLACE 69 KV CIRCUIT BREAKER AND ELEVATE RELAY AND CONTROL ENCLOSURE		
Item	**Equipment**	**Engineering, Permitting, Construction, Project Management, Testing and Commissioning**
Elevated Control Enclosure	$400,000	$300,000
69 kV Circuit Breaker	$100,000	$100,000
	$500,000	$400,000
Total	**$900,000**	



4.5 PROJECT 5

El Prado 69 kV Substation

Rebuild Substation with Open-air Distribution Circuit Breakers

HDR recommends rebuilding the El Prado Substation at the current site. Half of the substation site is not used and contains foundations and steel structures from decommissioned equipment. If those foundations are removed and the site re-graded, a 69 kV Circuit Switcher could be installed with a new 69/13 kV transformer and four (4) 13.8 kV package circuit breakers. This design would follow a more traditional design approach and improve switching operations and/or maintenance on the distribution breakers. An elevated control house would be installed with new relaying, and the 69 and 13.8 kV breakers and control cabinets would be elevated per the standard TECO design. An SPCC berm is also recommended for the power transformer. These steps would help harden the new substation against storm surge flooding.

Project Cost Estimate

Below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the alternative El Prado project.

Cost Benefit

Rebuilding the El Prado 69 kV Substation would be a large capitol project at a cost of $5MM. This cost would be justified by the operational and maintenance improvements. Another significant improvement would be the removal of the very old switchgear unit. If this unit failed due to storm surge flooding or during normal operation, the El Prado substation would be out of service for several months and the load would have to be back-fed by other substations. This configuration would present other operational and reliability issues. The cost of rebuilding the El Prado substation is beneficial due to the improvements in operations, maintenance, and customer service.

El Prado 69 kV Substation		
REBUILD SUBSTATION WITH OPEN-AIR DISTRIBUTION CIRCUIT BREAKERS		
Item	**Equipment**	**Engineering, Permitting, Construction, Project Management, Testing and Commissioning**
Demolish and Re-grade Substation	$250,000	$500,000
Elevated Control House	$2,000,000	$320,000
69/13 kV Transformer	$900,000	$210,000
69 kV Circuit Switcher	$50,000	$80,000
Four (4) 13 kV Circuit Breakers	$100,000	$190,000
Foundations and Steel Structures	$300,000	$100,000
	$3,600,000	$1,400,000
Total	**$5,000,000**	

Alternative Project: El Prado 69 kV Substation

Replace Switchgear Unit

As an alternative to replacing the switchgear unit at El Prado, The El Prado 69 kV Substation located in south Tampa in a well established neighborhood. It sits inside the FEMA 100-yr floodplain and is located ~1 mile from the Tampa Bay.

This substation has a 69 kV circuit switcher, a power transformer, and an old 13.8 kV Switchgear unit. El Prado has four (4) distribution circuits feeding approximately 4,700 direct customers.

If flooding occurs at El Prado due to storm surge, the control house and switchgear unit could be damaged and load would not be served from this substation. The switchgear unit is a long lead-time item so the service outage could be for an extended amount of time.

HDR recommends replacing the switchgear unit with a newer design on an elevated platform similar to recent installations on the TECO system. HDR also recommends elevating the control house on a platform or concrete slab. These improvements will harden the substation against storm surge flooding and improve the reliability of service to the TECO customers in the area.

Alternative Project Cost Estimate

In the table to the right is a high-level, budgetary cost estimate (+/- 25% accuracy) for the El Prado project.

Cost Benefit

The El Prado project is a large capital project and so the benefit to Tampa Electric and its customers should be great enough to justify that cost. The $5.3MM cost is justified by the improvements to the reliability of service to customers in the area. It also replaces an older switchgear unit that is less safe to operate than the newer units installed on the TECO system. In the event of storm surge flooding, if the older switchgear at El Prado is flooded and needs to be replaced, the lead-time on the new switchgear unit could be very long and the customer load would be served from other substations which could present operational issues. The cost of replacing the switchgear unit at El Prado is beneficial due to the customer service and safety improvements.

This project improves the Customer Service and Safety scores of El Prado and moves the substation to the right-hand side of both scorecards into an acceptable range.

El Prado 69 kV Substation		
REPLACE SWITCHGEAR UNIT		
Item	**Equipment**	**Engineering, Permitting, Construction, Project Management, Testing and Commissioning**
Replace Switchgear Unit	$2,500,000	$480,000
Elevated Control House	$2,000,000	$320,000
	$4,500,000	$800,000
Total	**$5,300,000**	

4.6 PROJECT 6

Skyway 69 kV Substation

Replace 13.8 kV Circuit Breakers and Elevate Control House

The Skyway 69 kV Substation is located adjacent to the Tampa International Airport and serves critical load at that facility. It sits inside the FEMA 100-yr floodplain and is located ¾ mile from the Tampa Bay.

This substation has two power transformers, 69 kV circuit breakers, seven (7) distribution circuits and a control house. Three of the distribution feeders serve the Tampa International Airport.

The control house at Skyway sits at ground level and nine (9) of the 13.8 kV circuit breakers are older, oil-filled breakers.

To harden the Skyway 69 kV Substation against flooding in a storm surge event, HDR recommends replacing the oil-filled 13.8 kV circuit breaker with a gas insulated package breakers per the TECO standard design.

HDR also recommends installing a new control house on an elevated platform or concrete slab. There is space at the south end of the substation for this modification to be made.

This substation project would increase the reliability of service to the airport during a storm surge event that brings flooding to the area.

Project Cost Estimate

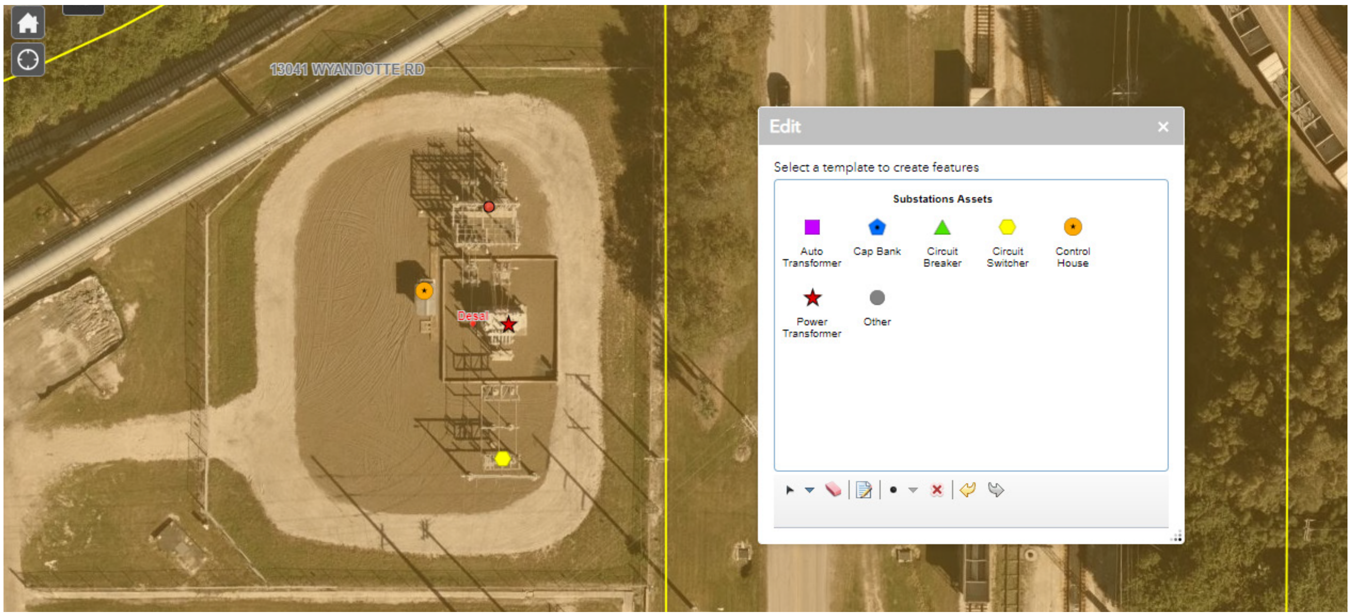
In the table below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the Skyway project.

Cost Benefit

The Skyway project is a large capital project at $3.5MM and will improve the reliability of service to TECO customers in the area, including critical load at the airport. It also improves the environmental safety of the substation by removing older 13.8 kV oil-filled circuit breaker and replacing them with newer units. The cost of replacing the circuit breaker and elevating the control house at the Skyway 69 kV Substation is beneficial due to the increase in reliability for critical load and environmental safety improvements.

This project improves the Customer Service and Environmental scores of Skyway and moves the substation to the right-hand side of both scorecards into an acceptable range.

Skyway 69 kV Substation		
REPLACE 13.8 KV CIRCUIT BREAKERS AND ELEVATE CONTROL HOUSE		
Item	**Equipment**	**Engineering, Permitting, Construction, Project Management, Testing and Commissioning**
Elevated Control House	$2,000,000	$320,000
9 qty 13.8 kV Circuit Breakers	$730,000	$450,000
	$2,730,000	$770,000
Total	**$3,500,000**	



4.7 PROJECT 7

Desal 69 kV Substation

Elevate Control Enclosure

The Desal 69 kV Substation is located adjacent to the Big Bend Generation Facility. It sits inside the FEMA 100-yr floodplain and is located approximately 1 mile from the Tampa Bay. This substation serves critical load at the Big Bend Generation facility.

This substation has a power transformer, a 69 kV circuit switcher and three (3) distribution circuits. The control cabinets inside the substation are not elevated and sit at ground level.

To harden the Desal 69 kV Substation against flooding in a storm surge event, HDR recommends replacing elevating the control cabinets.

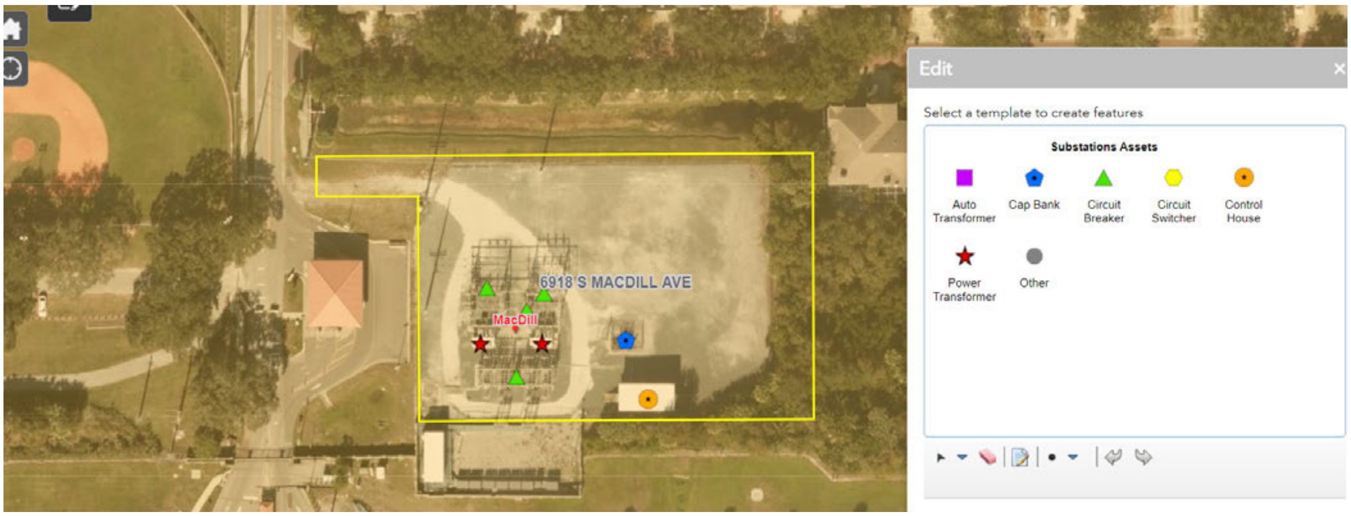
This substation project would increase the reliability of service to the Big Bend area during a storm surge event that brings flooding to the area.

Project Cost Estimate
In the table below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the Desal project.

Cost Benefit
The Desal project is a smaller capital project at $700,000 and will improve the reliability of service to TECO customers in the area, including critical load at the Big Bend Generation facility. The cost of elevating the control enclosure at the Desal 69 kV Substation is beneficial due to the increase in reliability of service to the critical load in the area.

This project improves the Safety and Cost scores of Desal moves the substation to the right-hand side of both scorecards into an acceptable range.

Desal 69 kV Substation		
ELEVATE CONTROL ENCLOSURE		
Item	Equipment	Engineering, Permitting, Construction, Project Management, Testing and Commissioning
Elevated Control Enclosure	$400,000	$300,000
	$400,000	$300,000
Total	$700,000	



4.8 PROJECT 8

MacDill 69 kV Substation

Install New SPCC Systems for Power Transformers

The MacDill 69 kV Substation is located adjacent to MacDill Air Force Base and feeds critical load at that facility. It sits inside the FEMA 100-yr floodplain and is located approximately 1 mile from the Tampa Bay. This substation serves critical load at the Big Bend Generation facility.

This substation has two power transformers, 69 kV circuit breakers, two (2) distribution circuits and an elevated control house.

To harden the MacDill 69 kV Substation against flooding in a storm surge event, HDR recommends installing new SPCC systems for the two power transformers that include ~3 ft concrete walls. The 3 ft wall may protect the transformer in a flood event related to storm surge by preventing flood water intrusion into the transformer control cabinets. This modification has a twofold benefit of hardening the substation and improving environmental protection.

This substation project would increase the reliability of service to the south Tampa area during a storm surge event that brings flooding to the area.

HDR also recommends replacing the oil-filled 13 kV Circuit Breaker to mitigate the environmental impact due to storm surge flooding.

Project Cost Estimate

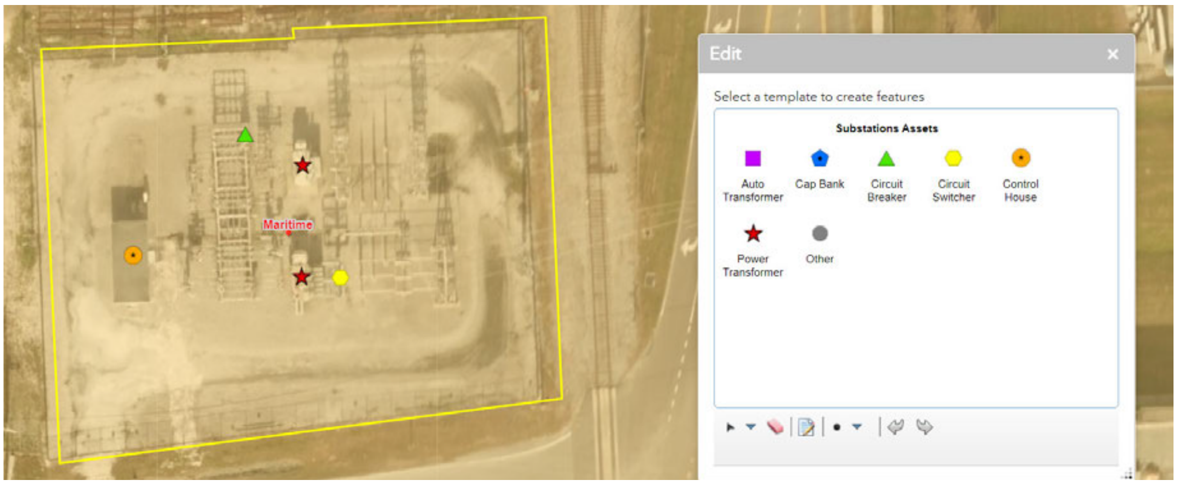
In the table below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the MacDill project.

Cost Benefit

The MacDill project is a smaller capital project at $700,000 and will improve the reliability of service to TECO customers in the area, including critical load at the MacDill AFB. The cost of installing new SPCC systems for the transformers at the MacDill 69 kV Substation is beneficial due to the increase in reliability of service to the critical load in the area as well as environmental safety improvements for capturing potential oil spills from the transformer tanks rupturing.

This project improves the Customer Service and Cost scores of MacDill and moves the substation to the right-hand side of both scorecards into an acceptable range.

MacDill 69 kV Substation		
INSTALL NEW SPCC SYSTEMS FOR POWER TRANSFORMERS		
Item	**Equipment**	**Engineering, Permitting, Construction, Project Management, Testing and Commissioning**
Install two SPPC Systems for 69/13 kV Transformers	$200,000	$375,000
13 kV Circuit Breaker	$75,000	$50,000
	$275,000	$425,000
Total	**$700,000**	



4.9 PROJECT 9

Maritime 69 kV Substation

Replace 13.8 kV Circuit Breakers, Install New Transformers and Elevate Control House

The Maritime 69 kV Substation is in the FEMA 100-yr floodplain and 0.3 miles from a canal/drainage feature discharging into Tampa Bay. This substation has two power transformers, a 69 kV circuit switcher, four (4) distribution circuits and a control house. This substation feeds critical port fuel load as part of it's approximately 38 MVA of load. For this reason it scores very high on the Customer Service scorecard as seen on page 12. The control house at Maritime sits at ground level and the four (4) of the 13.8 kV circuit breakers are older and sit close to the ground as well. The two 69/13 kV transformers are older units and susceptible to failure in the event of storm surge flooding.

To harden the Maritime 69 kV Substation against flooding in a storm surge event, HDR recommends replacing the control house with an elevated house on an elevated platform or concrete slab with new relaying, replacing the four (4) 13 kV Circuit Breakers and the two power transformers with newer units with SPCC designs with 3-foot walls that.

This substation project would increase the reliability of service to the critical port fuel load during a storm surge event that brings flooding to the area.

Project Cost Estimate

Below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the Maritime project.

Cost Benefit

The Maritime project is a larger capital project at $4.5MM and will improve the reliability of service to TECO customers in the area, including critical fuel load at the port. It also improves the environmental safety of the substation by removing older oil-filled transformers and replacing them with newer units with SPCC systems that can potentially keep storm surge flooding at bay. The cost of replacing the circuit breakers, 69/13 kV transformers and elevating the control house at the Maritime 69 kV Substation is beneficial due to the increase in reliability for critical load and environmental safety improvements.

This project improves the Customer Service and Cost scores of MacDill and moves the substation to the right-hand side of both scorecards into an acceptable range.

Maritime 69 kV Substation		
REPLACE 13.8 KV CIRCUIT BREAKERS, INSTALL NEW TRANSFORMERS AND ELEVATE CONTROL HOUSE		
Item	**Equipment**	**Engineering, Permitting, Construction, Project Management, Testing and Commissioning**
Elevated Control House	$2,000,000	$320,000
Two (2) 69/13 kV Transformers	$1,600,000	$290,000
Four (4) 13 kV Circuit Breakers	$100,000	$190,000
	$3,700,000	$800,000
Total	**$4,500,000**	

5.0 Conclusion

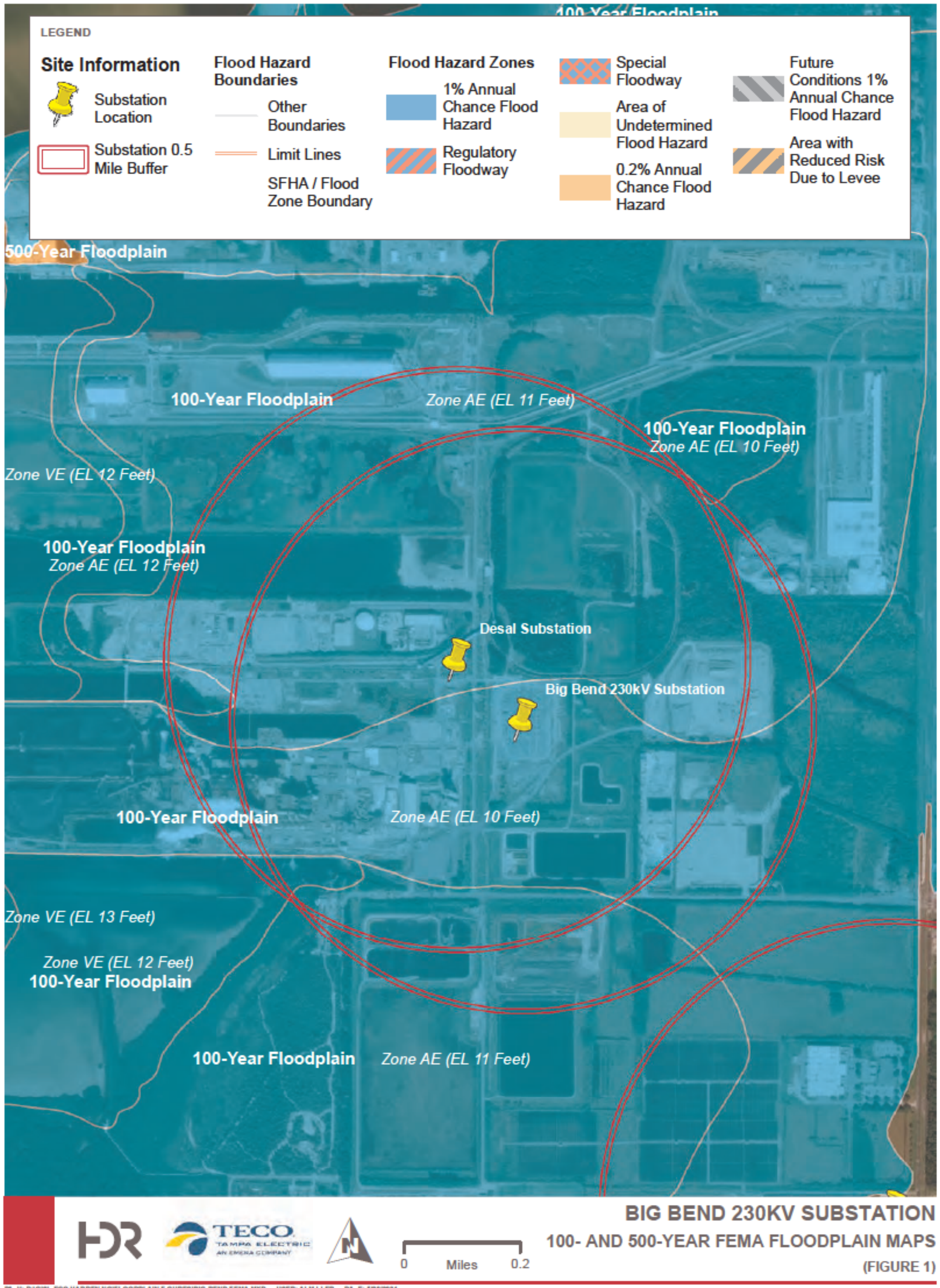
Tampa Electric Company sought out to determine the impact of storm surge flooding and for ways to harden twenty-four (24) of its substations against those flood events. HDR, Inc. performed desktop studies, site visits and built a cloud-based GIS platform to perform this analysis. After collecting this data, HDR then created a scoring methodology to rank and prioritize the substations based on several criteria. The result of this effort was a series of scorecards. These scorecards were used to develop nine (9) substation projects to harden the TECO system. The total cost for these projects is estimated to be $28.8MM and include three (3) transmission projects and six (6) distribution projects. The transmission projects are designed to harden those substations and increase grid stability by maintaining the critical tie points between the 230, 138 and 69 kV systems. The six (6) distribution projects harden the substations and improve reliability of service to the load served in the area, including critical load to south Tampa, Tampa International Airport, the Big Bend generation facility, and MacDill AFB.

The TECO system in Hillsborough County was studied for the impact of storm surge flooding and several projects were developed to harden substations in this region to improve grid stability and reliability of service.

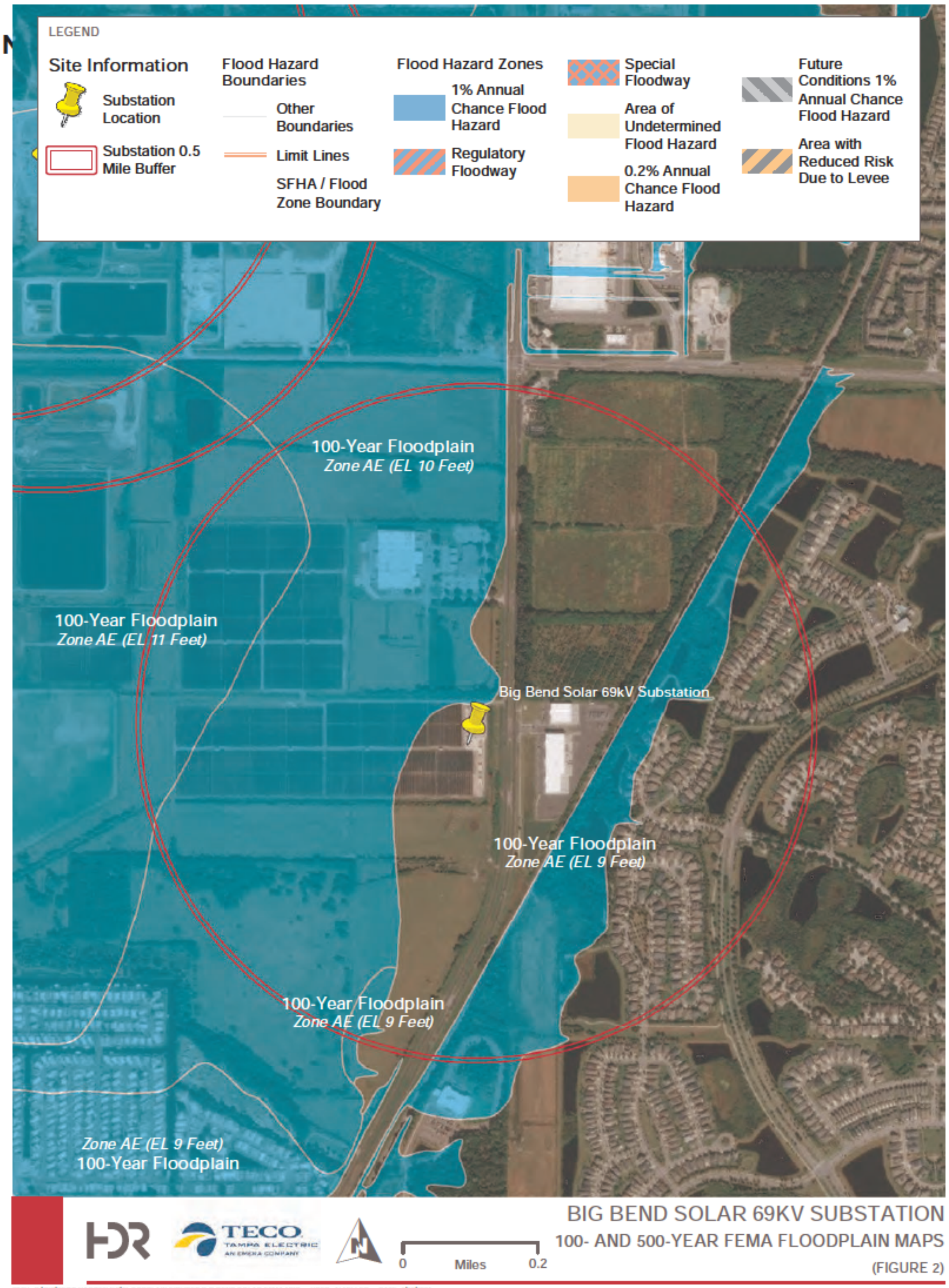
APPENDICES

TECO SUBSTATION CONSEQUENCE SCORES

Sub #	Substation	Overall Consequence Score
34	Big Bend 230kV	2.64
464	Big Bend Solar 69kV	1.68
154	Cypress Street	1.64
422	Desal	1.50
44	El Prado	1.25
91	Estuary	1.55
226	First Street	1.76
129	Gannon 230kv 230/138kV & 230/69kV	2.91
268	Harbour Island	1.69
2	Hookers Point 138/69kV	2.00
	Interbay	1.56
80	Jackson Road 230/69kV	1.74
23	MacDill	1.66
81	Manhattan	1.58
164	Maritime	1.48
311	McKay Bay Cogen	1.58
265	Meadow Park	1.78
242	Miller Mac	1.61
39	Millpoint 69kV	1.48
75	Port Sutton	1.76
160	Rocky Creek	1.63
140	Skyway	1.63
112	South Gibsonton	1.90
159	Twelfth Avenue	1.44



BIG BEND 230KV SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 1)



BIG BEND SOLAR 69KV SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 2)

TAMPA ELECTRIC COMPANY
DOCKET NO. 20220010-EI
STAFF'S FIRST SET OF INTERROGATORIES
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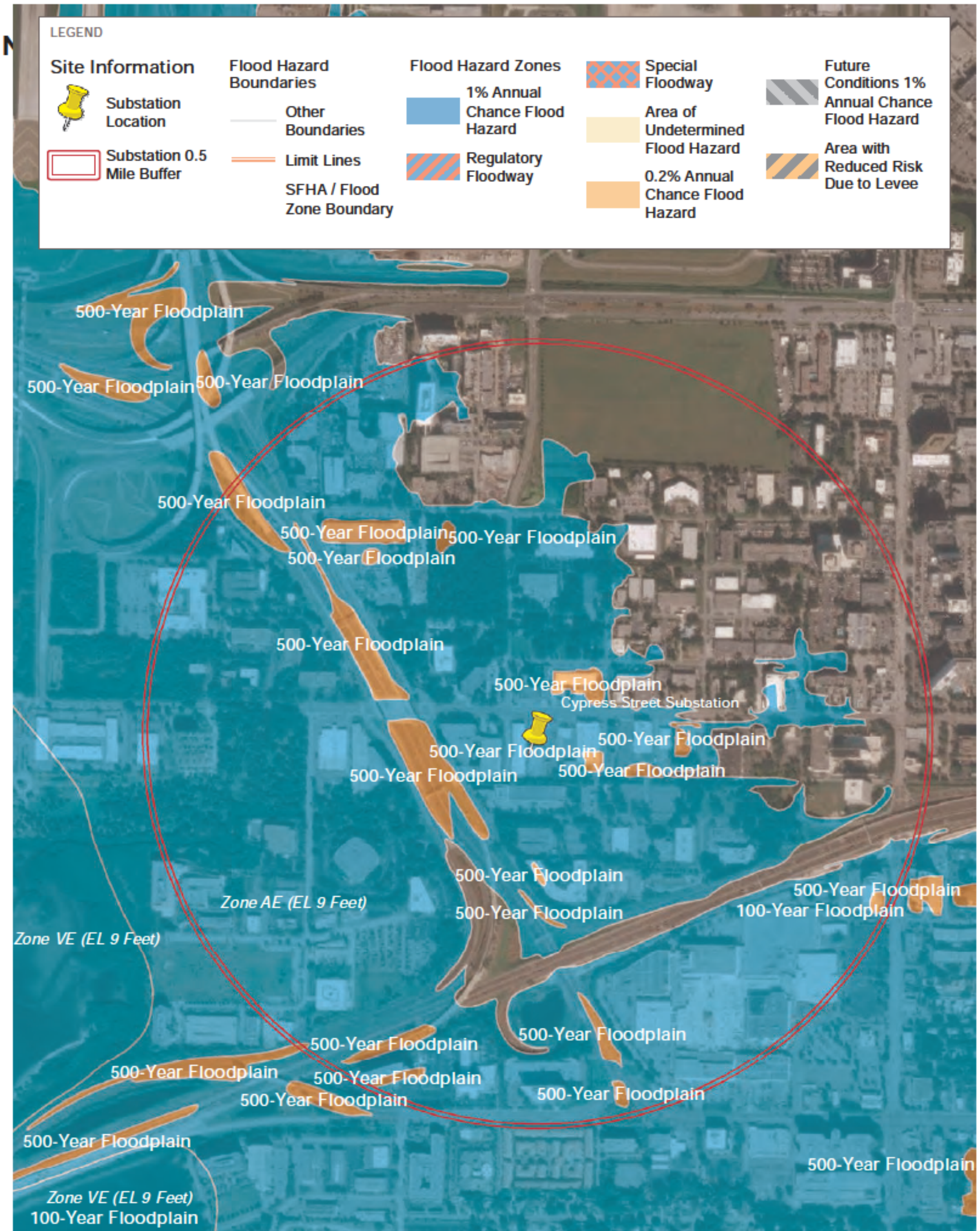
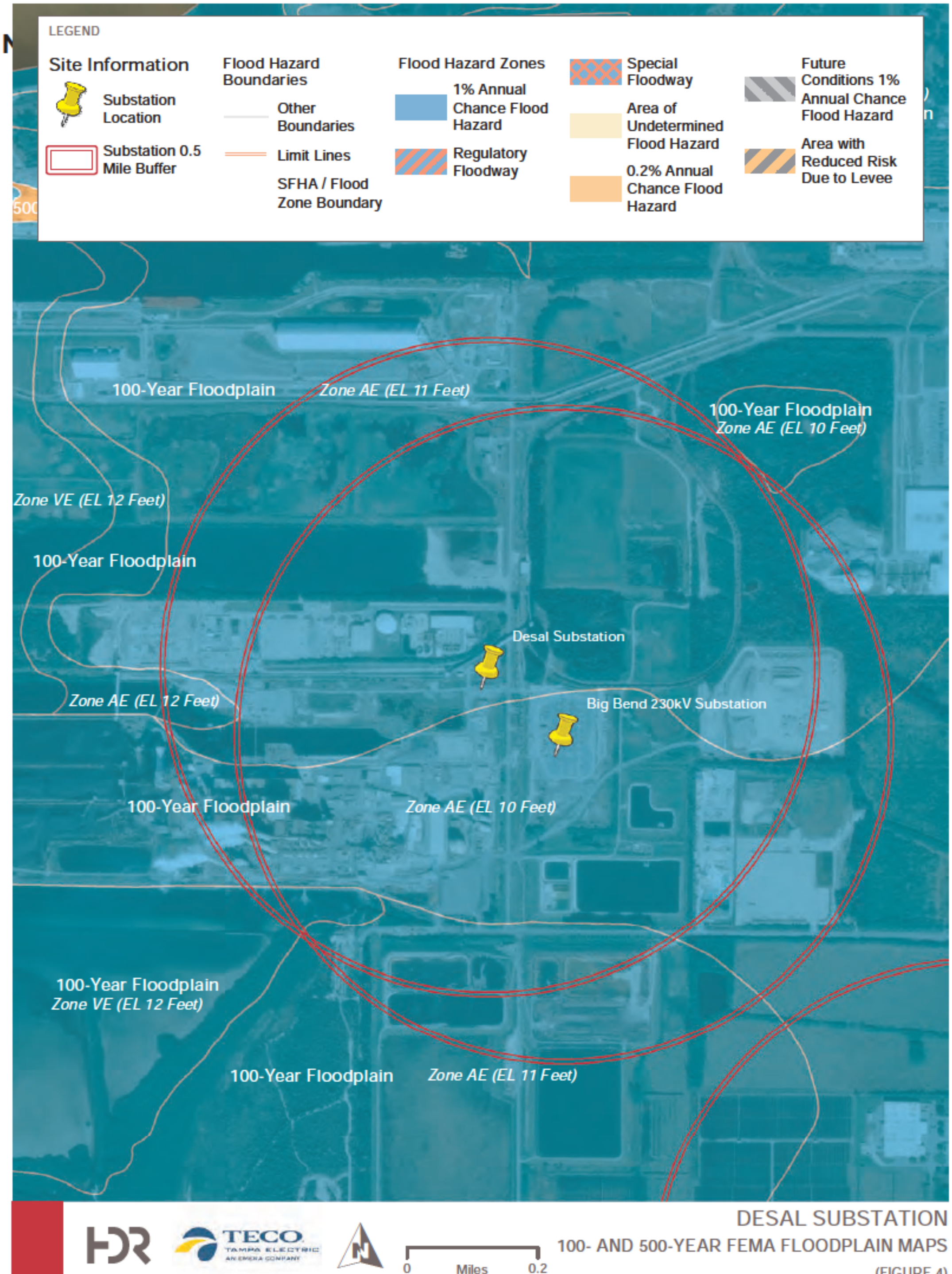


CYPRESS STREET SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 3)



DESAL SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 4)

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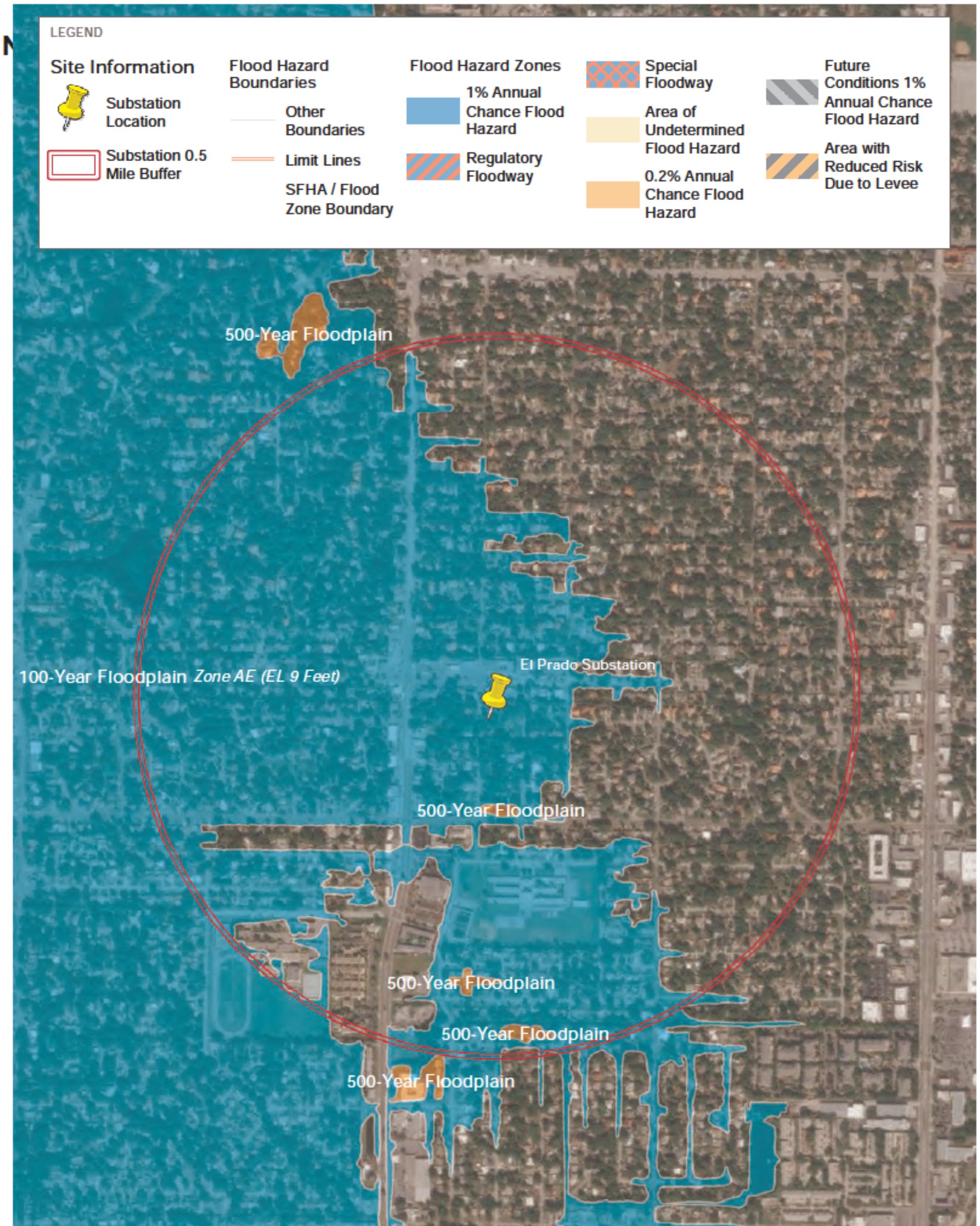

EL PRADO SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 5)

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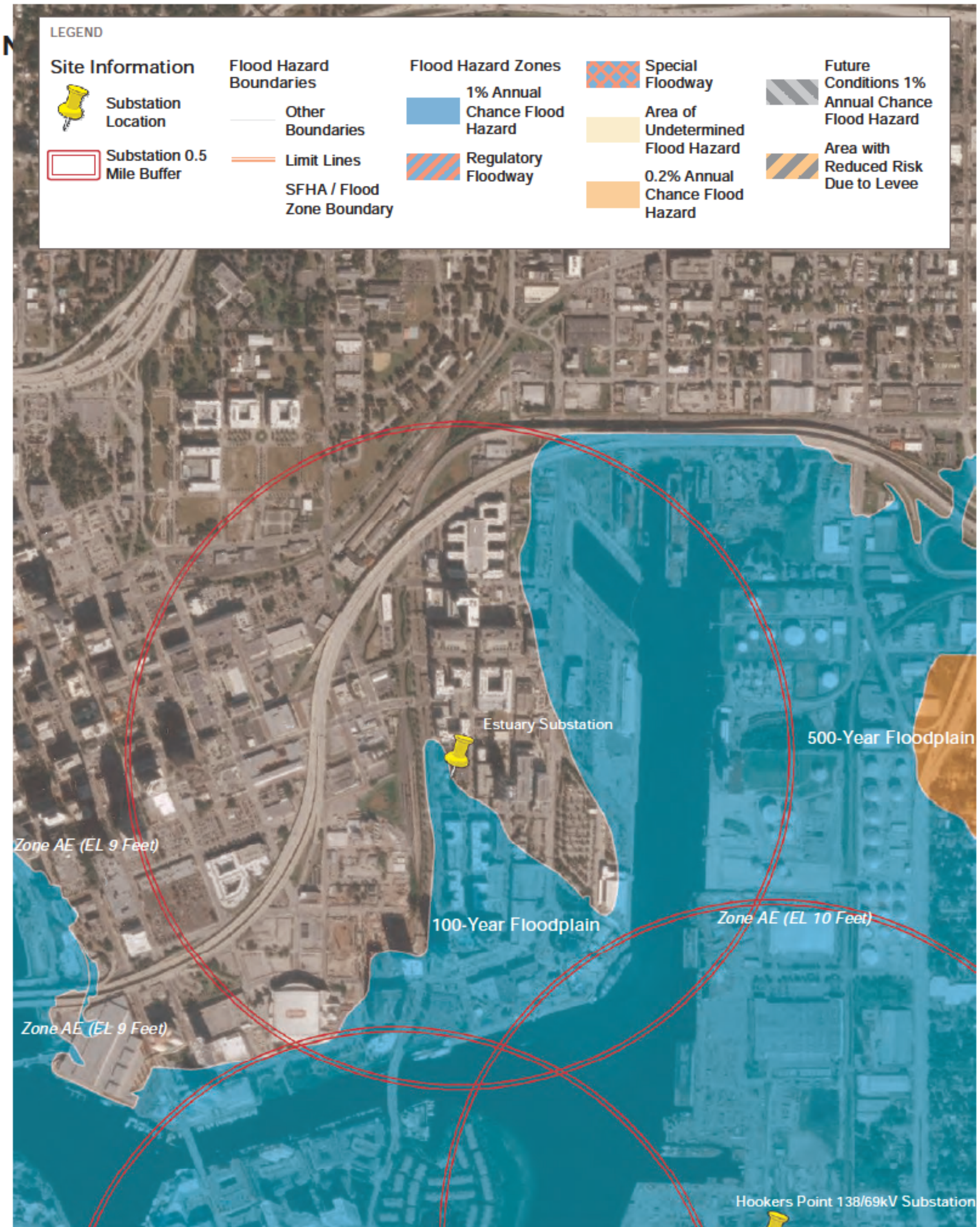

ESTUARY SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 6)

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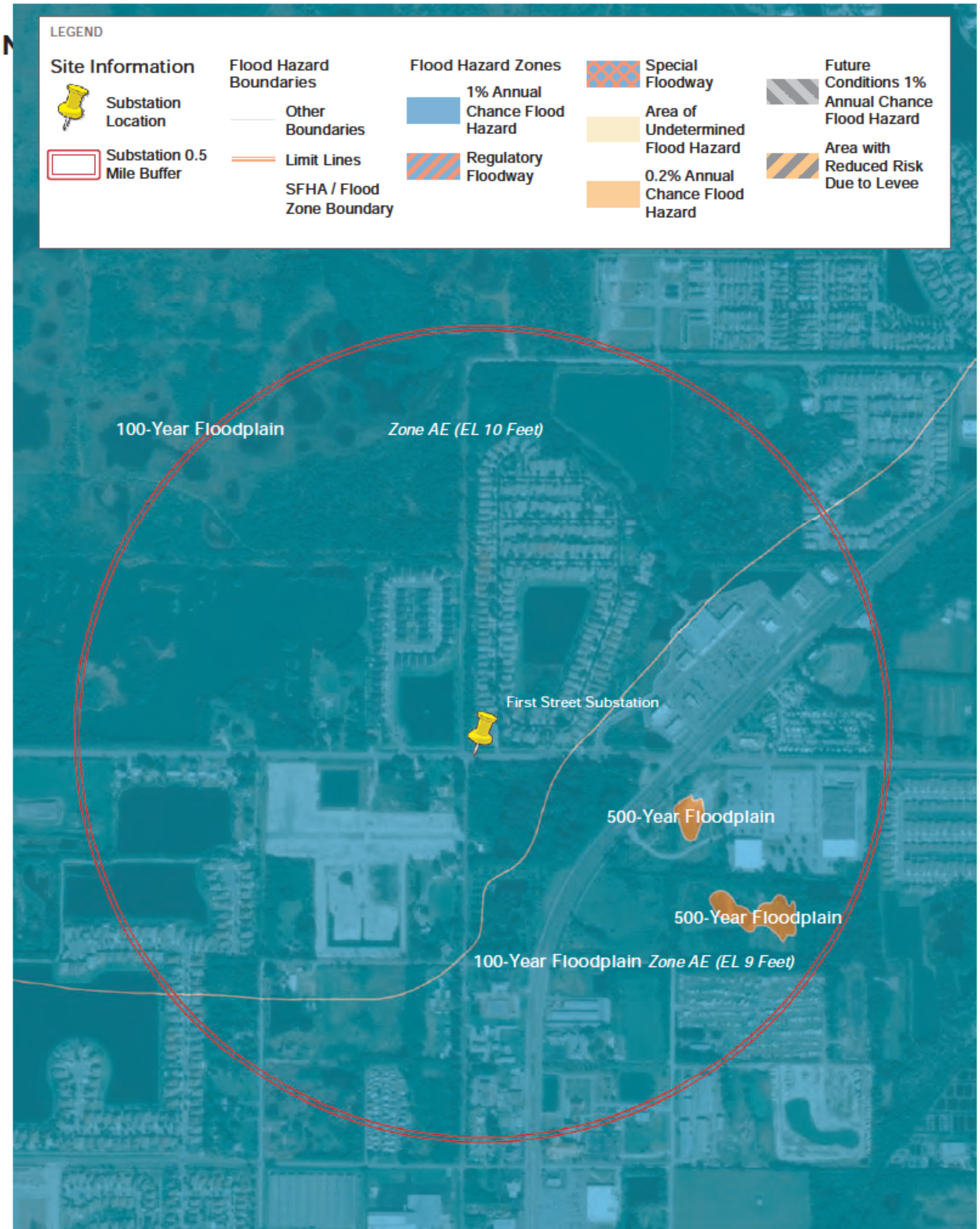

FIRST STREET SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 7)

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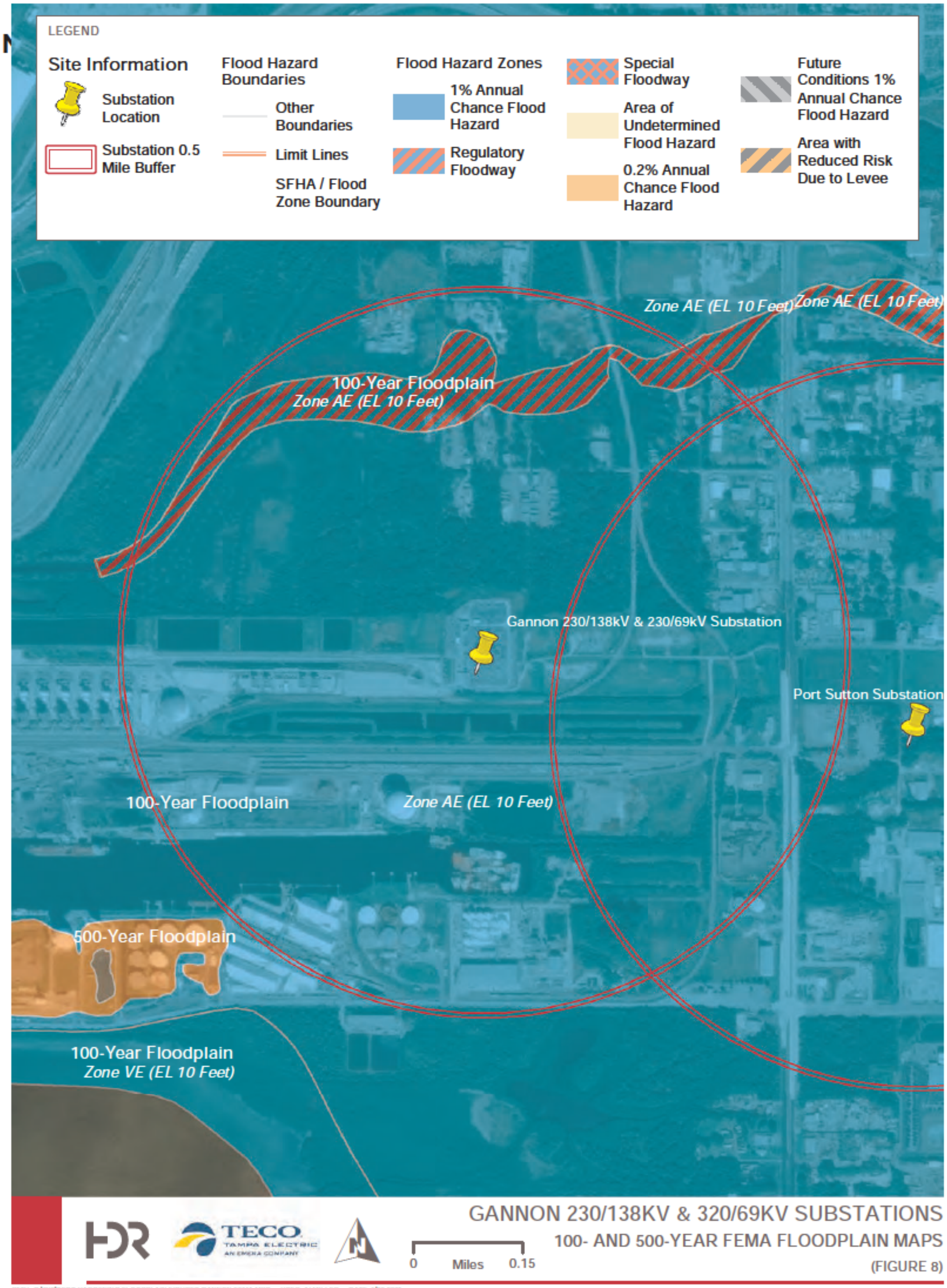

GANNON 230/138KV & 320/69KV SUBSTATIONS
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 8)

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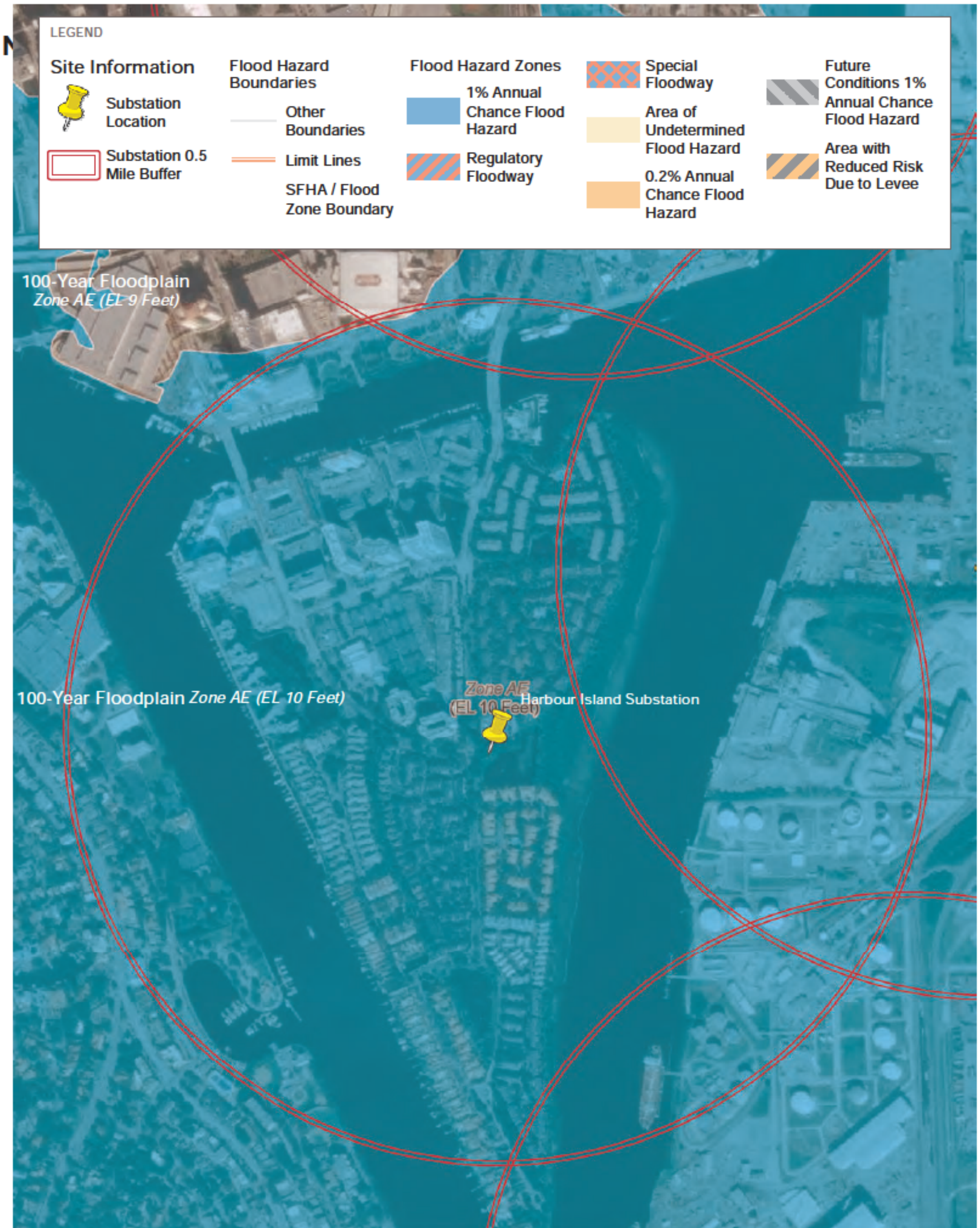

HARBOUR ISLAND SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 9)

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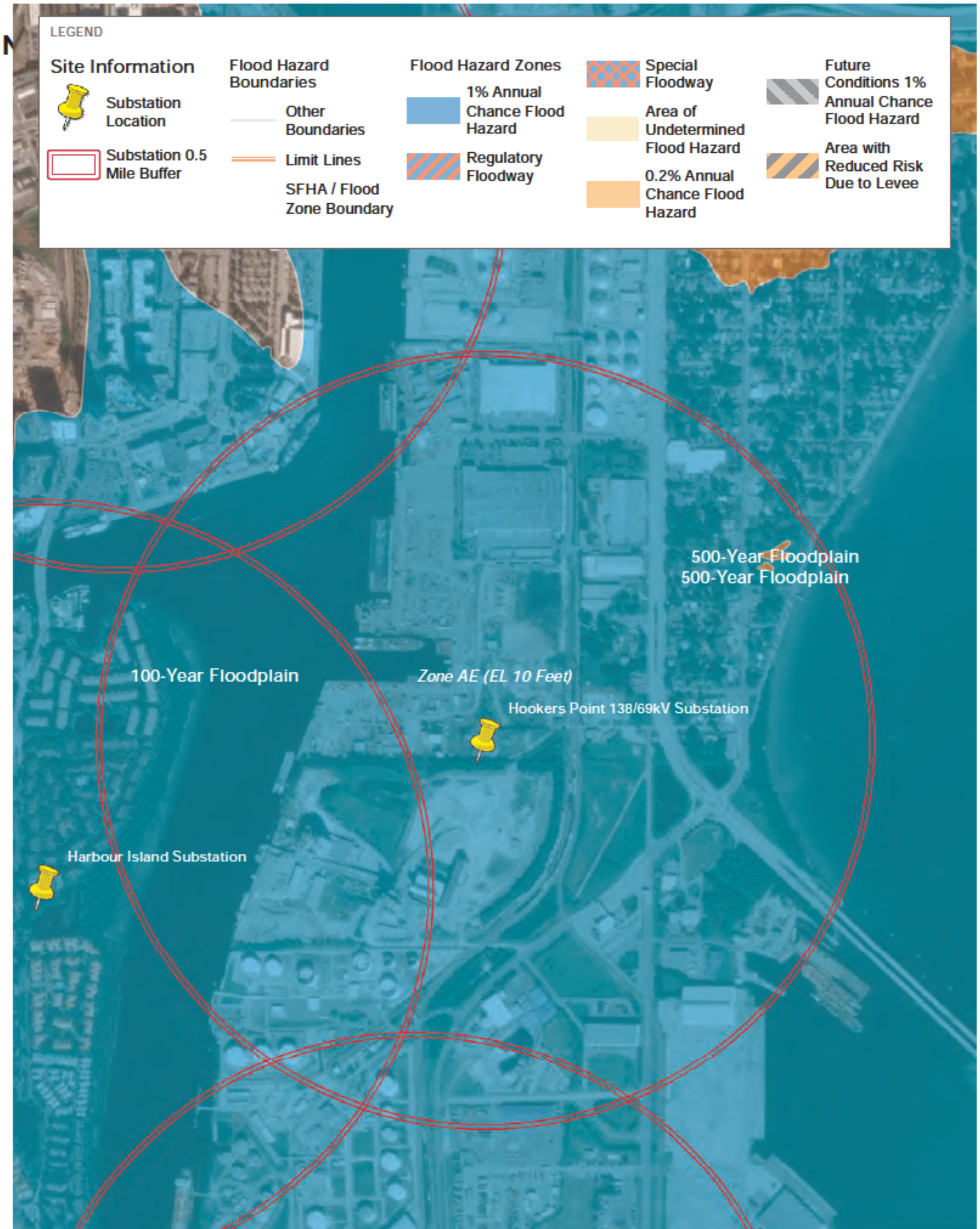

HOOKERS POINT 138/69KV SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 10)

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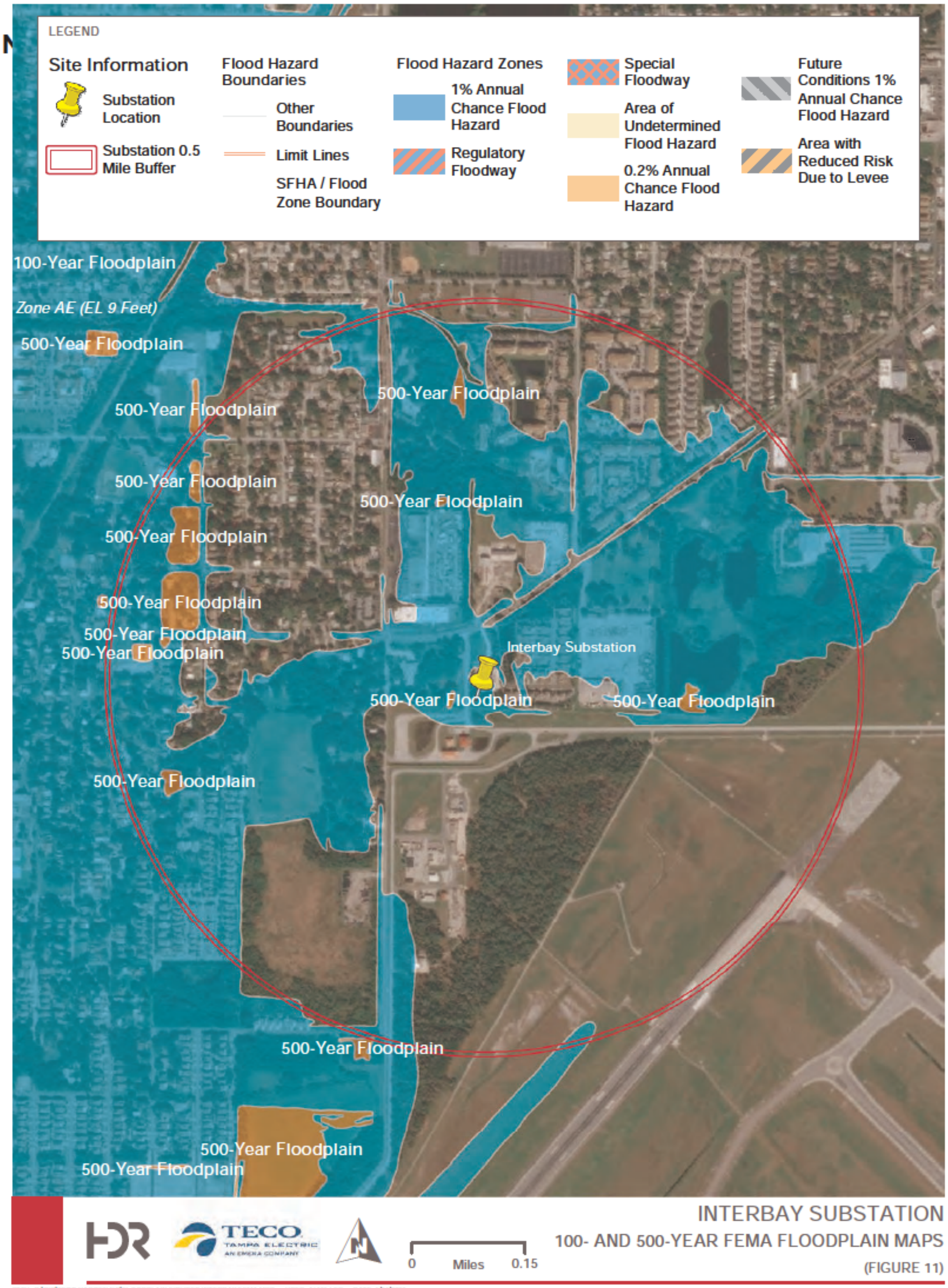

INTERBAY SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 11)

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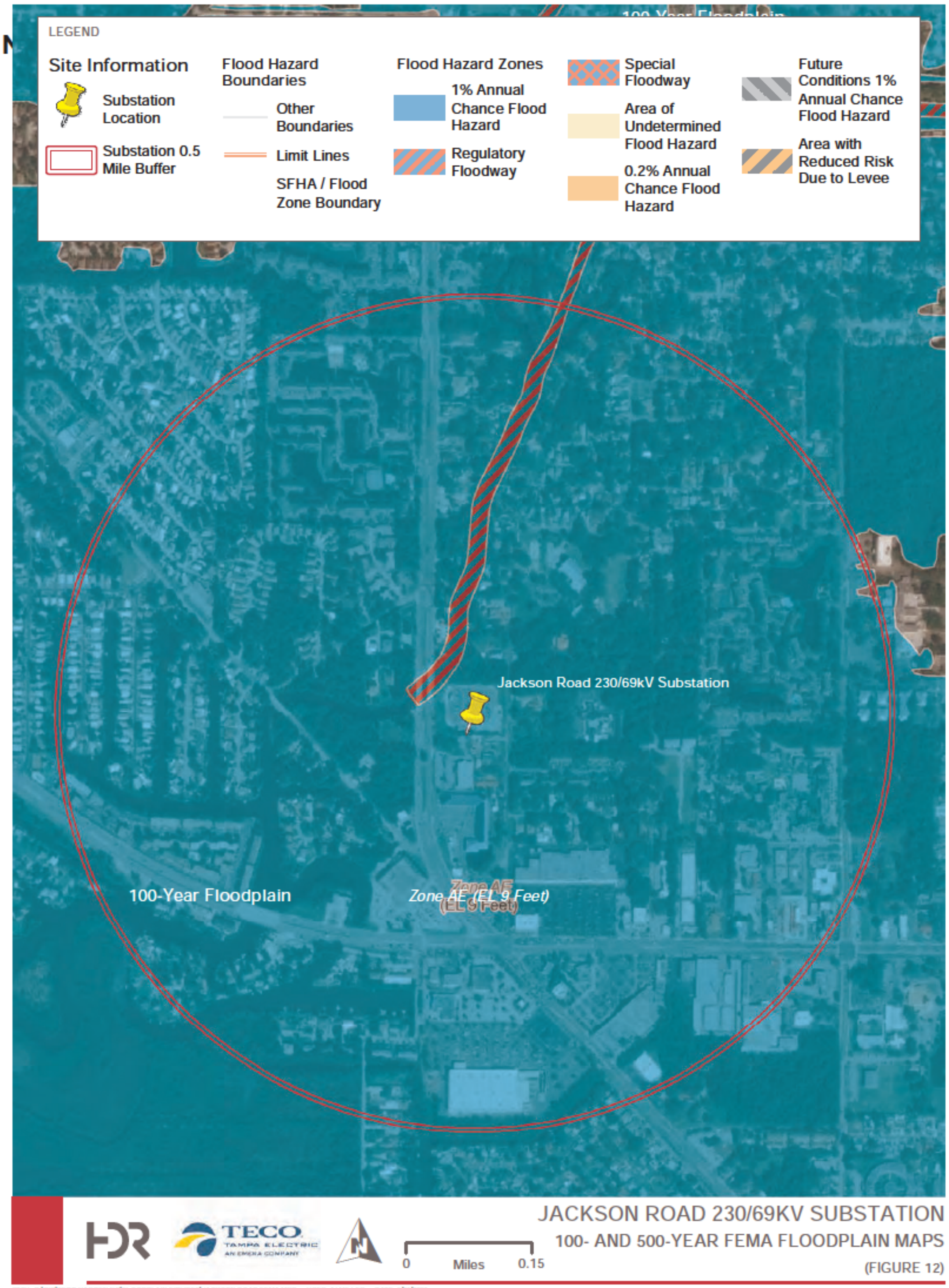

JACKSON ROAD 230/69KV SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 12)

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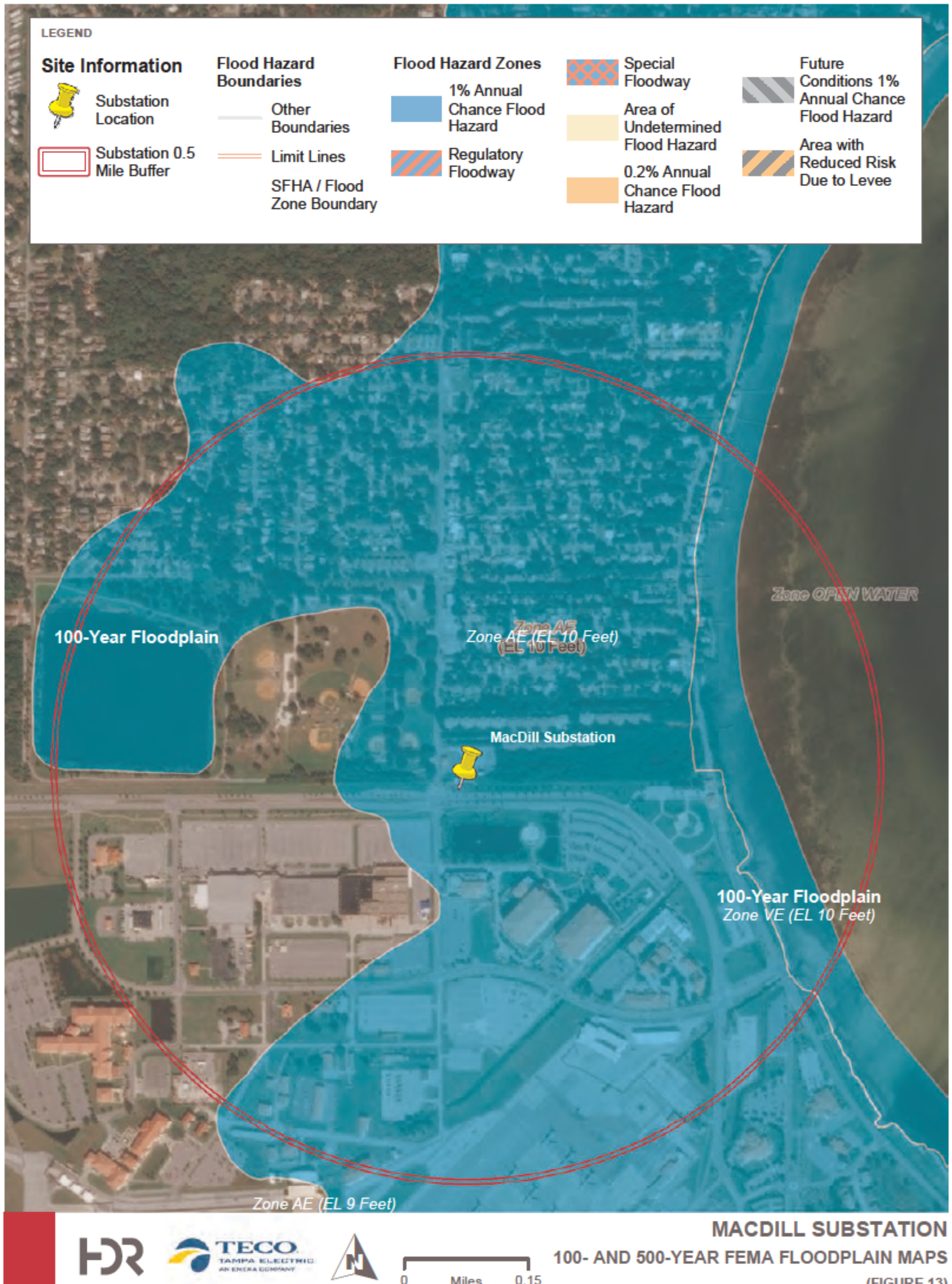

MACDILL SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 13)

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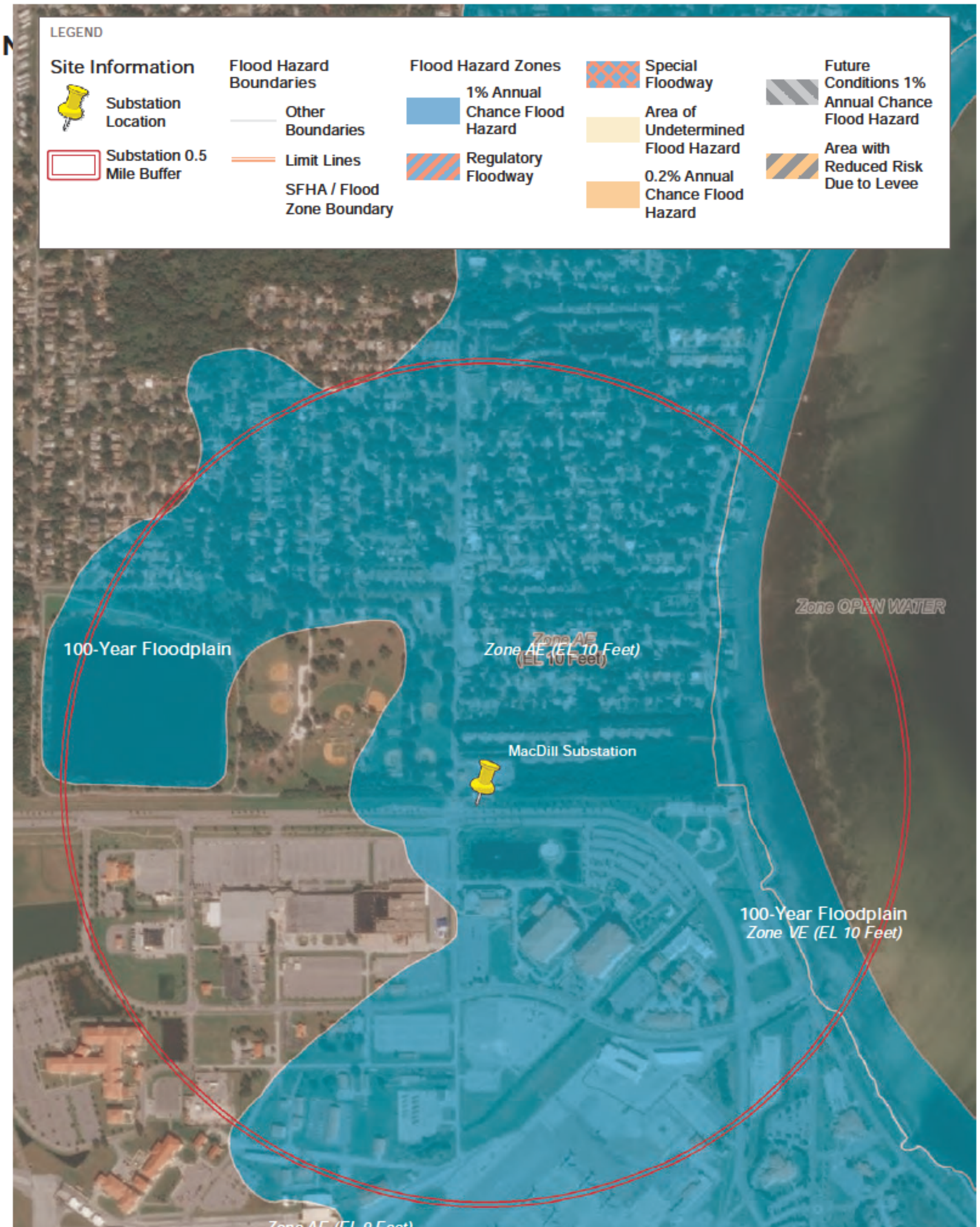
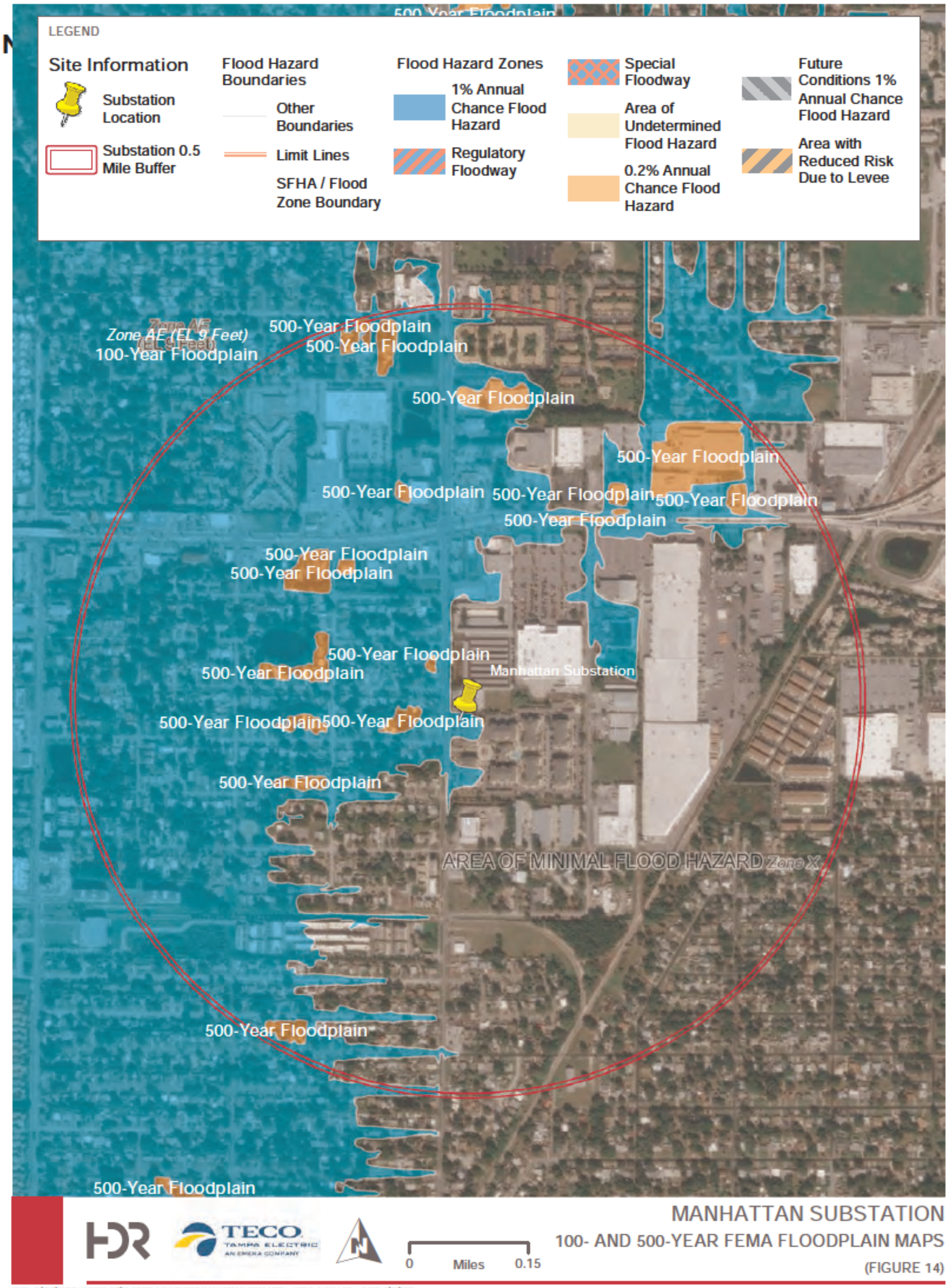
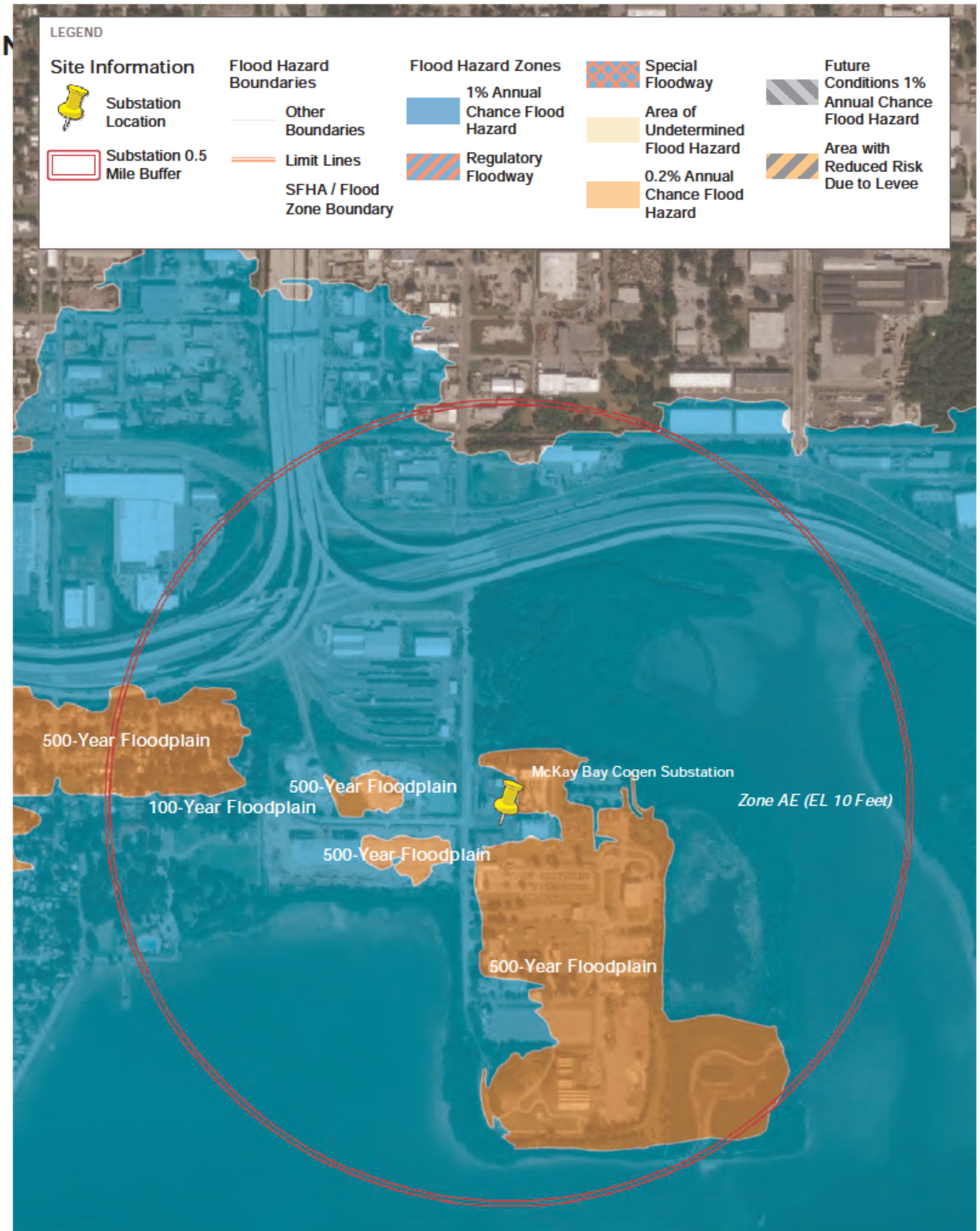


MACDILL SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 13)



MANHATTAN SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 14)

MARITIME SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 15)



MCKAY BAY COGEN SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 16)

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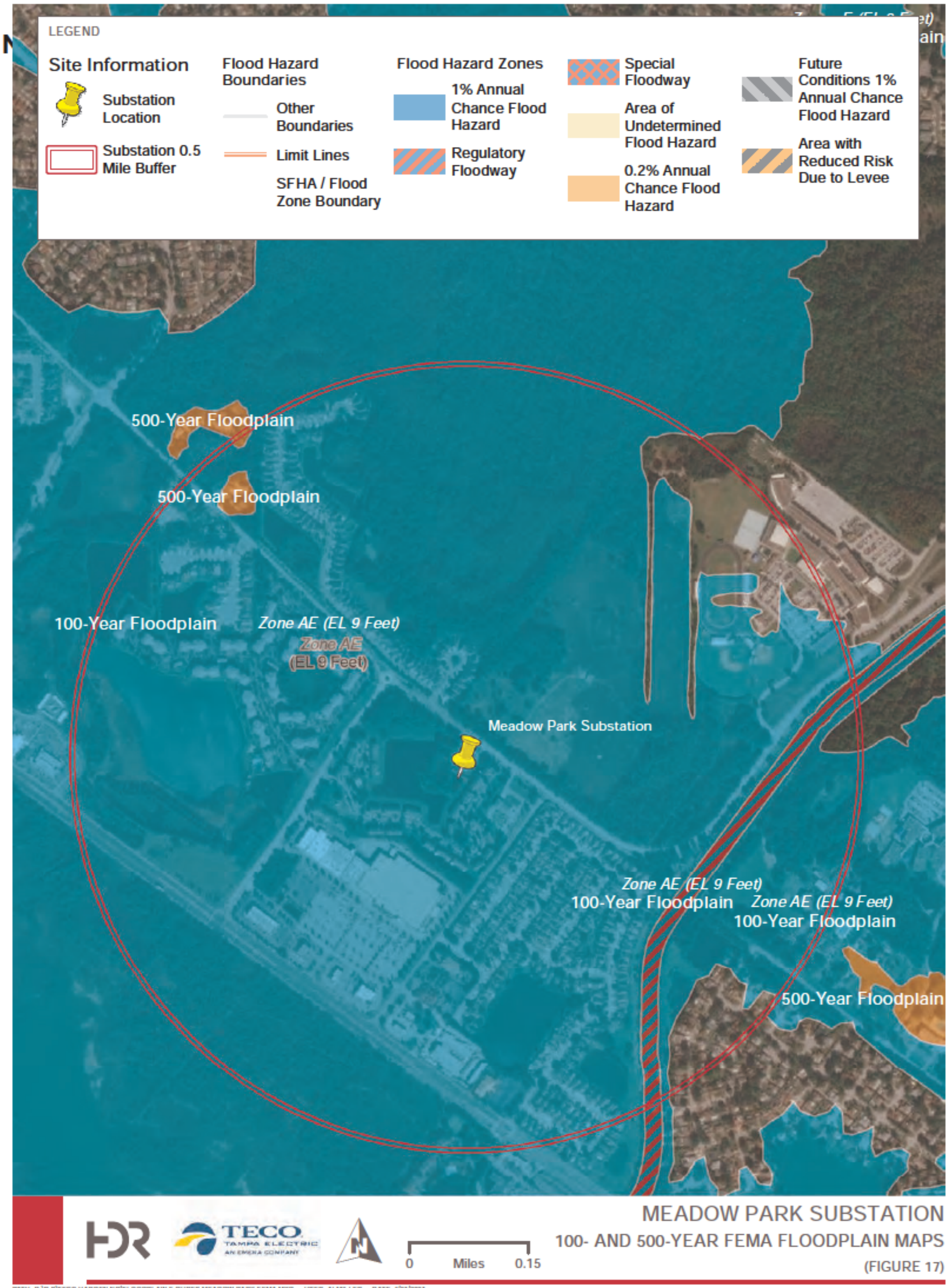

MEADOW PARK SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 17)

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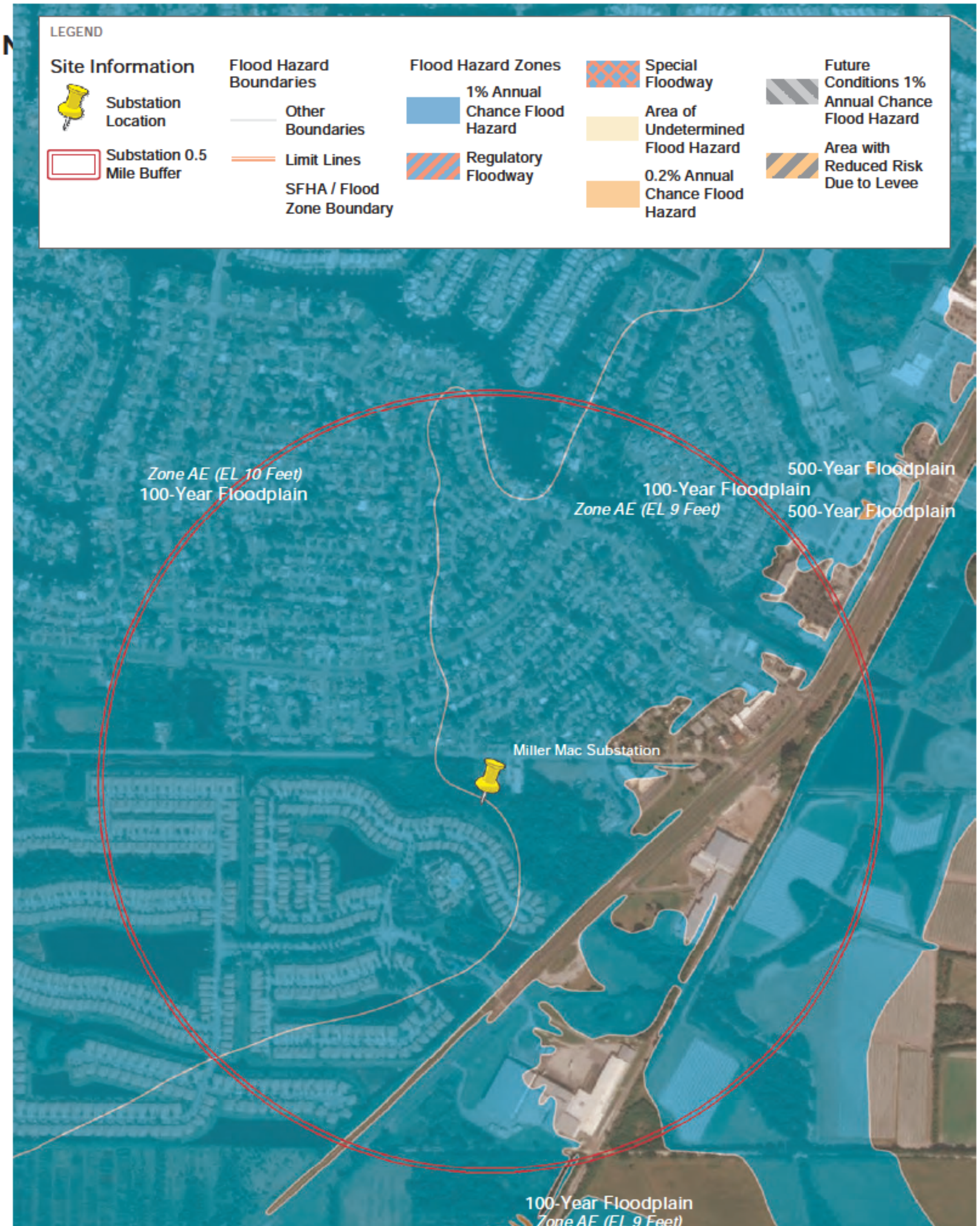
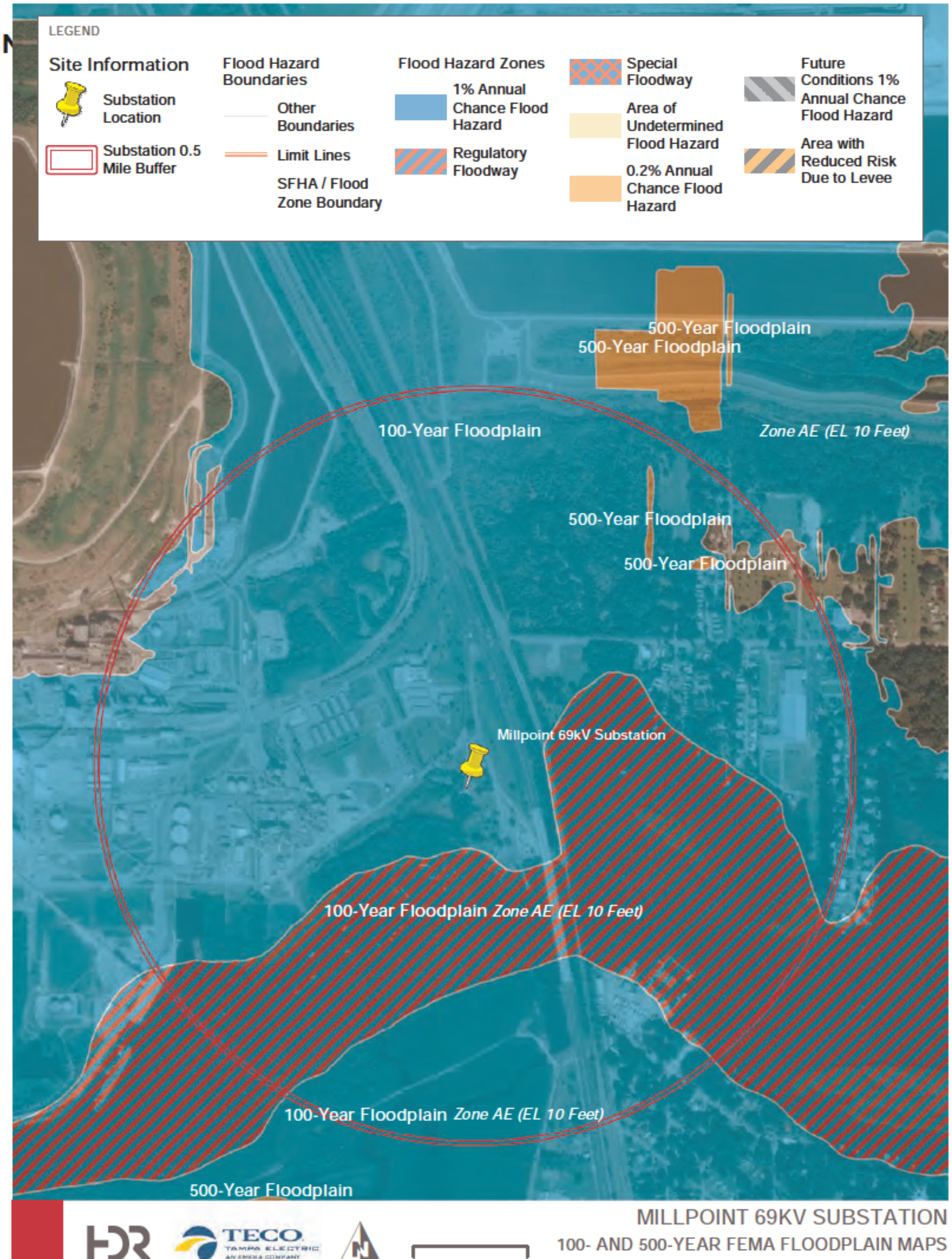
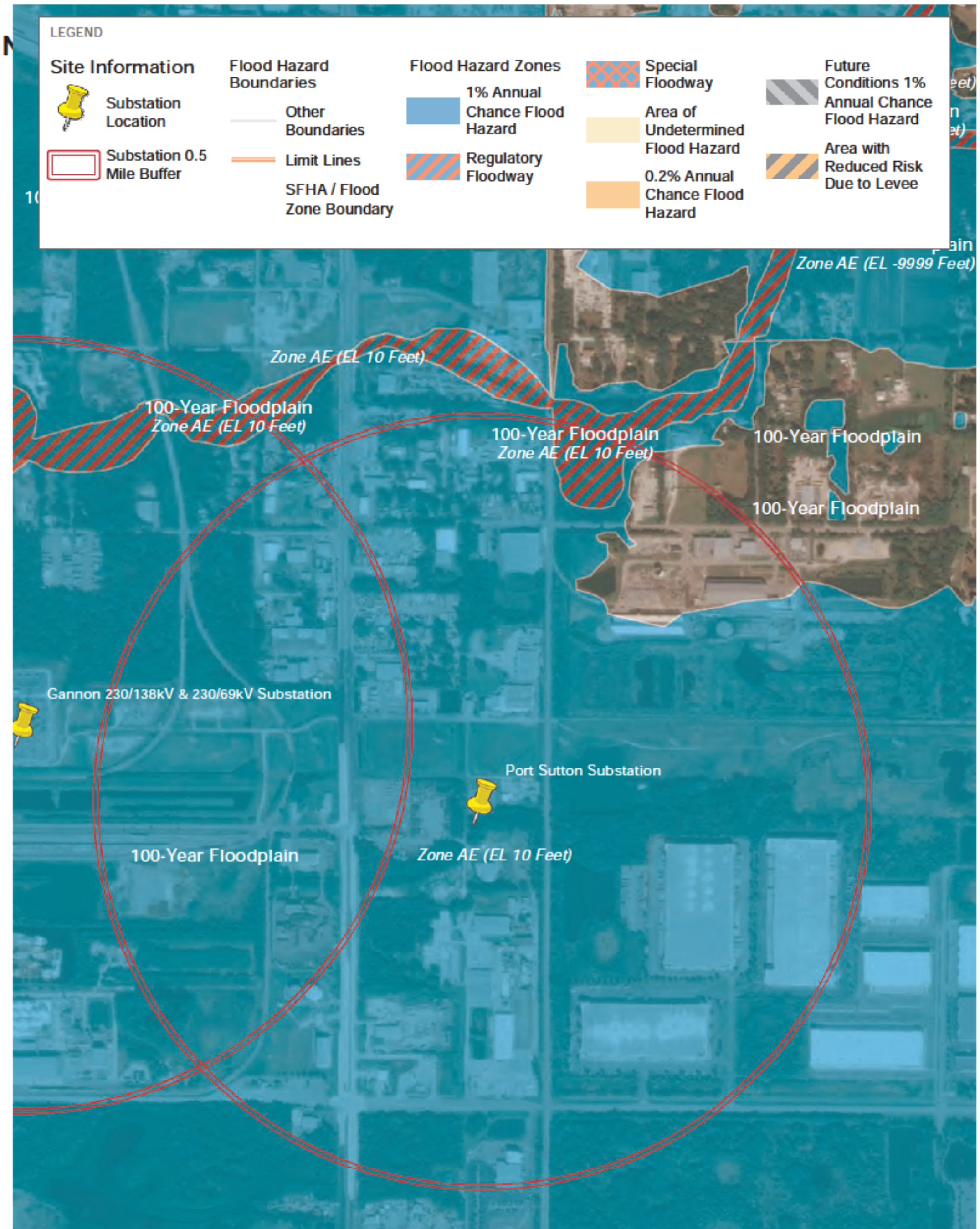


MILLER MAC SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 18)



MILLPOINT 69KV SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 19)



PORT SUTTON SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 20)

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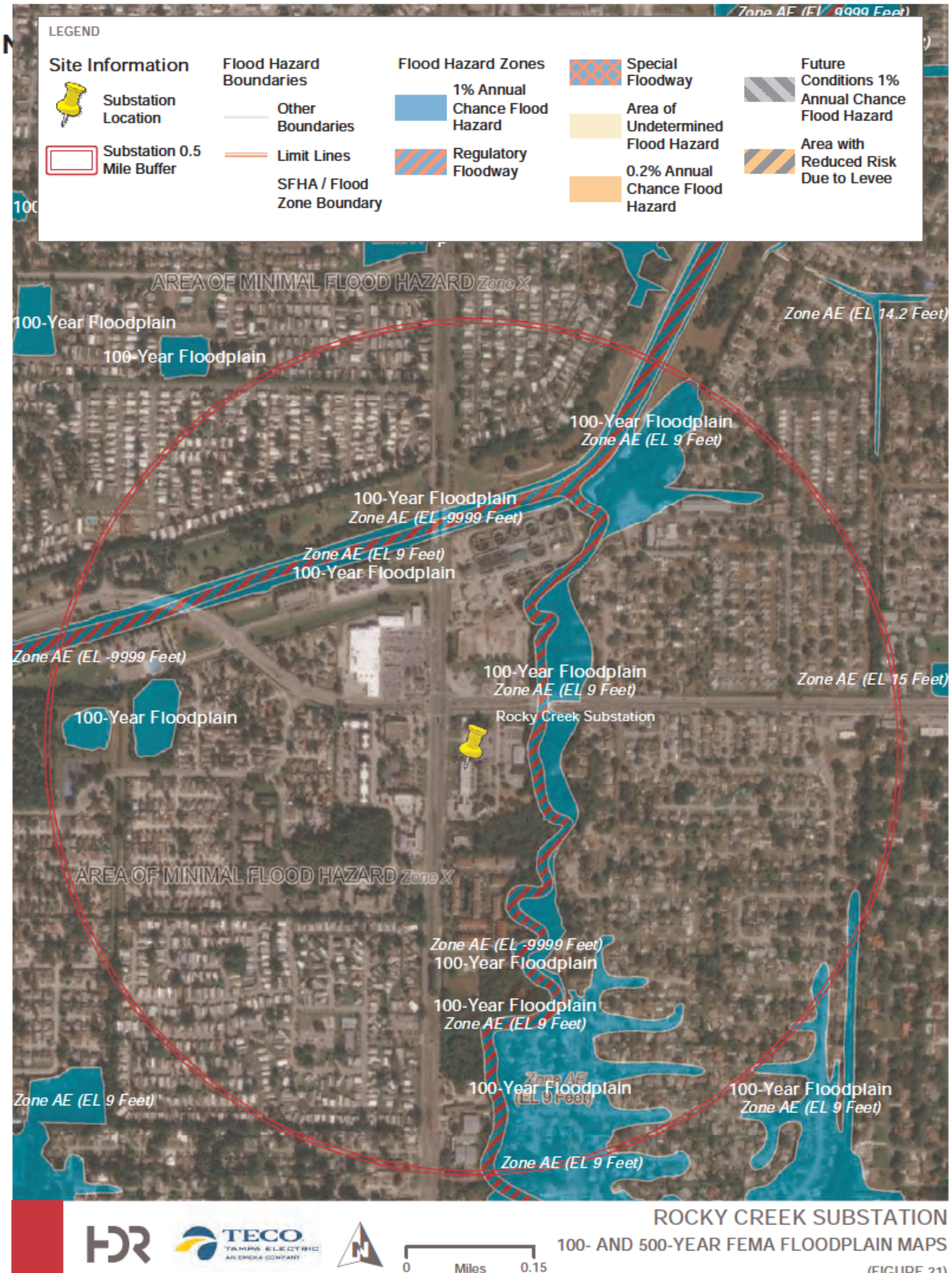

ROCKY CREEK SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 21)

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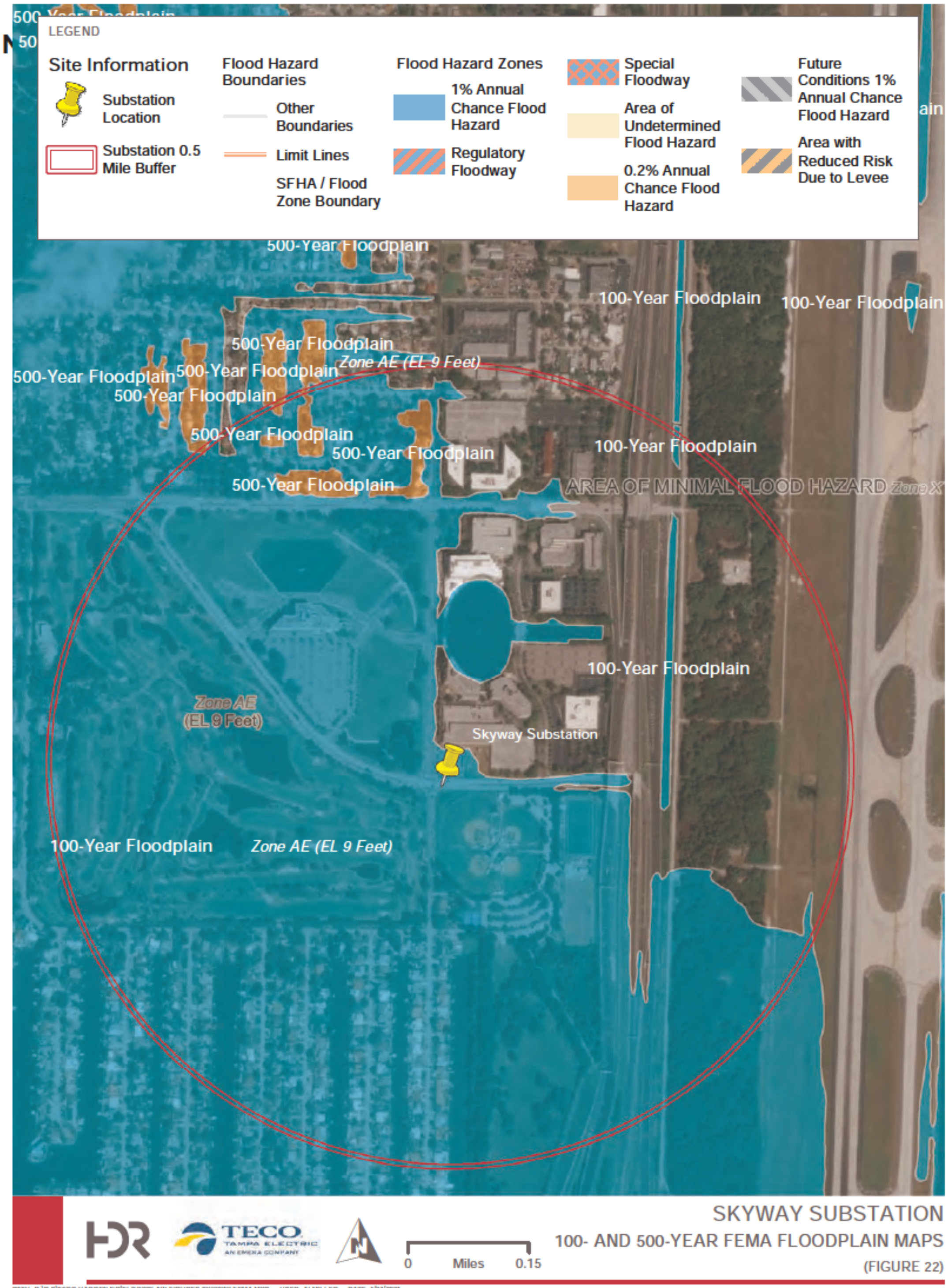
LEGEND
Site Information
Substation Location
Substation 0.5 Mile Buffer
Flood Hazard Boundaries
Other Boundaries
Limit Lines
SFHA / Flood Zone Boundary
Flood Hazard Zones
1% Annual Chance Flood Hazard
Regulatory Floodway
Special Floodway
Area of Undetermined Flood Hazard
0.2% Annual Chance Flood Hazard
Future Conditions 1% Annual Chance Flood Hazard
Area with Reduced Risk Due to Levee
500-Year Floodplain
100-Year Floodplain
Zone AE (EL 9 Feet)
AREA OF MINIMAL FLOOD HAZARD Zone X
Skyway Substation
0
Miles
0.15
SKYWAY SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 22)

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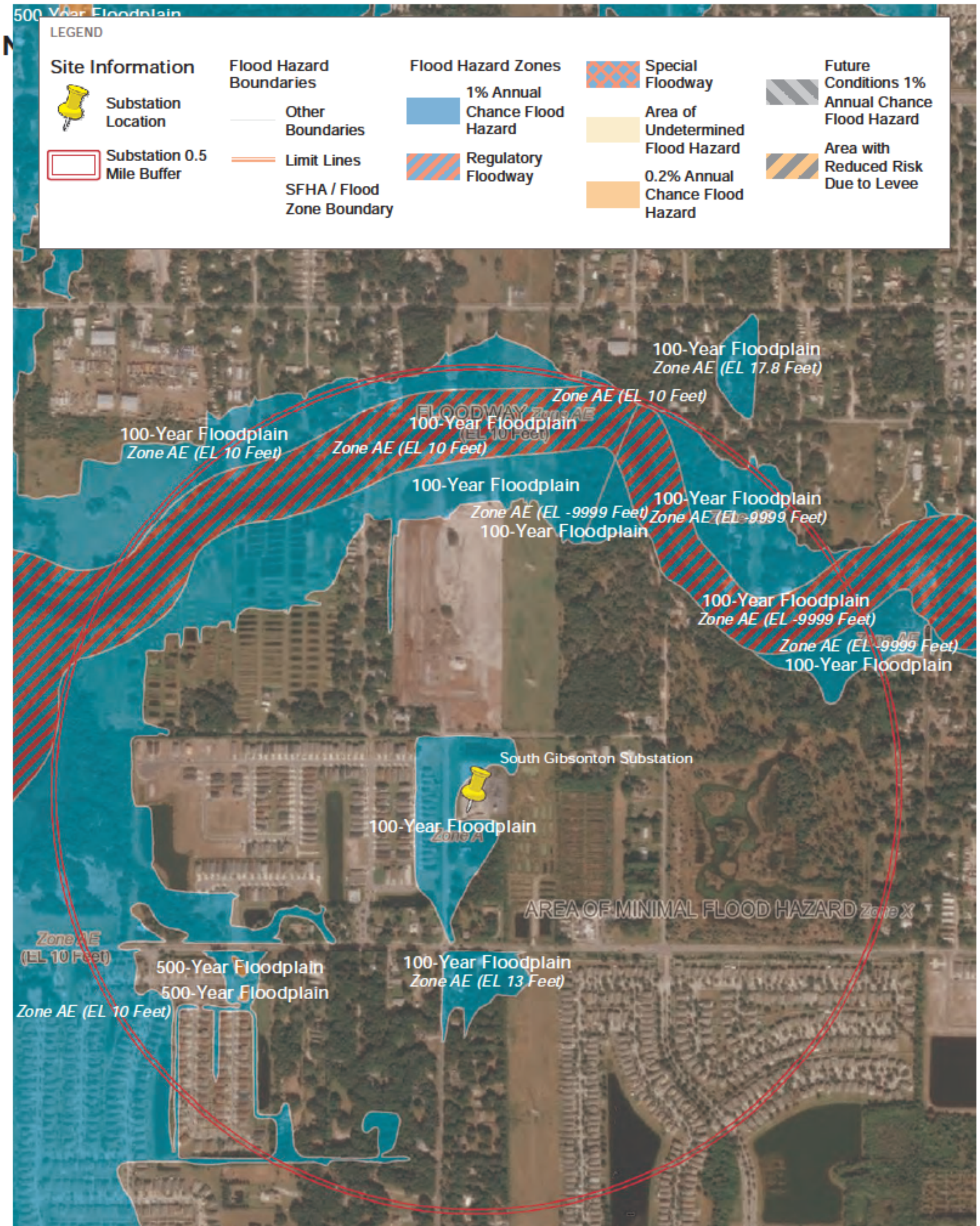

SOUTH GIBSONTON SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 23)

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VEGETATION MANAGEMENT STORM PROTECTION PROGRAM ANALYTIC SUPPORT REPORT

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1 Executive Summary

In 2019, the Florida Legislature enacted a law stating that each investor-owned electric utility (utility) must file a Transmission and Distribution Storm Protection Plan (SPP) with the Florida Public Service Commission ("FPSC").[1] The SPP must cover the utility's immediate ten-year planning period. Each utility must file, for Commission approval, an updated Storm Protection Plan at least every three years.[2] The SPP must explain the systematic approach the utility will follow to achieve the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability.[3] The FPSC later promulgated a rule to implement the SPP filing requirement.[4] This rule went into effect in February of 2020.

Since damage from wind-blown vegetation is a major cause of outages during extreme weather conditions, the rule requires utilities to provide, for each of the first three years of the SPP, a description of its proposed vegetation management activities including:

A. The projected frequency (trim cycle);
B. The projected miles of affected transmission and distribution overhead facilities;
C. The estimated annual labor and equipment costs for both utility and contractor personnel; and
D. A description of how the vegetation management activity will reduce outage times and restoration costs in extreme weather conditions.[5]

TECO is proposing a VM Storm Protection Program that includes three distribution vegetation management initiatives:[6]

1. Four-year distribution vegetation management cycle
2. Incremental initiative to augment annual distribution trimming by targeting supplemental miles each year:
   a. 400 miles in 2020
   b. 500 miles in 2021
   c. 700 miles in 2022 and beyond
3. Consolidate the gains of the baseline distribution cycle trim and supplemental trimming by introducing mid-cycle distribution vegetation inspections two years beyond each trim to prescribe additional distribution VM activities to:
   a. Ensure fast-growing species are kept in check until the next scheduled trimming.
   b. Remove troublesome species, hazard trees, and/or trees putting sensitive infrastructure at risk.

   The mid-cycle initiative will be phased in with the inspections applied to the feeder portion of circuits starting in 2021, rolling out to full circuits (feeder and lateral) starting in 2023.

Beyond the day-to-day and storm benefits, the distribution portion of the VM Storm Protection Program is planned to scale up over time, moving from today's complement of 196 field resources to a peak of 280 field resources across three years, and then settling into a steady-state number of approximately

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[1] § 366.96(3), Fla. Stat.
[2] Document No 09233-2019 Filed on 10/7/2019 with the FPSC, 25-6.030 Storm Protection Plan, p. 1, lines 2-6
[3] § 366.96(3), Fla. Stat. 1
[44] *See* R. 25-6.030, F.A.C.
[5] Document No 09233-2019 Filed on 10/7/2019 with the FPSC, 25-6.030 Storm Protection Plan, p. 3, lines 10-17
[6] The Vegetation Management Program also includes the baseline transmission trim cycles as well an incremental transmission vegetation management initiative, but those activities are outside of the scope of this report.

270 field resources. The phased rollout and associated resource load and budget are outlined in Table 1-1, below:

Table 1-1: Recommended Approach

	Baseline 4-Year Cycle	Supplemental Miles	Feeder Mid-Cycle	Lateral Mid-Cycle	Estimated Resource Load[7]	Budget[8]
2020	Yes	400	Pilot 1-5 Circuits	None	228	$17.1M
2021	Yes	500	Inspect 60 Miles	None	257	$20.0M
2022	Yes	700	Inspect 48 Miles	Pilot 1-5 Circuits	262	$21.4M
2023	Yes	700	Inspect 46 Miles	Inspect 208 Miles	280	$24.0M
2024	Yes	700	Inspect 45 Miles	Inspect 177 Miles	270	$24.3M
2025	Yes	700	Inspect 96 Miles	Inspect 156 Miles	270	$25.5M
2026	Yes	700	Inspect 60 Miles	Inspect 150 Miles	270	$26.8M
2027	Yes	700	Inspect 45 Miles	Inspect 198 Miles	270	$28.1M
2028	Yes	700	Inspect 52 Miles	Inspect 155 Miles	270	$29.5M
2029	Yes	700	Inspect 54 Miles	Inspect 186 Miles	270	$31.0M

These initiatives are projected to reduce day-to-day vegetation-caused customer interruptions by 21 percent and storm-related vegetation-caused outages by 29 percent relative to carrying out the 4-Year Trimming Cycle alone.

[7] Resource projections from 2023 forward fluctuate with the specific blend of circuits that come up for mid-cycle trimming each year. 270 represents the average for these years, and TECO will manage the mid-cycle scope to match budget.

[8] Budget reflects anticipated vegetation management costs for 1) the baseline 4-year cycle trim, 2) supplemental trim miles, 3) mid-cycle activities and 4) corrective maintenance. Excluded are the anticipated company-wide restoration costs associated with day-to-day outages and major storm events

2 Overview

TECO engages in 4-year distribution cycle trimming activities on an ongoing basis, working approximately one quarter of their overhead distribution system mileage every year. The goal is to trim tree limbs such that it will take four years before they can grow sufficiently to encroach on the clearances established for their lines. At various locations in the system, certain fast-growing tree species and/or right-of-way constraints on trimming result in isolated patches that may require attention between scheduled cycle trims. This often takes the form of Corrective Maintenance, where a crew is called out to address an impending issue on a specific tree because its limbs have grown too close to the line or because a tree, aided by the elements, makes contact with the lines and triggers an outage.

TECO continuously analyzes its vegetation management program using some of the industry's leading analytic tools. One of these tools is the Tree Trimming Model (TTM), originally developed by Davies Consulting (acquired by Accenture in 2017). Since the initial implementation of the model in 2006, TECO has continued to refine its program and update the tool's configuration using its growing set of historical spending and reliability performance data.

The TTM employs an analysis of day-to-day outages caused by vegetation, as well as a sampling of outages with unknown and weather cause codes which might be attributable to vegetation. TTM considers such outages in the context of the amount of time that has elapsed since the last time the trees on that circuit were trimmed. Universally, the analysis shows that outage volumes rise as a function of time since last trim, but the degree to which outages and their reliability impact escalate vary as a result of factors such as tree density, tree species, voltage, customer density, microclimate and a variety of others. In the configuration stages of the TTM modeling, circuits are grouped according to their similarity in terms of outage escalation and grouped separately as a function of how expensive it is to trim them, yielding a matrix of combinations of reliability and cost groupings. These expressions of cost and reliability, as a function of time, drive a ten-year prioritization aimed at getting the best day-to-day performance per dollar spent on trimming activities.

During extreme weather conditions, the proximity of limbs to lines and the cross-sectional area of vegetation upon which winds can exert force (referred to herein as the 'sail area') play a large factor in the degree of damage the electrical system will sustain due to vegetation-caused outages. Because the time elapsed since last trim is a direct driver of vegetation to conductor clearances when a storm arrives, the relationship between years since last trim, wind speed, and the extent of damage sustained has been studied and built into TTM's Storm Module. Using the trim list outputs of the TTM and an array of probable windspeeds for the Tampa area, the Storm Module predicts damage levels and associated restoration costs for typical years and can also project the impact of storms of specified magnitude.

Both TTM and the Storm Module address the effects of trimming circuits in their entirety, but some of TECO's proposed Vegetation Management initiatives are more targeted and address only portions of circuits in any given year. To accommodate this, Accenture crafted an Enhanced Storm Module for TTM to estimate the value derived from these targeted initiatives which change the state of only part of any given circuit at a time.

3 Approach

TECO used TTM and its storm modules to establish a set of baseline performance metrics associated with its four-year cycle, and then evaluated supplemental activities against that baseline:

- Supplemental trimming scenarios in which TECO targeted and trimmed an additional 100, 300, 500, 700 or 900 miles per year, and
- Mid-cycle activities whereupon circuits (either the feeder or the complete circuit) are inspected two years after their most recent trim, and follow-up vegetation management activities are prescribed to enhance both the day-to-day and extreme weather condition performance of the system.

The effects of the supplemental trimming and mid-cycle initiatives build upon the base of the 4-year trimming cycle. For consistency of presentation throughout the document, all three are referred to herein as initiatives:

Table 3-1: Initiative Approach

Initiative	Name
1	Baseline 4-year Trimming Cycle
2	Supplemental Trimming
3	Mid-cycle Inspection & VM Activities

The effects of these initiatives are cumulative, in that any version of Initiative 2 requires that the baseline 4-year cycle to be in effect, and Initiative 3 would not be implemented without the baseline trim cycle and Initiative 2 in place. There are many different combinations of activities, any of which could serve as the company's VM program. The benefits of each possible activity can only be evaluated by comparing the benefits of different programs, or combinations of activities. Consequently, the team created different possible VM programs, each with a different set of component activities. The programs which appear in this document consist of component activities as follows:

Table 3-2: Program Nomenclature and Initiative Components

Program Name	Initiative 1 Component	Initiative 2 Component	Initiative 3 Component
Program 1	4-year cycle trim	n/a	n/a
Program 2 – 100	4-year cycle trim	100 Supplemental Miles	n/a
Program 2 – 300	4-year cycle trim	300 Supplemental Miles	n/a
Program 2 – 500	4-year cycle trim	500 Supplemental Miles	n/a
Program 2 – 700	4-year cycle trim	700 Supplemental Miles	n/a
Program 2 – 900	4-year cycle trim	900 Supplemental Miles	n/a
Program 3a – 700	4-year cycle trim	700 Supplemental Miles	Mid-cycle on feeders only
Program 3b – 700	4-year cycle trim	700 Supplemental Miles	Mid-cycle on whole circuits
Program 2 – 457	4-year cycle trim	Phased approach – 400 Supplemental Miles in 2020, 500 in 2021 and 700 in 2022 and beyond	n/a
Program 3ab - 457	4-year cycle trim	Phased approach – 400 Supplemental Miles in 2020, 500 in 2021 and 700 in 2022 and beyond	Phased approach – mid-cycle on feeders only in 2021 and 2022, mid-cycle on full circuits in 2023 and beyond

Upon finding an optimal endpoint, TECO examined the resource implications of the program and adapted the approach to phase in both the supplemental trimming initiative and the mid-cycle initiative to allow for a smooth transition into the program.

Prior to running the various scenarios, TECO engaged Accenture to refresh the TTM configuration and the various assumptions built into the TTM Storm Module. The configuration process and associated assumptions are captured in Section 6: Tree Trimming Model & Modules Configuration.

4 Storm Protection Initiatives Analysis

TECO and Accenture analyzed several vegetation management activities to determine an optimal level of supplemental trimming to reduce vegetation related outages during extreme weather events while continuing to minimize day-to-day vegetation related outages.

The following initiatives were considered:

Table 4-1: Vegetation Management Initiatives Analyzed

	Initiative Name	Initiative Description	Modeling Methodology
1	Baseline: 4-Year Effective Cycle	Trim 25% of TECO's overhead lines (~1,562 miles) annually.	Target 25% of the miles in each of TECO's 7 districts for trimming annually.
2	Supplemental Circuit Trimming	Trim an additional 100 – 900 targeted miles annually with a view to mitigating outage risk on those circuits most susceptible to storm damage	Five scenarios modeled – 100, 300, 500, 700 and 900 miles. Due to the nature of the algorithm and available targeting data, targeting is based on SAIFI performance in regular weather.
3a	Mid-cycle VM Initiative – Feeders Only	Add mid-cycle inspections to feeder portions of circuits (~35% of line miles) two years after trim, prescribing additional VM activities to a fraction of the trees inspected.	The TTM Enhanced Storm Module assumes that one quarter of the trees inspected will be targeted for re-trimming when inspected and promptly trimmed. As TTM works with miles of circuit rather than individual trees, this is modeled as one quarter of the feeder miles re-setting to trimmed in that year, while the remainder of the circuit continues to age. Within the model, the costs associated with day-to-day restoration, storm restoration, and corrective maintenance costs are re-calculated to reflect the new trim-age profile of the circuit.
3b	Mid-cycle VM Initiative – Full Circuits	Extend the inspection and prescribed activities described in Initiative 3a to the entire circuit. As with 3a, it is assumed that a fraction of the trees inspected will require mid-cycle VM activities.	As described above in Initiative 3a, TTM Enhanced Storm Module assumes one quarter of the entire circuit is re-trimmed at two years, with an impact on day-to-day restoration costs, storm restoration costs and corrective maintenance costs.

The Supplemental Circuit Trimming initiative seeks to reduce tree-caused outages by reducing the proximity between tree limbs and lines, as well as reducing trees' sail area which would otherwise cause them to sway or break as wind speed increases.

The Mid-cycle VM initiative focuses on some of the same proximity and sail area reduction efforts on the trees which grow the quickest and may encroach on lines despite the best efforts of the trimming cycle and supplemental trimming, as well as other activities to slow tree growth or eliminate hazard trees altogether.

4.1 Baseline Trim Cycle and Initiative 1 Variants

TECO and Accenture ran the company's ongoing 4-year cycle trim through the model to project its full budget implications across seven categories of cost to form a baseline against which the incremental benefits of supplemental trimming activities can be measured. The associated costs are broken out as follows, along with indicators as to whether the cost component in question is part of the VM budget and whether the costs are associated uniquely with VM resources or, as in the case of outage restorations, extend further into the organization:

Table 4-2: Cost Categories

Cost Category	Applies to what resources?	Part of Storm Protection Program	Part of VM Budget?
Cycle Trimming	Vegetation	Yes	Yes
Supplemental Trimming	Vegetation	Yes	Yes
Mid-Cycle	Vegetation	Yes	Yes
Corrective Cost	Vegetation	No	Yes
Resource Premiums	Vegetation	Yes	Yes
Day to Day Restoration Costs	Line & Vegetation	No	No
Storm Restoration Costs	Line & Vegetation	No	No

Note that the anticipated spending levels for the two categories of restoration cost are driven by vegetation management decisions but are not part of the vegetation management budget. They are considered and presented within this analysis because the investments in enhancing vegetation management for the Storm Protection Plan should be offset by reductions in cost due to outage response.

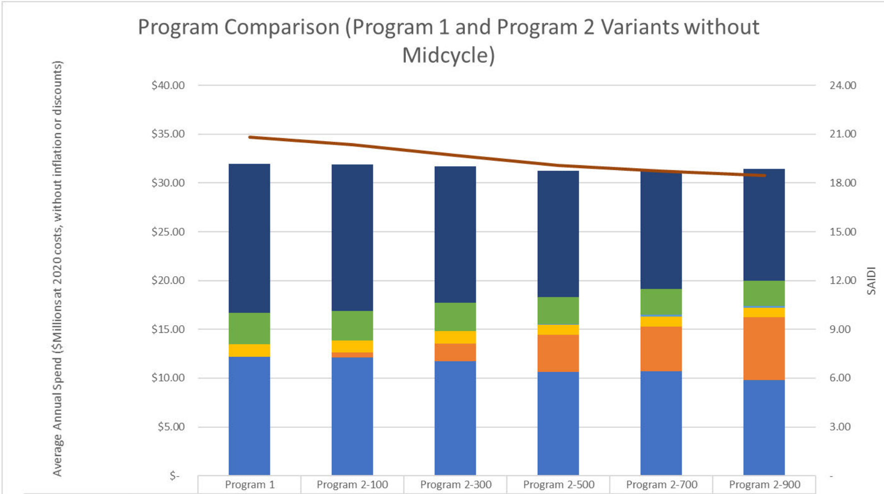
In the baseline scenario, each service area is allotted one quarter of its mileage every year, or approximately 1,562 miles in total. Central, for example, accounts for one sixth of TECO's overhead miles, and is afforded one sixth of the annual 1,562-mile budget as depicted below.

Table 4-3: Baseline 4-Year Effective Cycle Mileage Targets

Service Area	Mileage Target	Percentage
Central	260	16.6%
Dade City	93	6.0%
Eastern	209	13.4%
Plant City	310	19.8%
South Hillsborough	182	11.7%
Western	277	17.7%
Winter Haven	231	14.8%
Total	1,562	100.0%

In the supplemental trimming initiatives, one quarter of the supplemental miles is allocated across the service areas in the same proportions as the 4-year distribution trim cycle. The remainder of the miles are directed where they will deliver the greatest benefit. Thus, in a scenario where 400 supplemental miles were trimmed, 100 miles would be constrained with 16.6 occurring in Central, 6.0 miles in Dade City, 13.4 miles in Eastern, and so on with the remaining 300 miles of trimming directed to the areas where it would deliver the greatest benefit.

The costs for the baseline scenario and five variants of supplemental trimming, without mid-cycle, are plotted below:



	Program 1	Program 2-100	Program 2-300	Program 2-500	Program 2-700	Program 2-900
Storm Restoration Cost	$15.31	$14.99	$13.97	$12.92	$12.08	$11.42
Day-to-Day Restoration Cost	$3.19	$3.05	$2.91	$2.77	$2.69	$2.63
Resource Premiums	$-	$0.03	$0.00	$0.05	$0.14	$0.15
Corrective Cost	$1.30	$1.23	$1.30	$1.08	$1.03	$0.99
Mid-Cycle Cost	$-	$-	$-	$-	$-	$-
Supplemental Trimming Cost	$-	$0.50	$1.80	$3.81	$4.62	$6.44
Baseline 4-Year Cycle Cost	$12.19	$12.10	$11.72	$10.61	$10.69	$9.79
SAIDI	20.83	20.36	19.70	19.09	18.75	18.45

Figure 4-1: Program Comparison

The average annual vegetation management budget, without inflation, for these six options ranges from $13.5M for the as-is 4-year trimming cycle to $17.4M for the cycle plus 900 miles of supplemental trimming annually. Meanwhile the annual total restoration costs, which include all line work and vegetation management costs for storm restoration, trend in the opposite direction from $18.5M for the baseline 4-year cycle to $14.1M for the 900-mile variant. The total anticipated cost of the VM budget and restoration combined sits in a narrower range, at $32.0M for the baseline 4-year cycle and $31.25 M for the 500 and 700-mile variants.

The side-by-side comparison of scenarios yields several insights:

- The introduction of supplemental trimming drives down the cost of the baseline four-year cycle. This is because the extra activity on the lines makes trimming the annual 1,562 miles less expensive each year since the tree limbs have had less time to grow and are neither as long nor as close to the lines as they would have been otherwise.
- The increases in cost associated with the Storm Protection Program 2 variants and associated resource premiums is offset by decreases in cost in the 4-year cycle trim, corrective maintenance, day-to-day restoration costs and storm restoration costs, up to the 500 to 700-mile range.
- Although difficult to see in Figure 4-1, the 500 mile and 700-mile programs yield the best overall average annual cost, which, due to diminishing returns, begins to trend back upwards starting with the 900-mile program. See Figure 4-2, below, for a view focused on total cost.
- Each supplemental increase in Program 2 yields an improvement in SAIFI and SAIDI, although the gains slow in the 500-mile to 700-mile range.

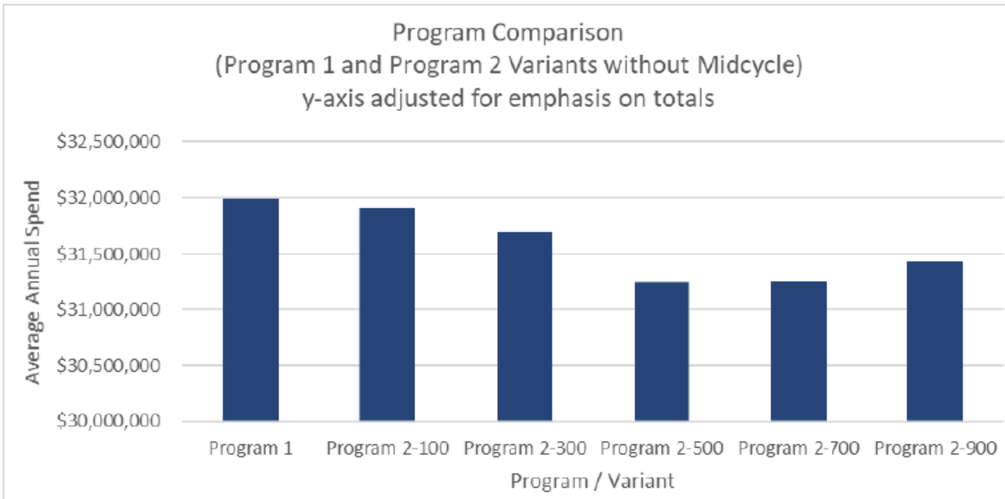


Figure 4-2: Program Comparison with Focus on Total Average Annual Spend

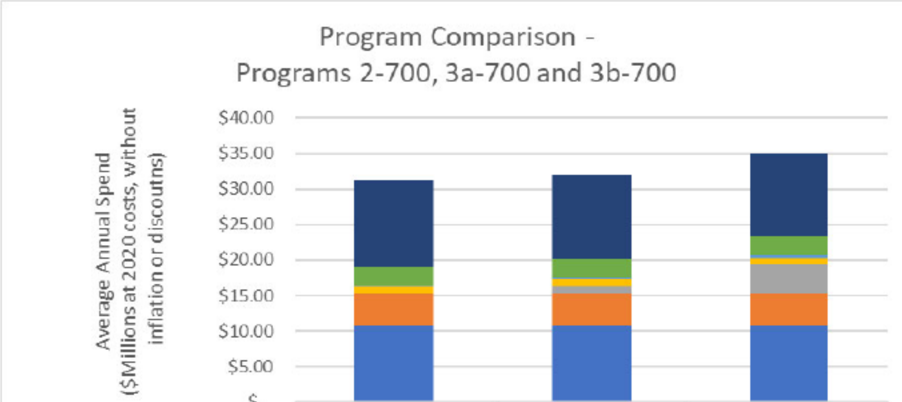
- While the 500 mile and 700-mile programs are in a virtual tie from an overall cost perspective, there is a clear advantage to the 700-mile program from the customer experience perspective. The 700-mile program drives 16 percent and 21 percent improvements in the ten-year average day-to-day and storm restoration costs, which are directly linked to customer interruptions. Across the ten-year span of the 500-mile program, these figures are 13 percent and 16 percent.

Table 4-4: 10-year Average Outage Restoration Improvements for Programs 2-500 and 2-700 Relative to Program 1

Cost Element	Program 1 Average 2020-2029	Program 2-500 Average 2020-2029	Program 2-700 Average 2020-2029	Improvement for Program 2-500	Improvement for Program 2-700
Day-to-Day Restoration	$3.19 M	$2.77 M	$2.69M	13.2%	15.7%
Storm Restoration	$15.31 M	$12.92M	$12.08M	15.6%	21.1%

4.2 Storm Protection Initiative 3a & 3b – Mid-cycle Inspection and VM Activities

Based on the results presented in Section 4.1, Initiatives 3a and 3b were analyzed in the context of Program 2-700, where 700 supplemental and targeted miles are trimmed each year. The average annual cost of the inspectors and VM resources for the mid-cycle initiatives was $1.06M and $4.05M, respectively, and they yielded a further 2.5 percent and 4.5 percent improvements to storm restoration costs from $12.08M to $11.77M and $11.54M.



	Program 2-700	Program 3a-700	Program 3b-700
Storm Restoration Cost	$12.08	$11.77	$11.54
Day-to-Day Restoration Cost	$2.69	$2.68	$2.65
Resource Premiums	$0.14	$0.16	$0.45
Corrective Cost	$1.03	$0.99	$0.95
Mid-Cycle Cost		$1.06	$4.05
Supplemental Trimming Cost	$4.62	$4.62	$4.62
Baseline 4-Year Cycle Cost	$10.69	$10.69	$10.69

Figure 4-3: Storm Protection Program Mid-Cycle Comparison

Table 4-5: 10-year Average Outage Restoration Improvements for Programs 3a-700 and 3b-700 Relative to Program 2-700

Cost Element	Program 2-700 Average 2020-2029	Program 3a-700 Average 2020-2029	Program 3b-700 Average 2020-2029	Improvement for Program 3a-700	Improvement for Program 3b-700
Storm Restoration	$12.08M	$11.77M	$11.54M	2.6%	4.5%
Day-to-Day Restoration	$2.69M	$2.68M	$2.65M	0.4%	1.5%

As noted previously, the modeling approach may not reflect the full value of the mid-cycle activities. While the Tree Trimming Model considers circuits in their entirety, the mid-cycle initiative would be targeted based on inspections and storm impact and is highly likely to yield greater benefits than what is reflected here. Also, some of the prescribed activities under the mid-cycle initiative, such as tree removals, will yield permanent and cumulative results not captured here. Simply put, it is believed that the benefits of the mid-cycle initiative will exceed what is shown here.

4.3 Developing a Blended Strategy to Accommodate Resource Constraint

Resource impact is one final element to draw out of the Storm Protection Program 2 and Storm Protection Program 3a/3b analyses. The 500, 700, and 900-mile versions of Storm Protection Program 2 all incur cost premiums associated with the rapid increase in size to the workforce required. Programs

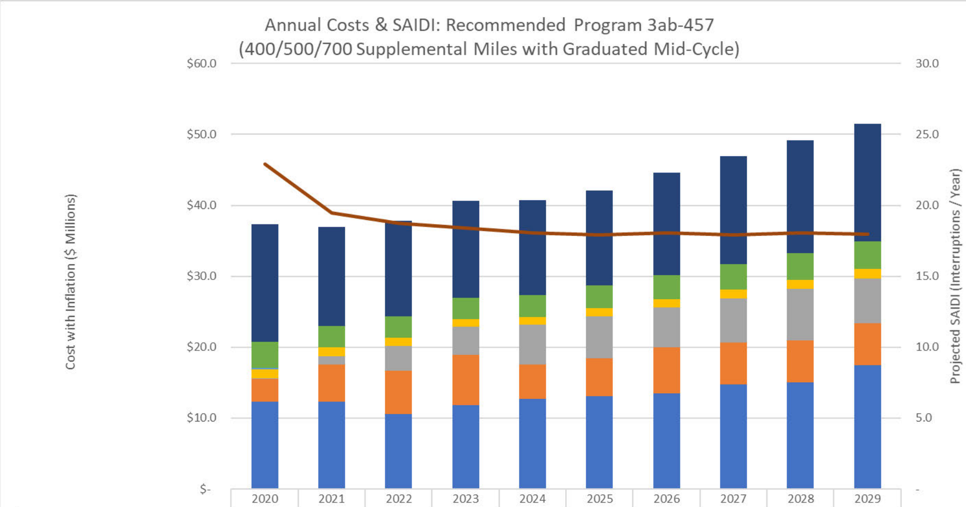
3a-700 and 3b-700 exacerbate the resource crunch. While the average annual VM budget (without inflation) for Program 2-700 (Baseline + 700 supplemental miles) is estimated at $16.4M and would require an average of 220 resources to execute, the first year VM budget would be $19.0M and require roughly 256 resources. With 196 resources in the field at present, the uptake of 60 workers in a single year would represent a very large challenge and require significant expenditure on overtime and premium incentives to achieve, particularly if the transition happens later in the year. Adding Initiative 3a or 3b simultaneously would further exacerbate the issue.

TECO is proposing instead to transition towards the 700-mile version of Initiative 2 over the course of three years by trimming 400 extra miles in 2020, 500 extra miles in 2021 and finally arriving at the 700-mile program in 2022. The mid-cycle initiative will also be introduced gradually, addressing feeders alone in the second and third years and moving towards inspecting full circuits in the fourth year and beyond as better data becomes available about the success of mid-cycle inspections and VM activities.

5 Recommendation

The recommended Vegetation Management Storm Protection Program (Program 3ab-457) consists of the following activities:

1) **Baseline Cycle**: continue the 4-year trimming cycle
2) **Supplemental trimming initiative**: scale up supplemental trimming miles by targeting an additional 400 miles in 2020, 500 miles in 2021, and 700 miles from 2022 going forward
3) **Mid-cycle VM initiative**: introduce mid-cycle inspections and associated targeted activities for the feeder portions of circuits in 2021, extending the inspections and prescribed activities to cover entire circuits from 2023 forward, with 60 miles inspected in 2021, 48 miles in 2022 and 254 miles in 2023 as the program rolls out to entire circuits.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Storm Restoration Cost	$16.6	$13.9	$13.5	$13.6	$13.3	$13.4	$14.4	$15.3	$16.0	$16.6
Day-to-Day Restoration Cost	$3.6	$3.0	$2.9	$3.0	$3.1	$3.2	$3.4	$3.5	$3.7	$3.9
Resource Premiums	$0.2	$-	$-	$-	$-	$-	$-	$-	$-	$-
Corrective Cost	$1.3	$1.3	$1.2	$1.1	$1.1	$1.1	$1.2	$1.2	$1.3	$1.3
Mid-Cycle Cost	$0.1	$1.2	$3.5	$4.0	$5.6	$6.0	$5.7	$6.2	$7.3	$6.3
Supplemental Trimming Cost	$3.2	$5.2	$6.1	$7.1	$4.8	$5.3	$6.5	$5.9	$5.9	$5.9
Baseline 4-Year Cycle Cost	$12.4	$12.3	$10.5	$11.8	$12.7	$13.1	$13.4	$14.7	$15.0	$17.5
SAIDI	22.9	19.5	18.8	18.4	18.1	17.9	18.1	17.9	18.1	18.0
Estimated Resource Requirement	228	257	262	280	270	270	270	270	270	270

Figure 5-1: Annual Costs and SAIDI – Recommended VM Program

The VM Budget (SPP and Non-SPP) and Restoration Costs are summarized below:

Table 5-1: VM Storm Protection Program 3ab-457 Performance Characteristics

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total VM Budget	$17.1	$20.0	$21.4	$24.0	$24.3	$25.5	$26.8	$28.1	$29.5	$31.0
Restoration Costs	$20.3	$17.0	$16.5	$16.6	$16.4	$16.6	$17.8	$18.8	$19.7	$20.5
Total VM-Influenced Costs	**$37.4**	**$36.9**	**$37.9**	**$40.6**	**$40.7**	**$42.1**	**$44.6**	**$46.9**	**$49.2**	**$51.5**

From a benefits perspective, two measures are worth exploring because the program takes a few years to establish: the overall ten-year average performance, and the future steady-state value taken in this case by considering the average of the last five years in the analysis. For the 10-year and 5-year end state averages, all years and cost elements are priced at 2020 rates, with no inflation.

Table 5-2: VM Storm Protection Program 3ab-457 Performance Characteristics

	10-Year Average			Future Steady-State (Average of Last Five Years)		
	Program 1	Program 2-457	Program 3ab-457	Program 1	Program 2-457	Program 3ab-457
SAIFI	0.229	0.195	0.193	0.227	0.184	0.181
SAIDI	20.8	18.9	18.8	20.7	18.2	18.0
Typical Storm Season	$15.3 M	$12.4 M	$11.9M	$15.1 M	$11.4 M	$10.7 M
65 mph Storm	$16.6 M	$14.0 M	$13.3 M	$16.3 M	$13.2 M	$12.4 M
85 mph Storm	$37.1 M	$31.3 M	$29.8 M	$36.5 M	$29.6 M	$27.6 M
105 mph Storm	$69.9 M	$59.0 M	$56.1 M	$68.7 M	$55.7 M	$52.1 M
125 mph Storm	$117.9 M	$99.5 M	$94.6M	$109.8 M	$94.0 M	$87.9 M

The proposed Program 3ab-457 is projected to improve SAIFI by 15.3 percent relative to the baseline 4-year cycle over the full period, or by 21.3 percent if just the final five years are considered. SAIDI improvement is 9.6 percent across ten years, or 14.0 percent in the future steady state. Storm performance improves by 22.2 percent across ten years, or 29.1 percent in the future steady state.

6 Tree Trimming Model & Modules Configuration

The Tree Trimming Model requires intermittent updates wherein the latest circuit configuration, trimming and outage history are employed to ensure the model is using the latest information available when targeting circuits for trimming. In addition, the storm module requires updates to a variety of cost and workforce assumptions to perform its functions correctly.

6.1 TTM Inputs and Assumptions

TTM requires three principal data sources:

- A complete inventory of the overhead circuits in the system, including circuit characteristics such as customer count, overhead mileage, and geographic coordinates;
- The outage database or databases; and,
- A history of trimming activity, preferably including start and end dates, costs, and covering multiple trims for each circuit.

6.1.1 Circuit List

A comprehensive list of circuits was obtained from TECO, which contained a total of 780 circuits.

Not all circuits and mileage were of interest, as TTM is only relevant to the overhead portion of circuits for which trimming is a regular concern. Ultimately, 709 “trimmable” circuits were included in the analysis, representing some 6,247 miles of overhead circuit length.

6.1.2 Performance Data

Circuit reliability performance data was gathered from TECO’s Distribution Outage Database (DOD). The analysis included outages from January 1, 2006 through November 26, 2019, thus accommodating at least thirteen years of data. Of interest were outages with the tree-related cause codes found in Table 6-1below. The table indicates the number of events associated with each cause code, as well as the total customer interruptions (CI) and customer minutes of interruption (CMI).

Table 6-1: Tree-Related Cause Codes (January 1, 2006 - November 26, 2019)

Cause Code	Events	CI	CMI
Tree\Blew into Line	305	20,060	1,219,189
Tree\Non-Prev.	9,970	811,842	68,744,420
Tree\ Prev.	9,776	740,361	66,143,332
Tree\Grew into Line	1,644	110,815	8,404,342
Tree\Vines	5,984	210,380	7,476,754
Trees (Other)	436	22,815	1,879,906
Incorporated Unknown (25%)	2,732	162,248	10,206,418
Incorporated Weather (25%)	6,190	389,703	35,775,171
Grand Total	37,037	2,468,224	199,849,532

TECO also incorporated a portion of CIs and CMIs from outages with "Unknown" and "Weather" cause codes. From experience, Accenture has found with other utilities that a significant portion of such catch-all causes is, in fact, tree-related. Therefore, after conducting an internal analysis of trends in outage counts for these cause codes in relation to explicit tree cause codes, TECO determined that 25 percent was a reasonable proportion to include in the analysis.

Finally, certain outages were excluded from this analysis irrespective of the cause code. These included those adjustments specified and allowed in accordance with Rule 25-6.0455, Florida Administrative Code.

6.1.3 Trim Data

TECO records and maintains trim history that includes the following types of data:

- Circuit number;
- Trim start date;
- Trim completion date;
- Miles trimmed; and,
- Cost to trim the entire circuit.

Similar to the performance data, the analysis included trimming data from January 1, 2006 through November 26, 2019. The trim data was pared down to the outage data with the circuit number being the link between the two data sources. For analysis purposes, the circuit number and trim completion date (year and month of trim) of each circuit trim were incorporated in the analysis.

6.2 Reliability Performance Curve Development

6.2.1 Creating Circuit Performance Groups

Circuits were ordered according to historical performance. A total of seven groups were identified so that around 1,130 miles were represented in each group. Group 07 were the circuits that had zero tree-related outages from 2006-2019.

Table 6-2: CI Grouping Characteristics

Circuit CI Group	CI per Mile Criteria	Circuits	Miles
01	Greater than 649	164	1,117
02	Between 467 and 649	95	1,135
03	Between 277 and 467	131	1,136
04	Between 193 and 277	70	1,134
05	Between 104 and 193	101	1,132
06	Between 0.3 and 104	168	1,130
07	Less than 0.3	66	19

Table 6-3: CMI Grouping Characteristics

Circuit CI Group	CMI per Mile Criteria	Circuits	Miles
01	Greater than 55,483	159	1,130
02	Between 34,277 and 55,483	114	1,125
03	Between 22,485 and 34,277	114	1,107
04	Between 14,427 and 22,485	83	1,133
05	Between 8,340 and 14,427	87	1,152
06	Between 19.3 and 8,340	172	1,136
07	Less than 19.3	66	19

6.2.2 Circuit Performance Curve Fitting

Performance data points were derived using historical outage data, trim data, and circuit length data. Every outage was expressed as a number of CI or CMI per circuit mile and was plotted relative to the most recent time it was trimmed. Values for 12 consecutive individual months were rolled up to create year-based values, and these were plotted in MS Excel so that a curve could be fit to them.

Several conditions had to be satisfied in order to ensure that the data points were correct:

- Outage data was omitted in the months when a circuit was being trimmed.

- Outages were associated only to the most recent trim.
- Figure 6-1 below reflects the mileage into which the 12-month roll-up of CI or CMI is divided and represents the total mileage of the system or group of circuits. This ensures that in a situation where several circuits do not have any outages in a particular 12-month roll-up, those circuits were not disregarded, but rather served to appropriately pull the curve downward as part of the averaging process. This provided assurance that the resulting curves were representative of the overall CI or CMI per mile of circuits in the group and not just the CI or CMI per mile on circuits that happened to have outages.

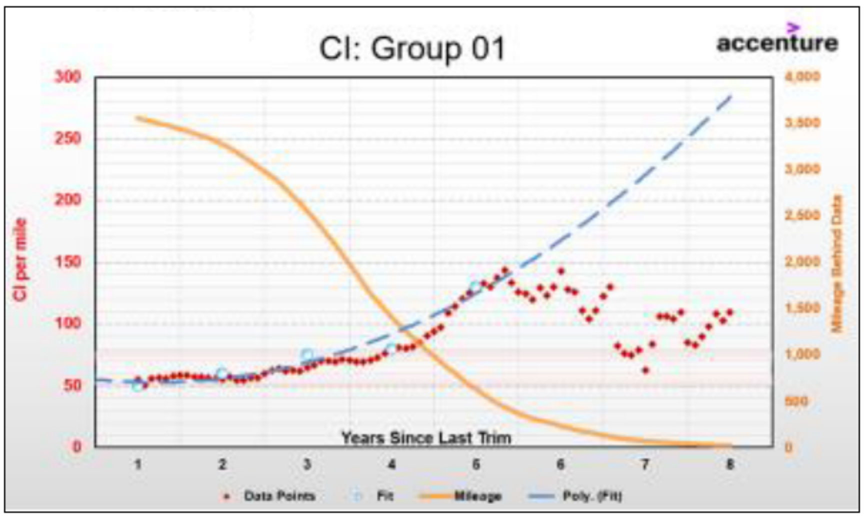


Figure 6-1: Example of Curve Fitting Analysis

A curve similar to that shown in Figure 6-1 was developed for each of the CMI groups, resulting in a total of fourteen curves, which are shown in Figure 6-2 and Figure 6-3 respectively. These curves provided the critical input required to compute the projected reliability associated with trimming each circuit. Eventually, the computed reliability values were used as the denominator to determine the cost-effectiveness score for circuits, which then served as the basis for their prioritization.

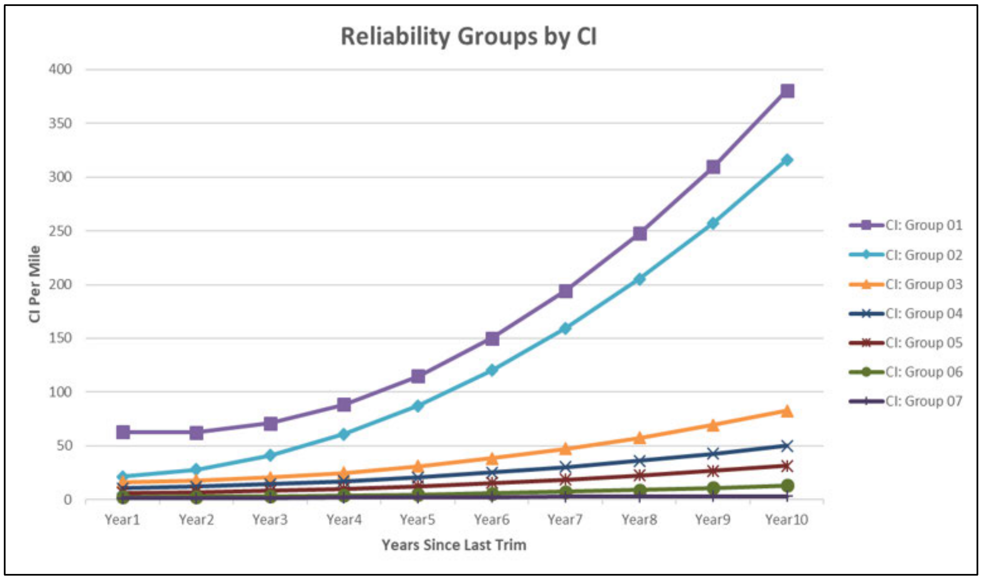


Figure 6-2: Customer Interruption (CI) Curve Groups

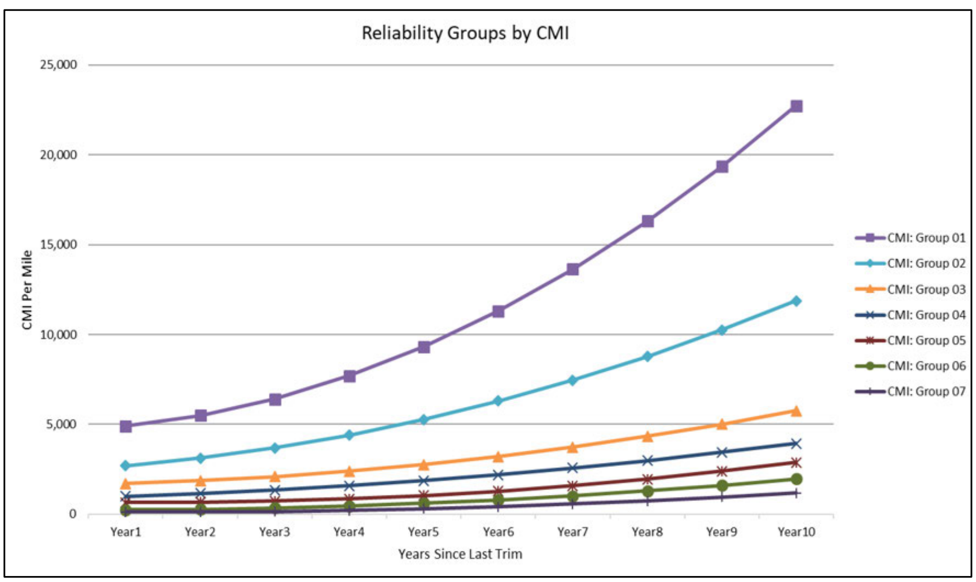


Figure 6-3: Customer Minute Interruption (CMI) Curve Groups

6.2.3 Cost Curves

Cost curves were the second factor in calculating the cost/benefit score of each circuit in TTM.

The shapes of the cost curves were based on a proprietary study called the Economic Impacts of Deferring Electric Utility Tree Maintenance by ECI[9] that quantified the percentage increase in the eventual cost of trimming a circuit for each year that it is left untrimmed beyond the recommended clearance cycle. The findings of the ECI study are summarized in Figure 6-4 below. For instance, if the clearance cycle is three years, then waiting four years between trims will increase the cost per mile by 20 percent. Delaying trimming by another year will further inflate costs to 40 percent of the base cost and further increase it for subsequent years.

The ECI study only considered annual trimming cost increases between the recommended clearance cycle and up to a four-year delay. In generating a comprehensive cost curve that goes from one year since last trim onward, Accenture supplemented the percentages from the ECI study with two assumptions:

- Cost reduction from annual trimming – the percentage reduction from the clearance trim that will be achieved if the circuit was trimmed every year; and,
- Escalation – annual percentage increase in cost to be applied from the ninth year and beyond.

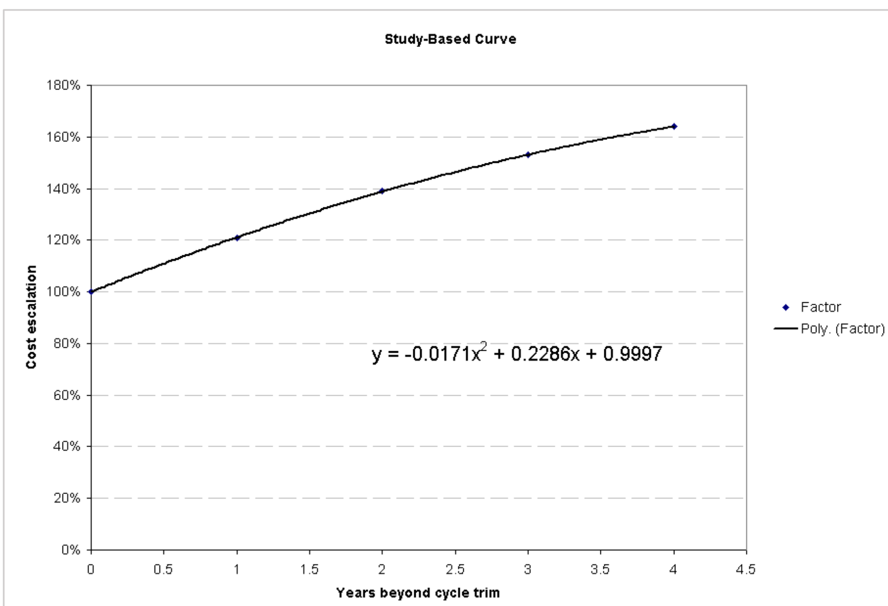


Figure 6-4: ECI Study-Based Cost Curve

The following section describes how such a cost curve methodology was applied to each cost group.

[9] Browning, D. Mark, 2003, Deferred Tree Maintenance, Environmental Consultants Incorporated (ECI)

Similar to how the performance groups were created, circuits were ordered according to the average cost per mile. Initially a total of six groups were identified so that each had around 1,000 miles represented in each group. Group 01 ranged from $7,600/mile to $41,000/mile and it was important to further divide it into smaller groups due to the large range between costs. Ultimately, Group 01 was divided into 4 smaller groups so that the ranges were more reasonable. The same was true on the other side of the spectrum and the lowest cost group was split into two groups. Ultimately, circuits were grouped into 10 distinct groups as shown in the following table:

Table 6-4: Cost Grouping Characteristics

Circuit Cost Group	Cost per Mile Criteria	Circuits	Miles
01	Greater than $25,000	14	79
02	Between $15,500 and $25,000	26	158
03	Between $10,000 and $15,500	42	225
04	Between $7,600 and $10,000	90	713
05	Between $6,100 and $7,600	103	1,088
06	Between $5,000 and $6,100	109	1,016
07	Between $4,100 and $5,000	91	1,037
08	Between $3,300 and $4,100	89	1,058
09	Between $1,500 and $3,300	116	896
10	Less than $1,500	25	100

With this group information a curve was created for each using the average cost per mile in each group with an additional twenty-five percent increase on each. The additional twenty-five percent was added to adjust historical trimming costs to 2019 dollars. Since TECO is on a four-year effective trim cycle each cost group is anchored on Year 4 with its respective adjusted average cost per mile. The remaining points were determined using the expertise of TECO and Accenture:

- Years 1: A 35 percent reduction in average cost if TECO would return to a circuit a year later
- Years 2-3: Linear increase in spending from Year 1 to Year 4
- Years 5-8: Follow the cost escalation described in Figure 6-5.
- Years 9-10: A 5 percent increase for each year trimming is delayed

These datapoints and assumptions were used to fit a curve for each of the cost groups shown below:

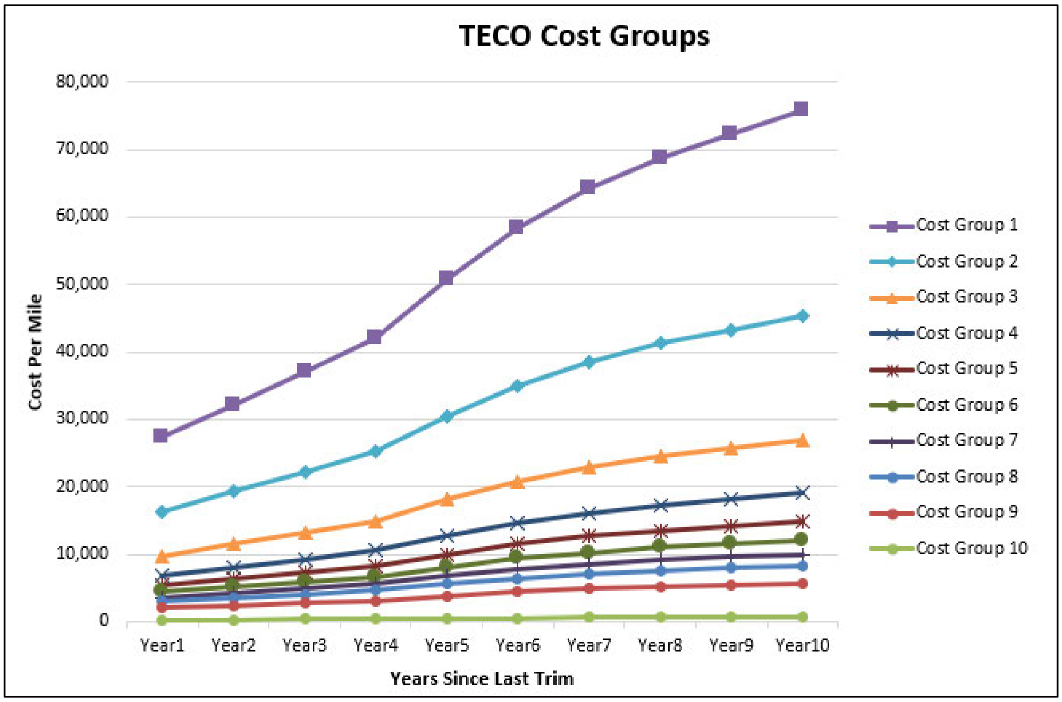


Figure 6-5: Cost Groups

TTM uses these curves to identify the estimated cost per mile to trim a circuit based on its year since last trim. These costs are in 2019 dollars and an estimated 5 percent inflation rate is used for subsequent trimming costs in future years.

6.3 Storm Module Inputs and Assumptions

Storm protection initiative cost and benefit modeling was accomplished using TTM and its associated Storm Module which have been used to prioritize trimming activities since 2006, and an Enhanced Storm Module to cover analyses not originally anticipated in the original Storm Module. The following cost implications were generated for each vegetation management activity considered:

Table 6-5: Storm Module Cost Assumptions

Cost	Cost Generator	Key Assumptions
Baseline: 4-Year Cycle Cost	TTM Core Module	• Cost curves (TTM Configuration Analysis) • Years since last trim (TECO records) • Proportional allocation of mileage across work areas
Supplemental Trimming Cost	TTM Core Module	• Cost curves (TTM Configuration Analysis) • Years since last trim (TECO records) • Proportional allocation of mileage across work areas for 25% of supplemental miles
Mid-Cycle VM Initiative Cost	TTM Enhanced Storm Module	• Cost premium for inspection and enhanced activities (SME Estimate) • Timing of mid-cycle activities (SME decision) • Proportion of circuit population targeted (SME decision – 2 scenarios) • Proportion of circuit targeted (SME decision)
Corrective Maintenance Tickets	TECO Subject Matter Expert Input	• Proportion of corrective maintenance tickets attributable to tree growth (TECO Records) • Relationship between tree growth corrective maintenance tickets and system effective cycle (SME estimate, past filings)
Premiums Associated with Attracting Additional Workforce	TTM Core Module	• VM budget (Cycle + Supplemental + Mid-Cycle + Corrective) • Straight and overtime loaded cost rates for VM crews (SME estimate) • Maximum organic growth rate of the VM workforce (SME estimate) • Productivity adjustment for training new VM resources (SME estimate) • Incentive costs for VM resources required beyond the organic growth capacity (SME estimate)
SAIDI-Driven Restoration Costs	TTM Storm Module	• Reliability outputs from TTM Core Module • Average cost to restore a CMI (SME estimate)
Storm Restoration Costs	TTM Storm Module	• Trim list from TTM Core Module • Storm damage calculation function • FEMA HAZUS windspeed return dataset

Cost	Cost Generator	Key Assumptions
		• Average cost to restore in major event including mutual assistance (Irma Analysis, SME adjustment)

6.3.1 Baseline: 4-Year Cycle Costs

Routine cycle trimming costs are projected by the Tree Trimming Model based on curves derived in the model configuration stages.

Cycle targets are established by declaring a number of miles to trim each year. In the baseline four-year scenario, the budget was allocated such that each service area would be on its own four-year cycle.

6.3.2 Supplemental Trimming Costs

Supplemental trimming costs are projected by the Tree Trimming Model based on curves derived in the model configuration stages.

In all supplemental scenarios, each service area was guaranteed their allocation of one quarter of the supplemental miles, with the remaining three-quarters of the miles getting targeted to where they were most needed.

6.3.3 Mid-Cycle Costs

There are four key assumptions relating to mid-cycle trimming activities:

- The cost premium for inspection and targeted trimming relative to cycle activities
- The timing of mid-cycle activities
- The portions of circuits to target
- The fraction of trees which will require mid-cycle intervention

Inspection-based activities come at a premium. There is first the cost of patrolling and inspecting the lines before vegetation management activities are taken, which must then be loaded into the costs of performing the actions in question. Second, relative to regular maintenance trimming, there are cost inefficiencies to trimming selectively. In regular maintenance trimming, vegetation crews can trim multiple trees each time they set up their vehicle and raise the bucket. In selective trimming, the ratio of setup time to actual wood removal goes up, further increasing the per-unit cost. Based on an analysis of corrective maintenance tickets, the TECO subject matter experts estimated that mid-cycle trimming would cost 80 percent more on a per-tree basis than routine trimming.

Mid-cycle activities are timed to promote the best possible performance out of the routine trimming initiative. Based on TECO subject matter expert input and considering the intervals between trimming in the baseline and enhanced scenarios, two years was selected as the optimal time for a mid-cycle inspection and associated vegetation management activities.

Mid-cycle activities will have similar impact in terms of overall restoration effort in a major event whether they occur on the feeder or lateral. Activities on the feeder will, however, protect more customers per tree outage avoided. With this in mind, TECO subject matter experts specified two possible scopes for Initiative 2 – feeder miles and all miles to be considered in that order.

The final component of scoping this cost was to predict the maximum number of trees to be targeted for mid-cycle activities as a result of the inspections. TECO subject matter experts estimated up to 25 percent of trees would grow sufficiently quickly to merit additional trimming prior to the next scheduled cycle trim. The analysis uses this figure but presumes that additional activities may be substituted for portions of the potential trimming, such as performing removals and the like, as long as the activities fit within the stipulated budget. As the cost per tree is 180% of regular trimming cost, and only 25 percent of trees can be targeted for mid-cycle activity, this should never amount to greater than 45% (180% * 25%) of the regular 4-year cycle budget.

6.3.4 Corrective Costs

TECO responds to approximately 4,000 corrective maintenance tickets annually, of which one third are related to tree limbs growing too close to the wires. The remainder are related to various forms of capital work, moving lines to accommodate construction, and the like. In total, the corrective maintenance tickets currently amount to $1.3 million per year, with TECO trimming to a four-year cycle. In prior filings, TECO estimated that moving from a three-year to a four-year cycle would result in a 30 percent increase in corrective maintenance tickets. Conversely, moving from four years back to three years would effectively revert the current $1.3 million budget to $1.0 million, or a roughly 23 percent reduction. Postulating that all growth-related tickets (33 percent) would be eliminated in a two-year cycle, the team fit a curve and generated a set of assumptions as follows, relative to the baseline 4-year scenario:

Table-6-6: Cost Assumptions by Effective Cycle

Effective Cycle (years)	Cost Reduction	Resulting Cost
4.00	0.0%	$1.30M
3.75	7.0%	$1.21M
3.50	13.0%	$1.13M
3.25	18.5%	$1.06M
3.00	23.0%	$1.00M
2.75	26.7%	$0.95M
2.50	29.6%	$0.91M
2.25	31.7%	$0.89M
2.00	33.0%	$0.86M

6.3.5 Resource Premium Costs

Experience has shown that there is a limit to the rate at which TECO can expand its workforce without incurring some degree of premium cost. To account for this, the TTM Storm Module estimates the number of resources that would be required to do the Trimming, Mid-cycle and Corrective work in an assumed 2,000-hour work year, and applies a number of cost adjustment factors if that amount is significantly higher than the current size. Cost Premium calculations consider the maximum number of resources that can be added in a given year without offering overtime or a per diem premium, and the assumed productivity of new resources in their first year.

6.3.6 Day-to-Day Restoration Costs

A key output of the Tree Trimming Model is the anticipated reliability performance of the system due to vegetation-caused outages in each year of the analysis. The reliability predictions are produced through TTM's CI and CMI configuration curves, which are derived on the basis of several years of outage and tree trimming data.

Outages trigger restoration costs through the use of the dispatch function, line crews and tree crews. The average cost for responding to an outage is estimated at $1,300 and the calculated average number of customers interrupted per vegetation outage is 65, resulting in an estimated average cost per CI due to tree-caused outages of twenty dollars.

Annual restoration costs are estimated multiplying the SAIFI values generated by TTM by the number of customers served by TECO, and in turn multiplying that product by the estimate of $20 per customer interrupted.

6.3.7 Storm Restoration Costs

The TTM Storm Module projects storm restoration costs per year using a function which determines the fraction of customers who will experience power loss based on wind-speed experienced and the number of years since the circuit was last trimmed, an amalgam of annual windspeed probabilities derived from FEMA's Hazards-US dataset and an estimate of restoration cost per customer derived from TECO's recent experience with Hurricane Irma.

The TTM Storm Module's central equation is based on a study conducted in southern Florida around 2005 which determined that wind-driven tree outages are influenced by the length of time since last trim. The equation accepts as parameters the wind speed experienced and the number of years since the circuit was last trimmed. The equation returns a percentage which is then applied to the number of customers served by the circuit to come up with an estimate of customers interrupted. In cases of extremely high winds (150 mph and up) and long intervals since last trim, the equation can return values above 100 percent, which is taken to mean that while only 100 percent of the customers on a circuit will be interrupted, the effort to restore them will go beyond the usual cost per customer due to the multitude of damage locations on the circuit.

Wind Gusts (3 second sustained @10m elevation)	Years Since Last Trim					
	1	2	3	4	5	6
40	0.19%	0.48%	0.83%	1.21%	1.63%	2.08%
45	0.27%	0.69%	1.18%	1.73%	2.32%	2.96%
50	0.38%	0.94%	1.61%	2.37%	3.18%	4.06%
55	0.50%	1.25%	2.15%	3.15%	4.24%	5.40%
60	0.65%	1.63%	2.79%	4.09%	5.50%	7.01%
65	0.82%	2.07%	3.55%	5.20%	6.99%	8.91%
70	1.08%	2.58%	4.43%	6.48%	8.74%	11.13%
75	1.27%	3.18%	5.45%	7.99%	10.74%	13.69%
80	1.54%	3.88%	6.61%	9.69%	13.04%	16.61%
85	1.84%	4.63%	7.93%	11.63%	15.64%	19.93%
90	2.19%	5.49%	9.42%	13.80%	18.57%	23.66%
95	2.57%	6.48%	11.07%	16.23%	21.84%	27.82%
100	3.00%	7.54%	12.92%	18.93%	25.47%	32.45%
105	3.47%	8.72%	14.93%	21.92%	29.48%	37.56%
110	3.99%	10.03%	17.19%	25.20%	33.90%	43.19%
115	4.56%	11.46%	19.63%	28.79%	38.73%	49.35%
120	5.18%	13.02%	22.32%	32.71%	44.01%	56.07%
125	5.86%	14.72%	25.23%	36.98%	49.74%	63.38%
130	6.59%	16.56%	28.38%	41.59%	55.95%	71.29%
135	7.38%	18.54%	31.78%	46.58%	62.66%	79.84%
140	8.23%	20.68%	35.44%	51.95%	69.88%	89.04%
145	9.15%	22.98%	39.38%	57.72%	77.64%	98.93%
150	10.13%	25.44%	43.60%	63.90%	85.95%	109.52%
155	11.17%	28.06%	48.10%	70.50%	94.84%	120.84%
160	12.29%	30.87%	52.91%	77.55%	104.31%	132.91%

Figure 6-6: Expected Damage by Wind Gusts for a Given Year Since Last Trim

The windspeed probabilities employed by the TTM Storm Module are derived from wind speed return values calculated by FEMA in their Hazards-US (HAZUS) package. HAZUS provides a geographically specific listing of windspeeds that can be expected to return to a given location every year, 10 years, 20 years, 50 years, and so on through 1,000 years based on an analysis of tropical storm tracks over several decades. Those data points are transformed to point probabilities for individual windspeeds, from which expectations for given ranges are calculated. The TTM Storm Module is loaded with probabilities every 10 miles from 55 miles per hour through 195 miles per hour, representing the probability of seeing windspeeds in the 50-60 mile per hour range, 60-70 mile per hour range and so on through to the 190-200 mile per hour range.

With an estimate of the expected number of customers to experience outages due to extreme weather events established, the final step is to multiply by the expected cost to restore customers. In Accenture's storm benchmark database, storm restoration is calculated based on total cost per customers out at peak. As illustrated below, while TECO experienced a grand total of about 328,000 customers out from Hurricane Irma, the number of customers out simultaneously was 213,000, as many quick wins are achieved early through switching and the restoration of substation and transmission issues. Approximately two thirds of this peak value are believed to be tree-caused.

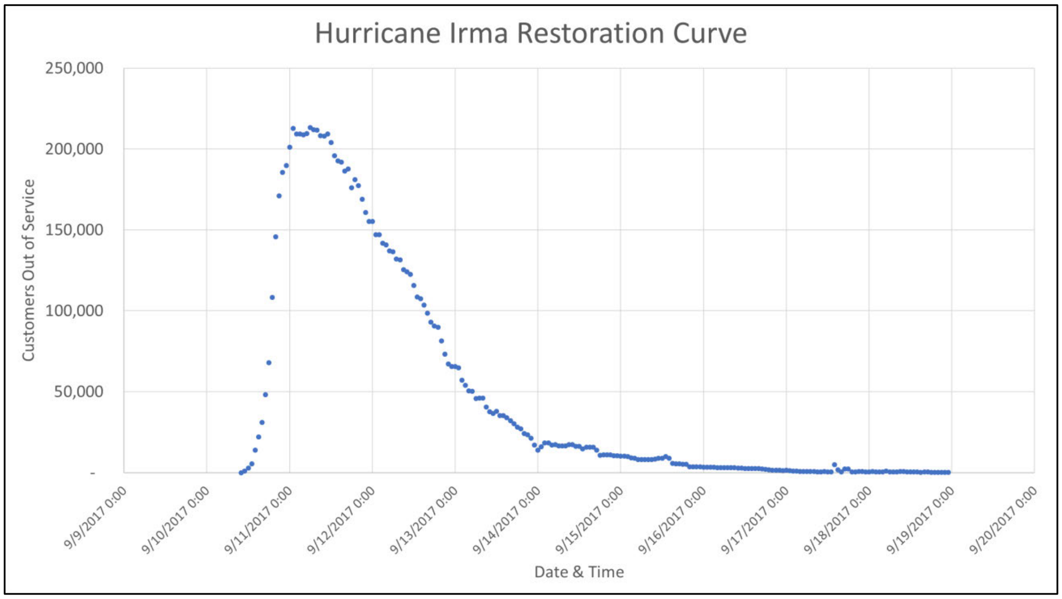


Figure 6-7: TECO Restoration Curve for Hurricane Irma

The peak number of customers out forms a more consistent denominator for cost per customer calculations, and in the case of TECO's experience with Irma this worked out to $389 per CI in line, tree, planning, logistics and other costs, which is in line with other Irma experiences in the State. Given the demand pressure on tree and line resources coming out of California's wildfire crisis, and general inflationary pressure, TECO's subject matter experts estimate that costs have risen by ten percent in the past two years, so the same restoration today would cost $424 per CI.

7 Work Plan

7.1 Baseline Summary

Work Area	2020		2021		2022		2023	
	Miles	Customers	Miles	Customers	Miles	Customers	Miles	Customers
CENTRAL	260.3	43,997	262.1	44,336	260.0	51,889	260.1	52,612
DADE CITY	93.3	4,618	80.1	2,308	107.8	5,541	90.8	3,015
EASTERN	212.4	30,524	210.1	34,845	208.8	35,717	208.6	27,808
PLANT CITY	311.9	16,511	308.9	16,875	309.7	22,055	311.4	12,296
SOUTH HILLSBOROUGH	178.3	16,775	176.1	26,999	181.4	14,380	184.5	18,196
WESTERN	279.3	67,510	279.5	60,773	277.0	64,125	278.2	59,307
WINTER HAVEN	227.0	26,391	237.9	9,676	228.4	16,338	230.7	25,762
Total	1,562.6	206,326	1,554.6	195,812	1573.0	210,045	1,564.2	198,996

7.2 Supplemental Summary

Work Area	2020		2021		2022		2023	
	Miles	Customers	Miles	Customers	Miles	Customers	Miles	Customers
CENTRAL	77.9	21,357	159.1	29,226	113.5	20,418	127.1	19,538
DADE CITY	99.9	5,208	6.2	484	127.6	5,578	44.9	681
EASTERN	99.8	18,598	153.3	12,341	72.9	8,794	149.8	18,918
PLANT CITY	76.7	9,702	25.2	2,443	202.2	8,347	31.1	3,579
SOUTH HILLSBOROUGH	15.3	2,264	20.5	2,427	20.2	3,236	138.9	28,399
WESTERN	15.7	3,926	82.8	13,024	112.4	20,376	155.8	27,165
WINTER HAVEN	16.8	1,277	63.1	5,063	43.2	5,784	53.2	7,950
Total	402.3	62,332	510.2	65,008	692.0	72,533	700.8	106,230

7.3 Mid-cycle Summary

Work Area	2020		2021		2022		2023	
	Miles Inspected	Customers	Miles Inspected	Customers	Miles Inspected	Customers	Miles Inspected	Customers
CENTRAL	0.0	0	48.6	17,262	36.0	9,488	176.8	25,321
DADE CITY	0.0	0	2.8	1,293	5.1	904	0.0	0
EASTERN	0.0	0	17.3	4,730	34.5	12,007	115.3	16,234
PLANT CITY	0.0	0	18.0	8,234	12.0	7,191	231.0	12,380
SOUTH HILLSBOROUGH	0.0	0	51.7	16,233	23.0	13,900	82.1	3,925
WESTERN	0.0	0	58.8	27,318	53.3	19,073	171.2	27,479
WINTER HAVEN	0.0	0	45.9	20,663	32.1	14,565	241.5	7,779
Total	**0.0**	**0**	**243.1**	**95,733**	**196.0**	**77,128**	**1017.9**	**93,118**

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INTERROGATORY NO. 2
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2. If the Company has not documented any of the policies and practices for oversight, deployment, and control it used for any of the following during the 2021 period, please explain why.

a. Distribution Lateral Undergrounding;

b. Transmission Asset Upgrades;

c. Substation Extreme Weather Hardening;

d. Transmission Access Enhancement;

e. Vegetation Management;

f. Infrastructure Inspections; and

g. Common Storm Protection Plan Activities and Costs.

A. a. Not applicable

b. Not applicable

c. Not applicable

d. Not applicable

e. Not applicable

f. Not applicable

g Not applicable

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INTERROGATORY NO. 3
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3. Please refer to page 8 of Witness Plusquellic's April 1, 2022 testimony and Table TAU.1 – 2021 Transmission Asset Upgrades on page 12 of Exhibit No. DLP-1.

a. Please clarify the primary factors that resulted in the revenue requirements being under budget.

b. Please state whether the revenue requirements for pole replacements outside of SPP Projects are included in the Final True-Up for 2021.

c. If the costs of pole replacements outside of SPP Projects are included in the revenue requirements, please state the revenue requirement amounts.

A. a. The primary factors that resulted in the revenue requirements being under budget were the following:

For capital: the timing of projects and the associated clearings to plant was less than projected.

For O&M: the company experienced less transfer costs in 2021 than projected.

b. No, Transmission pole replacements that are replaced outside of the Transmission Asset Upgrades program are funded through base rates and not through the SPPCRC

c. Not applicable

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INTERROGATORY NO. 4
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4. Please refer to page 10 of Witness Plusquellic's April 1, 2022 testimony.

a. Please explain why TECO completed less construction that was originally forecasted for the Distribution Overhead Feeder Hardening program in 2021.

b. Please provide an estimate of the percentage of TECO's Distribution Overhead Feeder Hardening program that was completed at the end of 2021.

A. a. Tampa Electric completed less Distribution Overhead Feeder Hardening projects in 2021 for a few reasons. First, in 2021, the company started the calendar year with carryover projects from 2020. Those 2020 projects were delayed because the company lost crews for multiple weeks in 2020 due to providing mutual assistance to other utilities impacted by extreme weather events. Second, during 2021, the program was directly impacted by labor and material supply issues. The company's contractor partners were not able to provide as many personnel that would have been needed for the entire year as originally projected. Third, projects were delayed while waiting for individual pieces of material to be delivered. Lastly, some projects were essentially complete with only a small amount of work remaining that required a coordinated/scheduled customer outage to reach 100 percent complete.

b. The company's filed and approved 2020-2029 SPP included 363 feeder circuits with a total projected spend of $289.5 million over that timeframe. The company estimates the completion of work at the end of 2021 to be 5.5 percent. The company anticipates the Overhead Feeder Hardening program will continue beyond 2029 so the actual percentage complete of the long-term program is likely lower than this percentage.

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DOCKET NO. 20220010-EI
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INTERROGATORY NO. 5
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5. Please provide an estimate of the percentage of TECO's Distribution Lateral Undergrounding program that was completed at the end 2021.

A. The company's 2020-2029 filed and approved SPP plan called for approximately 1,100 miles of distribution overhead laterals to be converted to underground and a projected total spend of $976.8 million over that timeframe. At the end of 2021, the company estimates the completion of work to be approximately 3.5 percent. The company anticipates the Distribution Lateral Undergrounding program will continue beyond 2029, so the actual percentage complete of the total long-term program is likely lower than this percentage.

TAMPA ELECTRIC COMPANY
DOCKET NO. 20220010-EI
STAFF'S FIRST SET OF INTERROGATORIES
INTERROGATORY NO. 6
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6. Did your April 1, 2022 filings include an adjustment to reflect a change in the Florida state tax rate from 4.458% to 3.535%?

a. Did the change in tax rate impact the 2020 and 2021 tax years for SPPCRC purposes?

b. If the answer to (a) is "yes," please describe how you addressed the reduction in tax rate for 2020 and 2021.

c. If the answer to (a) is "no," please provide a full explanation of your answer.

A a. Yes, the state tax rate reduction from 4.458% to 3.535% impacted 2021 for SPPCRC purposes. However, this state tax rate reduction did not impact 2020 for SPPCRC purposes.

b. The state tax rate in the calculation of the expansion factor used in the return on investment ("ROI") Equity rate for the SPPCRC 2021 Final True-Up filed on April 1, 2022, was 3.535 percent. This resulted in an expansion factor of 1.31599 as referenced in Note (A) on Form A-7 Detail pages, bates stamped pages 17 through 22. The expansion factor used in the SPPCRC 2021 Actual/Estimate filing based on the prior 2021 state tax rate of 4.458 percent was 1.32830 as referenced in Note (A) on Form E-7, bates stamped pages 76 through 81.

c. Not Applicable, please see Response No. 6b above.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared David L. Plusquellic who deposed and said that he is Director, Storm Protection and Support Services, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's First Set of Interrogatories, (No. 1 -6) prepared or assisted with the responses to these interrogatories to the best of his information and belief.

Dated at Tampa, Florida this 2nd day of May, 2022.

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Sworn to and subscribed before me this 2nd day of May, 2022.

____

Notary Public State of Florida
Tison C Vega
My Commission GG 950315
Expires 02/01/2024

My Commission expires ____________________