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TECO's Response to OPC's First Set of Interrogatories Nos.1-32

TAMPA ELECTRIC COMPANY
DOCKET NO. 20220048-EI
OPC FIRST SET OF INTERROGATORIES
INTERROGATORY NO. 1
BATES PAGE: 1
FILED: APRIL 11, 2022

1. Please provide a detailed description of all new programs and projects compared to those included in the Company's initial approved (2020) storm protection plan filings (including any modifications considered or approved in 2020), including the detailed information for each program required by Rule 25-6.030(3)(d) and (e).

A. In the settlement agreement entered into by Tampa Electric and the consumer parties with respect to the company's 2020-2029 Storm Protection Plan ("SPP"), Tampa Electric agreed that it would not materially expand the scope of its SPP programs over the years 2020-2022. In accordance with this provision, Tampa Electric has not initiated any new programs over that period.

Tampa Electric's 2022-2031 SPP includes the same eight programs as those included in the 2020-2029 SPP.

With respect to new projects, the company has not initiated any new projects that were not included in the company's 2020–2029 SPP. The company is providing the information required by Rule 23-6.030 for each program and project in its 2022-2031 SPP filing. Any new projects identified as part of the company applying lessons learned, improved analytics, or the addition of 2030 and 2031 plan years are included in the company's 2022-2031 SPP. As described throughout the company's 2022-2031 SPP filing and supporting testimonies and appendices, Tampa Electric engaged 1898 & Co. to assist the company with analysis and prioritization of individual projects. 1898 & Co.'s process and methodology are described in the company's direct testimony and in the 2022-2031 SPP.
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2. Please provide a detailed description of all completed, modified, and/or expanded programs and projects compared to those included in the Company's initial approved (2020) storm protection plan filings (including any modifications considered or approved in 2020), including the detailed information for each program required by Rule 25-6.030(3)(d) and (e).

A. At this time, none of the company's SPP programs have been fully completed. As described in the company's response to Interrogatory No. 1 above, the company complied with the settlement in the previous SPP docket and did not modify any of the SPP programs that were approved initially by the Commission.

With respect to projects in the 2020-2029 plan that have been initiated, the company has made minor and routine modifications, including schedule changes, to most projects during the actual design and engineering phase. The prioritization model does not contain engineered costs so actual field conditions and scope is often modified while performing an actual engineered construction design. These minor modifications have not been captured for the projects that have been initiated. Examples of project modifications include:

- More / fewer actual assets to install than projected
- Field obstructions that require modifications
- Land rights required or refused
- Proposed route for looping is not feasible
- Connecting additional services to customers on an underground project that were not in the original scope
- Combining adjacent or near-adjacent lateral underground projects into a single project

The company is providing below a list of completed projects for the Distribution Lateral Undergrounding, Overhead Feeder Hardening, and Transmission Asset Upgrades programs. In addition, the current working excel file containing this list is provided in the company's response to the Office of Public Counsel's First Production of Documents No. 3.

In addition to project scope modifications, the company's Electric Delivery Storm Protection Plan's financial team has maintained a change log that tracks various changes to the financial tracking and reporting aspects of the lateral underground projects. This log is provided in response to the Office of Public Counsel's First Production of Documents No. 3.

3. Please provide a separate detailed comparison of the actual benefits and costs for each program and project to the forecast benefits and costs set forth in the Company's initial approved (2020) storm protection plan filings (including any modifications considered or approved in 2020.

A. First and foremost, as described in the company's 2020-2029 SPP and the 2022-2031 SPP, the projected benefits are based upon reducing restoration costs and the duration of outages during extreme weather events. The company has not had a direct impact from an extreme weather event since filing its initial 2020-2029 SPP on April 10, 2020. In addition to the completed projects shown in Interrogatory Response No. 2 above, the company is including a listing of the projects currently in progress. This listing reflects a comparison of the current actual and projected costs and the costs that were filed in prior cost recovery petitions for those projects. The list of projects is included in the company's response to the Office of Public Counsel's First Production of Documents No. 3.

4. Please describe specifically how the Company measures the success of each approved storm protection program and project "to achieve the objectives of reducing restoration costs and outage times associated with extreme weather events and enhancing reliability."

A. The company's 2020-2029 and 2022-2031 SPP filing plans, witness testimony and supporting appendices describe the process the company undertook to develop the comprehensive storm protection plan and the benefits it will yield for customers. The company has also described the expected benefits that will result from the long-term investment in the programs and projects.

From purely an operational perspective, the company would determine success of the Plan, programs and individual projects by using traditional management metrics (e.g. "schedule", "budget", "scope achievement", etc.) or efficiency metrics such as "cost per mile", "cost per pole", "poles per day" or other similar metrics. The company would also measure actual performance against market pressures such as labor increases, underlying price increases as well as against other peer utilities embarking on similar initiatives. These types of traditional measures could be applied to the plan as a whole, to the programs or to individual projects. Used collectively, one could draw a conclusion on "success".

Two other critical factors must be used to determine success though. The first is safety. Tampa Electric must complete all work in a manner that is safe for our employees, teammates, constituents, members of the public, and our customers. Success cannot be achieved otherwise. In addition, and perhaps most importantly, the company's SPP is designed to yield benefits for customers in the form of reduced minutes and reduced after-storm restoration costs. The company has implemented a communications protocol for the lateral undergrounding program and projects to ensure customers are presented with information to help them understand the benefits to them individually and to the system as a whole. Customers should feel informed and like they received first class treatment throughout the life of a project.

If the company can successfully attain the operational, safety and customer service performance levels on each project, each day the projected benefits will be evident when Tampa Electric experiences an extreme weather event in the future.

Vegetation Management (VM) – Distribution Program

5. Please provide average cost for trimming laterals on a per mile basis for 2020, 2021, and 2022.

A. Tampa Electric's distribution vegetation management ("VM") per mile costs are recorded at the circuit level; feeder and lateral costs are not separately tracked. The 2020 and 2021 actual per mile costs and 2022 estimated per mile cost are shown in the table below:

	Distribution Vegetation Management Per Mile Costs (Four-Year Cycle and Supplemental)
2020	$7,896
2021	$8,229
2022	$8,200

6. Please confirm that outage restoration costs which include the cost of tree trimming crews are excluded from the Storm Hardening Program and costs. If not, please provide the annual costs for 2020, 2021, and 2022 for tree trimming/clearing related to power restoration.

A. Tampa Electric includes the cost of tree trimming crews that perform outage restoration as part of the "All-in" SPP costs that are filed with the Commission as "Unplanned Distribution Vegetation Management." These Unplanned Vegetation Management costs are recovered through base rates and are not included in the company's annual Storm Protection Plan Cost Recovery Clause costs. In addition, any vegetation management that is required for restoration during responses due to named storms are charged against the storm reserve. The annual Unplanned Vegetation Management actual costs for 2020 and 2021 and the estimated cost for 2022 are in the table below:

	Unplanned Distribution Vegetation Management Costs
2020	$2,026,699
2021	$1,672,323
2022	$1,608,772

7. Please provide criteria for the 700 miles of supplemental distribution circuit VM to reduce proximity between vegetation and electrical facilities. When answering, please define goals for spacing/clearance of vegetation and electrical facilities by vegetation above primary distribution lines and vegetation horizontal from primary distributions lines. Please also provide data used for circuit prioritization

A. For the development of Tampa Electric's 2020-2029 Storm Protection Plan, the company contracted with a consultant (Accenture LLP) to perform a VM study to analyze the benefits of various supplemental distribution circuit VM mileage scenarios, i.e., 100, 300, 500, 700, and 900 miles, and determined 700-miles was best from a customer experience perspective. The results of the study estimated that there should be a 16 percent and 21 percent improvement in the ten-year average day-to-day and storm restoration costs. A complete copy of the VM study performed is included as an exhibit within the direct testimony of David L. Plusquellic in this proceeding. The company is also providing the report in its response to OPC's First Set of Production of Documents No. 2 in this proceeding. The post-trim vegetation to conductor clearance is consistent with those in the company's four-year distribution initiative, ten feet side and below and fifteen above for primary facilities. All work is performed in accordance with ANSI arboricultural guidelines. Similar to the four-year distribution initiative, supplemental distribution circuits are prioritized using the company's reliability-based methodology but with an emphasis on storm benefits rather than day-to-day reliability.

8. Please provide details related to specifications, contracts and plan

A. Tampa Electric's Mid-Cycle Initiative is designed to preemptively identify trees that cannot be maintained effectively within the four-year distribution VM cycle because of their rapid growth rate and hazard tree threats between trim cycles. Trained contract inspectors identify areas of concern and write specific orders for follow up tree crews. The initiative calls for feeder-only inspections through 2022 and full-circuit inspections beginning in 2023. Circuits that are at least two years since last trim and not included in another distribution VM initiative may be selected for the mid-cycle list. Tampa Electric plans to inspect approximately 200 miles of feeder in 2022 and approximately 1,000 miles of circuit in 2023.

9. Please provide costs analysis of the plan

A. The Mid-Cycle Initiative, as outlined in the company's VM study, is projected to yield an additional 4.5 percent improvement to storm restoration costs. However, the modeling may not reflect the full value of the mid-cycle activities because it does not factor in hazard tree removals which will yield permanent benefits not captured in the analysis.

10. Please describe the total clear zone achieved by the initiative (previously 15 foot vegetation-to-conductor)

A. The total clear zone for the initiative depends on land rights; however, tree clearance specification is ground-to-sky, fifteen feet from the outermost conductor. All hazard trees are removed or trimmed to a height whereby a fall-in outage could not occur. Areas restricted by land rights are mitigated separately and as appropriate.

11. Does this program address danger trees outside the easement or properties? If so, provide the costs for danger tree removal by year 2020, 2021, and 2022

A. Yes, this initiative addresses hazard trees outside the easement or property boundary. Hazard tree removal costs are not tracked separately because they are removed as a component of nearly all VM initiatives. Hazard tree removal costs are rolled into the total VM costs.

12. Please provide number of miles completed in 2020, 2021, and 2022.

A. The initiative is composed of three activities: real estate research, surveying, and vegetation management. The initiative progress is shown in the table below:

	69kV Reclamation Initiative Progress (miles)		
	Real Estate Research	Surveying	Vegetation Management
2020	49.8	0.0	0.0
2021	33.4	9.3	6.5
2022	0.0	38.1	26.8

13. Please provide the actual cost by year.

A. The 69kV Reclamation Initiative 2020 and 2021 actual costs and 2022 projected costs are shown in the table below:

	69kV Reclamation Initiative Costs
2020	$87,716
2021	$859,434
2022	$714,200

14. What is the expected completion date of this initiative?

A. Tampa Electric is projecting the 69kV Reclamation Initiative to be completed by December 31, 2023.

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15. Please describe the method used to prioritize structure replacement

A. The Transmission Asset Upgrades Program is a systematic and proactive replacement Program of all Tampa Electric's remaining transmission wood poles with non-wood material. The company intends to complete this conversion from wood transmission poles to non-wood material poles during the timeframe of this initial ten-year SPP. Tampa Electric has over 25,400 transmission poles and structures with approximately 1,350 circuit miles of transmission facilities. Of these transmission structures, approximately 20 percent are supported with wood poles. Historically, the company's transmission hardening Program focused on replacing existing wood transmission poles with non- wood material upon a failed inspection. During replacement, the company would also upgrade existing hardware and insulators. From 2007 through 2019, the company hardened 8,971 wood transmission structures with non-wood material as a part of the existing Storm Hardening Plan. The company will continue to use the ongoing multiple transmission inspection methods to prioritize the replacement of existing wood transmission poles that fail inspection. Tampa Electric will also prioritize the systematic and proactive replacement of all other remaining wood transmission poles.

In the early 1990s, Tampa Electric made the decision to begin building all new transmission circuits with non-wood structures. Replacing all existing transmission wood poles with non-wood material gives Tampa Electric the opportunity to bring aging structures up to current, and more robust, wind loading standards than required at the time of installation. The Transmission Asset Upgrades Program will reduce restoration cost and outage times as a result of the anticipated reduction in the quantity of poles requiring replacement from an extreme weather event. Of the ten transmission poles replaced due to Hurricane Irma in 2017, nine were wood poles with no previously identified deficiencies that would warrant the pole to be replaced under the existing transmission hardening Program.

Tampa Electric used the 1898 & Co.'s resilience-based modeling to develop the initial prioritization of Projects. This initial prioritization is based upon the transmission circuit's historical performance relative to criticality of the transmission line, reducing customer outage times and restoration costs, age of the transmission wood pole population on a given circuit, and its historical day-to-day performance. In order to account for technical and operational constraints like access and the long lead time for permits, the list was reviewed by Tampa Electric personnel for feasibility.

Once this review was complete a revised prioritization that incorporated access challenges, long lead time for permit requirements and scheduling constraints was developed. The revised prioritization is reflected in this ten-year SPP with Projects that are most feasible to implement accelerated into the first three years of the SPP. The remainder of the SPP years were scheduled by 1898 & Co.'s resilience-based model beginning in year 2023 to allow for scheduling, permitting and access issues to be addressed.

The methodology used to prioritize Transmission Asset Upgrade projects is described further in the Direct Testimonies of David L. Plusquellic and Jason De Stigter, as well as 1898 & Co.'s report in Appendix F of the company's 2022-2031 SPP

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16. The 2020 Storm Protection Plan calls for the replacement of wood poles with non-wood poles

a. Please provide the number of concrete poles installed by year 2020, 2021, and 2022

b. Please provide the cost for installation of concrete poles by year 2020, 2021, and 2022

c. Please provide the number of steel poles installed by year 2020, 2021, and 2022

d. Please provide the cost for installation of steel poles by year 2020, 2021, and 2022

A. a. The table below provides the actual number of transmission wood poles that were replaced with concrete poles in 2020 and 2021 and the estimated number of transmission wood poles that are projected to be replaced with concrete poles in 2022:

	Transmission Asset Upgrades "Number of Wood Poles Replaced with Concrete"
2020	33
2021	132
2022	90

b. The table below provides the actual cost of installing concrete poles to replace wood transmission poles in 2020 and 2021 and the estimated cost to install a concrete pole in 2022:

	Transmission Asset Upgrades "Cost to Install Concrete Poles"	
	69 kV	230 kV
2020	$31,590	$21,050
2021	$31,590	$21,050
2022	$31,590	$21,050

c. The table below provides the actual number of transmission wood poles that were replaced with steel poles in 2020 and 2021 and the estimated number of transmission wood poles that are projected to be replaced with steel poles in 2022:

	Transmission Asset Upgrades "Number of Wood Poles Replaced with Steel"
2020	263
2021	590
2022	384

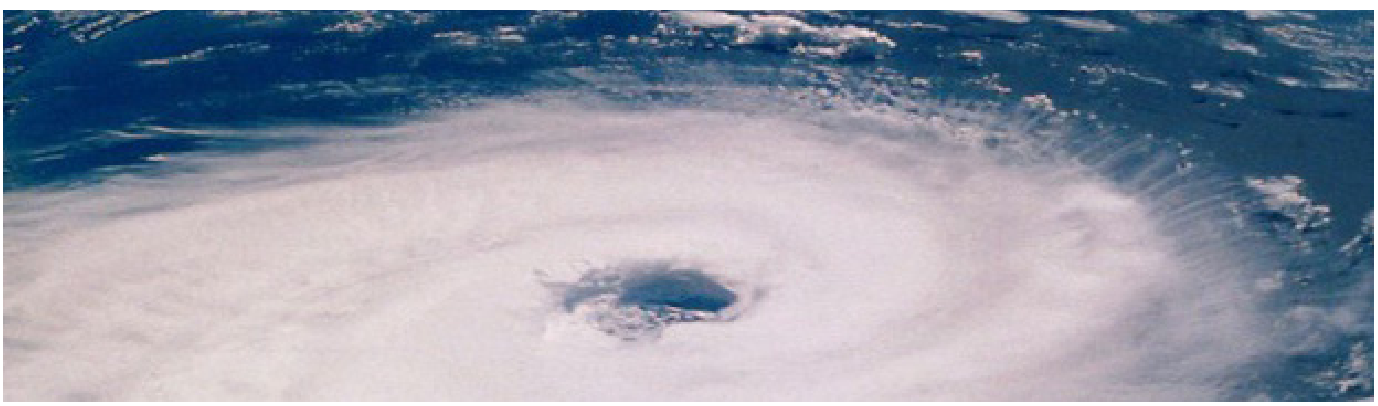
d. The table below provides the actual cost of installing steel poles to replace wood transmission poles in 2020 and 2021 and the estimated cost to install a concrete pole in 2022:

	Transmission Asset Upgrades "Cost to Install Steel Poles"	
	69 kV	230 kV
2020	$31,590	$21,050
2021	$31,590	$21,050
2022	$31,590	$21,050

Substation Extreme Weather Hardening

17. Please provide a complete copy of the study on twenty of the company's substation located closest to the coastline.

A. The complete copy of the Substation Extreme Weather Hardening Study that was performed in 2021, is included as Exhibit DLP-1, Document No. 5 to the Direct Testimony of David L. Plusquellic. It is also included with this Response starting on the page below:



SUBSTATION HARDENING STUDY

Prepared by: HDR Engineering, Inc

August 27, 2021

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%

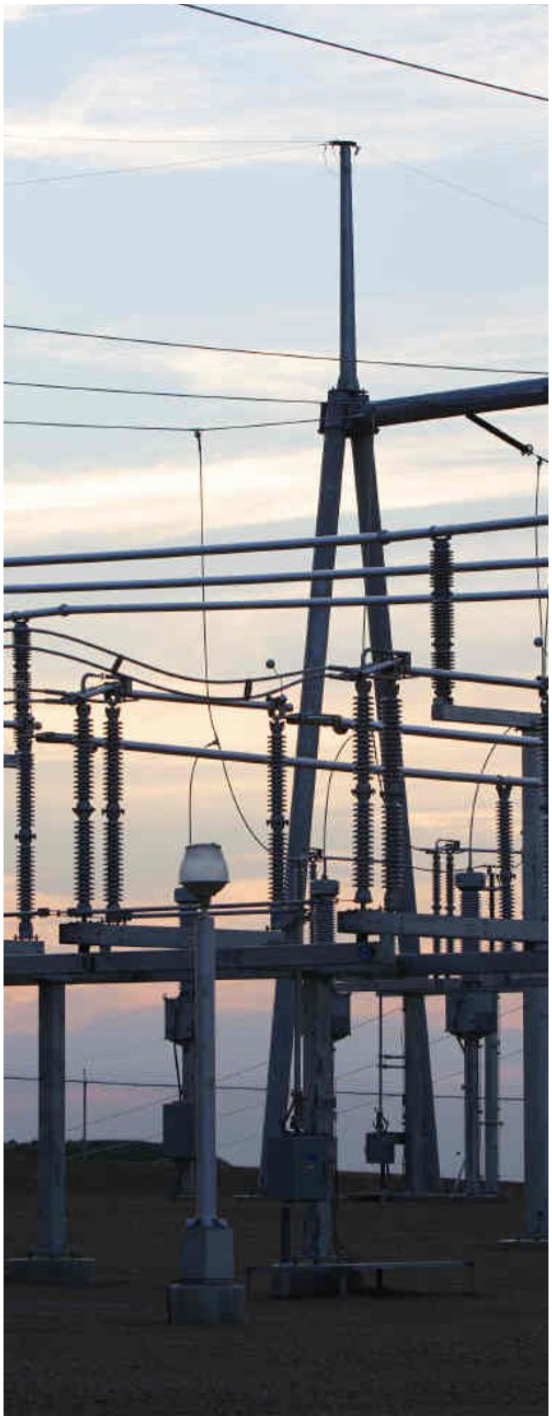
Environmental – weighted at 10% of overall score

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.

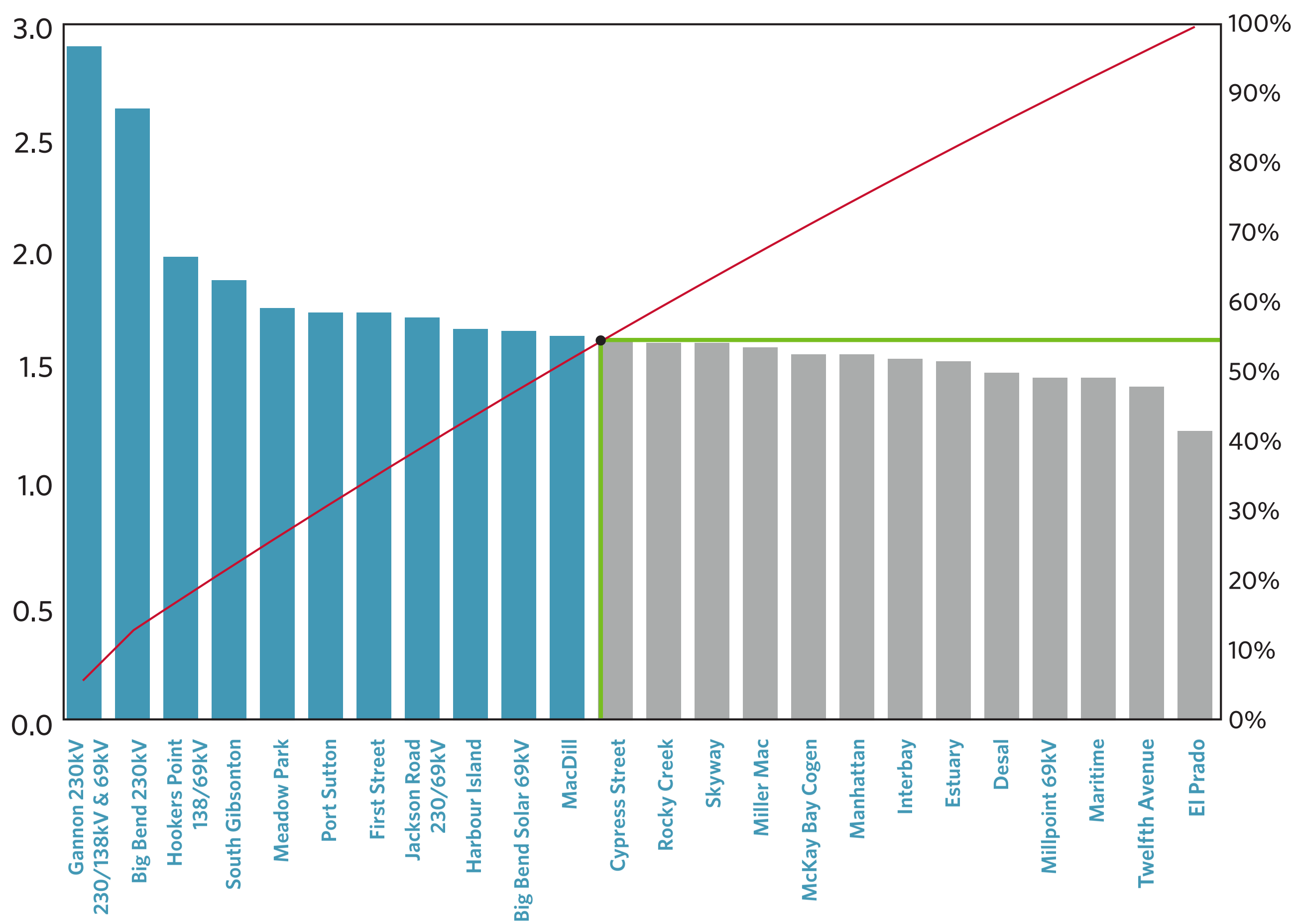
As the substation hardening projects were developed, budgetary cost estimates were created for each. These costs were turnkey – including equipment, construction, testing and commissioning. These costs were then used in a cost benefit analysis to justify the hardening project and its effectiveness in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

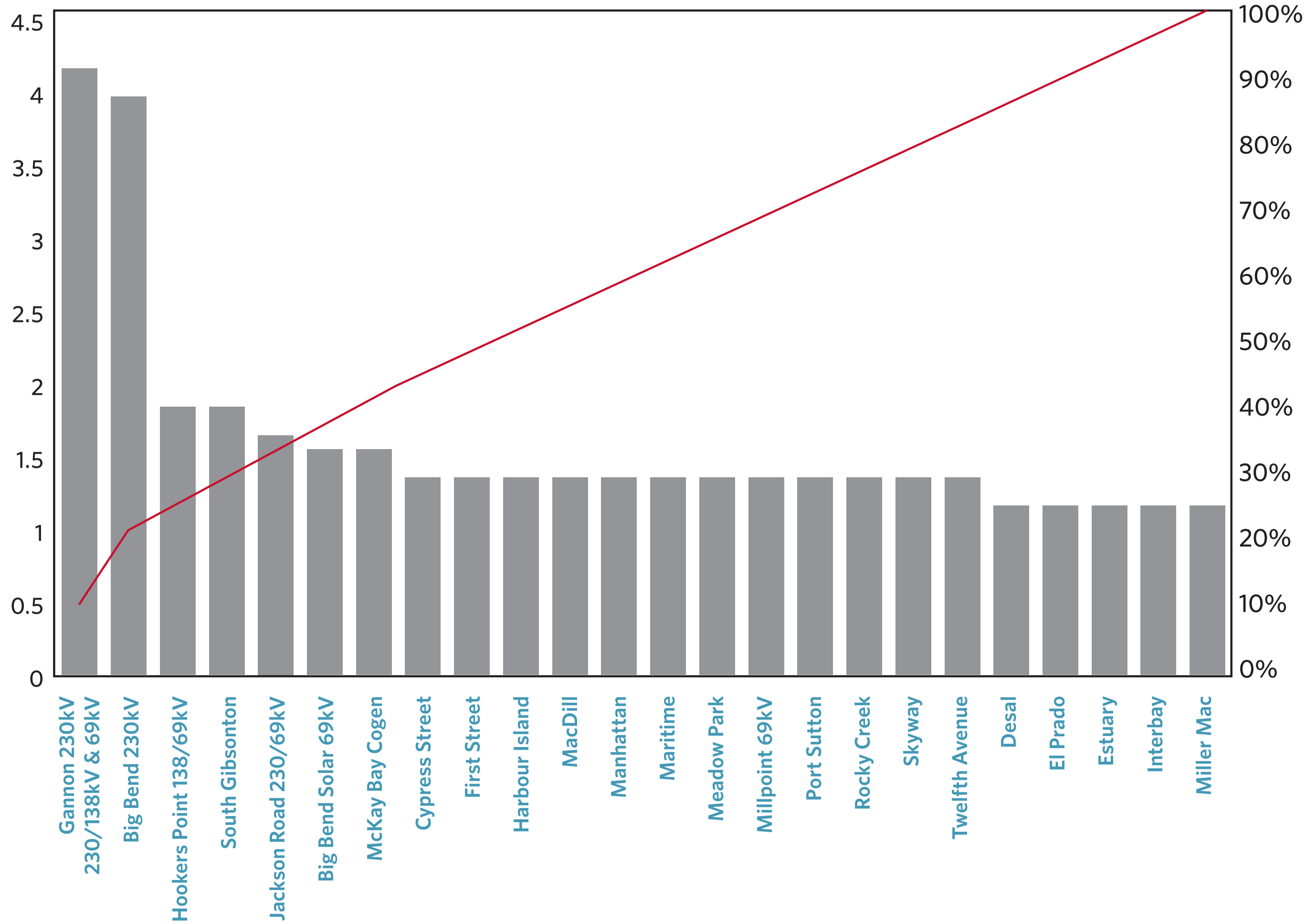
3.1 OVERALL SCORES

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).

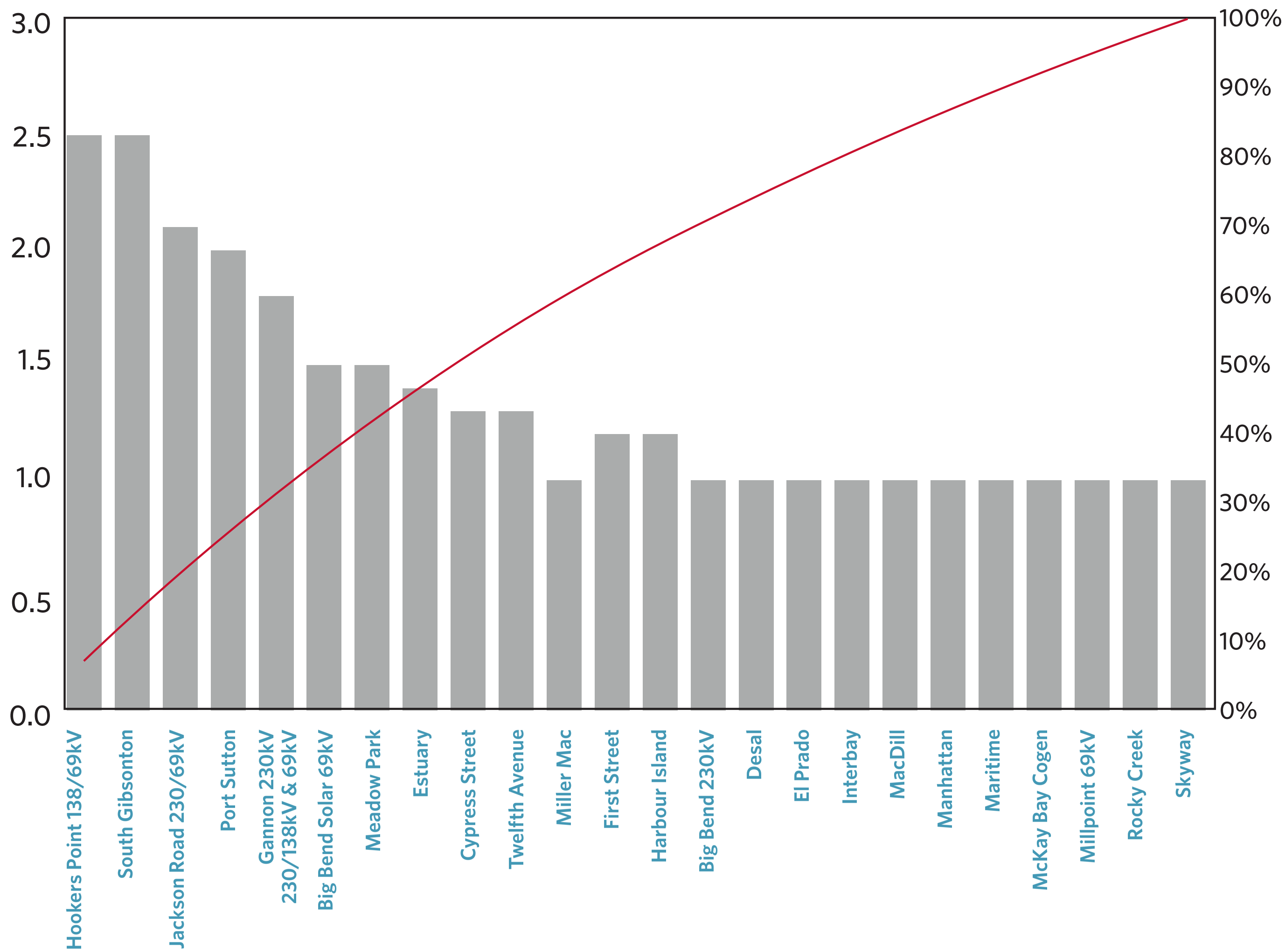


3.2 GRID STABILITY/CAPACITY

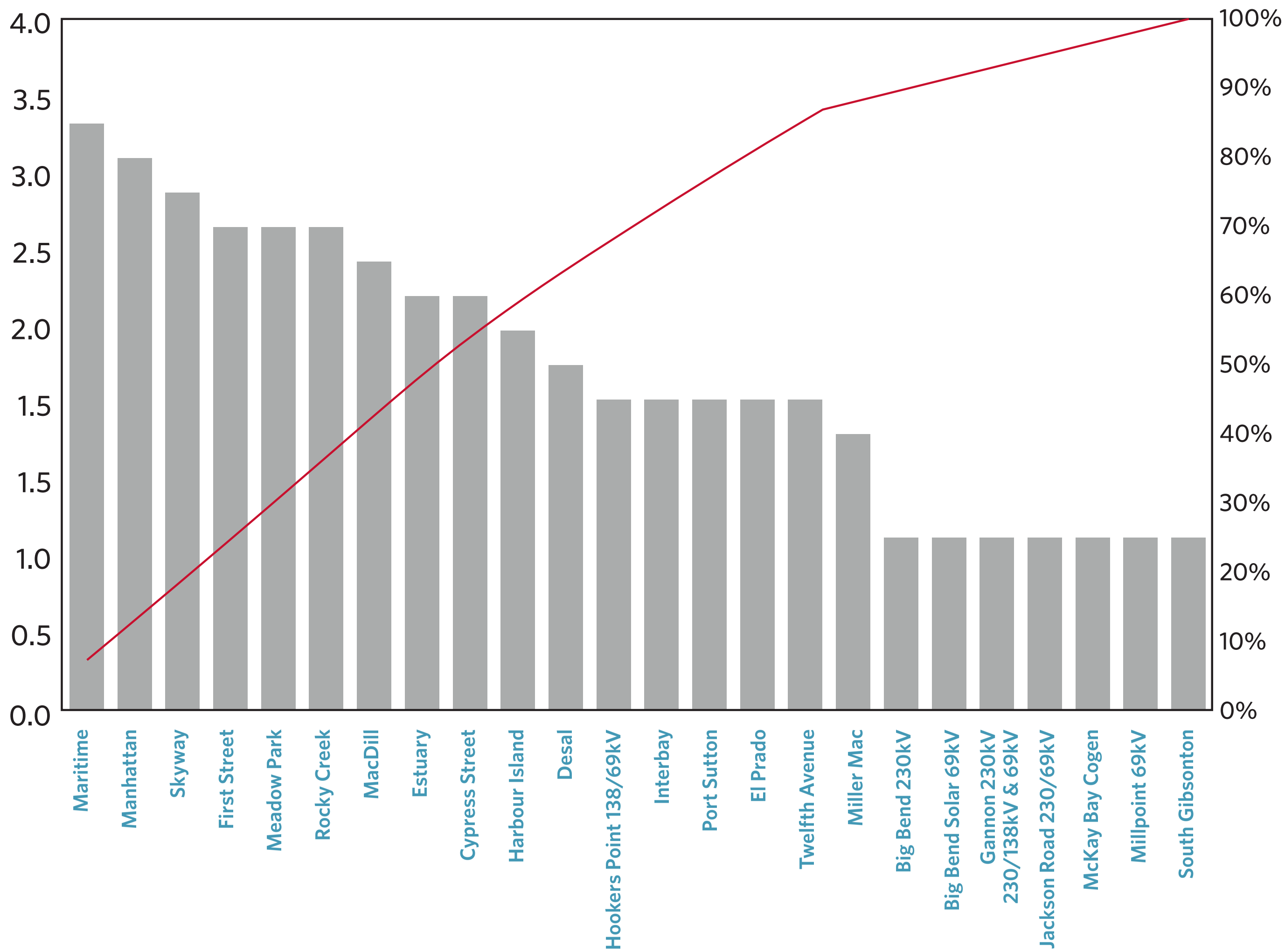
The component scores and rankings that made up the overall score are shown in the charts below and on the following pages:



3.3 RELIABILITY



3.4 CUSTOMER SERVICE



TAMPA ELECTRIC COMPANY
DOCKET NO. 20220048-EI
OPC'S FIRST SET OF
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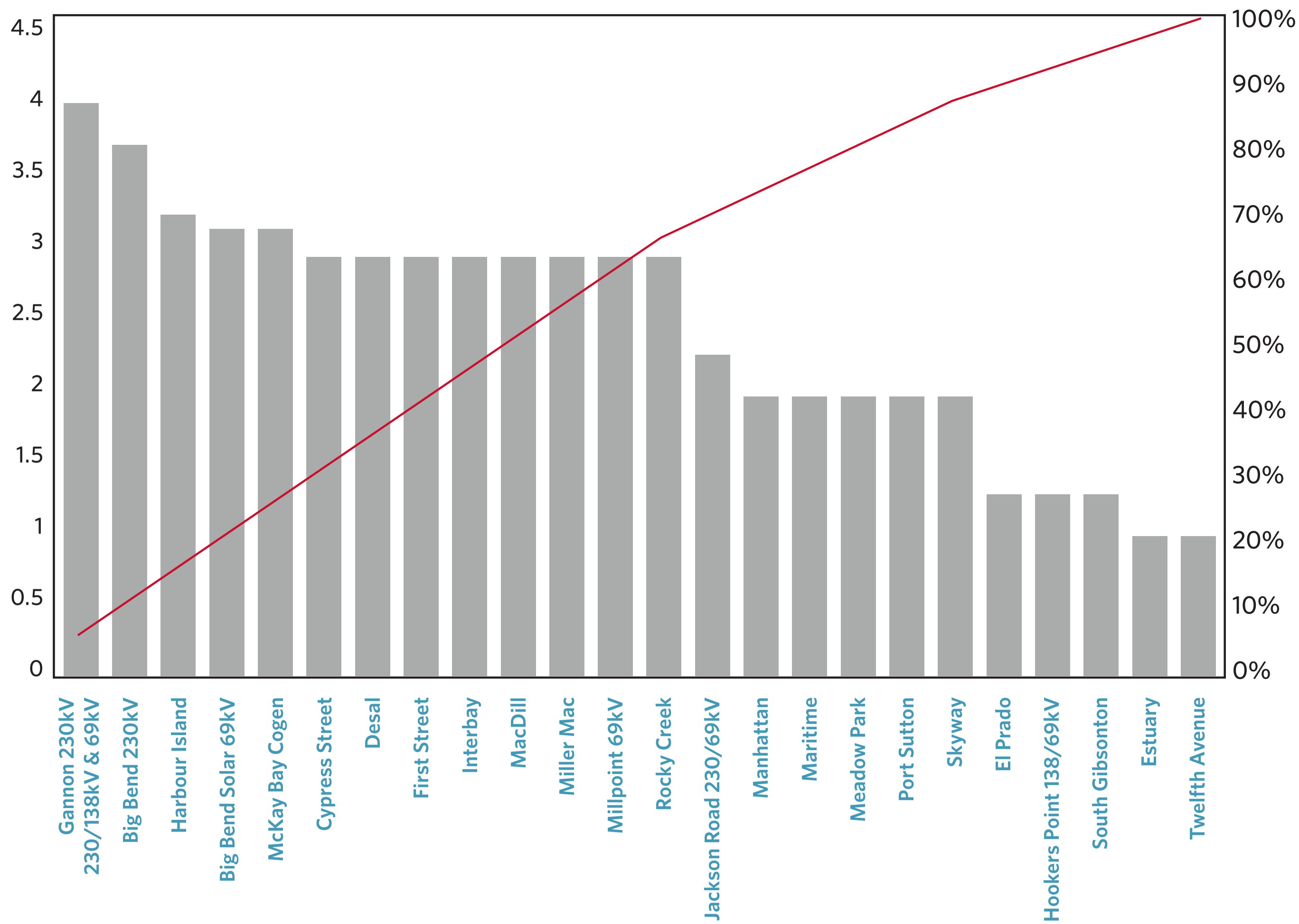
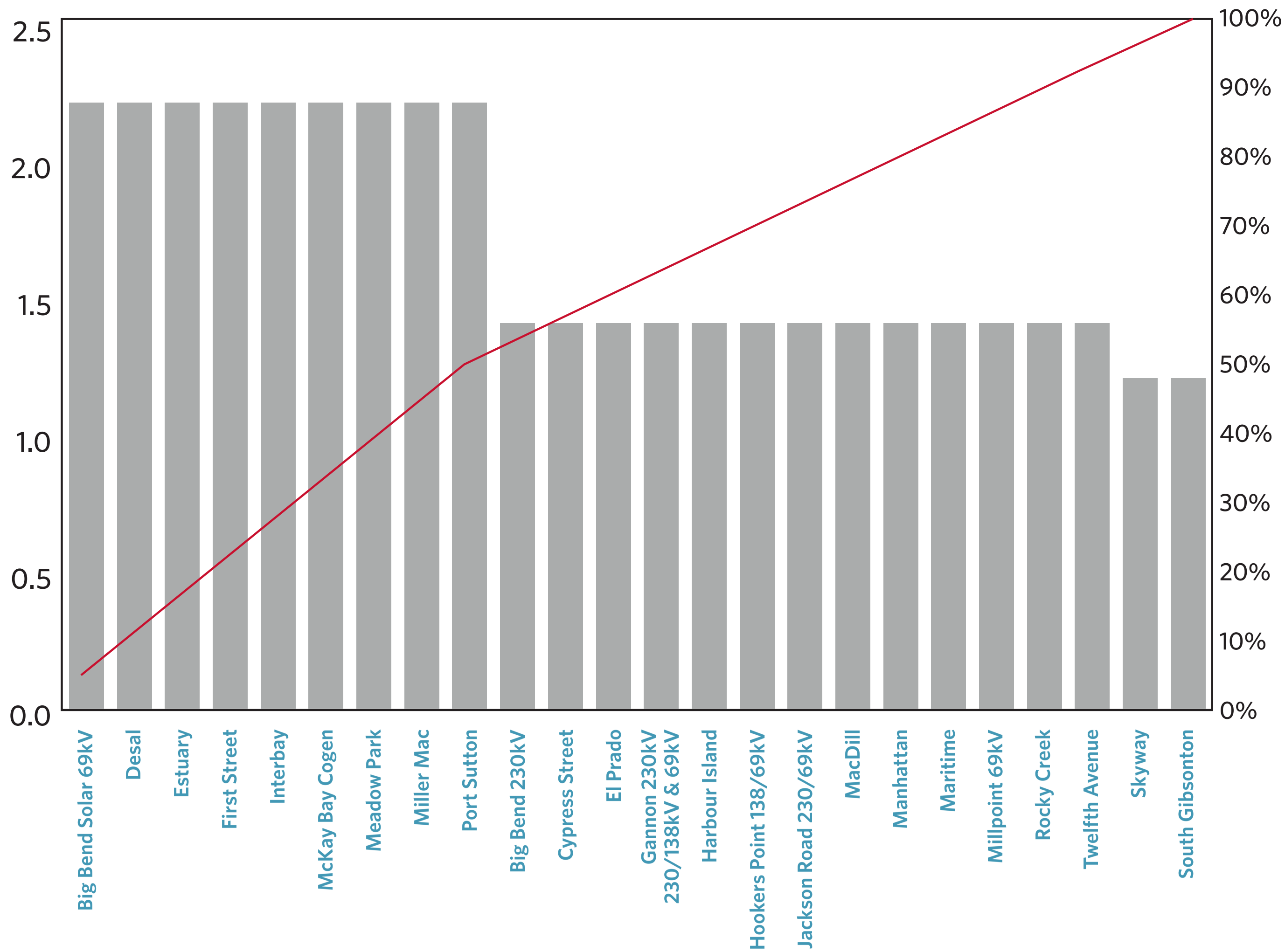
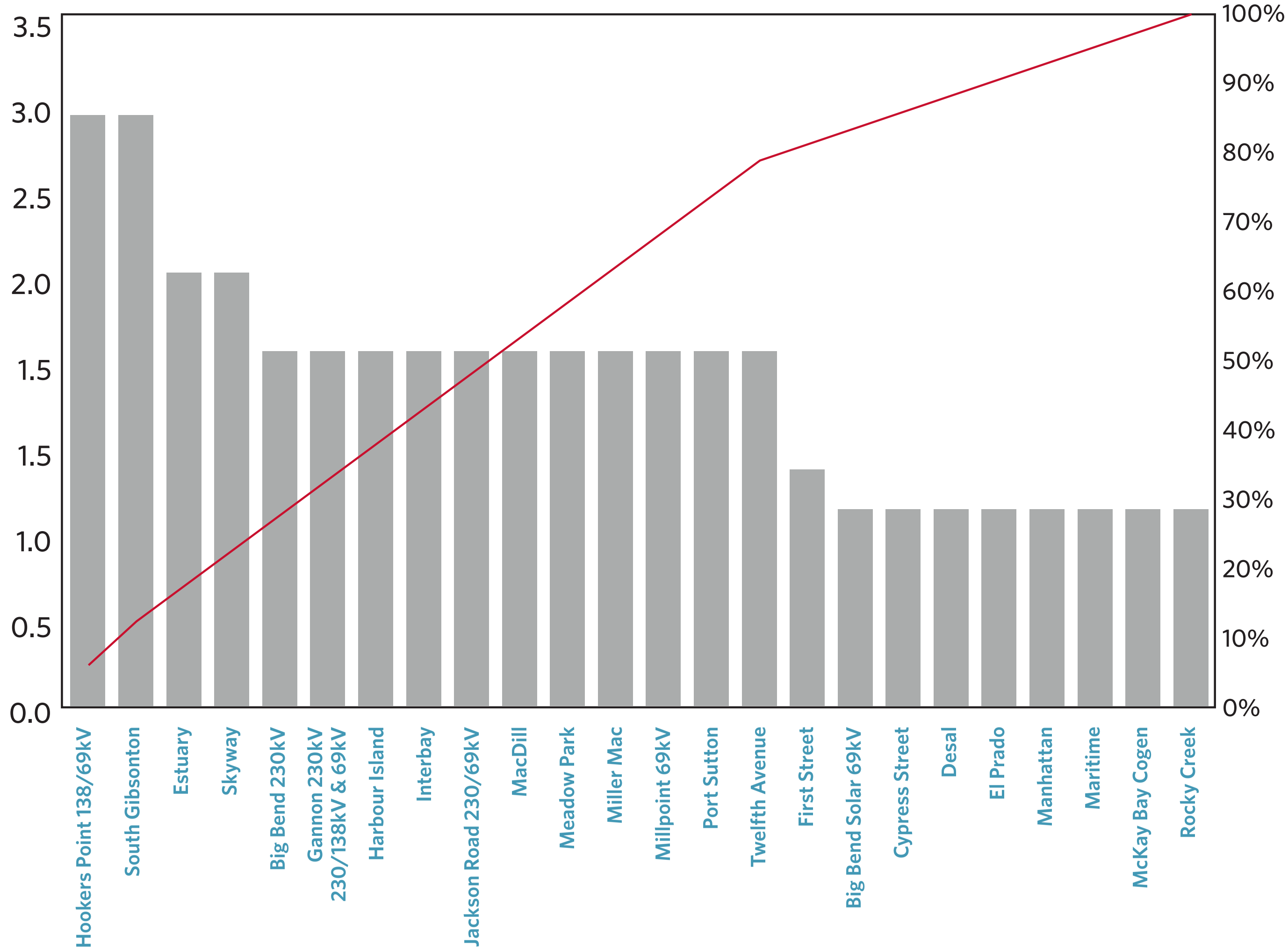
3.5 COST


4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Gannon 230kV 230/138kV & 69kV
Big Bend 230kV
Harbour Island
Big Bend Solar 69kV
McKay Bay Cogen
Cypress Street
Desal
First Street
Interbay
MacDill
Miller Mac
Millpoint 69kV
Rocky Creek
Jackson Road 230/69kV
Manhattan
Maritime
Meadow Park
Port Sutton
Skyway
El Prado
Hookers Point 138/69kV
South Gibsonton
Estuary
Twelfth Avenue

3.6 SAFETY


2.5
2.0
1.5
1.0
0.5
0.0
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Big Bend Solar 69kV
Desal
Estuary
First Street
Interbay
McKay Bay Cogen
Meadow Park
Miller Mac
Port Sutton
Big Bend 230kV
Cypress Street
El Prado
Gannon 230kV 230/138kV & 69kV
Harbour Island
Hookers Point 138/69kV
Jackson Road 230/69kV
MacDill
Manhattan
Maritime
Millpoint 69kV
Rocky Creek
Twelfth Avenue
Skyway
South Gibsonton

3.7 ENVIRONMENTAL



4.0 Substation Hardening Projects

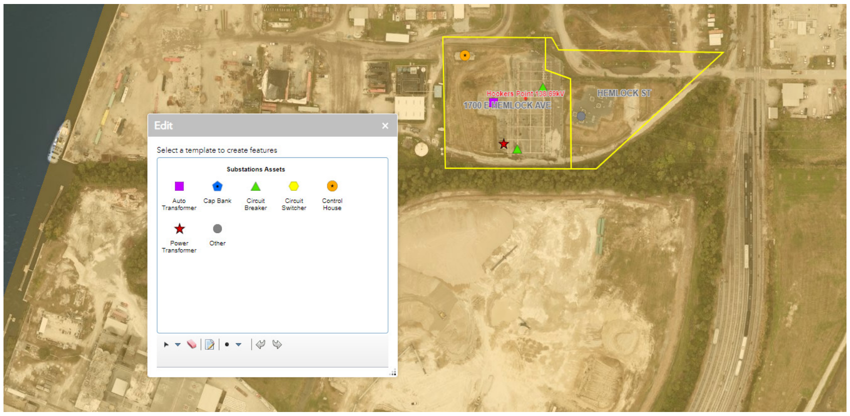
Based on the data collected in the Discovery Phase and scorecards developed in Evaluation Phase, eight (8) projects were developed to harden TECO substations against extreme weather events. Three projects at transmission substation aim to improve grid stability and five were developed to improve customer 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**



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.

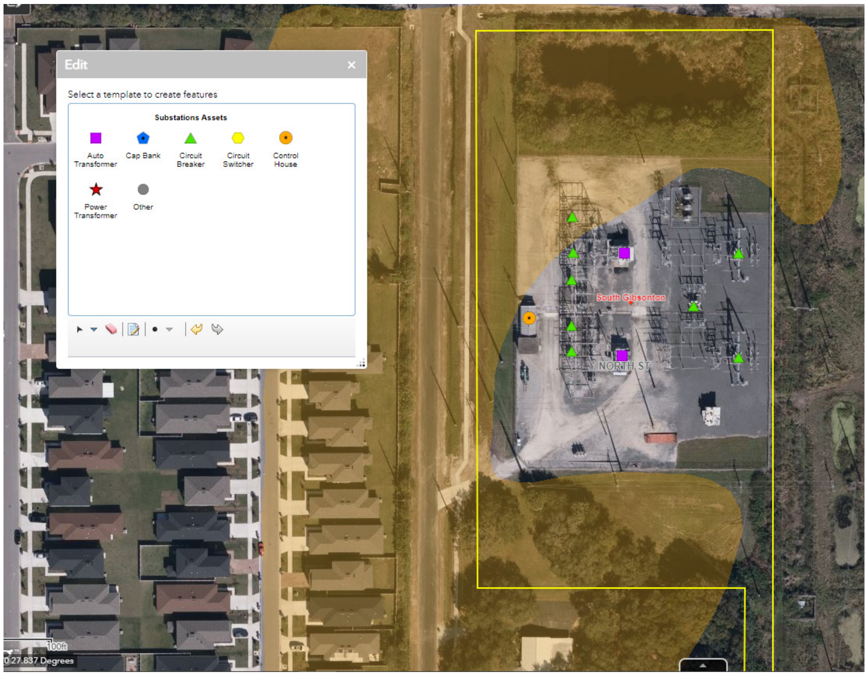
Cost Benefit

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

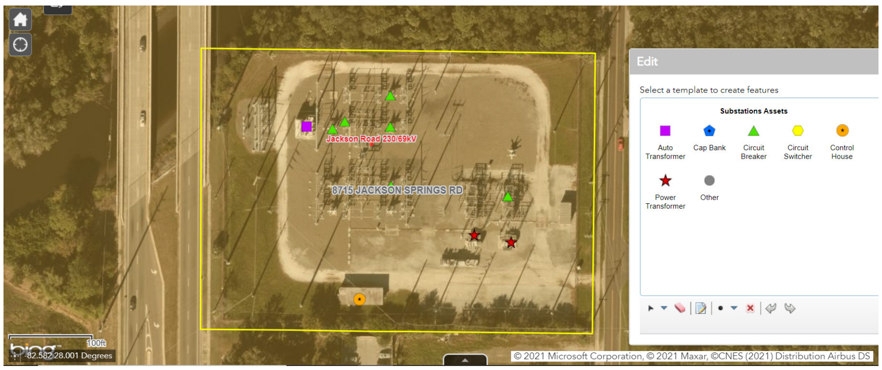
In the table below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the South Gibsonton project.

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

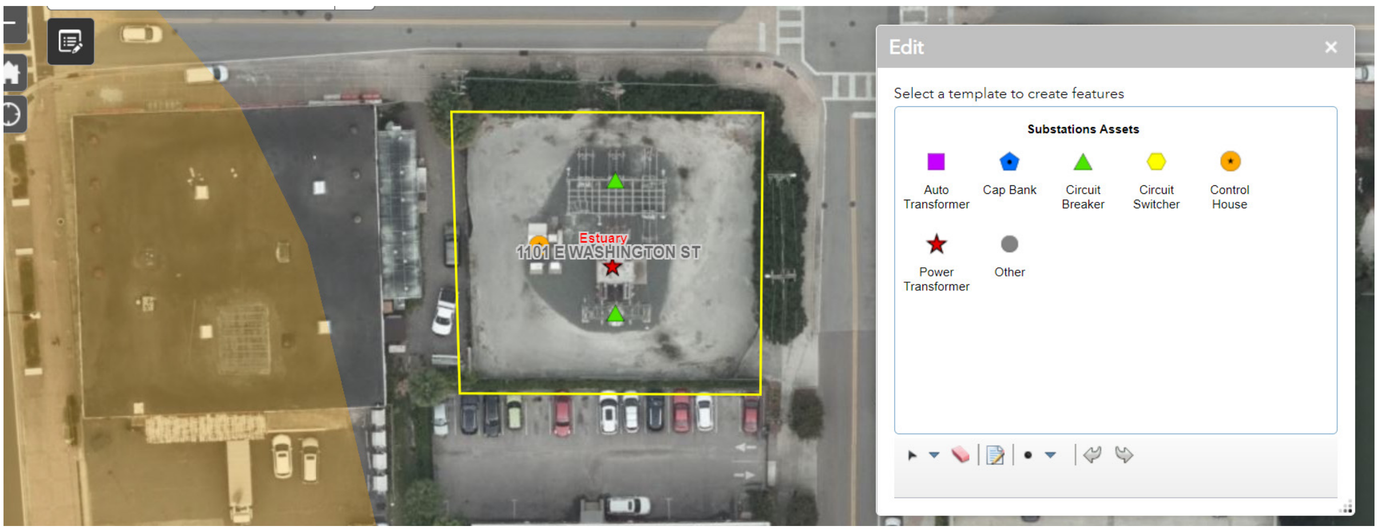
In the table below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the Jackson Rd project.

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

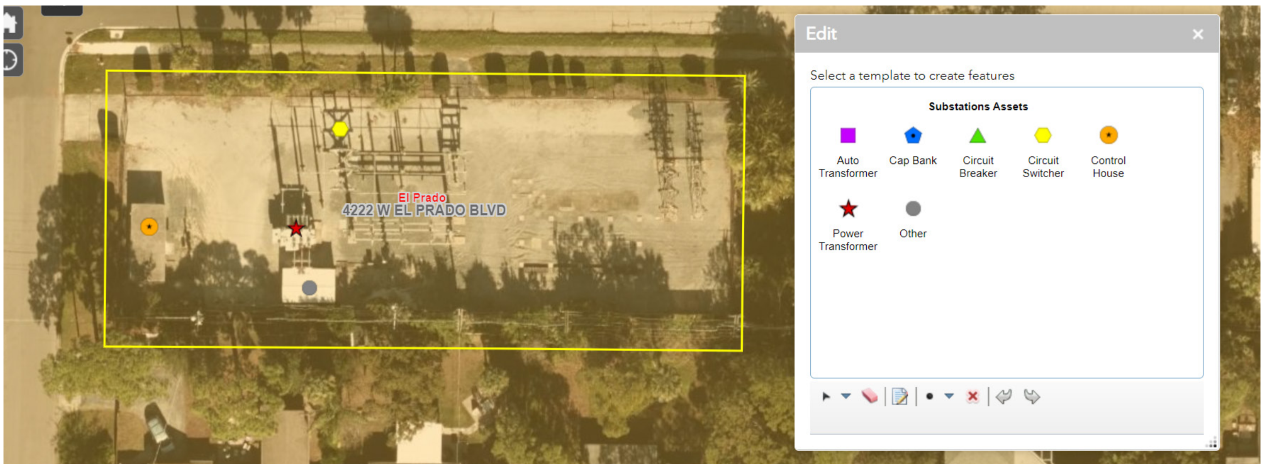
The Estuary project is a smaller capital project at $900,000 and will improve the reliability of service to TECO customers in the area, including critical downtown load. It also improves the environmental safety of the substation by removing an older 69 kV oil-filled circuit breaker and replacing it 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.

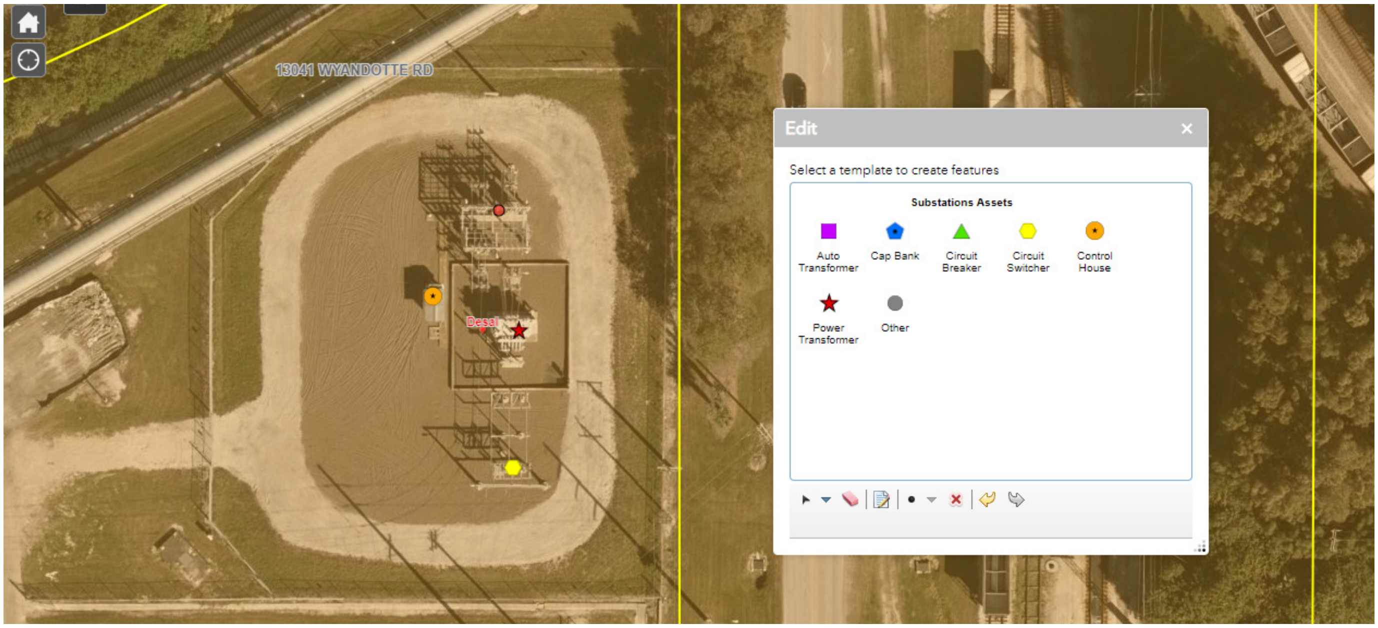
Cost Benefit

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

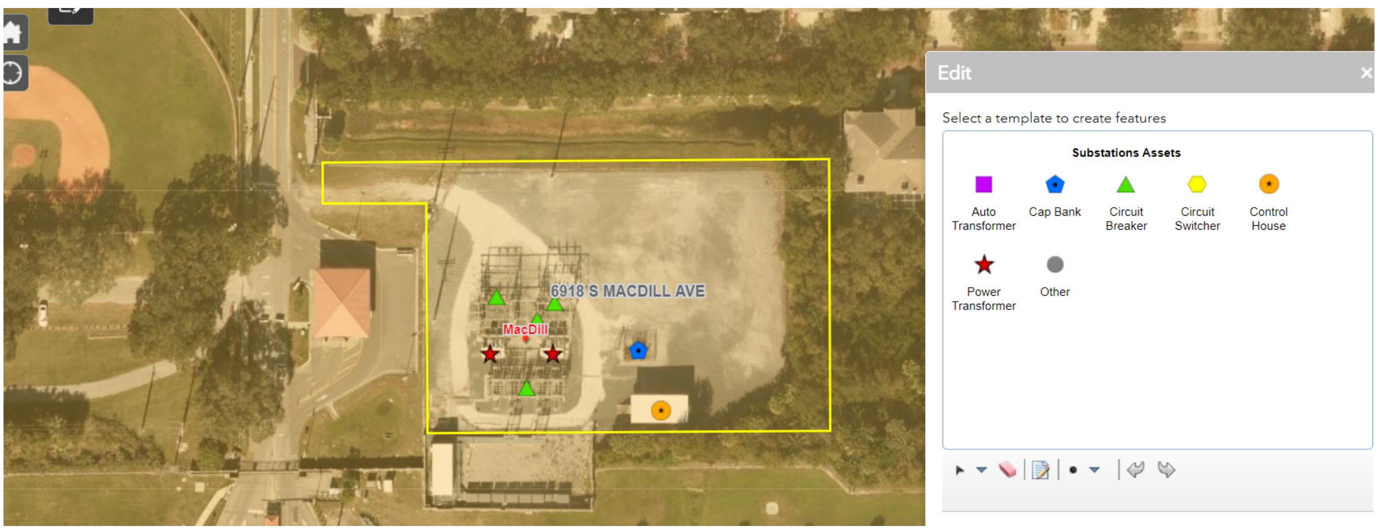
In the table below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the Desal project.

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

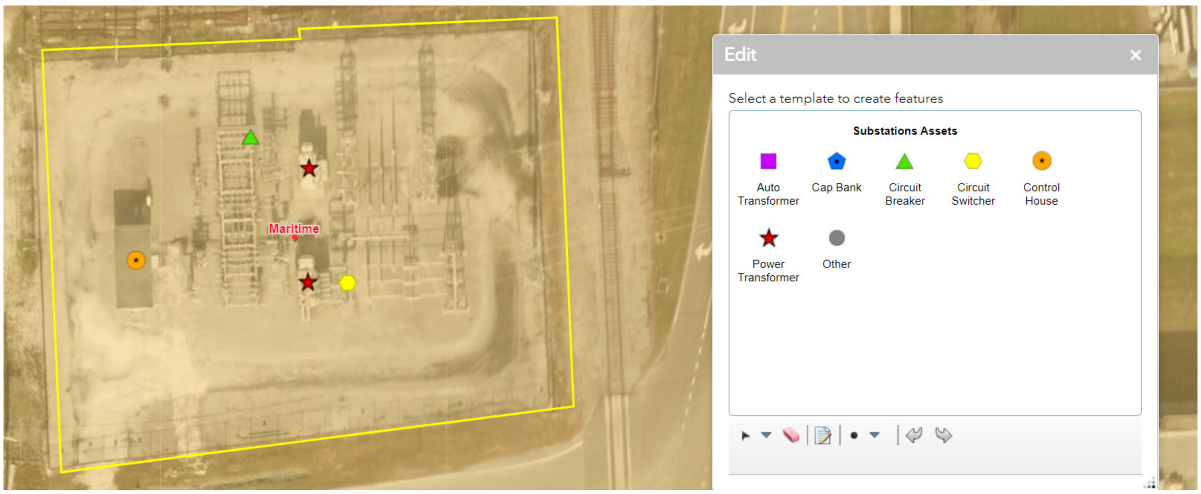
In the table below is a high-level, budgetary cost estimate (+/- 25% accuracy) for the MacDill project.

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

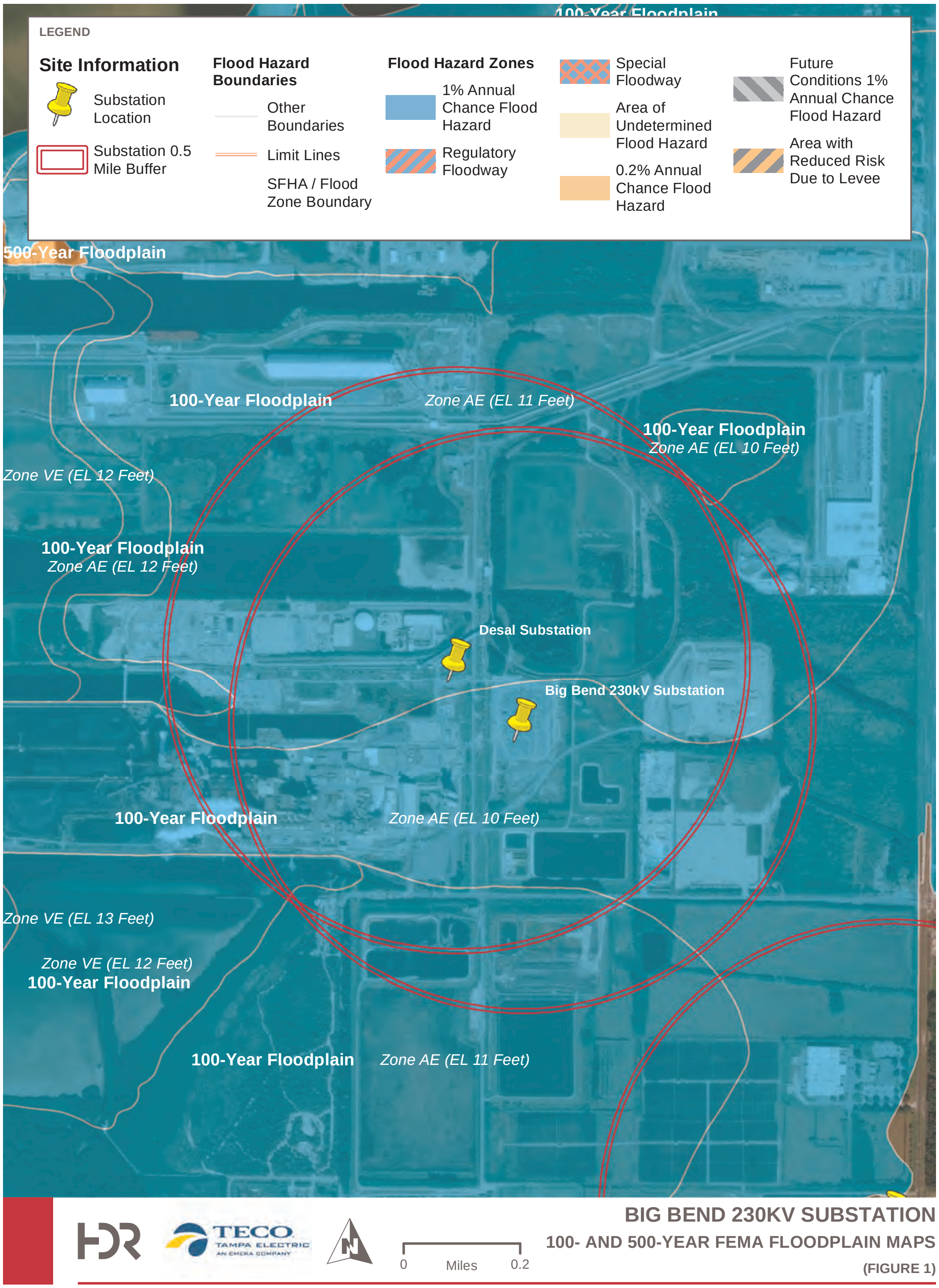
Tampa Electric Company sought out to determine the impact of storm surge flooding and for ways to harden twenty-four (24) of its substations against those flood events. HDR, Inc. performed desktop studies, site visits and built a cloud-based GIS platform to perform this analysis. After collecting this 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)

PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\BIG BEND FEMA.MXD - USER: ALMILLER - DATE: 5/20/2021

TAMPA ELECTRIC COMPANY
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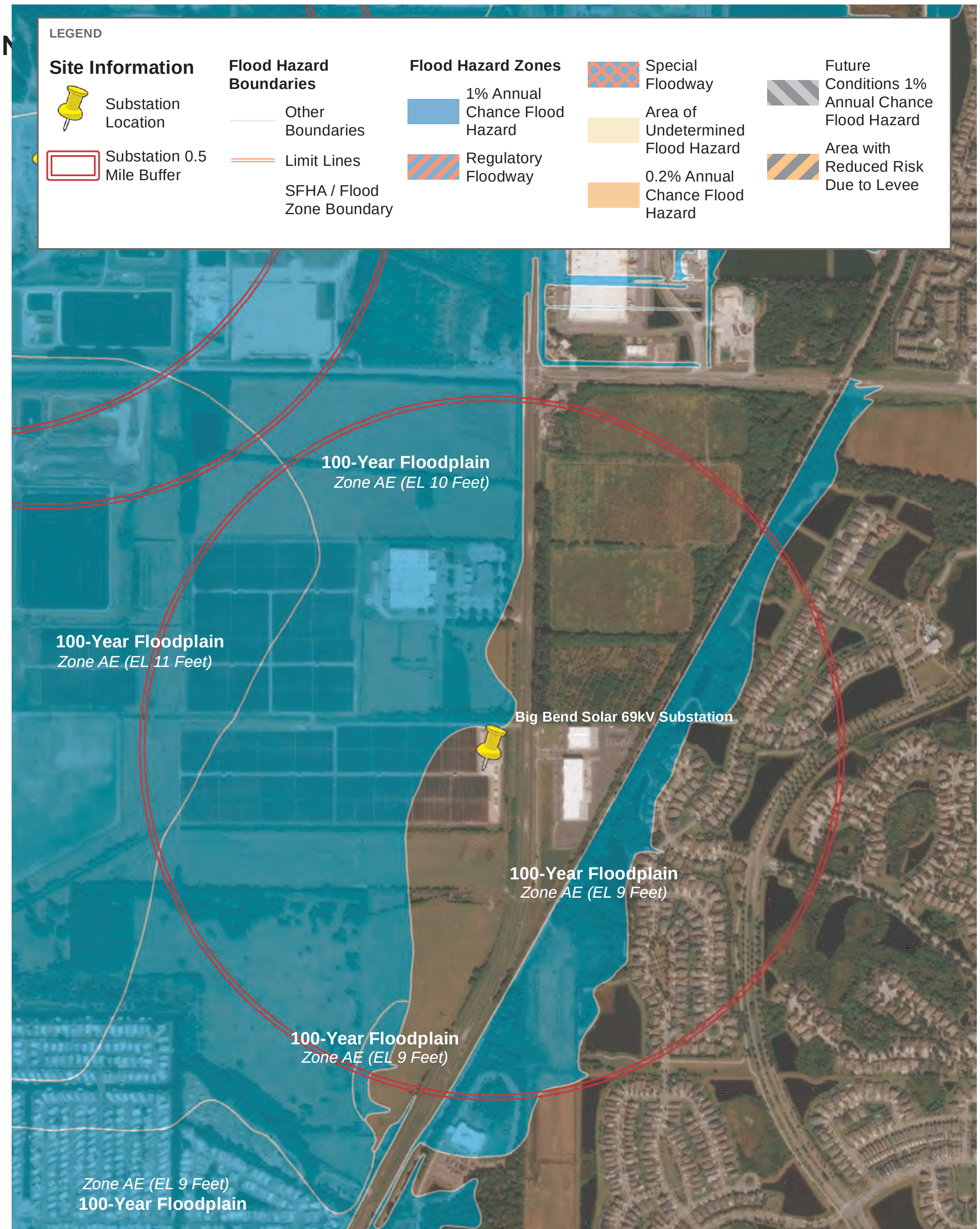

0 Miles 0.2

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

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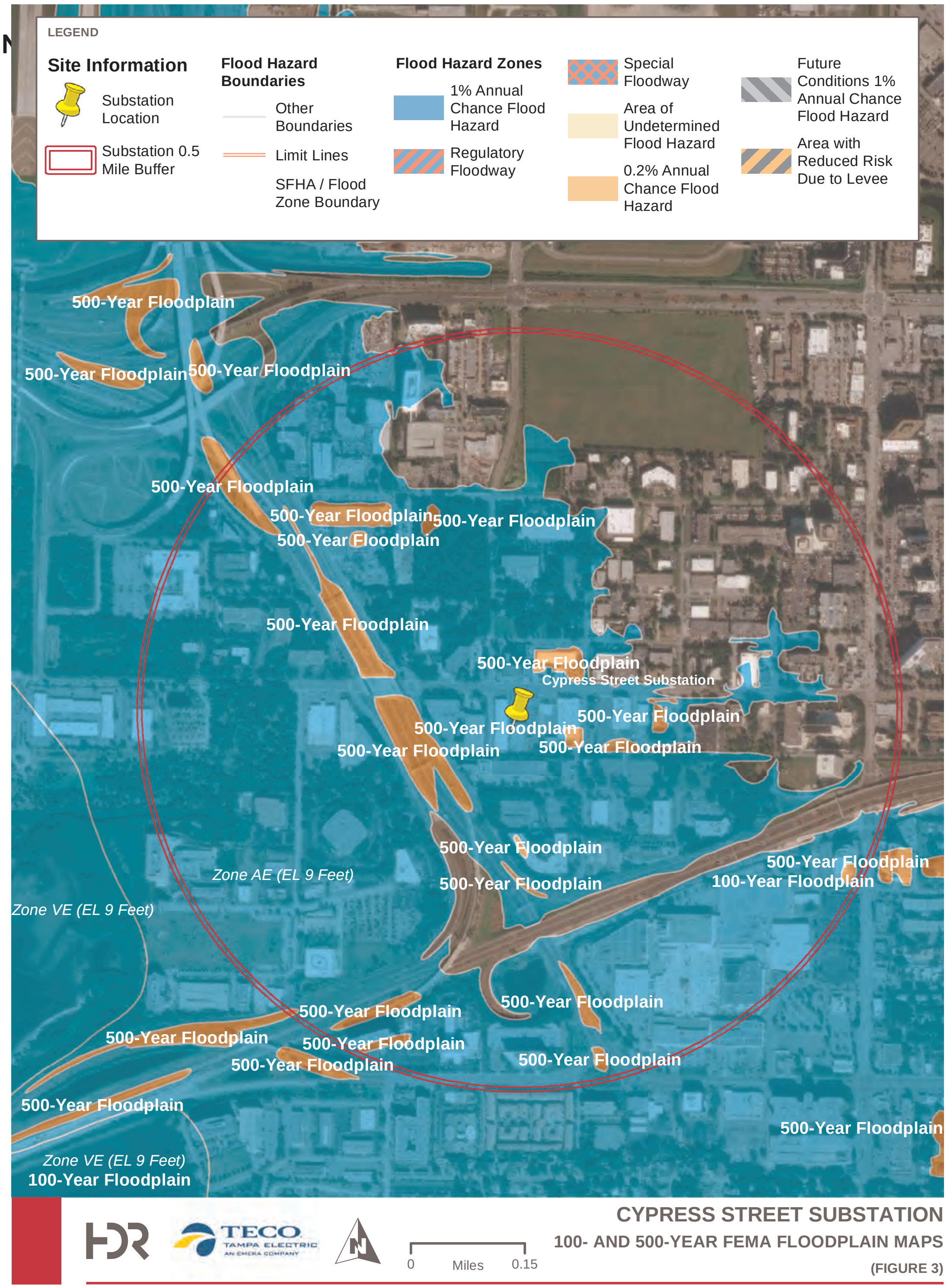
LEGEND
Site Information
Substation Location
Substation 0.5 Mile Buffer
Flood Hazard Boundaries
Other Boundaries
Limit Lines
SFHA / Flood Zone Boundary
Flood Hazard Zones
1% Annual Chance Flood Hazard
Regulatory Floodway
Special Floodway
Area of Undetermined Flood Hazard
0.2% Annual Chance Flood Hazard
Future Conditions 1% Annual Chance Flood Hazard
Area with Reduced Risk Due to Levee
500-Year Floodplain
Cypress Street Substation
Zone AE (EL 9 Feet)
Zone VE (EL 9 Feet)
100-Year Floodplain
0
Miles
0.15
CYPRESS STREET SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 3)
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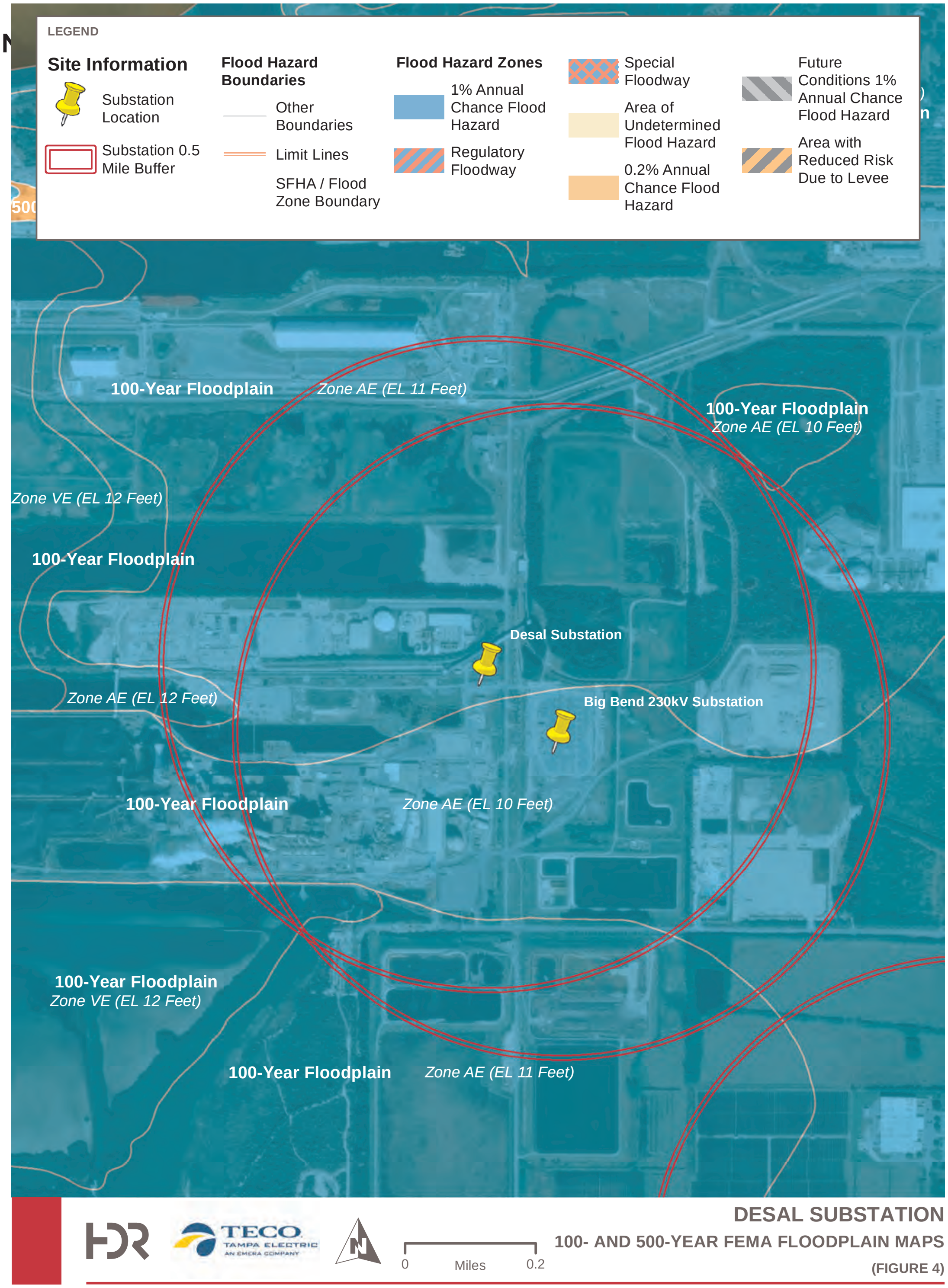

DESAL SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 4)

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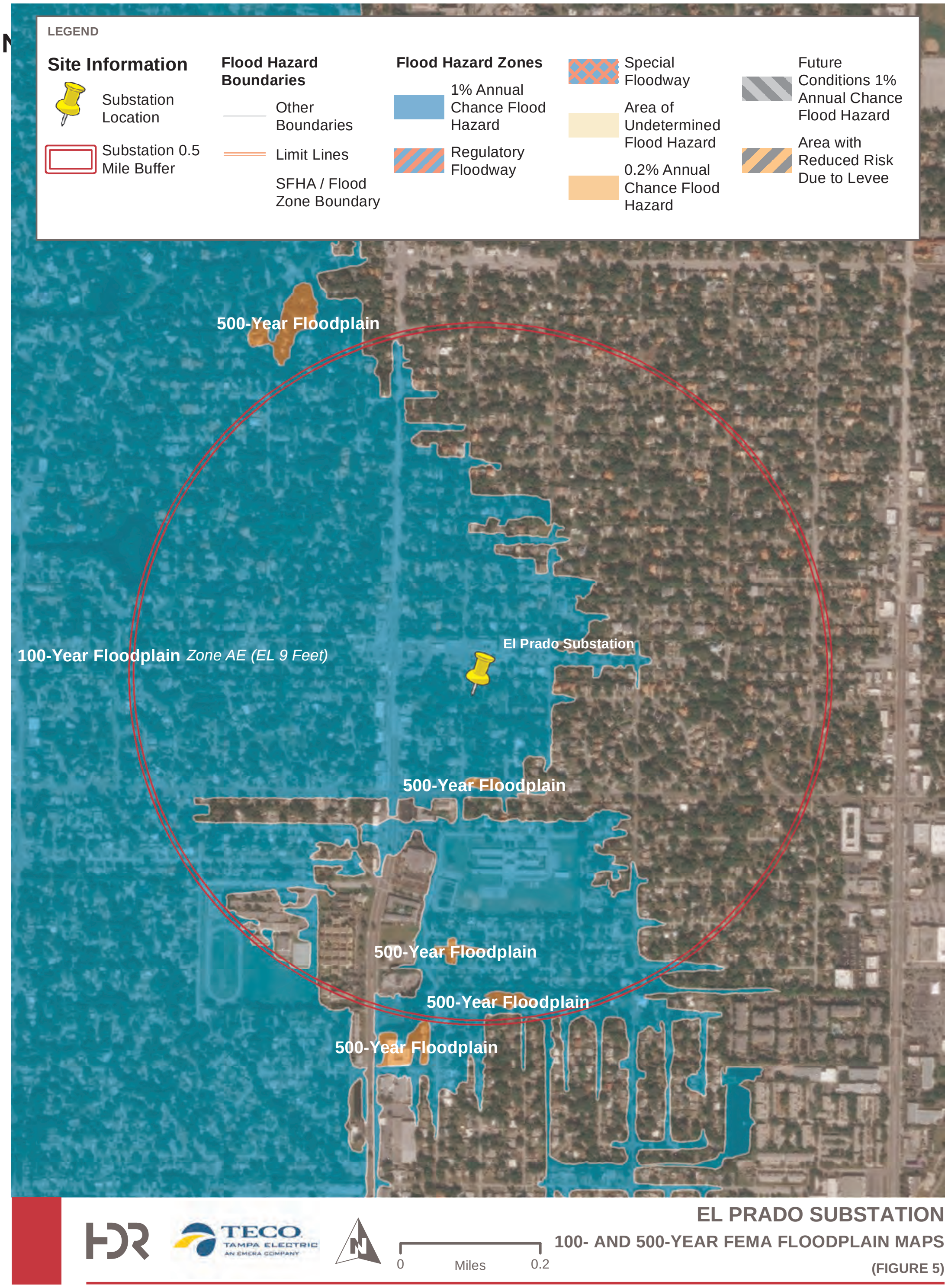
LEGEND
Site Information
Substation Location
Substation 0.5 Mile Buffer
Flood Hazard Boundaries
Other Boundaries
Limit Lines
SFHA / Flood Zone Boundary
Flood Hazard Zones
1% Annual Chance Flood Hazard
Regulatory Floodway
Special Floodway
Area of Undetermined Flood Hazard
0.2% Annual Chance Flood Hazard
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)
El Prado Substation
500-Year Floodplain
500-Year Floodplain
500-Year Floodplain
500-Year Floodplain
TECO TAMPA ELECTRIC AN EMERA COMPANY
N
0
Miles
0.2
EL PRADO SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 5)
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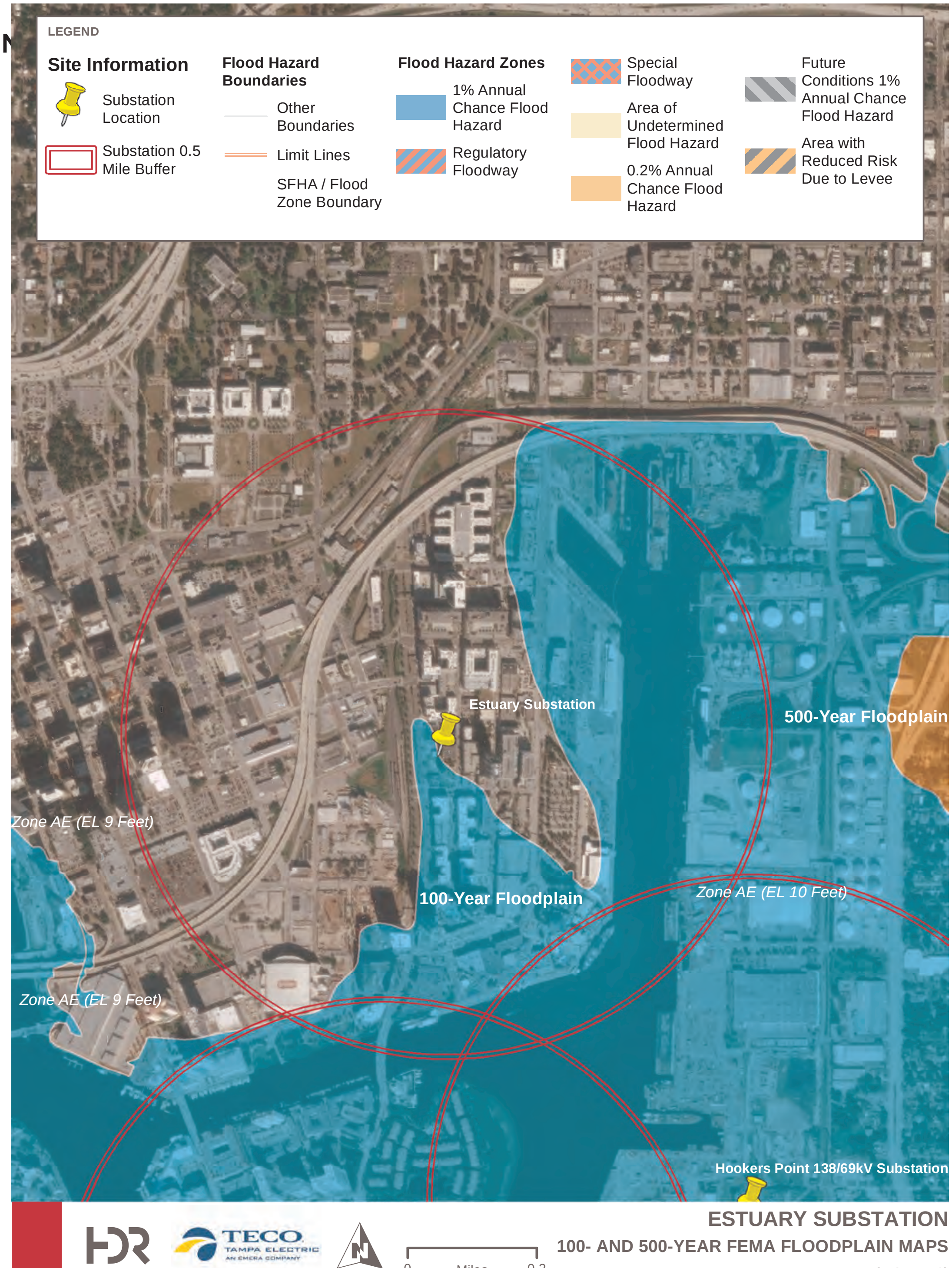

ESTUARY SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 6)

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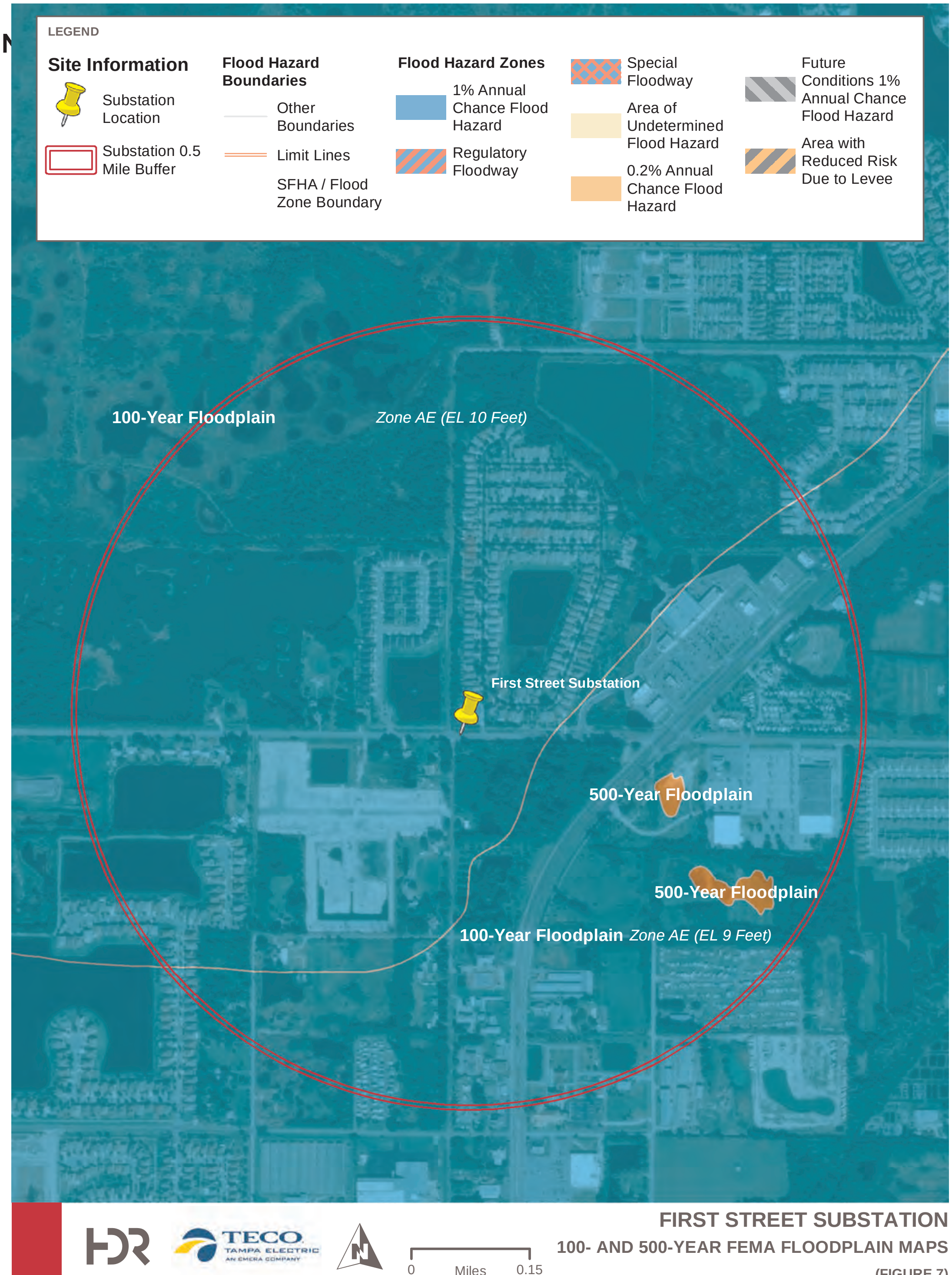

FIRST STREET SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 7)

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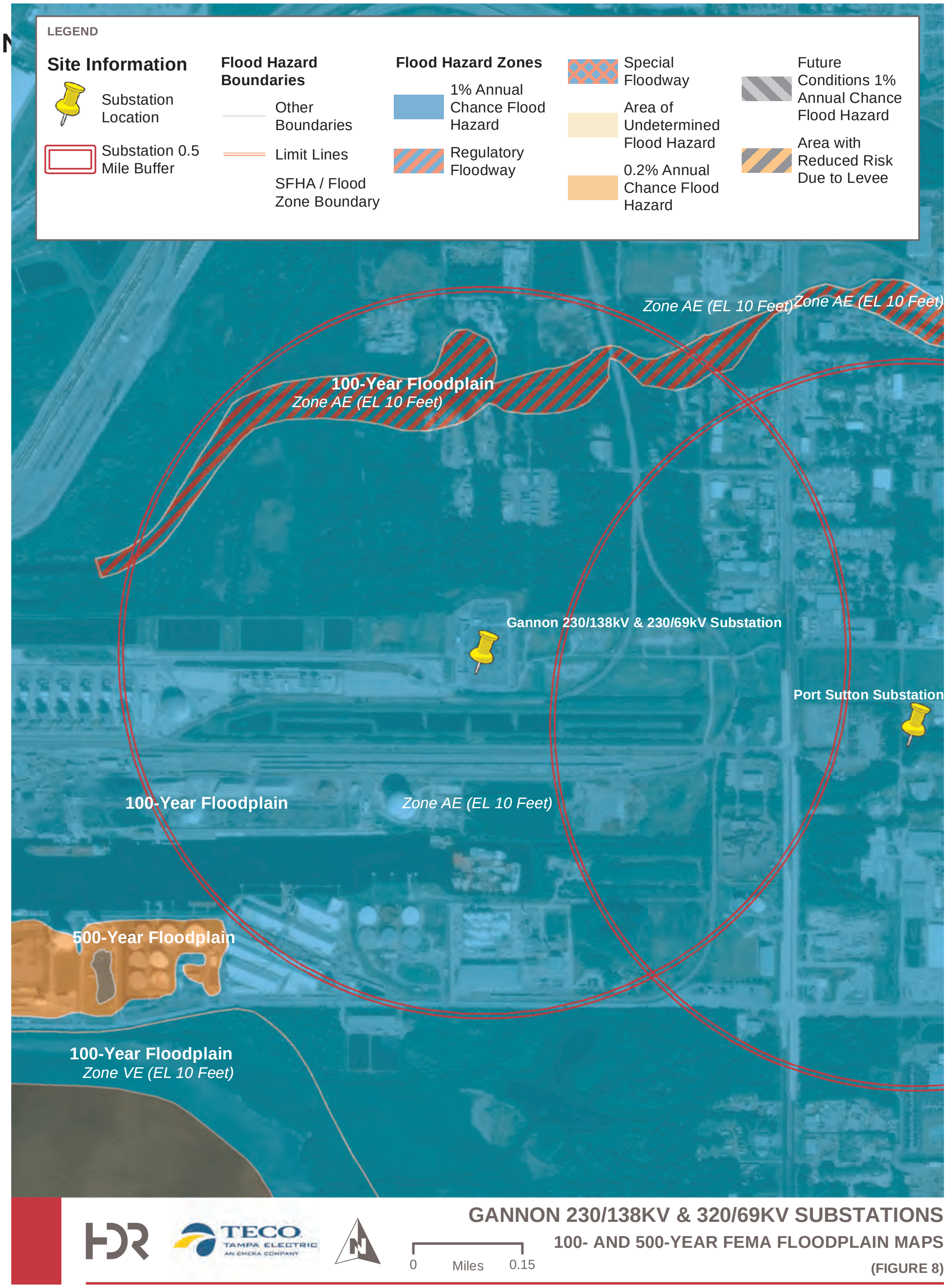

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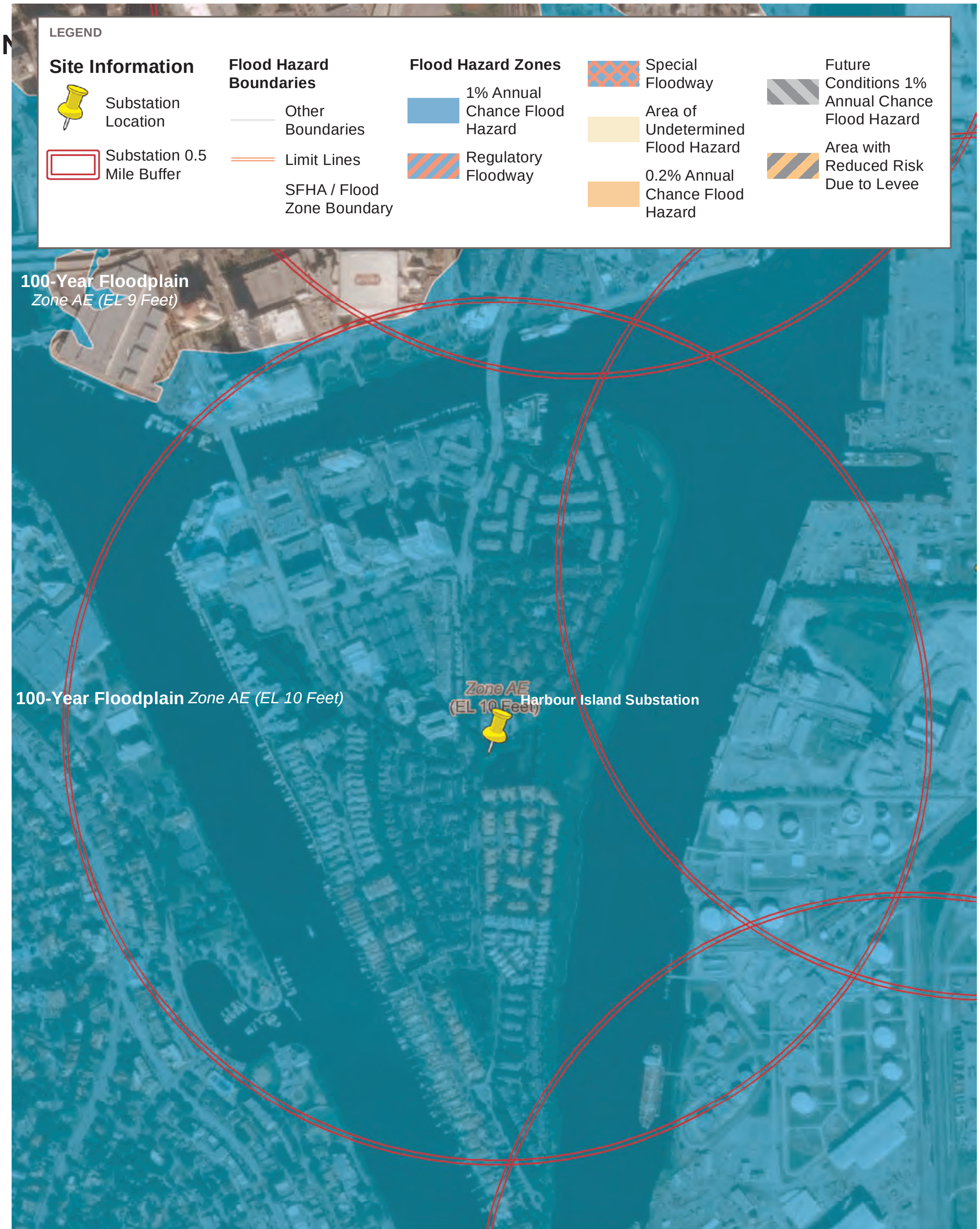

HARBOUR ISLAND SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 9)

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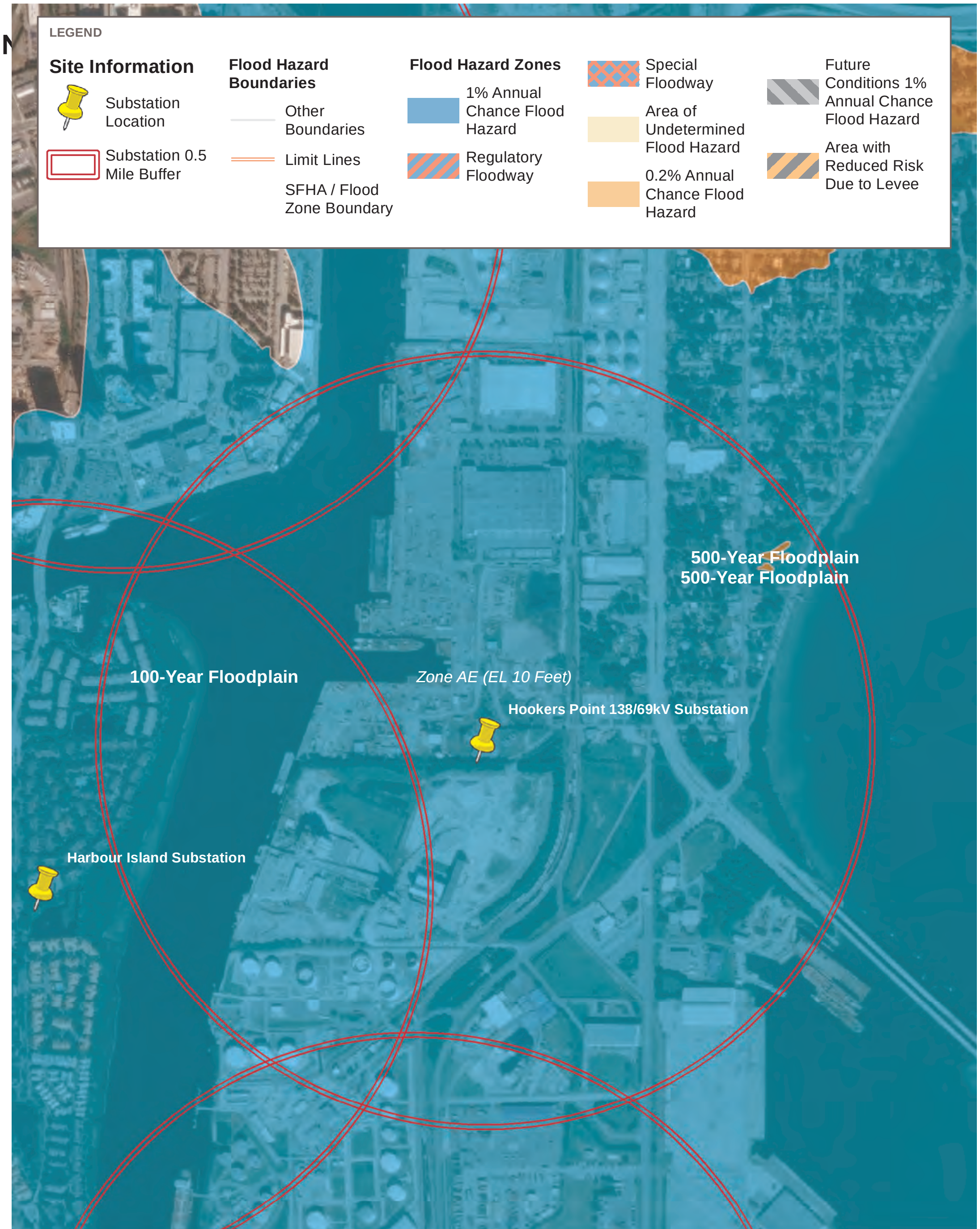

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HOOKERS POINT 138/69KV SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 10)

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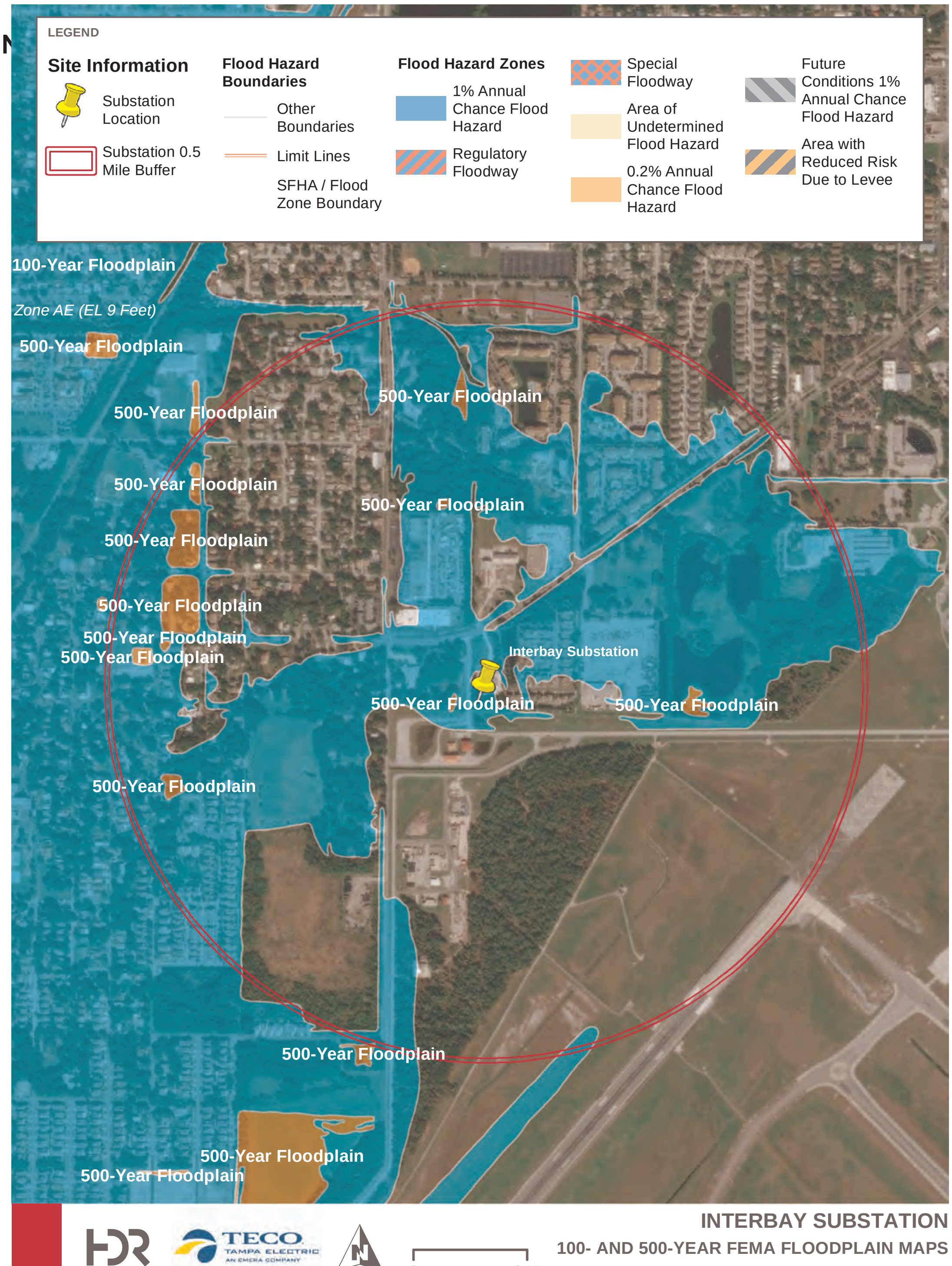

INTERBAY SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 11)

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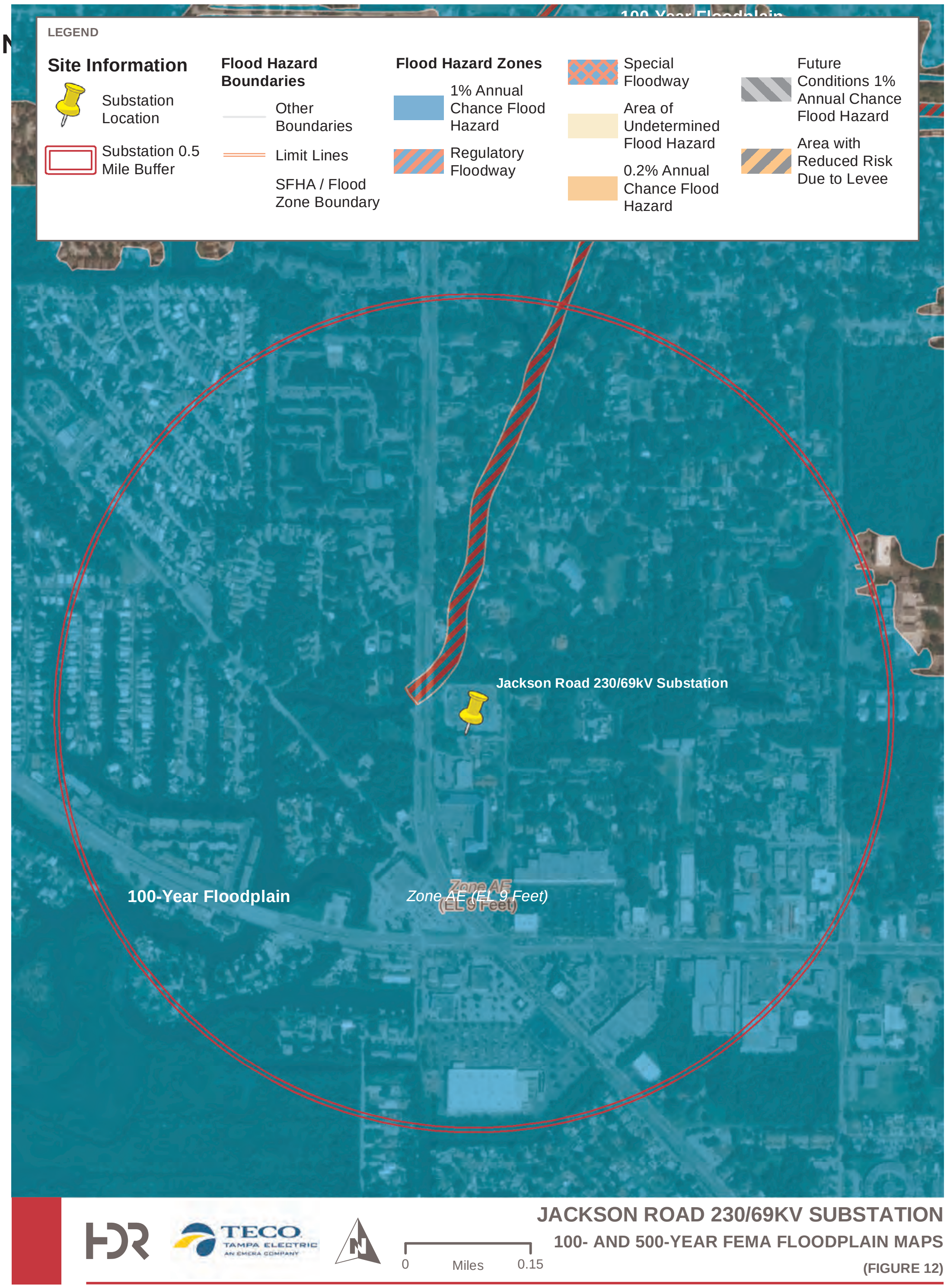

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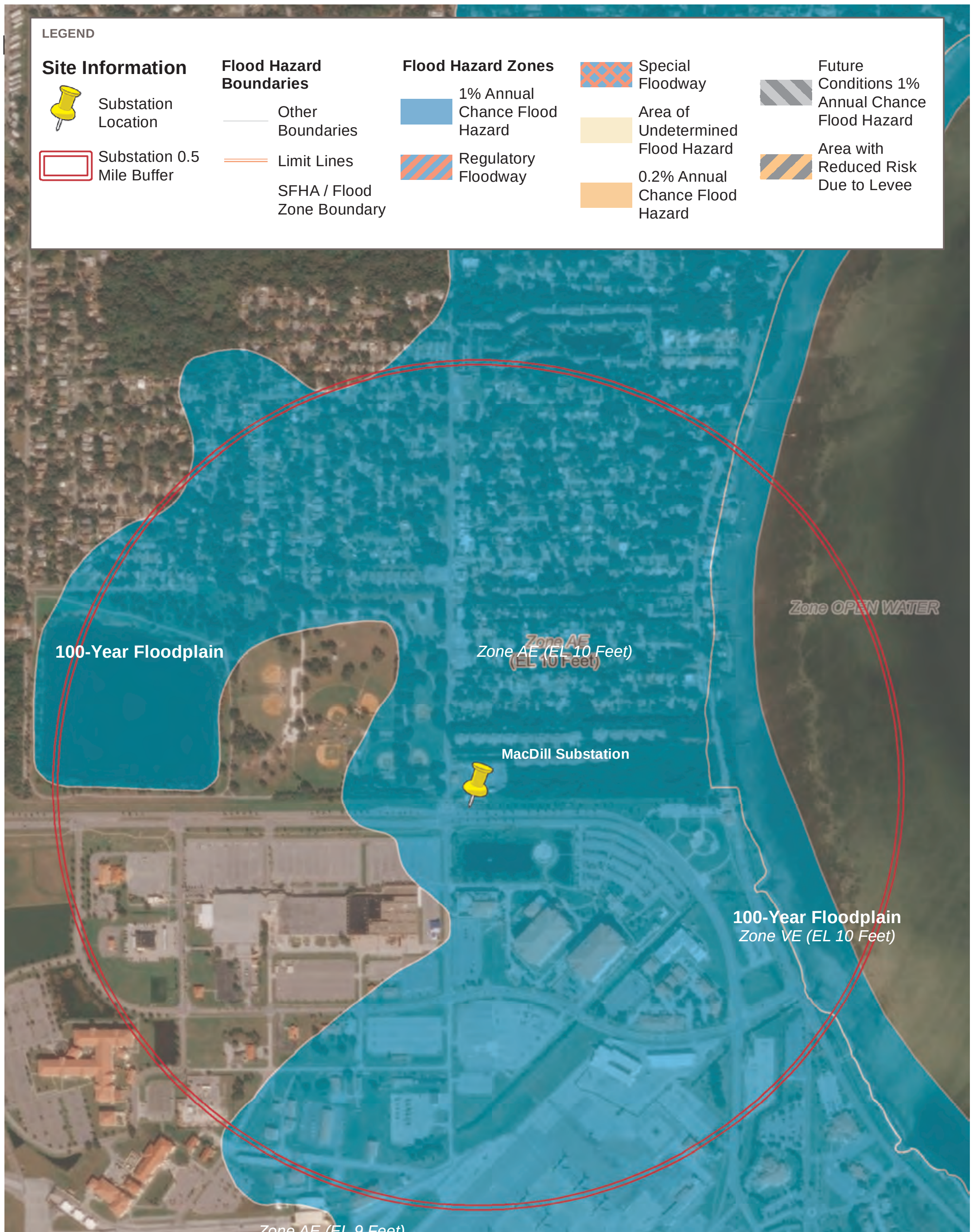

MACDILL SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 13)

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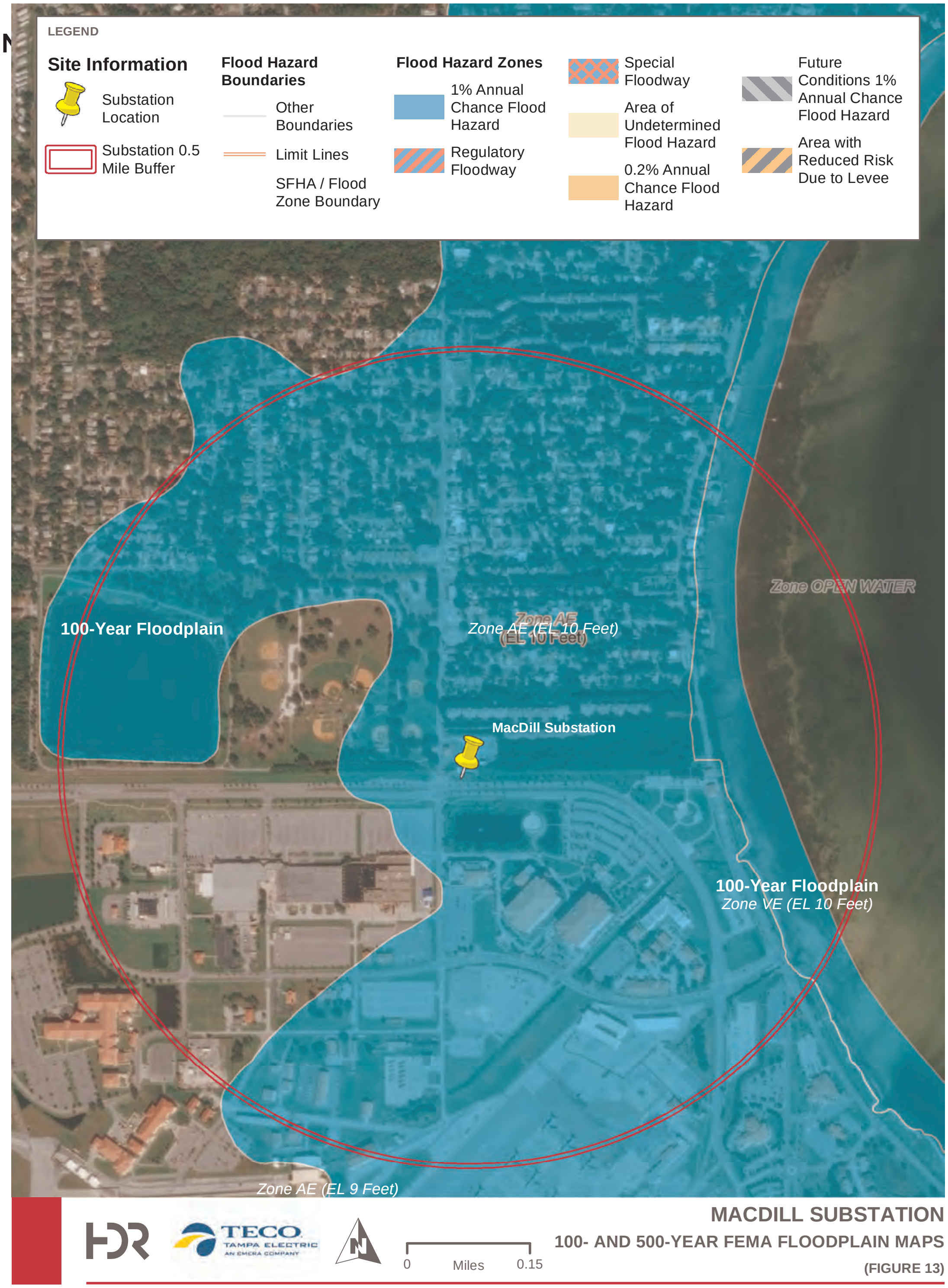

MACDILL SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 13)

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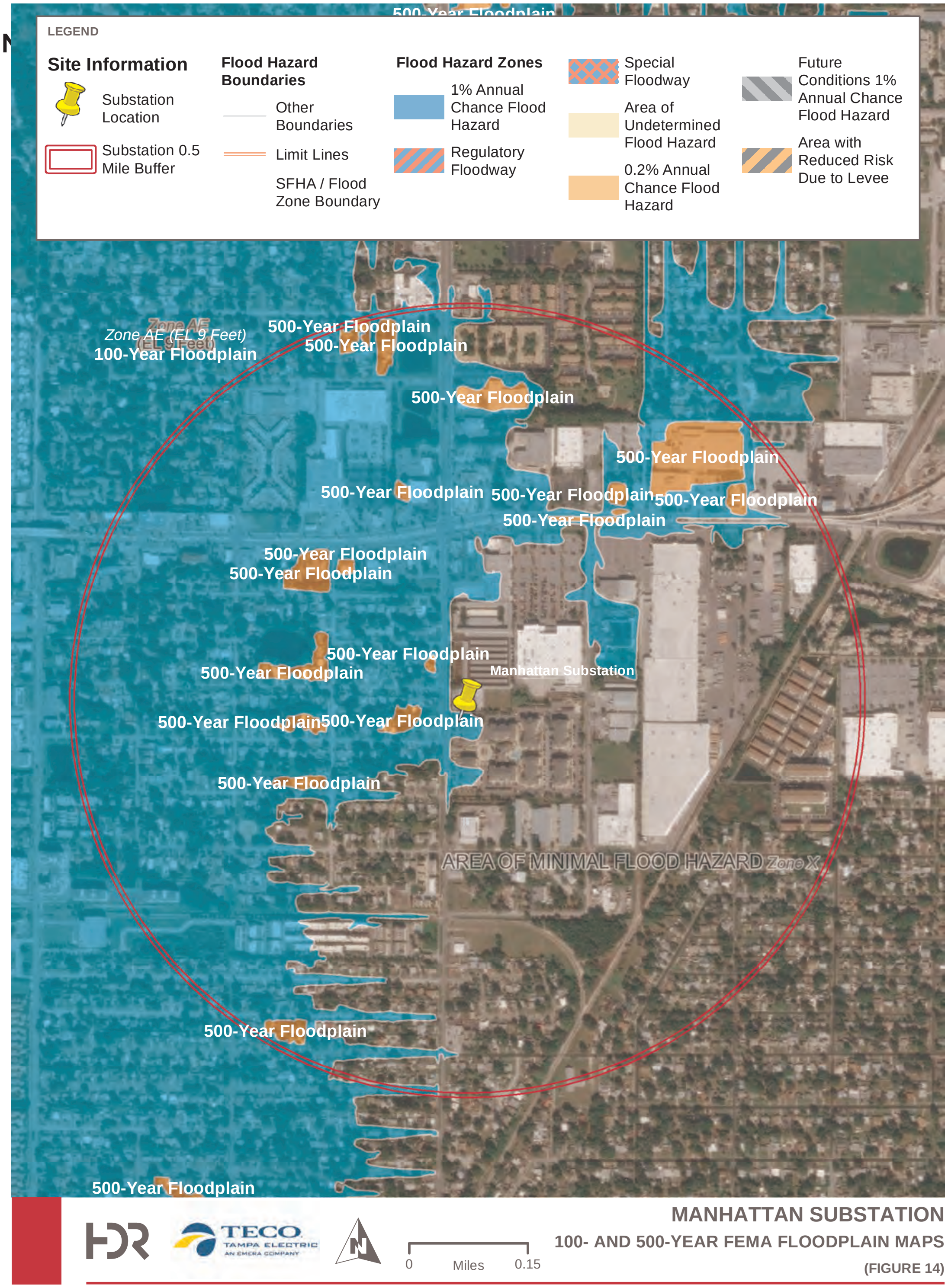
LEGEND
Site Information
Substation Location
Substation 0.5 Mile Buffer
Flood Hazard Boundaries
Other Boundaries
Limit Lines
SFHA / Flood Zone Boundary
Flood Hazard Zones
1% Annual Chance Flood Hazard
Regulatory Floodway
Special Floodway
Area of Undetermined Flood Hazard
0.2% Annual Chance Flood Hazard
Future Conditions 1% Annual Chance Flood Hazard
Area with Reduced Risk Due to Levee
Zone AE (EL 9 Feet)
100-Year Floodplain
500-Year Floodplain
Manhattan Substation
AREA OF MINIMAL FLOOD HAZARD Zone X
0
Miles
0.15
MANHATTAN SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 14)
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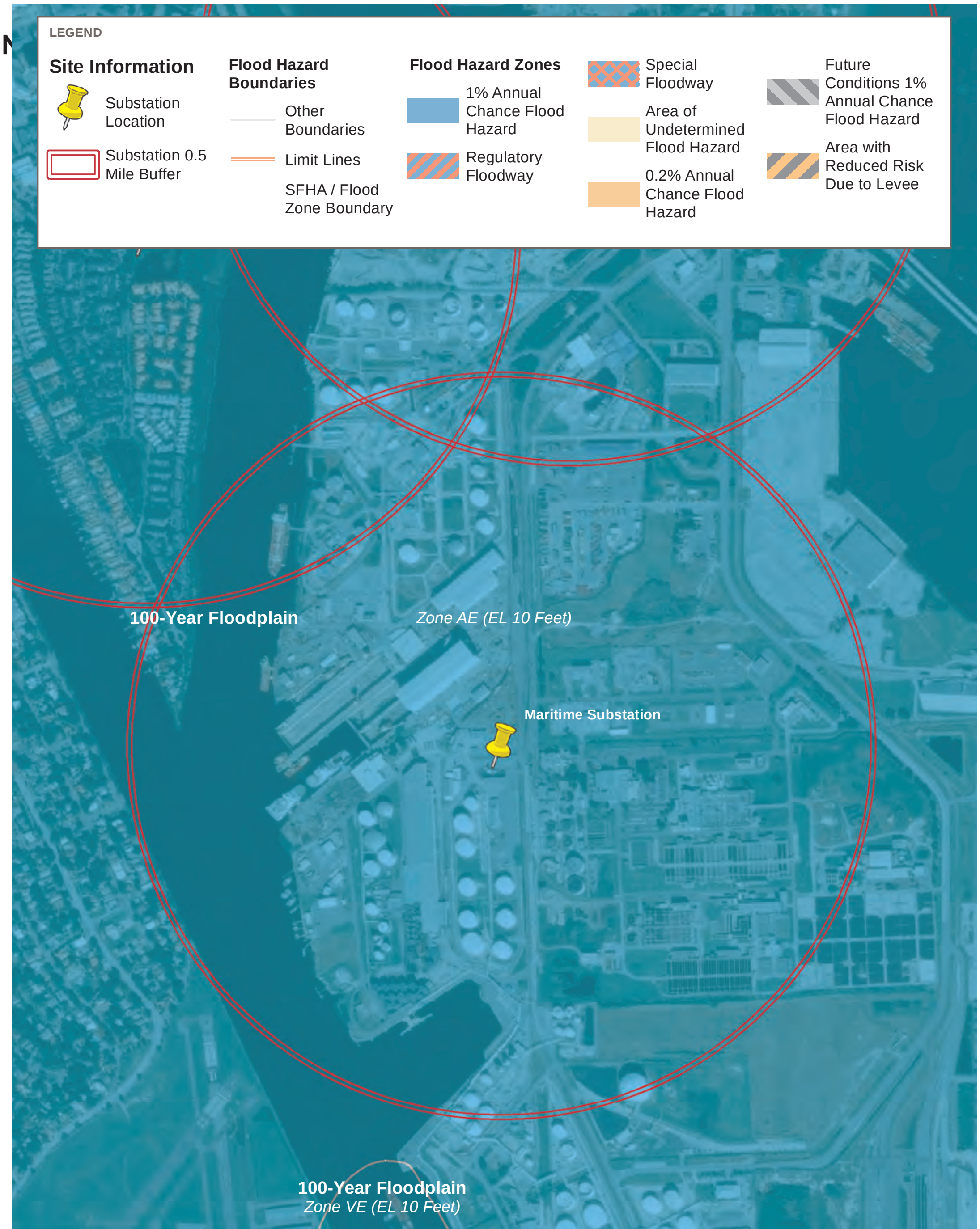

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MARITIME SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 15)

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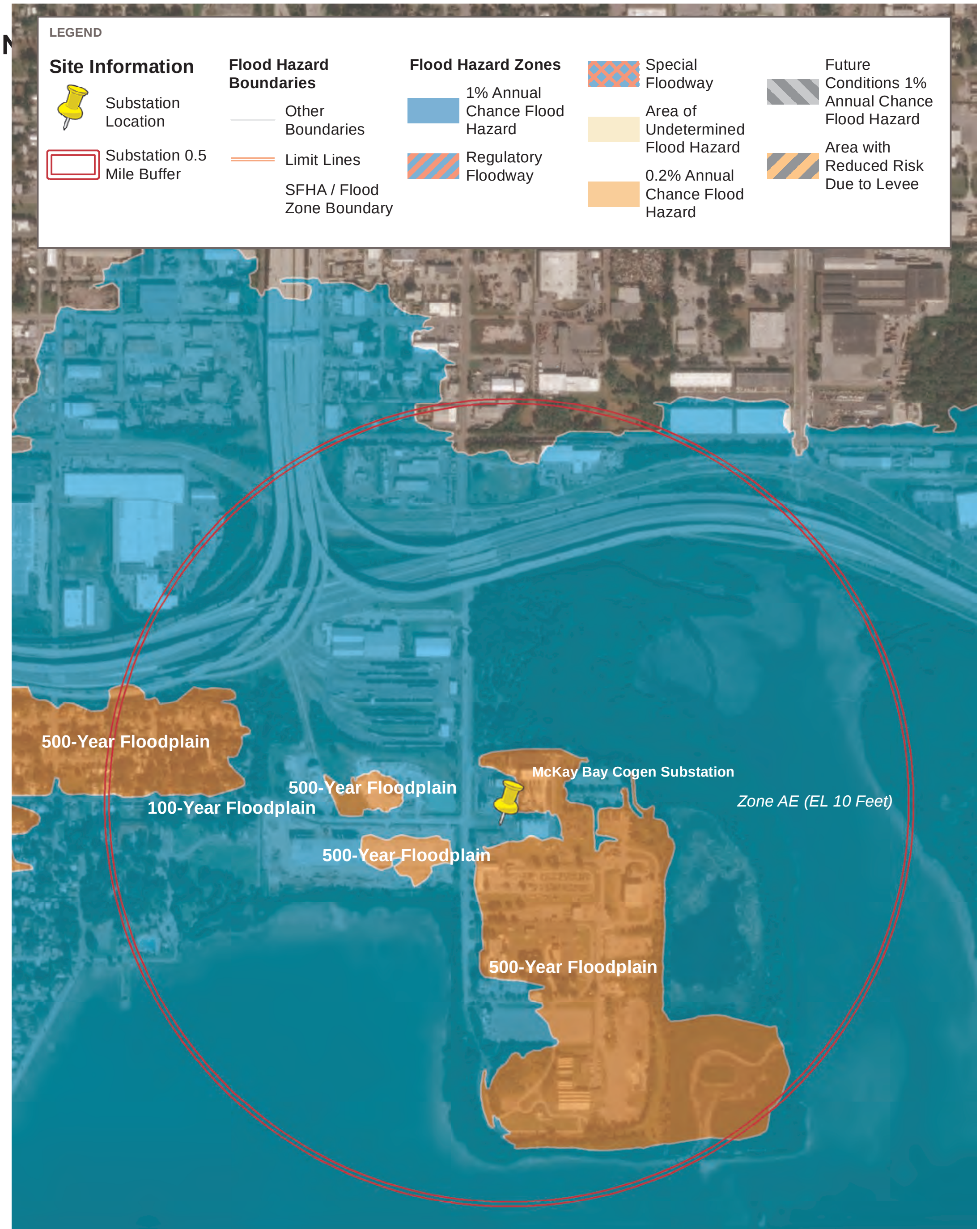

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MCKAY BAY COGEN SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 16)

PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\MCKAY BAY COGEN FEMA.MXD - USER: ALMILLER - DATE: 5/21/2021

TAMPA ELECTRIC COMPANY
DOCKET NO. 20220048-EI
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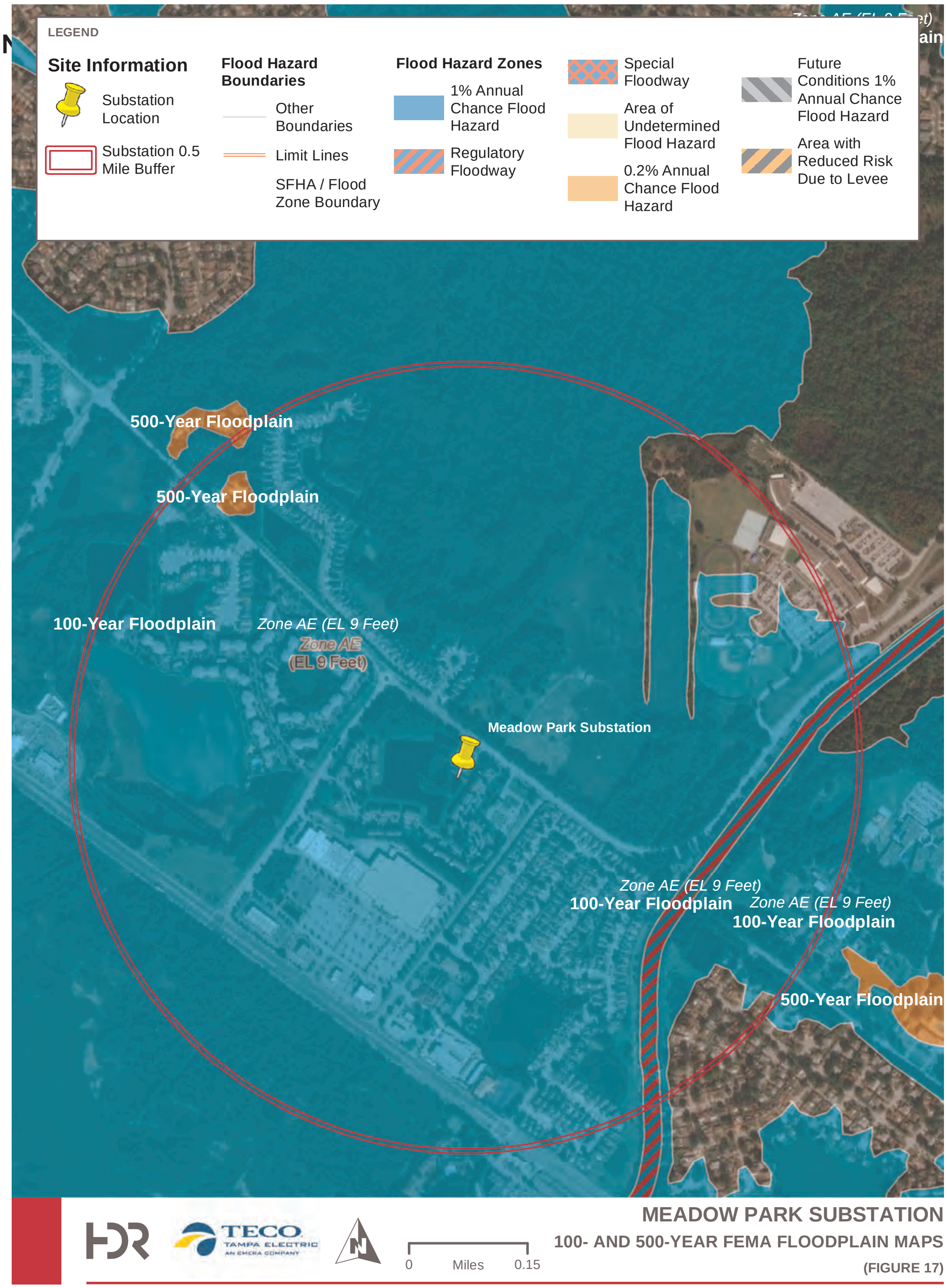
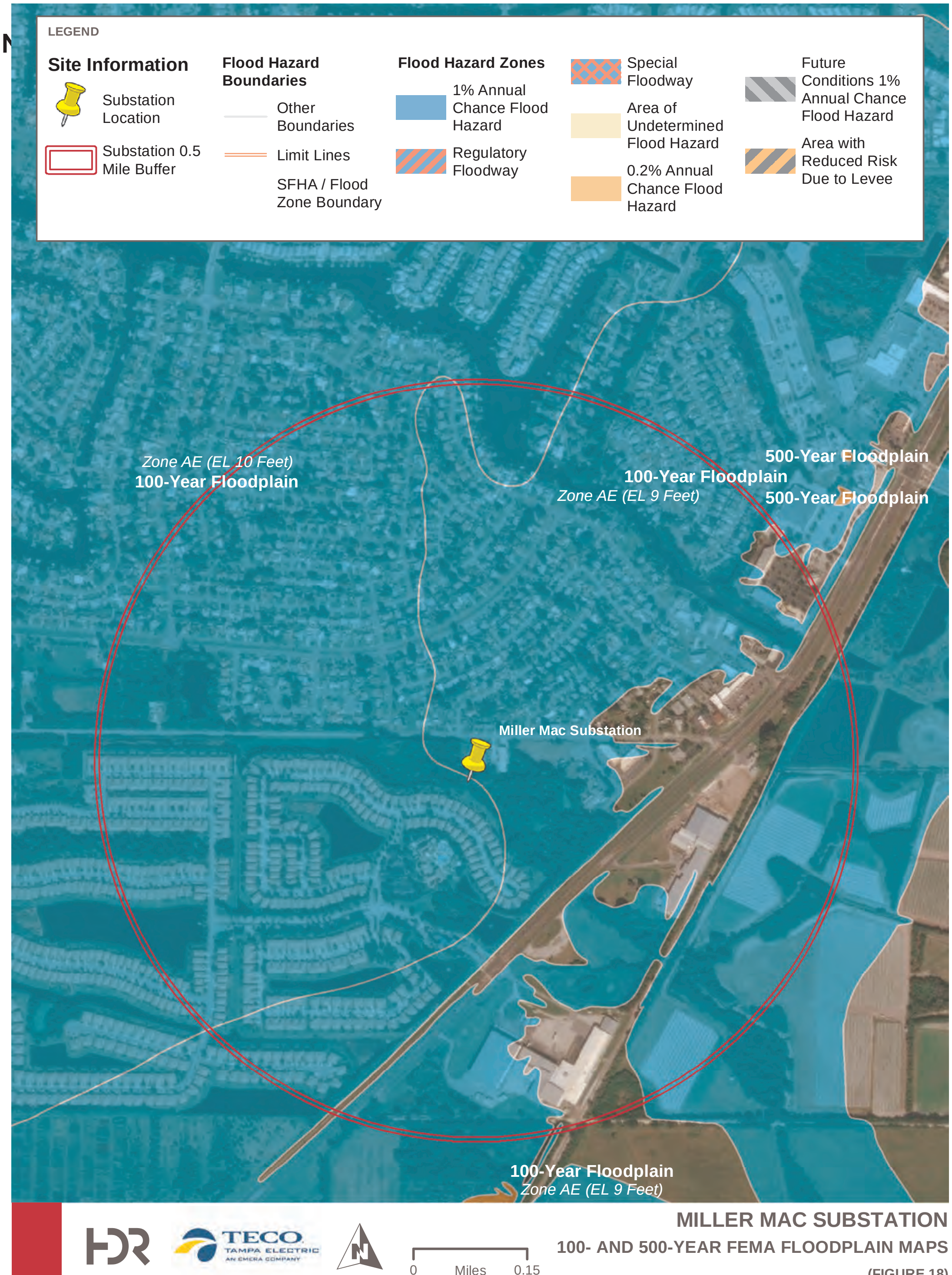
INTERROGATORIES
INTERROGATORY NO. 17
PAGE 69 OF 75
FILED: APRIL 11, 2022





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

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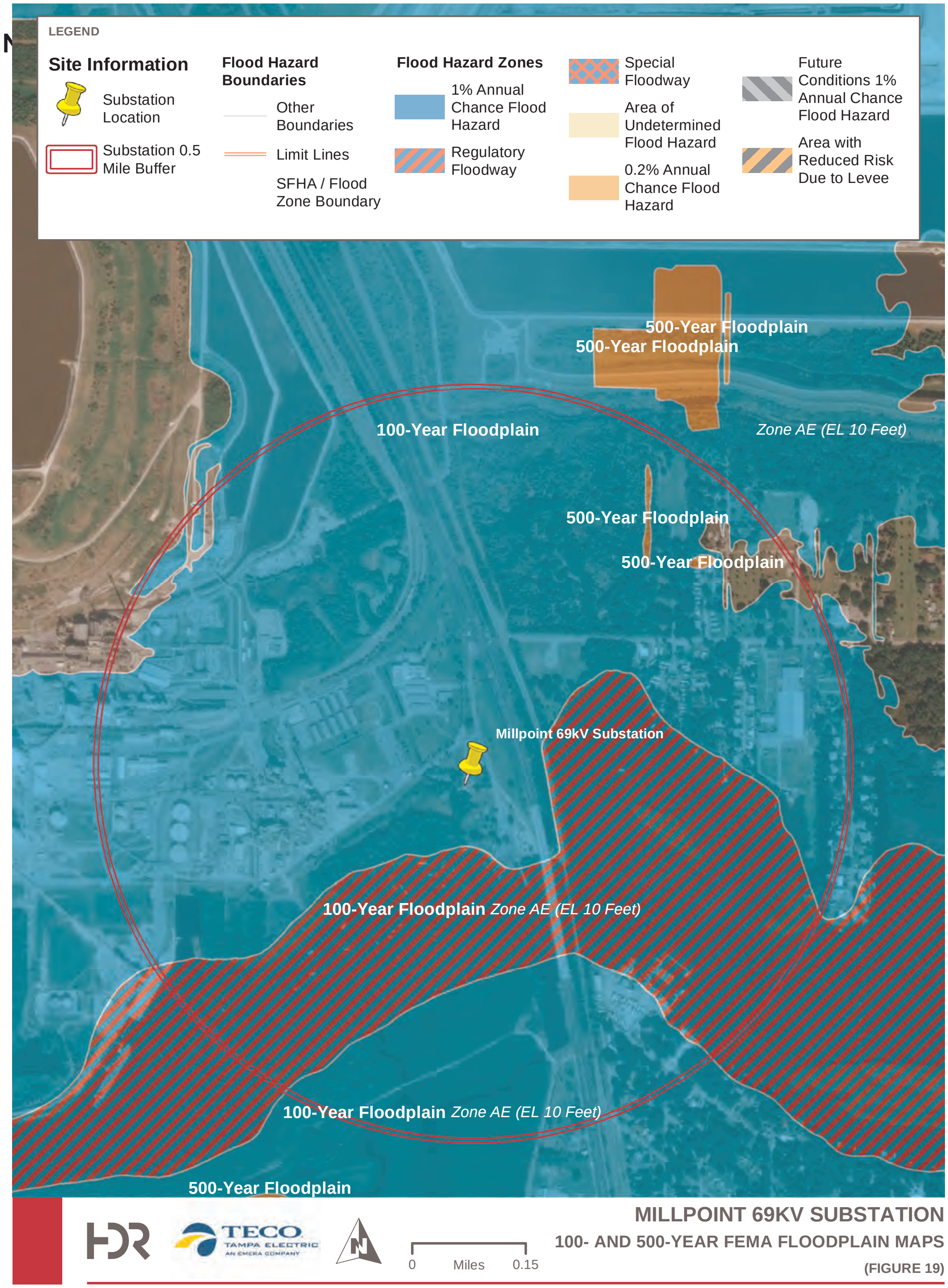
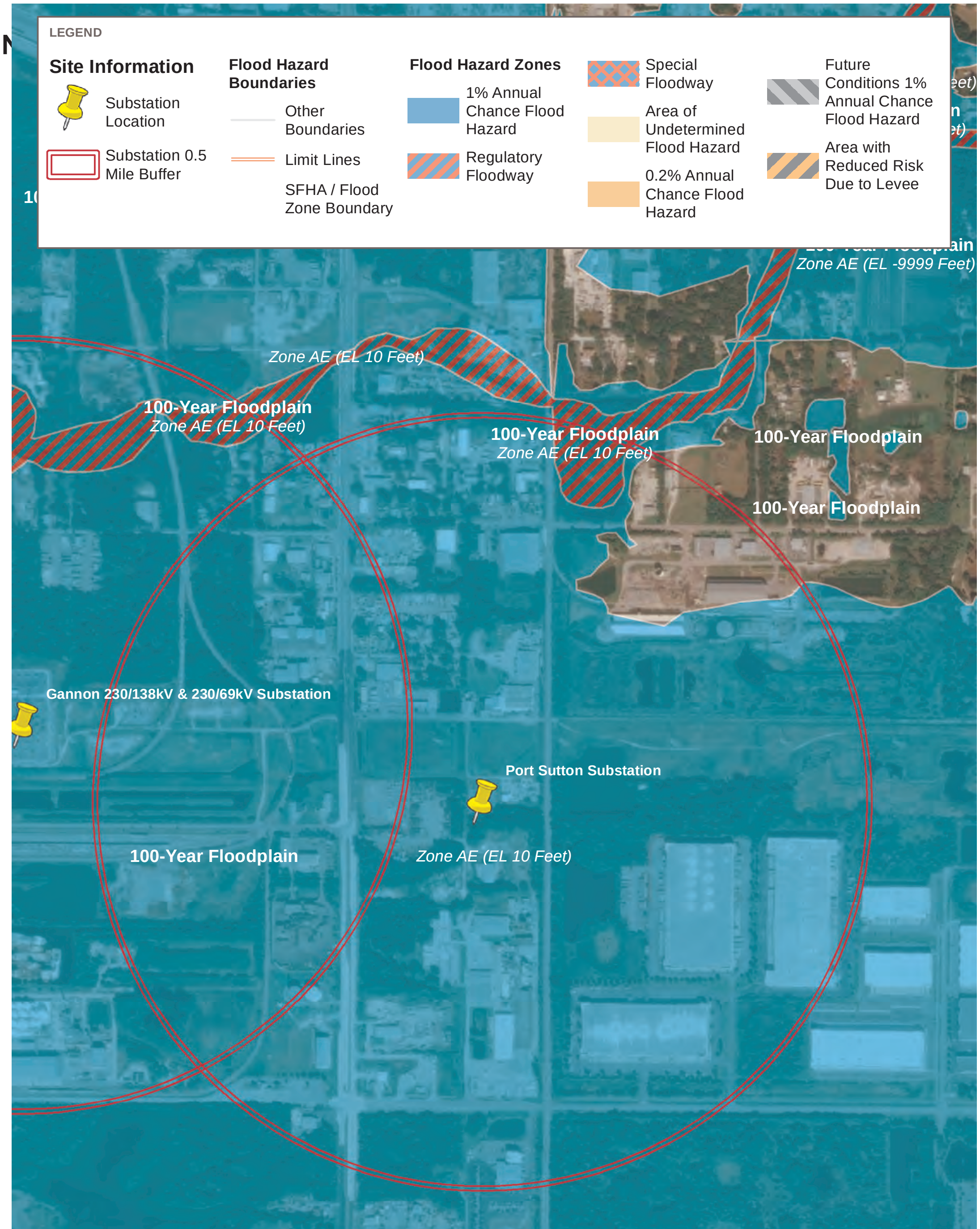

LEGEND
Site Information
Substation Location
Substation 0.5 Mile Buffer
Flood Hazard Boundaries
Other Boundaries
Limit Lines
SFHA / Flood Zone Boundary
Flood Hazard Zones
1% Annual Chance Flood Hazard
Regulatory Floodway
Special Floodway
Area of Undetermined Flood Hazard
0.2% Annual Chance Flood Hazard
Future Conditions 1% Annual Chance Flood Hazard
Area with Reduced Risk Due to Levee
500-Year Floodplain
500-Year Floodplain
100-Year Floodplain
Zone AE (EL 10 Feet)
500-Year Floodplain
500-Year Floodplain
Millpoint 69kV Substation
100-Year Floodplain Zone AE (EL 10 Feet)
100-Year Floodplain Zone AE (EL 10 Feet)
500-Year Floodplain
0 Miles 0.15
MILLPOINT 69KV SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 19)
PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\MILLPOINT FEMA.MXD - USER: ALMILLER - DATE: 5/21/2021



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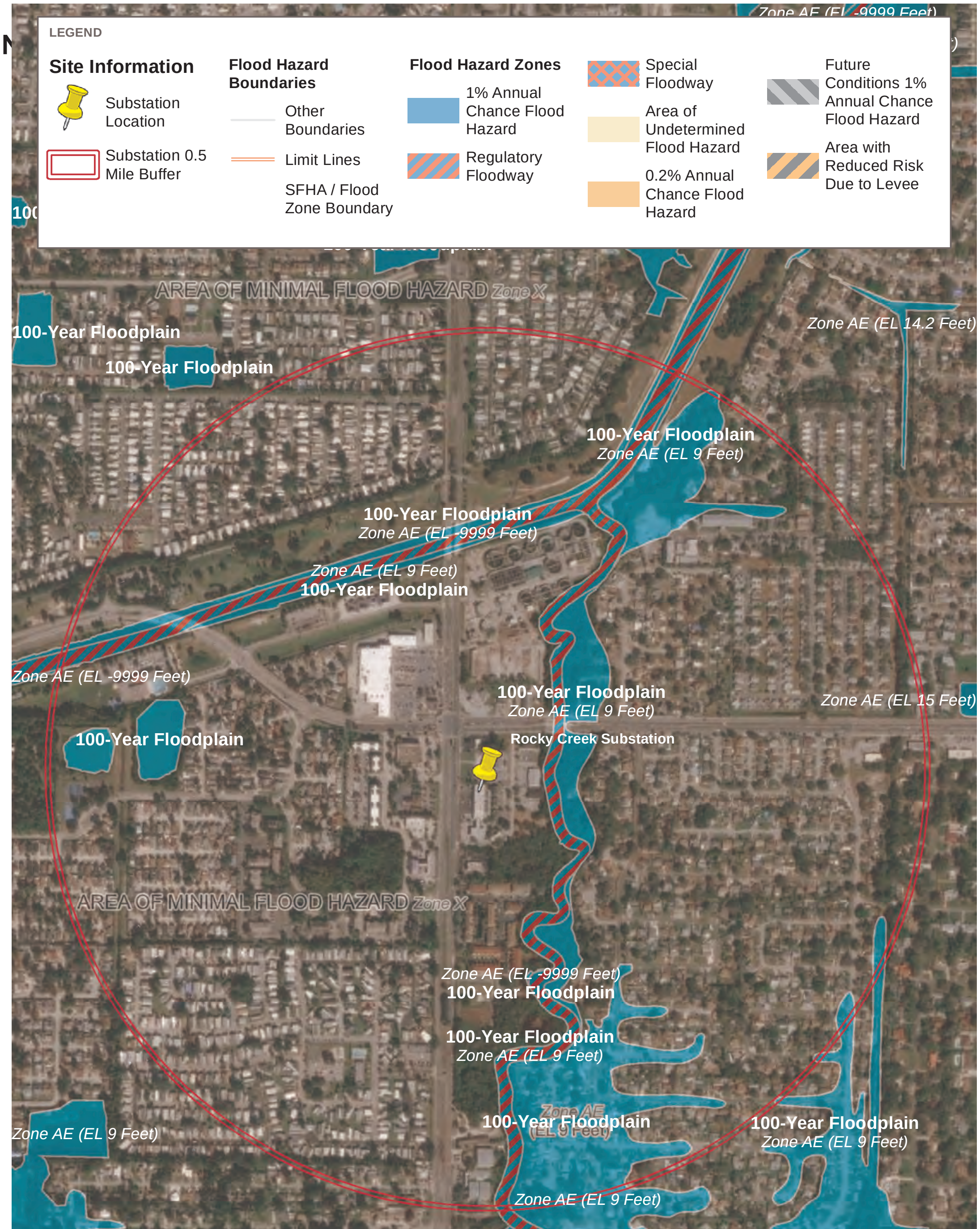
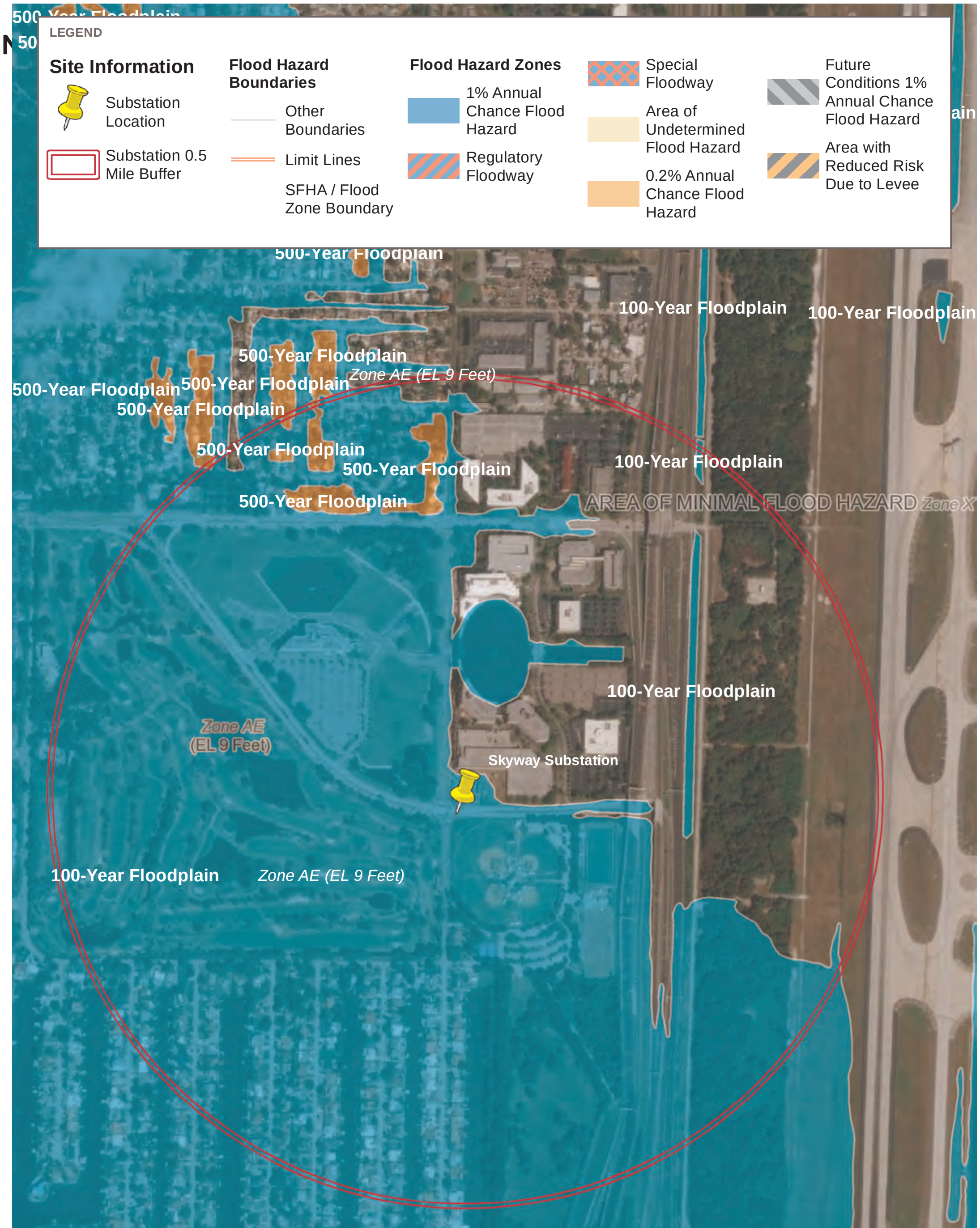
PORT SUTTON SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 20)

PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\PORT SUTTON FEMA.MXD - USER: ALMILLER - DATE: 5/21/2021



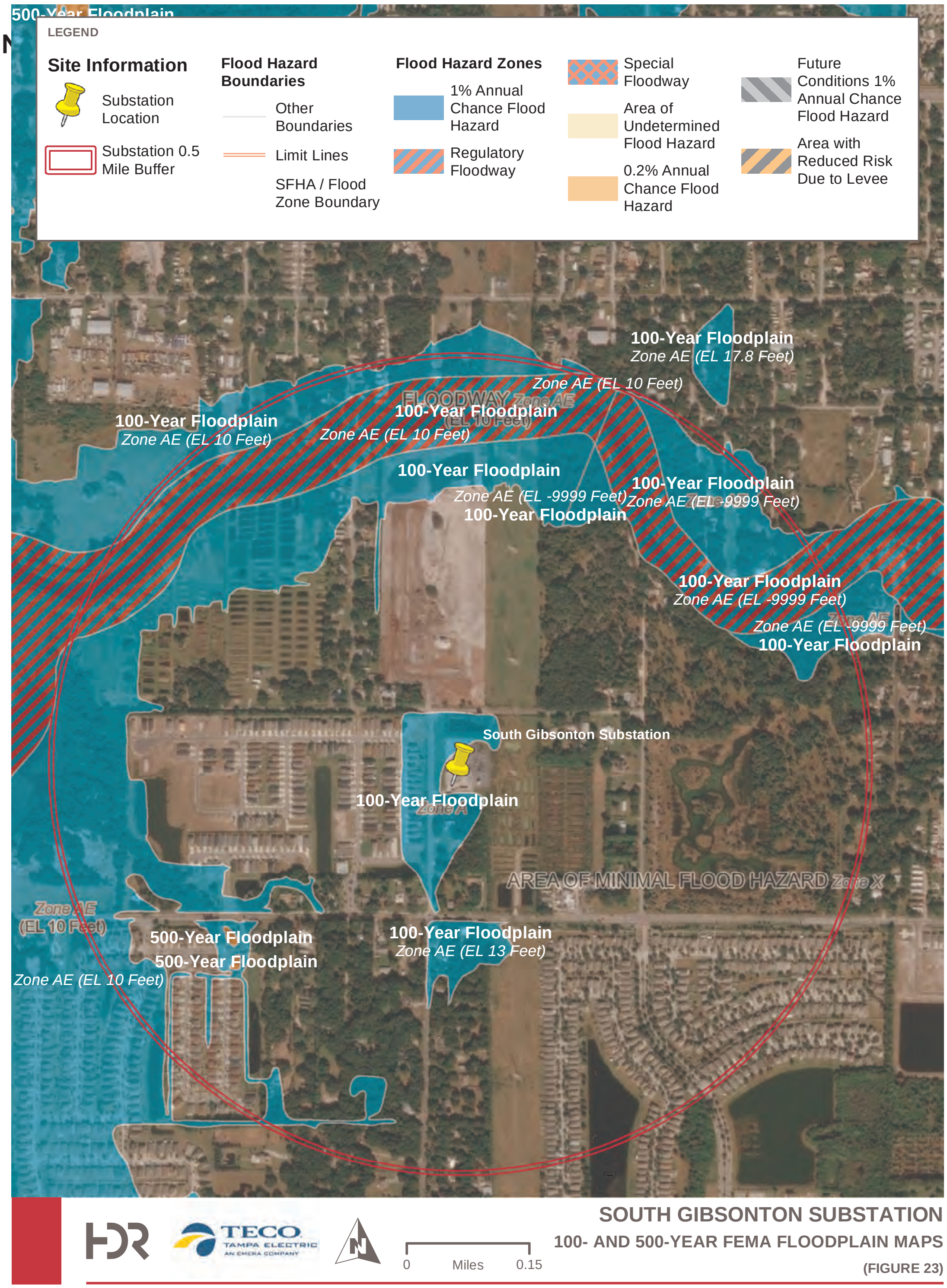
ROCKY CREEK SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 21)

PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\ROCKY CREEK FEMA.MXD - USER: ALMILLER - DATE: 5/21/2021



SKYWAY SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 22)

PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\SKYWAY FEMA.MXD - USER: ALMILLER - DATE: 5/21/2021


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
100-Year Floodplain
Zone AE (EL 17.8 Feet)
Zone AE (EL 10 Feet)
FLOODWAY Zone AE
Zone AE (EL -9999 Feet)
South Gibsonton Substation
AREA OF MINIMAL FLOOD HAZARD Zone X
500-Year Floodplain
Zone AE (EL 13 Feet)
0 Miles 0.15
SOUTH GIBSONTON SUBSTATION
100- AND 500-YEAR FEMA FLOODPLAIN MAPS
(FIGURE 23)
PATH: D:\GIS\TECO HARDENING\FLOODPLAIN FIGURES\SOUTH GIBSONTON FEMA.MXD - USER: ALMILLER - DATE: 5/21/2021

18. Please provide details relating to mitigation plans and costs

A. The details and costs related to the nine substation projects/mitigation plans identified in the company's 2022-2031 SPP are provided below:

Hookers Point - Re-grade Substation. Install New Elevated Control House. Replace Autotransformer. Replace 69/13 kV Power Transformer. Replace Three (3) 69 kV Oil Filled Circuit Breakers. $7,600,000

South Gibsonton - Install Elevated Control House. Regrade North End of Substation. Replace one (1) 69 kV Oil Circuit Breaker. $3,100,000

Jackson Rd - Install Elevated Control House. Install New Spill Prevention, Control, and Countermeasure (SPCC) System for The Existing Autotransformer. Replace one (1) 69 kV Oil Circuit Breaker. $2,800,000

Estuary - Replace one (1) 69 kV Oil Circuit Breaker. Elevate Relay and Control Enclosure. $900,000

El Prado - Rebuild Substation with Re-grading the Station. Install Elevated Control House. Replace 69/13 kV Transformer. Install a New 69 kV Circuit Switcher. Install new Four (4) 13 kV Circuit Breakers. $5,000,000

Skyway - Replace Nine (9) 13.8 kV Circuit Breakers. Install Elevated Control House. $3,500,000

Desal - Elevate Control Enclosure. $700,000

MacDill - Install Two (2) New SPCC Systems for Power Transformers. Replace Two 13 kV Circuit Breakers. $700,000

Maritime - Replace Four 13.8 kV Circuit Breakers. Replace Two 69/13 kV Transformers. Elevate Control House. $4,500,000

Additional information regarding these projects is included in the study provided in response to OPC's First Set of Interrogatories No. 17 and as Exhibit DLP-1, Document No. 5 to the Direct Testimony of David L. Plusquellic.

Distribution Overhead Feeder Hardening

19. Please provide criteria for feeder selection.

A. The methodology utilized to prioritize feeder hardening projects is described in detail in the Direct Testimonies of David L. Plusquellic and Jason De Stigter and in 1898 & Co.'s report included as Appendix F to the company's 2022-2031 SPP.

20. Please provide criteria for storm hardening poles (extreme wind, Grade B, etc).

A. National Electrical Safety Code ("NESC") Grade B Extreme Wind – 120 miles per hour ("MPH").

21. Please provide criteria used for determining when to install of phase-three reclosers.

A. The reason for installing three-phase reclosers is to increase the sectionalizing capability of a circuit. Three main criteria were used in determining when and where to place reclosers on a circuit:

- Target a 200-500 maximum customer range on each segment;
- Limit segment distance to two to three miles; and
- Limit serving between two to three MW of load on each segment.

22. Please provide the total number of customers served by feeders in Tables OVHF.1 and OCHF.2 in the 2020 Storm Protection Plan Annual Status Report

A. As of February 28, 2022, the total number of customers served by the feeders is 7,559.

23. Provide the total number of three-phase reclosers on feeders in Tables OVHF.1 and OCHF.2 in the 2020 Storm Protection Plan Annual Status Report

A. As of February 28, 2022, the total number of three-phase reclosers on the feeders is 27.

Wood Pole Inspection Program

24. What criteria is used to determine NESC strength "at replacement"? (ie Grade B or Grade C)

A. Strength at replacement is defined in 2017 NESC Table 261-1, footnotes 2&3, and is independent of Construction Grade. Wood structures designed under NESC Rule 250B (not Extreme Wind) - Non-Feeder Hardened Poles - must be replaced when strength reaches 2/3 of the pole's design strength. Wood structures designed under NESC Rule 250C (Extreme Wind) - Feeder Hardened Poles - must be replaced when the strength reaches 3/4 of the pole's design strength.

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25. Please provide details of pole inspection for years 2020, 2021, and 2022 including:

a. Poles inspected

b. # of poles failed

c. # of poles rehabilitated

d. Cost to rehabilitate poles

e. # of poles replaced

f. Cost to replace poles

g. Average cost per pole for inspection less replacement and rehabilitation costs

A. The table below provides the details of pole inspections the company completed for the years 2020 and 2021. Tampa Electric has not completed the pole inspections for the year 2022 at this time.

		Pole Inspections		
		2020	2021	2022
25. a	Poles Inspected	24,962	19,861	N/A
25. b	# of Reject Poles	993	798	N/A
25. c	# of Poles Rehabilitated	935	0	N/A
25. d	Cost to Rehabilitate Poles	$434,229	$0	N/A
25. e	# of Poles Replaced	1,435	417	N/A
25. f	Cost to Replace Poles	$9,256,216	$4,752,341	N/A
25. g	Average Cost for Pole Inspection	$26.22	$25.86	N/A

a. See table directly above.

b. See table directly above.

c. See table directly above.

d. See table directly above.

e. See table directly above.

f. See table directly above.

g. See table directly above.

Joint-Use Pole Attachments Audits

26. Provide the Tampa Electric Standards used to evaluate loading on joint use poles.

A. Tampa Electric uses NESC 2012 Light Grade B to evaluate loading on joint use poles.

27. Are these requirements different from the requirements used on non-joint use pole?

A. No, the requirements are the same as used on non-joint use poles.

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28. Please provide the number of joint use poles that receive comprehensive loading analysis in 2020, 2021, and 2022

A. The table below provides the amount of joint use poles that received comprehensive loading analysis in 2020 and 2021. Tampa Electric has not completed the pole loading analysis for the year 2022 at this time.

	Joint Use Poles that Received Comprehensive Loading Analysis
2020	156
2021	568
2022	N/A

29. Please provide the cost of the analysis.

A. The table below provides the cost to perform the analysis for those joint use poles that received comprehensive loading analysis in 2020 and 2021. Tampa Electric has not completed the pole loading analysis for the year 2022 at this time.

	Cost to Perform Comprehensive Loading Analysis on Joint Use Poles
2020	$23,400
2021	$85,200
2022	N/A

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30. Please provide number of poles that failed the loading/strength requirements.

A. The table below provides the amount of joint use poles that failed the loading/strength requirements in 2020 and 2021. Tampa Electric has not completed the pole loading analysis for the year 2022 at this time.

	Joint Use Poles that Failed Loading/Strength Requirements
2020	3
2021	9
2022	N/A

31. Please provide the cost paid by Tampa Electric for upgrade/replacement of these failure poles.

A. Tampa Electric incurs no cost for upgrading or replacement of these failed joint use poles, the joint use attachers pays for the costs.

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32. Please provide the cost borne by joint-use attachees for these failed poles.

A. The table below provides the cost borne by the joint use attachers for these failed poles for 2020 and 2021. Tampa Electric has not completed the pole loading analysis for the year 2022 at this time.

	Costs Borne by Joint Use attachers for Failed Poles
2020	$7,500
2021	$22,500
2022	N/A