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DEF's Response to OPC's Third Production of Documents Nos. 35, 37, 40

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Storm Protection Plan pursuant to Rule 25-6.030, F.A.C., Duke Energy Florida, LLC.

DOCKET NO. 20220050-EI

Dated: May 17, 2022

DUKE ENERGY FLORIDA, LLC'S RESPONSE TO CITIZENS' THIRD REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 35-41)

Duke Energy Florida, LLC ("DEF"), responds to the Citizens of the State of Florida, through the Office of Public Counsel's ("Citizens" or "OPC") Third Request to Produce Documents (Nos. 35-41), as follows:

DOCUMENTS REQUESTED

35. Please provide all documents identified in your response to interrogatory 68.

Response:

Please see the attached documents bearing bates numbers 20220050-DEF-005236 through 20220050-DEF-005284.

[redacted]

37. Please provide all documents identified in your response to interrogatory 74.

Response:

Please see document number "04878-2019 - Irma Settlement" in docket number 20170272.

[redacted]

[redacted]

40. Please provide all documents identified in your response to interrogatory 81.

Response:

Please see the attached document bearing bates number 20220050-DEF-005320 through 20220050-DEF-005379.

[redacted]

The Road Ahead:
Shaping the future

Grid Solutions Engineering
Self Optimizing Grid: Grid of the Future

The Road Ahead: *Customer-Focused Strategy*

The **Road Ahead Strategy** is centered on a **long-term investment plan** that delivers ever greater value for our customers, and is defined by:

- Transforming the Customer Experience
- Modernizing the Power Grid
- Generating Clean Energy

***Modernizing the Power Grid* drives customer value through:**

- Enhancing customer services
- Ensuring constant and reliable power
- Enabling distributed energy resources

The Road Ahead: *Customer-Focused Strategy*

A set of guiding principles (or ***North Stars***)
were established to lead us to that *customer-valued future* of the grid.

One such **North Star** is:

Reliable & Smart

Our customers rarely experience interruption due to a **dynamic self-optimizing grid** which automatically, anticipates and mitigates failures

Grid of the Future - Key Principles: The 3 C's

Increased Capacity for both Circuits and Banks

- Enables grid connectivity, circuit ties, and the self healing grid
- Increased hosting capacity
- Enables Volt Var Optimization
- Improves system efficiency
- Hardens the system against storms

Grid Connectivity

- Builds circuit ties and the self healing grid – step change in reliability metrics
- Provides operating and hosting flexibility
- **Supports dynamic self-optimizing grid**
- **Begins the move away from "circuits" to multiple "grid segments"**
- Improves resiliency for the distribution grid

Control

- Provides intelligence and control for the self healing grid
- Enables dynamic grid optimization
- Supports system and edge technology

Self Optimizing Grid Connectivity, Segmentation, and Circuit Ties (Future State)

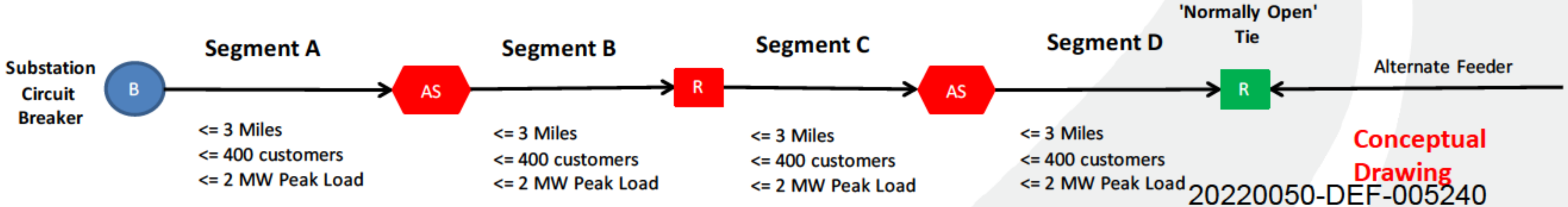
1. Circuits will have **no backbone radial** sections

2. Circuits will be designed such that power can be restored to un-faulted backbone sections through switching to adjacent circuits or alternate sources under all load conditions

3. Circuits will be transitioned to **switchable feeder segments**. Segment characteristics are:
   1. No more than **3 miles** of feeder exposure in the segment.
   2. No more than **400 customers** in the segment.
   3. No more than **2 MW peak load** in the segment. Also, load in segments should be balanced between phases.
   4. New switches installed to define segments will be **automated**.

4. The target is to have **80% of Customers** on the Self Optimized Grid

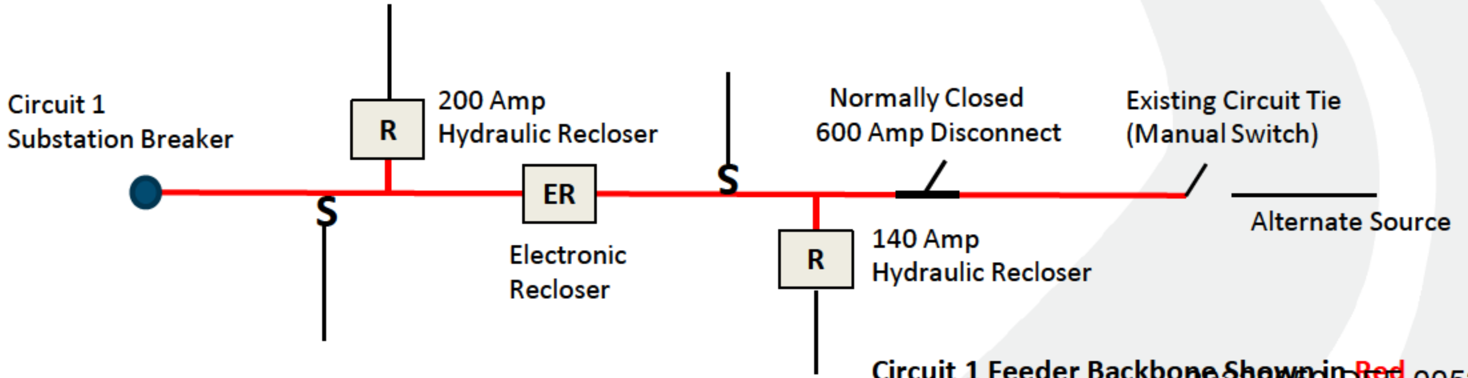
Self-Optimized Circuit with Full Segmentation, Automated Switches, and Automated Tie Point:



Definition: Feeder Backbone

- All 3 phase, unfused line sections protected by a reclosing device larger than 200 amps, including the breaker.
- Any three phase line section protected by a reclosing device 200 amps or smaller with a circuit tie that will be utilized for self optimizing grid is considered feeder backbone.
- Any three phase line section protected by a reclosing device 200 amps or smaller without a utilized circuit tie is not considered the backbone.

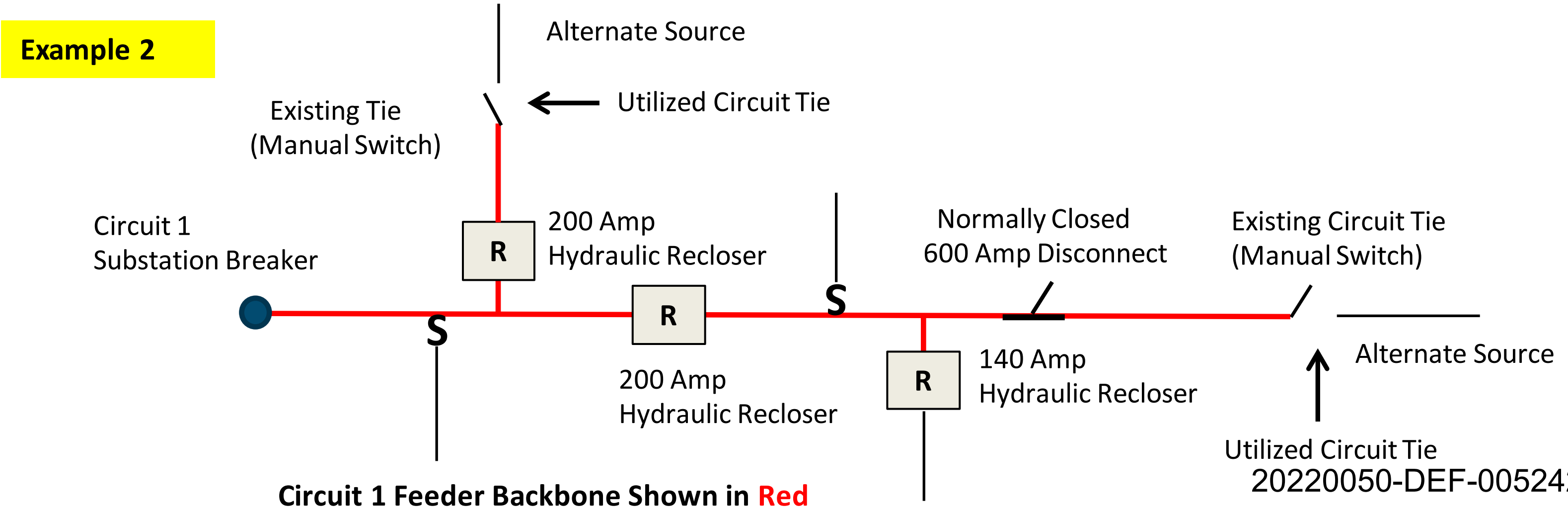
Example 1



Circuit 1 Feeder Backbone Shown in Red

Definition: Feeder Backbone

- All 3 phase, unfused line sections protected by a reclosing device larger than 200 amps, including the breaker.
- Any three phase line section protected by a reclosing device 200 amps or smaller with a circuit tie that will be utilized for self optimizing grid is considered feeder backbone.
- Any three phase line section protected by a reclosing device 200 amps or smaller without a utilized circuit tie is <u>not</u> considered the backbone.

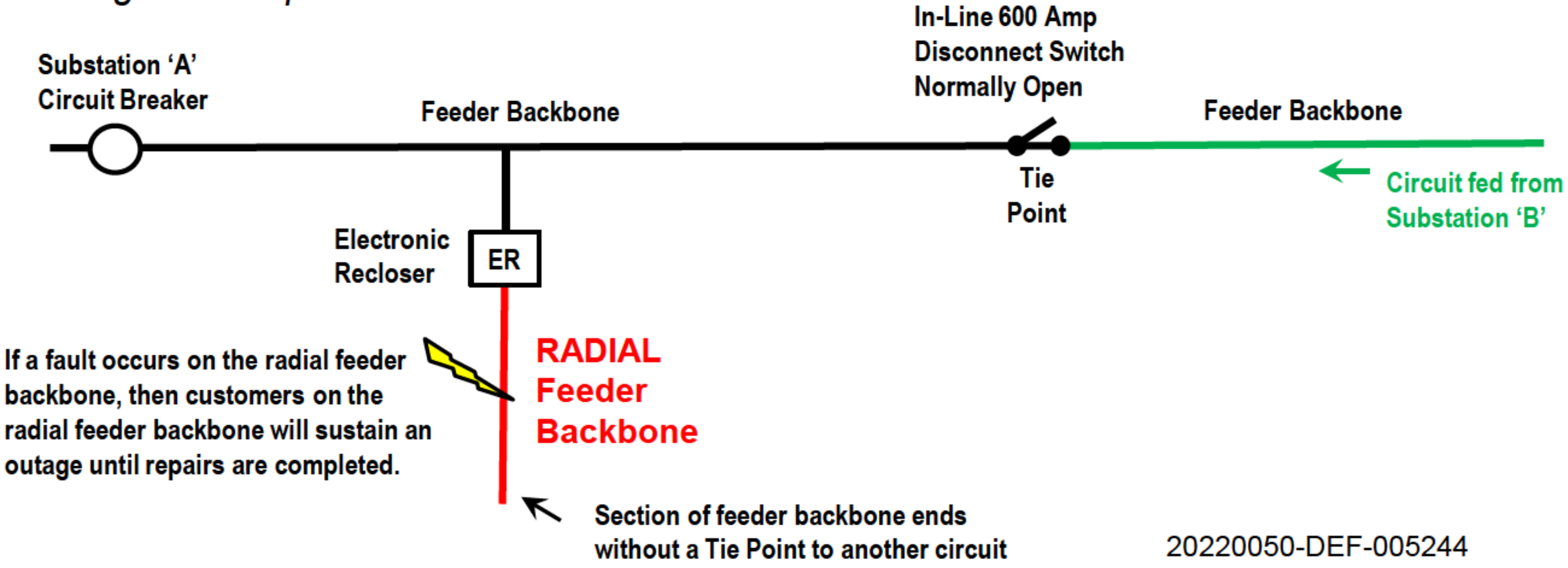


Feeder Backbone

The goal of the Self Optimizing Grid (S.O.G.) is to further segment our lines and add inter-circuit connectivity to automatically restore power to as many customers as possible in the event of a sustained fault. In most cases, load and customer count is high beyond electronic reclosers and as a result the line section beyond electronic reclosers is considered feeder backbone. In most cases, hydraulic reclosers have fewer customers and therefore the line section beyond hydraulic reclosers are not considered part of the feeder backbone except when there is a utilized circuit tie.

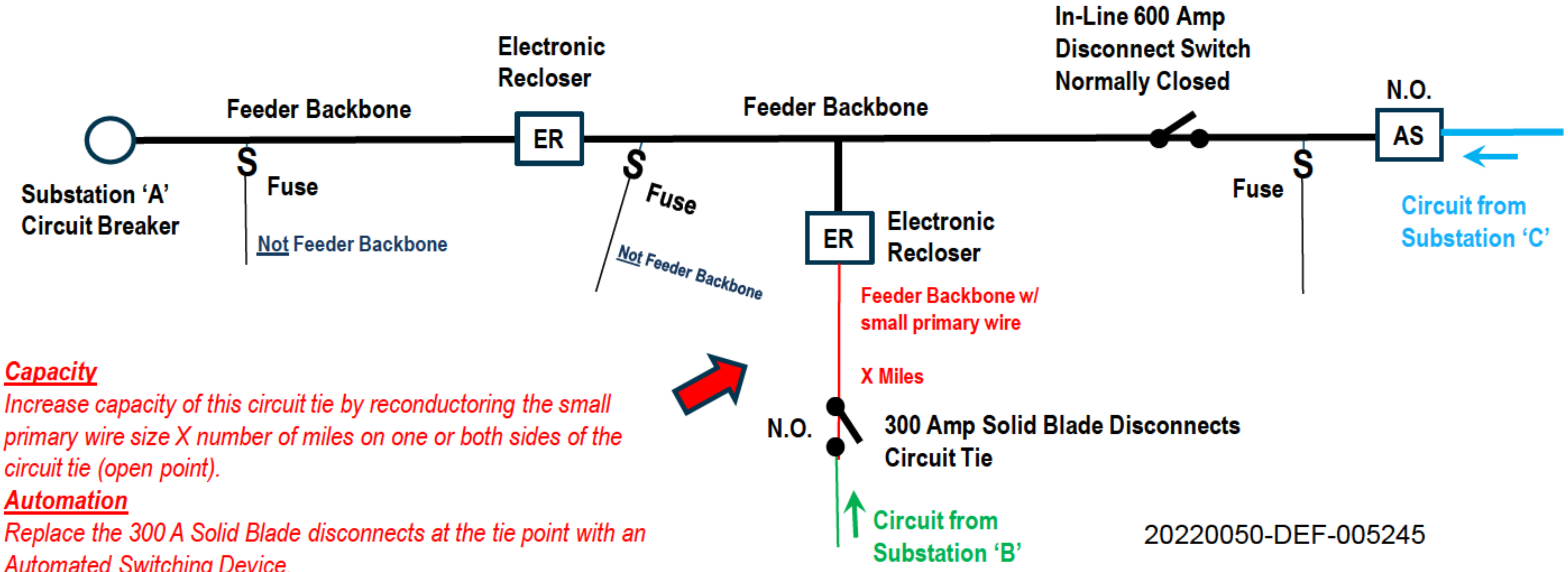
Definition: Radial Feeder Backbone

*Radial Feeder Backbone is the section of the Feeder Backbone that has **no** switchable tie point to a separate source (i.e. – no circuit tie). If a fault occurs on a section of the Radial Feeder Backbone, then customers served from the Radial Feeder Backbone will sustain an outage until repairs can be made.*



Example: Existing Weak Circuit Tie

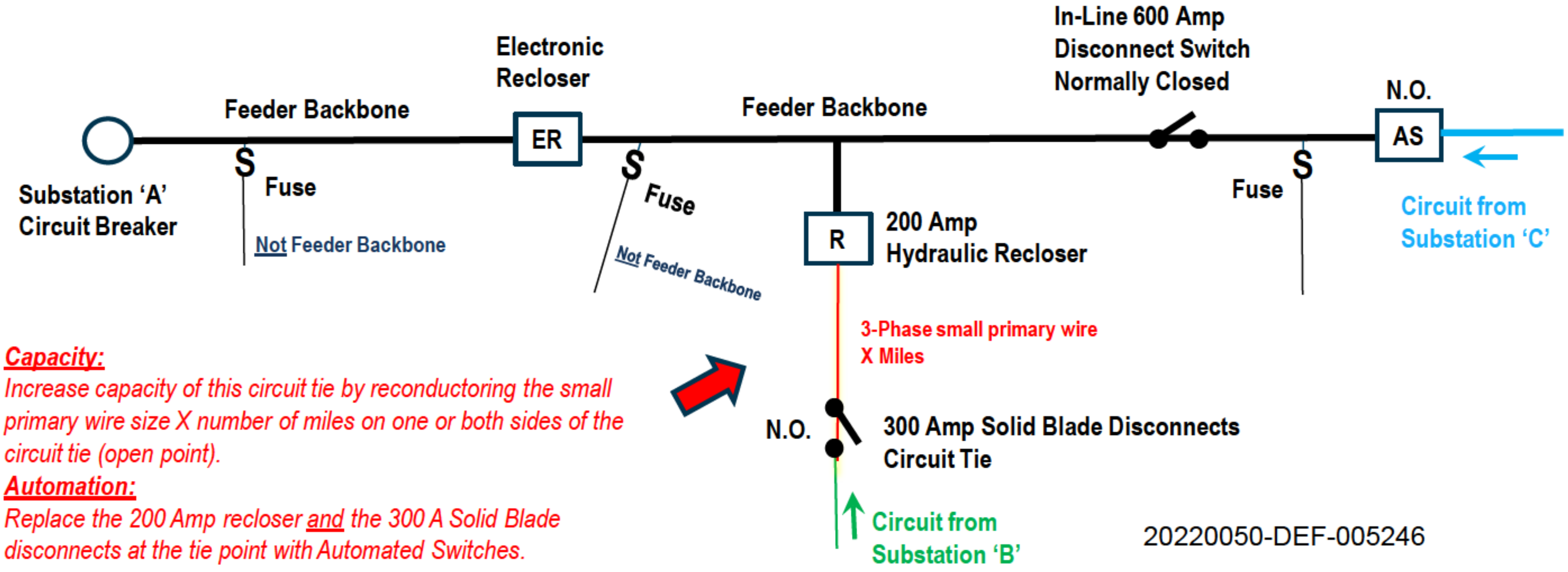
In this example, there is an existing circuit tie (Normally Open) with 300 Amp Solid Blade disconnects on a section of the feeder backbone behind an Electronic Recloser. The primary wire size beyond the Electronic Recloser is small (i.e. 1/0 ACSR).



Capacity
Increase capacity of this circuit tie by reconductoring the small primary wire size X number of miles on one or both sides of the circuit tie (open point).
Automation
Replace the 300 A Solid Blade disconnects at the tie point with an Automated Switching Device.

Example: Existing Weak Circuit Tie Not on Feeder Backbone

In this example, there is an existing circuit tie downstream from a 200 Amp Hydraulic recloser. The segment of line beyond the 200 Amp recloser consists of small wire (i.e. 1/0 ACSR).



Capacity:

Increase capacity of this circuit tie by reconductoring the small primary wire size X number of miles on one or both sides of the circuit tie (open point).

Automation:

Replace the 200 Amp recloser and the 300 A Solid Blade disconnects at the tie point with Automated Switches.

20220050-DEF-005246

Self Optimizing Grid: Conclusion

Self Optimizing Grid (S.O.G.) is the concept of transforming the distribution system from a population of circuits with minimal automated alternate source capability, to a network of circuits with spare load capacity, automated inter-circuit connectivity and smaller automatically switchable line segments along the feeder backbone. With the integration of self-healing/Closed Loop FISR technology, a sustained fault will be automatically isolated to a smaller line segment, while all other un-faulted line segments are restored from alternate sources most of the time. The objective is to drastically change the customer experience through improved reliability.

Self Optimizing Grid will consist of four components: **Connectivity**, **Segmentation**, **Capacity** and **Automation** (see Section II). To become part of S.O.G, a circuit must meet all four component rules. Due to topology, not all circuits have potential alternate sources nearby. Also, some circuits have a lower customer count. As a result, the target is to apply all S.O.G. components to 80% of our distribution customers. The remaining 20% of our customers will have the Segmentation and Automation components applied only and will not be considered part of S.O.G. However, they will still benefit from smaller line segments and SCADA enabled devices.

Self Optimizing Grid Application Guide

(This document is **not** intended to supersede existing Distribution Standards)

Document Number: GDLP-ADM-GRS-00166

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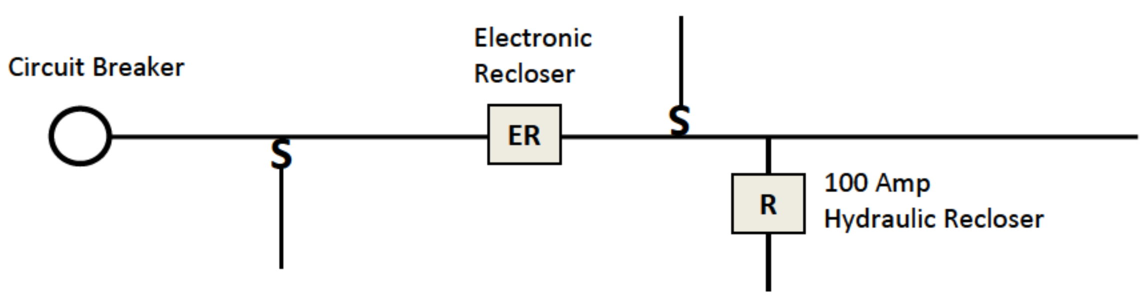
Self Optimizing Grid Purpose and Description

Current State:

The existing distribution grid consists mostly of individual circuits that fall into three categories with respect to sustained outages; radial circuits with no alternate source tie capabilities, circuits with alternate source tie capabilities via manual switches, and circuits on self-healing teams. Although the number of self-healing teams on our system is increasing, the percentage of circuits on a self-healing team is relatively low. Capacity rules concerning substation bank and circuit loading are not the same across the company. Utilizing alternate feeders to restore power to part or all of the load on a circuit that is experiencing a major outage is typically limited by equipment and conductor ratings and can be dependent on the time of day or year.

Sectionalization on each circuit typically consists of the breaker, a mainline midpoint recloser (hydraulic or electronic), along with laterals/taps off of the mainline that are protected by either a recloser or fuse. The term mainline is a generic term that differs based on the jurisdiction and is sometimes called the feeder backbone, circuit backbone and recloser subfeeder. These protective devices are coordinated in an effort to affect the fewest customers possible in the event of a sustained fault and outage. Sustained faults along the mainline typically result in all or a large portion of the customers on a circuit experiencing an outage. Although circuits with self-healing technology do isolate around sustained faults and restore power to un-faulted line segments, the number of customers that experience an outage tends to be high due to the number of customers on the faulted line segment.

Typical Existing Distribution Circuit

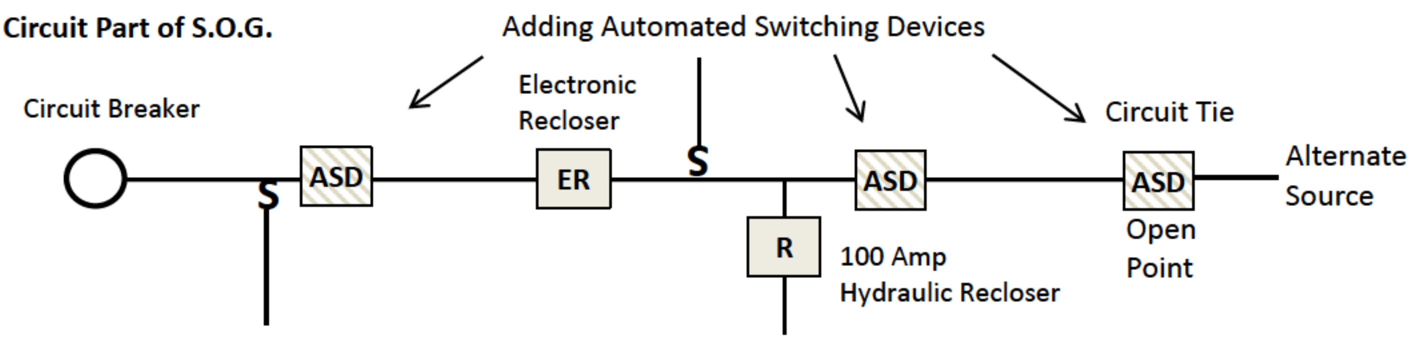


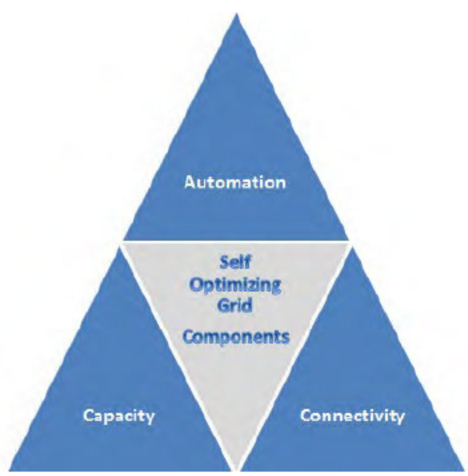
Self Optimizing Grid Purpose and Description

Future State:
Self Optimizing Grid (S.O.G.) is the concept of transforming the distribution system from a population of circuits with minimal automated alternate source capability, to a network of circuits with spare load capacity, automated inter-circuit connectivity and smaller automatically switchable line segments along the feeder backbone. With the integration of self-healing/Closed Loop FISR technology, a sustained fault will be automatically isolated to a smaller line segment, while all other un-faulted line segments are restored from alternate sources most of the time. The objective is to drastically change the customer experience through improved reliability.

Self Optimizing Grid will consist of three components: **Capacity, Connectivity** and **Automation** (see Section II). To become part of S.O.G, a circuit must meet all three component rules. Due to topology, not all circuits have potential alternate sources nearby. Also, some circuits have a lower customer count. As a result, the target is to apply all S.O.G. components to 80% of our distribution customers. The remaining 20% of our customers will have the Automation component applied only and will not be considered part of S.O.G. (see Section IV). However, they will still benefit from smaller line segments and SCADA enabled devices. The implementation of S.O.G. will result in the addition of SCADA enabled switchable devices between each line segment and at utilized circuit ties to alternate sources. Depending on the current state of capacity and connectivity to alternate sources, the work required to meet S.O.G. rules may include reconductoring, the installation of new circuit ties, line regulator upgrades and new installs, along with substation bank upgrades and additions.

Circuit Part of S.O.G.





Section I – Definitions

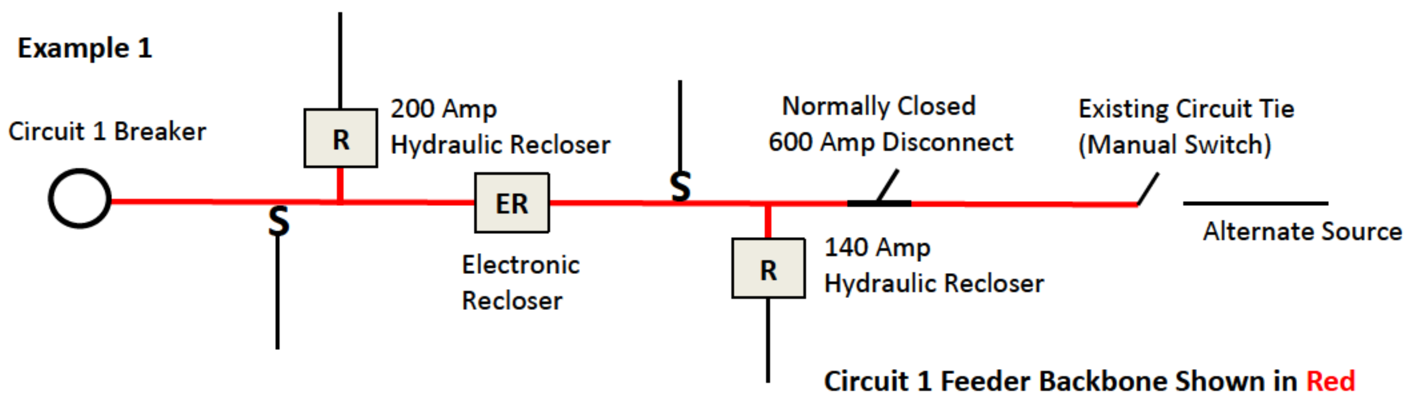
Feeder Backbone - definition to be used in applying the S.O.G. rules in this document

The Self Optimizing Grid Feeder Backbone of a circuit is defined as the following:

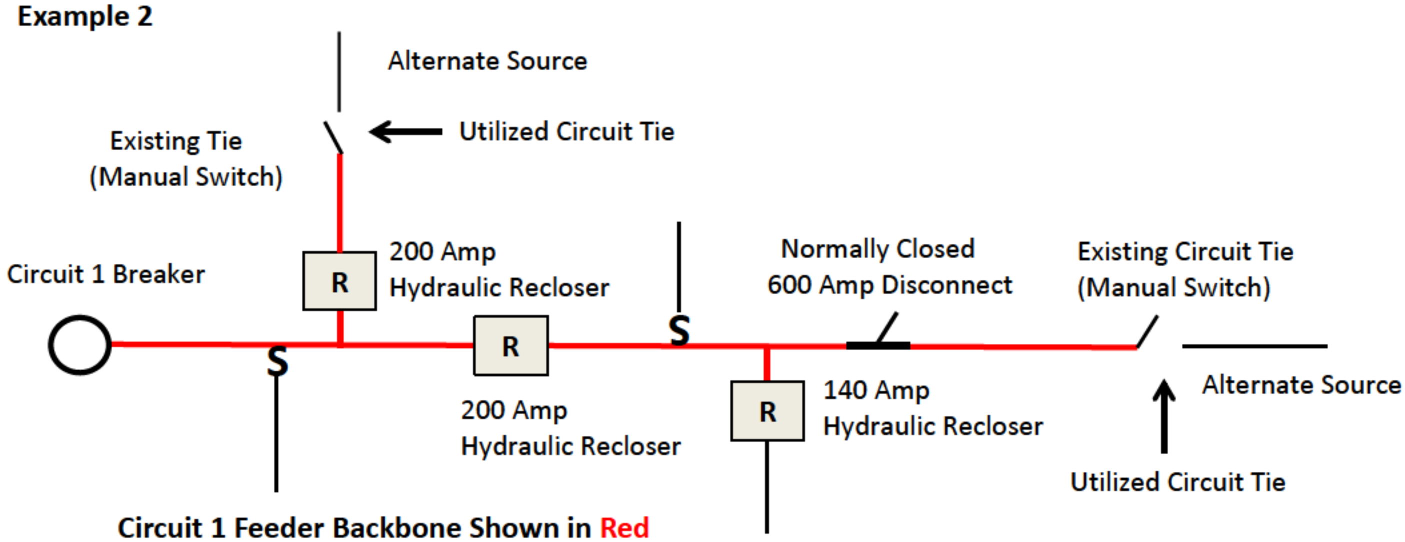
- All 3 phase, unfused line sections protected by a reclosing device larger than 200 amps, including the breaker.
- Any three phase line section protected by a reclosing device 200 amps or smaller with a circuit tie that will be utilized for self optimizing grid is considered feeder backbone.
- Any three phase line section protected by a reclosing device 200 amps or smaller without a utilized circuit tie is not considered the backbone.

Background: The goal of the Self Optimizing Grid (S.O.G.) is to further segment our lines and add inter-circuit connectivity to automatically restore power to as many customers as possible in the event of a sustained fault. In most cases, load and customer count is high beyond electronic reclosers and as a result the line section beyond electronic reclosers is considered feeder backbone. In most cases, hydraulic reclosers have fewer customers and therefore the line section beyond hydraulic reclosers are not considered part of the feeder backbone except when there is a utilized circuit tie.

Example 1



Example 2



Definitions (Continued)

Alternate Source – An alternate electrical source used to restore power to un-faulted line segments during a major outage. This will typically be an adjacent distribution circuit. However, this could be a DER in a future state.

Utilized Circuit Tie – If a circuit has multiple existing circuit ties, not all circuit ties must be used and converted to automated devices under these standards. "Utilized" circuit tie refers to a circuit tie that will be converted to an automated device for restoration purposes under these standards.

Automated Switching Device (ASD) – As part of the Self Optimizing Grid standards, a key part to automation is having SCADA controllable field equipment that allows remote switching. The term "automated switching device" refers to a switchable SCADA controllable device. These devices will most likely be electronic reclosers setup as a switches, but in some cases may be setup as reclosers or sectionalizers.

Line Segment – A section of line on a distribution circuit bound by switching devices on all sides with the exception of circuit end points without a circuit tie.

Segmentation – The act of dividing a distribution circuit into switchable line segments for the purpose of fault isolation and restoration. All devices placed to define line segments in these standards will be SCADA enabled and controllable switching devices.

Section II – Self Optimizing Grid Components (Applies to Overhead and Underground)

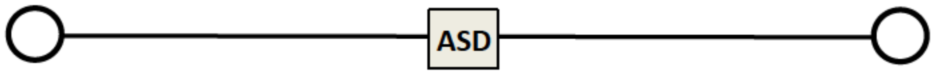
1.0 Capacity and Connectivity (Circuit Ties)

- Minimum Requirement: Any circuit part of Self Optimizing Grid (S.O.G.) shall be designed such that all of the circuit load can be restored from an alternate source(s) 90% of the hours in a year (90% Restoration Availability minimum requirement). This correlates to being able to restore all of the load on a circuit at approximately 75% of the projected peak load. **See Example 1 for application. See below for further explanation of how this percentage was derived.**
  Exception: Restoration at 75% of projected peak load in order for the average circuit to be restored 90% of the hours in a year is based on retail system load data. If substantial capacity work is required in order to meet this requirement and individual hourly circuit load data is available, circuit level data can be used to determine a more accurate % of projected peak load to meet the 90% Restoration Availability minimum requirement. Follow the steps on page 7 (next page) to determine an individual circuit % of projected peak load.
- Restoration of load to meet the 90% Restoration Availability minimum requirement shall not exceed the emergency thermal ratings of <u>any</u> distribution equipment including the substation bank, circuit breaker, the wire, reclosers, automated switching devices, regulators and inline disconnects.
- When performing a circuit study, the alternate source(s) substation bank loading should also be considered at 75% of projected peak.
- Multiple alternate sources per circuit can be utilized to meet the 90% Restoration Availability minimum requirement, if available.
- Alternate source(s) used to meet the 90% Restoration Availability minimum requirement should <u>preferably</u> include circuits from a different substation or from a different bank in the same substation if possible. **Note: While it is preferred to have an alternate source(s) from a different substation or bank, this is not a requirement. The minimum requirement is to be able to restore a single circuit, i.e. single circuit loss contingency.**
- If the only possible alternate source is from a circuit on the same substation bank, the circuit tie point should be in a location on the circuit in which at least half of the circuit customer count is upstream. A circuit tie close to the substation adds limited value for restoration. Use engineering judgment in accessing the reliability benefits in this scenario.

Percent of Projected Peak Load Derivation:
Hourly system load data was obtained for multiple years in each jurisdiction. For each year, the peak load hour was identified. The remaining hours of the year were then compared to this peak to determine an hourly percentage of that peak. 90% of the hours in a year equates to 8760 X .9 or 7884 hours. This also represents a possible unavailability of 10% or 876 hours per year. By sorting the hourly data from highest to lowest, the percentage of peak load for which at or below represented approximately 90% of the hours for each year was established. For example, in DEF for 2014, there were 790 hours in which the system hourly load was higher than 75% of the annual peak hour of that year. There were also 7970 hours in 2014 in which the load was below 75% of the annual peak hour, which equates to a 91% availability. All jurisdictions were very close to 75% and as a result, 75% of projected peak load should be used unless you have data to calculate the percent for an individual circuit.

Example 1: (Both Circuits are 12.47KV)

Circuit Breaker | **Circuit Tie** | **Circuit Breaker**



	Circuit Tie	
Circuit 1 Alternate Source for Circuit 2	**Automated** **Switching Device**	**Circuit 2** Alternate Source for Circuit 1
Projected Peak Load 6.48 MVA 300 Amps	A balanced load is assumed in this example	**Projected Peak Load** 7.02 MVA 325 Amps

Circuit 1 and Circuit 2 are the only alternate sources for each other in this example, similar to a typical two circuit self-healing team. Applying the 90% restoration availability minimum requirement results in the following load assumptions in considering capacity compliance:

Circuit 1 load at *75% of peak = 0.75 X 6.48 MVA = 4.860 MVA(total), 225 amps/phase
Circuit 2 load at *75% of peak = 0.75 X 7.02 MVA = 5.265 MVA(total), 244 amps/phase

If Circuit 1 restores all of the load of Circuit 2, the capacity of the bank, wires (including both sides of the circuit tie), voltage regulators, switching devices, etc., must be able to carry an extra 5.265 MVA, plus the existing load of 4.860 MVA without exceeding emergency thermal ratings. Note: When considering if the substation bank for circuit 1 has capacity to pick-up the additional load of circuit 2, assume the bank is also loaded at 75% of projected peak.

If Circuit 2 restores all of the load of Circuit 1, the capacity of the bank, wires (including both sides of the circuit tie), voltage regulators, switching devices, etc., must be able to carry an extra 4.860 MVA, plus the existing load of 5.265 MVA without exceeding emergency thermal ratings. Note: When considering if the substation bank for circuit 2 has capacity to pick-up the additional load of circuit 1, assume the bank is also loaded at 75% of projected peak.

Individual Circuit % of Peak Load Determination (in Excel)

Step 1: Obtain circuit level hourly load data for at least one year. You can use more frequent data if available.
Step 2: Filter out outages, blanks, etc.
Step 3: Sort all load data from largest to smallest with all data in one column.
Step 4: Click on the top of the load data column and view the bottom to see the total data “count”. This is needed in figuring out the 90% availability.
Step 5: In a column next to the load data, divide each row of load data by the peak load. This will give you a percentage of peak load for each row.
Step 6: Multiply the total data count by 0.1. This is the number of load data points that are at or above 90% availability.
Step 7: Scroll down until the row number equals the count calculated in step 6. This represents the percentage of peak load that equates to 90% availability.

2.0 Automation (Includes segmentation and self healing/FISR integration)

The feeder backbone will be transitioned to automated switchable segments. See Section I for feeder backbone definition. Segment target characteristics are:

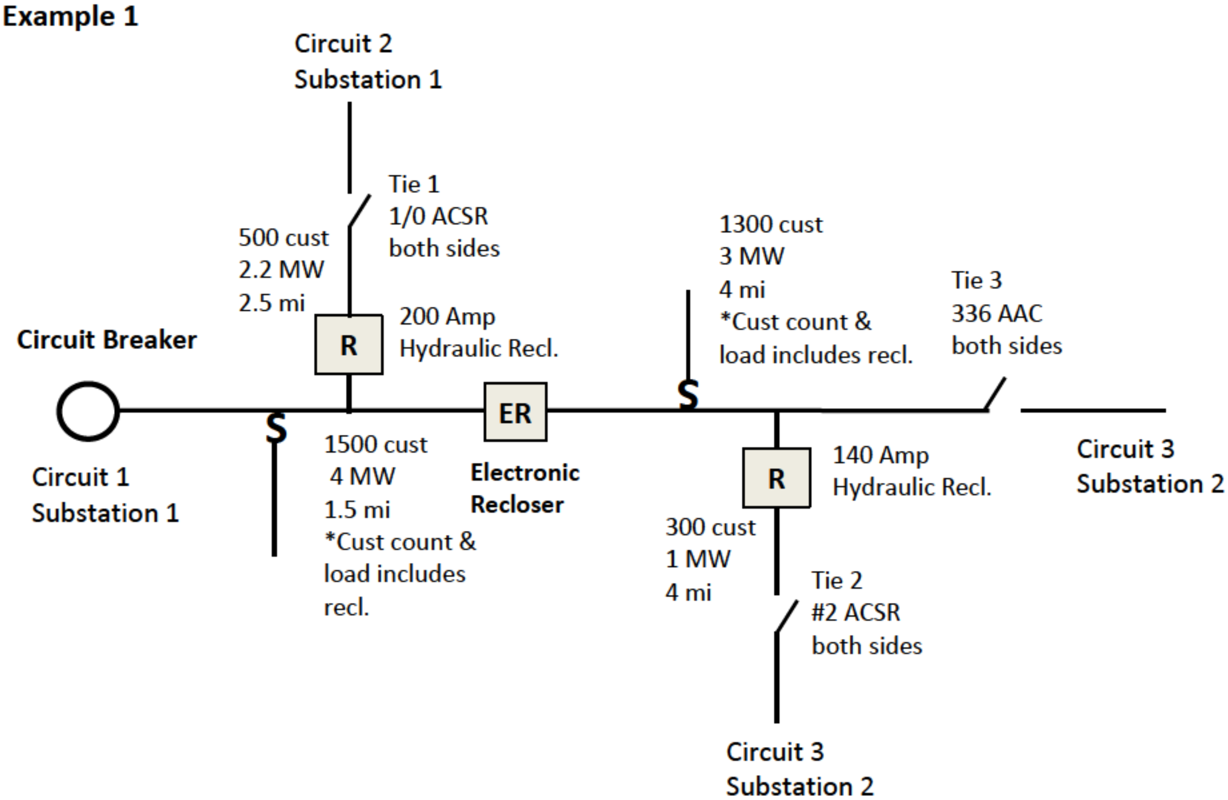
- No more than 400 customers in the segment. *
- No more than 3 miles of exposure in the segment. *
- No more than 2 MW load in the segment. *

  *These are general guidelines that will vary depending on field conditions. Note that the segment load target is based on meeting 90% availability rule (75% of projected peak).

  - New switches installed to define segments will be automated, including utilized circuit ties. Existing manual switches and hydraulic reclosers that define segments will be converted in accordance with these Automation rules.
  - Planning engineers and Grid Management will use current standards and engineering judgment for additional segmentation switches (critical customer feeds, T points, OH to UG, etc.).
  - Segments will have adequate fault protection and coordination between devices to facilitate the ability for load transfers between circuits.
  - Voltage levels should be maintained within ANSI C84.1 Range A (minimum 114V at the meter), whenever there is a segment transfer. When performing a circuit analysis to ensure voltage levels are maintained during a reconfiguration, limit that analysis to adjacent interconnected circuits only.
  - All substation circuit breakers must have electronic relays and are SCADA enabled and controllable.
  - Self-healing/Closed Loop FISR will be enabled on each circuit after work is complete for the appropriate Self Optimizing Grid components.
  - **Feeder backbone segmentation exception:** If a line segment has no feasible circuit tie, is protected by a reclosing device regardless of size and has 700 or more customers, further segmentation should be performed. Any segmentation should utilize automated switching devices.

3.0 Automation and Connectivity (Circuit Ties) Examples

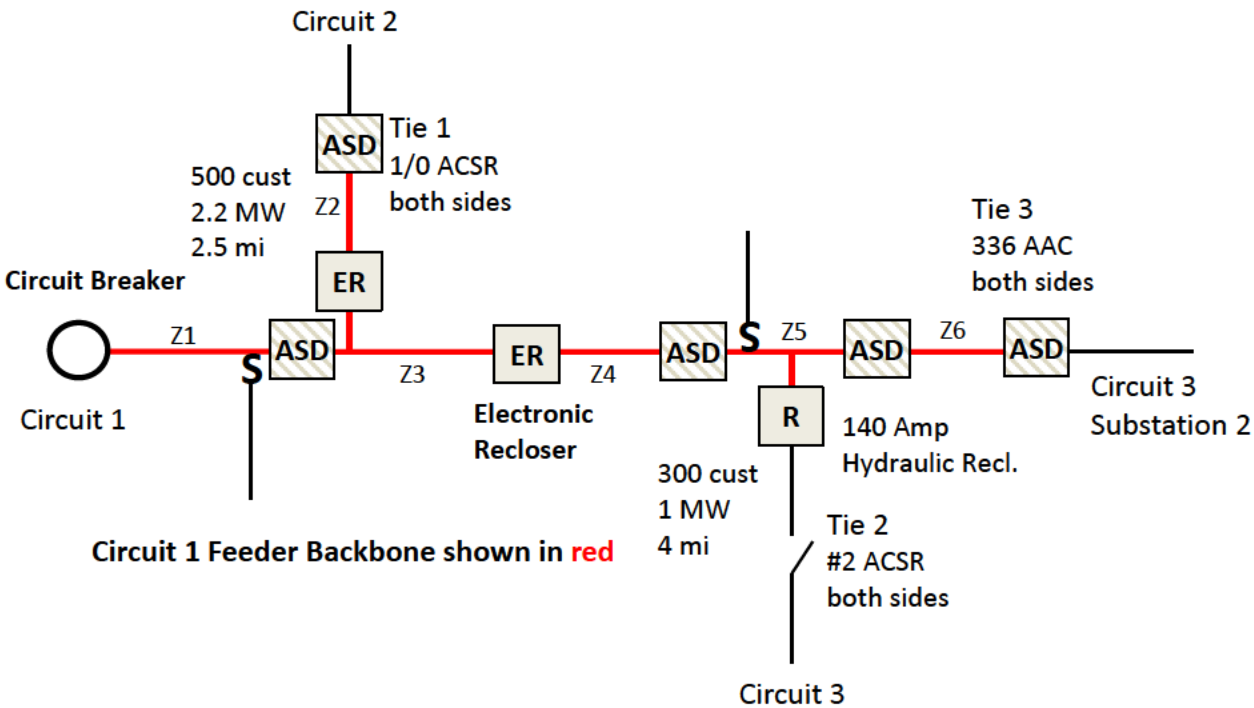
3.1 Example 1



Background:

- All segment loads shown are at 75% of peak.
- All load of Circuit 1 can be picked up from **Circuit 3** per the capacity rules through **Tie 3**.
- Tie 1 and Tie 2 can only pick up partial load but add some redundancy.
- The line segments downstream of both the 200 and 140 amp hydraulic reclosers exceed SOG line segment rules.
- Circuits 1 & 2 are fed out of the same substation and bank.
- Circuit 3 is out of a different substation.

3.1.1 Example 1 Solution



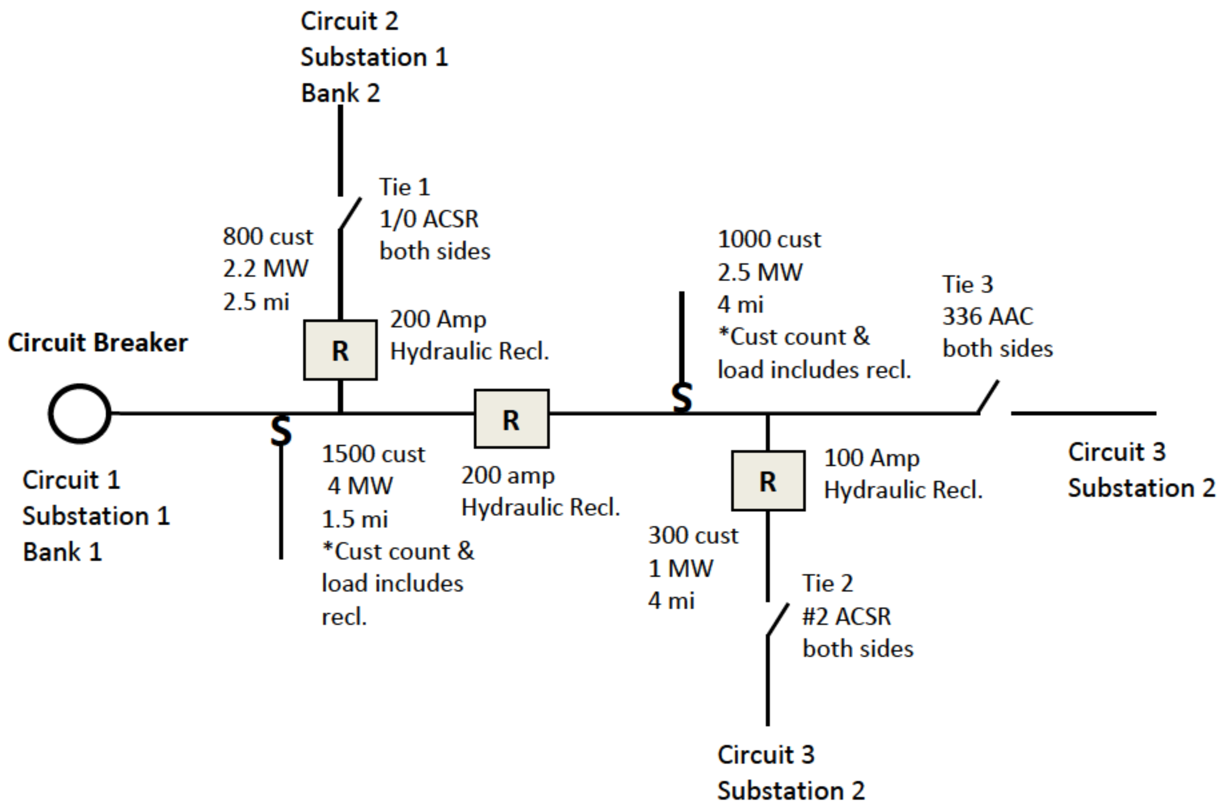
Circuit 3 is capable of picking up all of the load of Circuit 1 and is out of another substation making it the highest priority tie at the lowest cost to utilize. Tie 1 is considered a weak tie and is out of the same substation and bank. However, not utilizing this tie would result in a zone with 950 customers. Utilizing this tie will result in a lower zonal customer count, plus replace an existing hydraulic recloser. It should be noted that this was an engineering judgment decision based on the relative low risk of a bank failure versus the expected benefits. In the event of a bank failure, Circuit 3 can still pick up all of the load. By definition, since Tie 1 is being utilized, the line segment beyond the old 200 amp hydraulic recloser becomes part of the feeder backbone shown in red. Tie 2 is also considered a weak tie, with very little spare capacity. Increasing the capacity and adding automated devices for Tie 2 is not justified and therefore, by feeder backbone definition, the line section beyond the 140 amp hydraulic recloser is not feeder backbone.

Zone Information:

Z1 – 550 customers, 0.8 MW, 1.1 miles Z4 – 450 customers, 1.1 MW, 1.4 miles
Z2 – 500 customers, 2.4 MW, 0.5 miles Z5 – 500 customers, 1.2 MW, 1.0 miles
Z3 – 450 customers, 0.8 MW, 0.8 miles Z6 – 350 customers, 0.7 MW, 0.9 miles

Average Customers per Line Segment = 467
Average Load per Line Segment = 1.17 MW
Average Distance per Line Segment =0.95 miles

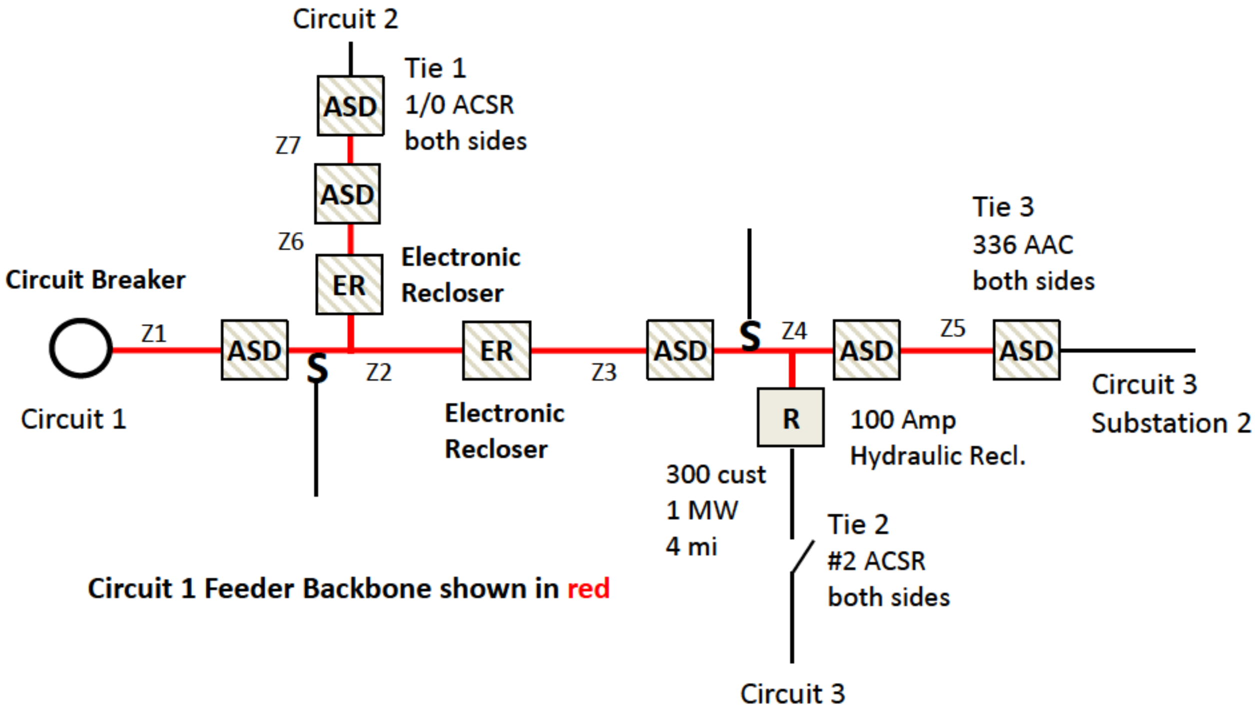
3.2 Example 2



Background:

- All segment loads shown are at 75% of peak.
- All load of circuit 1 can be picked up from **Circuit 3** per the capacity rules through **Tie 3**.
- Tie 1 and Tie 2 can only pick up partial load but add some redundancy.
- Circuits 1 & 2 are fed out of the same substation but on different banks.
- Circuit 3 is out of a different substation.

3.2.1 Example 2 Solution



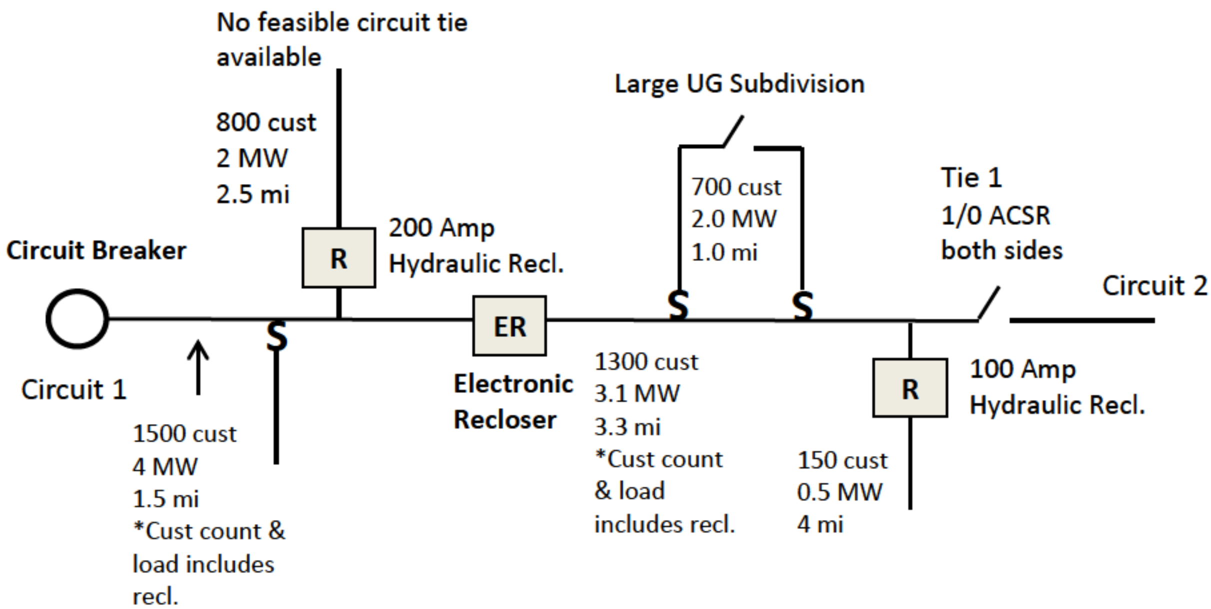
Circuit 3 is capable of picking up all of the load of Circuit 1 and is out of another substation making it the highest priority tie at the lowest cost to utilize. As a result of Tie 3 being utilized, the line section beyond this recloser is considered the feeder backbone and therefore is segmented and automated accordingly. Although Tie 1 is not a full capacity tie and this lateral is protected by a 200 amp hydraulic recloser, the line section has a high customer count and the alternate source is a circuit on a different bank. Therefore, this line section is also considered feeder backbone and as a result is subject to be further segmented and automated. Tie 2 is considered a weak tie, with very little spare capacity. Increasing the capacity and adding an automated device for Tie 2 is not justified.

Zone Information:

Z1 – 300 customers, 0.8 MW, 1.1 miles
Z2 –400 customers, 1.0 MW, 0.5 miles
Z3 – 350 customers, 0.6 MW, 0.8 miles
Z4 – 400 customers, 1.3 MW, 1.4 miles
Z5 – 250 customers, 0.6 MW, 1.0 miles
Z6 – 450 customers, 1.2MW, 0.9 miles
Z7 – 350 customers, 1.0 MW, 0.8 miles

Average Customers per Line Segment = 357
Average Load per Line Segment = 0.93 MW
Average Distance per Line Segment =0.93 miles

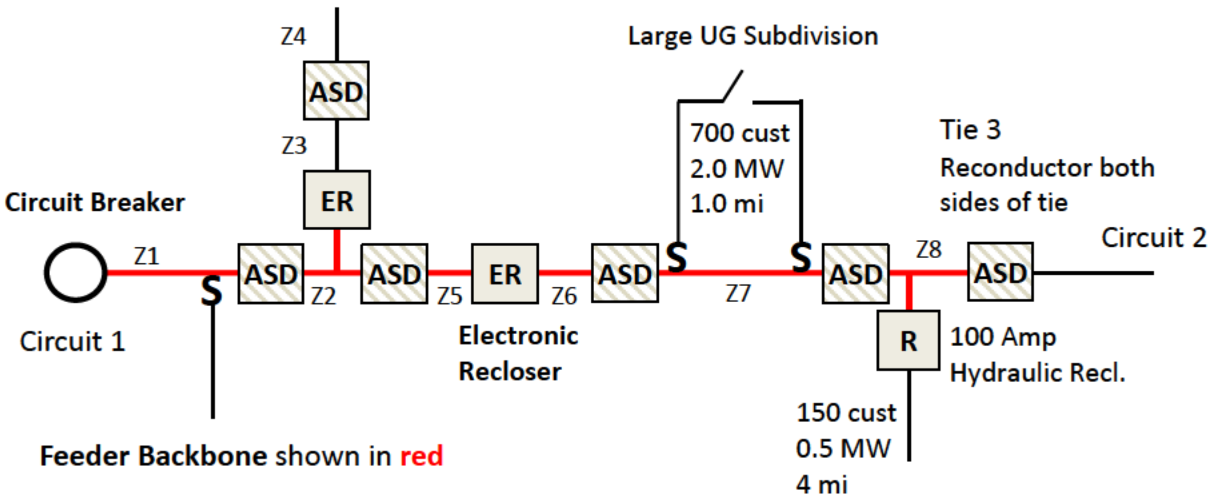
3.3 Example 3



Background:

- All segment loads shown are at 75% of peak.
- The only available existing circuit tie is Tie 1, which does not meet the capacity rules due to the small conductor.
- Circuit 2 is out of another substation.
- The line segment downstream of the 200 amp hydraulic recloser has 800 customers, above the segmentation rule for reclosing devices with no feasible tie.
- A very large looped subdivision exists downstream of the electronic recloser.

3.3.1 Example 3 Solution



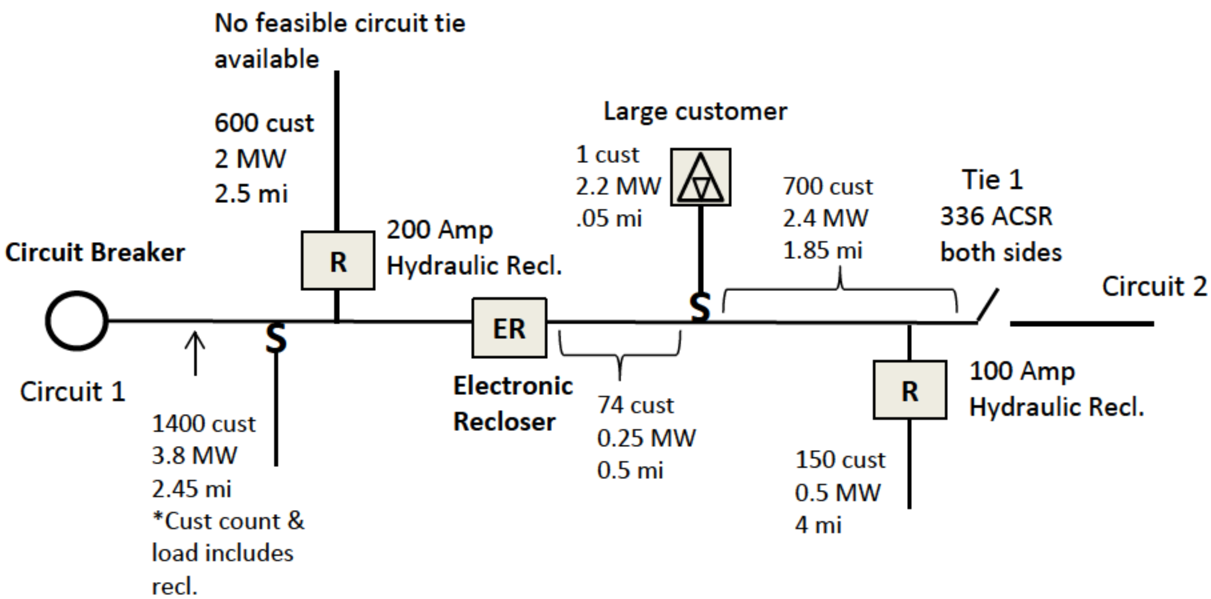
Circuit 2 is capable of picking up all of the load of Circuit 1 from an equipment and bank capacity perspective, but the 1/0 ACSR around the tie point is not adequate. Reconductoring must take place on both sides of the tie to meet capacity rules. The 200 amp recloser has 800 customers, meaning it is drastically higher than the 400 customer count segment target. Even though there is not a feasible tie point for back-feeding, the section of line beyond the 200 amp hydraulic recloser is subject for further segmentation and automation based on the feeder backbone segmentation exception on page 8. Because there is no tie point, this line section is **not** considered feeder backbone. Cases with this many customers beyond a hydraulic recloser should be rare but does exist. Beyond the existing electronic recloser, the tendency would be to place a device between the two dips of the large underground subdivision in an effort to lower the customer count per segment. However, doing so creates operational concerns due to potentially having two different circuits feeding this subdivision if the tie point moves in the future. Therefore, automated switching devices were installed on both sides of these dips. Reference: Legacy Progress Engineering manual – Section 9.0, part D, Legacy DEC Engineering Resources manual – Section 9.4, Enterprise Wide Construction manual - Section 20. There may be cases in which segmenting outside of the dips will result in very large segments due to the distance between dips. Consider utilizing ASD's to prevent a loop split or splitting the loop into two loops.

Zone Information:

Z1 – 400 customers, 0.9 MW, 1.1 miles Z5 – 250 customers, 0.6 MW, 0.8 miles
Z2 – 850 customers, 2.5 MW, 0.5 miles Z6 – 325 customers, 1.1 MW, 1.4 miles
Z3 – *400 customers, 1.0 MW, 1.3 miles Z7 – 700 customers, 1.2MW, 1.0 miles
Z4 – *400 customers, 1.0 MW, 1.2 miles Z8 – 275 customers, 0.8MW, 0.9 miles
*Z2 includes the customer count and load of Z3 and Z4.

Average Customers per Line Segment = 467
Average Load per Line Segment = 1.18 MW
Average Distance per Line Segment =0.95 miles

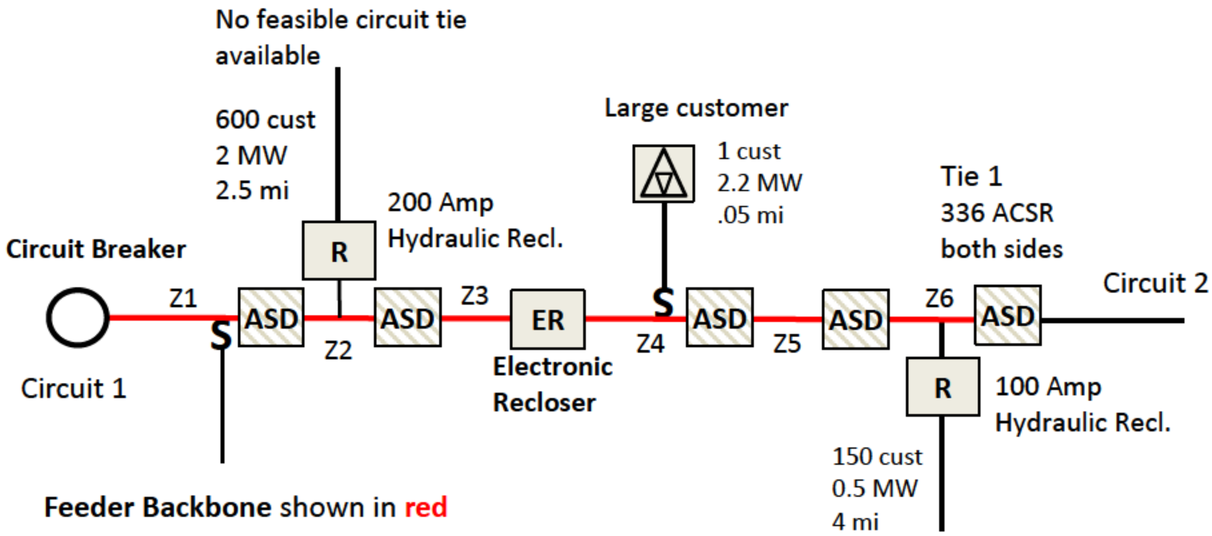
3.4 Example 4



Background:

- All segment loads shown are at 75% of peak.
- The only available existing circuit tie is Tie 1.
- Circuit 2 is out of another substation.
- The line segment downstream of the 200 amp hydraulic recloser has 600 customers, below the 700 or more exception for further segmentation.
- There is a large single customer off the backbone.

3.4.1 Example 4 Solution



Circuit 2 is capable of picking up all of the load of Circuit 1 from an equipment and bank capacity perspective. The 200 amp recloser has 600 customers with no feasible circuit tie. The customer count is below the segmentation threshold of 700 customers for radials. As a result, no further segmentation is justified. The 200 amp recloser can be changed out to an ASD through the oil filled recloser replacement budget in the H&R program. Because there is no tie point, this line section is **not** considered feeder backbone. There is a large customer below the existing electronic recloser that is greater than the segment target. By the segment target for load, ASD's should be placed on both sides of the customer along the feeder backbone. While this was no issue on the downstream side, placing an ASD on the upstream side would create a segment with only 74 customers and very little load. Although <u>not</u> placing the additional upstream ASD increased the segment load even more, the additional load was minimal and avoided an extra device.

Zone Information:

Z1 – 400 customers, 1.0 MW, 1.0 miles Z4 – 75 customers, 2.45 MW, 0.5 miles
Z2 – 625 customers, 2.1 MW, 0.35 miles Z5 – 450 customers, 1.5 MW, 1.1 miles
Z3 – 375 customers, 0.7 MW, 1.1 miles Z6 – 400 customers, 1.4 MW, 0.75 miles

Average Customers per Line Segment = 488
Average Load per Line Segment = 1.53 MW
Average Distance per Line Segment = 0.8 miles

Section III – Work Flow Process

1.0 Self Optimizing Grid Circuit Identification and Prioritization Rules

1.1 Background and Initial Circuit Identification:

The Grid Improvement Plan target is to have 80% of our customers on the Self Optimizing Grid. 80% of our customers are on approximately 60% of our circuits. Therefore, the top 60% of our highest customer count circuits will be targeted per jurisdiction as a starting point in determining which circuits will become part of the S.O.G. Circuits equal to or above the customer count listed below are to be considered first for becoming part of S.O.G.

Jurisdiction	Circuit Customer Count
DEI	725
DEO	1060
DEK	1025
DEC	880
DEP	1155
DEF	1400

Note: The above criteria is a general guideline in determining what circuits should be in scope for S.O.G. Even though a circuit may meet the customer count criteria above, it may be excluded due to other factors such as no feasible ties or alternate sources. Also, there will be circuits that are below the listed customer count that will become part of the S.O.G. due to the proximity to circuits that do meet the customer count.

1.2 Annual circuit prioritization should be based on the following in order:

From the population of circuits selected by using the chart above, use the following items in sequential order to further target/identify circuits annually. Go through all 7 items before making circuit selections. Selecting S.O.G. circuits in this manner is expected to result in a higher reliability impact earlier in the program.

1. **Customer count** - Choose circuits with the highest customer count.
2. **Load growth** – Circuits requiring capacity upgrades as a result of load growth should be coordinated with S.O.G. work. The intent is to prevent capacity rework as a result of S.O.G.
3. **Historically poor reliability** – Choose circuits with the worst reliability.
4. **Available circuit tie to alternate source** – To increase early cost benefit, choose circuits with existing circuit ties to alternate sources early in the program if possible.
5. **No substation upgrade work required** – To increase early cost benefit, choose circuits that do not need substation upgrade work (New or larger bank, a new circuit breaker, or relay) early in the program if possible.
6. **Lowest cost*** – Choose circuits where the least amount of work is needed.
7. **Societal impact** – Choose circuits that have societal impacts such as hospitals and airports.

***Note:** Determining a highly accurate estimate of the lowest cost circuits can be more difficult, requiring circuit modeling for final determination. However, for circuit selection in item 6 above, consider if work will be needed concerning Connectivity and Capacity components only (wire, regulators and substation bank). Automation will be performed on every circuit regardless of S.O.G.

1.2.1 Alternate Sources

- Any circuit that will serve as the only alternate source for another circuit that is part of S.O.G. should also be brought up to S.O.G. standards even if the circuit is below the circuit customer count guidance.
- If a circuit does not meet the circuit customer count and is one of multiple alternate sources to another circuit part of S.O.G., this circuit is not required to be part of S.O.G., but should eventually be segmented and automated along the feeder backbone. Use engineering judgment in these cases.

1.3 Next Steps

- Each potential circuit should be studied to understand the full scope of work in applying and meeting all three components (capacity, connectivity, automation) of S.O.G. Once the scope of work required has been determined, the remaining items below (2.0 – 5.0) should be referenced for work generation.

1.4 Visualization Tool

The Visualization Tool can be utilized to assist in year to year planning to quickly identify potential issues around lack of ties, weak ties and small conductor. This tool provides a SOG growth area view by year that can potentially be used for planning beyond the next year. A full study will still need to be performed on each circuit. See the Visualization Tool Manual below:

SOG Visualization Tool - Manual V6 201ℓ   SOG Visualization Tool - CheatSheet V2

2.0 S.O.G. Work Process Steps and Owners (Per Circuit)

Work Process Steps	DEO/DEK/DEI	DEC/DEP	DEF
1. Create Kickoff (Shell) W.O.	Grid Solutions (G.S.)	Grid Solutions (G.S.)	Grid Solutions (G.S.) Planning Engineer
2. Attach Scope Documents to Kickoff W.O.	* Capacity Planning	Capacity Planning	Grid Solutions (G.S.) Planning Engineer
3. Forward Kickoff (Shell) W.O. to	Cust Delivery PM	E&TCR	Contractor – Automation Cust Delivery PM - C&C
4. Create all Needed W.O.'s Per Circuit	Project Controls	E&TCR/Contractor	Contractor – Automation Cust Delivery PM - C&C
5. Design Job for Construction	E&TCR/Contractor	E&TCR/Contractor	Contractor

*For segmentation devices, info is entered in a workbook/template

3.0 S.O.G. Circuit Work Order Structure and Creation

The chart below refers to the work order (W.O.) structure per circuit for SOG work. **1)** <u>Grid Solutions</u> will create the initial Kickoff (Shell) W.O. per SOG circuit. This W.O. is intended to hold all capacity planning generated analysis and scope documents. **2)** Attach all scope documents to the Kickoff W.O. **3)** Forward Kickoff W.O. **4)** Utilizing the Kickoff W.O. and attachments, the remaining W.O.'s are created for the circuit. **5)** Design jobs for construction. All W.O.'s should utilize the common naming convention and include the circuit number, along with using "Related Record" Ref Type "SOG" and Ref Value "Circuit #" to link all SOG W.O.'s per circuit for tracking purposes. See next page for common W.O. description naming conventions. See W.O. creation job aid below. <u>Exception:</u> Capacity (inside fence) work is initiated via a communication from Capacity Planning to the Transmission organization.

Analysis	Automation (Segmentation device Installs. Includes tie devices)	Connectivity (Excludes tie devices)	Capacity Outside Fence (SOG Driven Circuit Capacity Work)	Capacity Inside Fence (SOG Driven Sub Capacity Work)
Kickoff (Shell) W.O. for scope/analysis attachments. **Job Plan** = SGSELFHEAL **Related Record** Ref Type=SOG, Value=ckt# <u>Grid Solutions:</u> Creates Kickoff W.O.'s for each circuit targeted for SOG	**Work Order - N** **Job Plan** = SGSELFHEAL **Related Record** Ref Type=SOG, Value=ckt#	**Specific Project ID** When creating WO's, a specific project may be generated requiring approval.	**Specific Project ID** When creating WO's, a specific project may be generated requiring approval.	**Capacity Planning:** Communication to Transmission organization to initiate work. All W.O. creation, design and construction performed by Transmission. **Grid Solutions:** Monitoring of job status via SOG program management reporting.
	Work Order – N+1 **Job Plan** = SGSELFHEAL **Related Record** Ref Type=SOG, Value=ckt#	**Work Order - N** **Job Plan** = SGUPGDISTLINE **Related Record** Ref Type=SOG, Value=ckt#	**Work Order - N** **Job Plan** = SGFEEDERCAP **Related Record** Ref Type=SOG, Value=ckt#	
	Work Order – N+2 **Job Plan** = SGSELFHEAL **Related Record** Ref Type=SOG, Value=ckt#	**Work Order – N+1** **Job Plan** = SGUPGDISTLINE **Related Record** Ref Type=SOG, Value=ckt#	**Work Order – N+1** **Job Plan** = SGFEEDERCAP **Related Record** Ref Type=SOG, Value=ckt#	
	Work Order – N+3 **Job Plan** = SGSELFHEAL **Related Record** Ref Type=SOG, Value=ckt#	**Work Order – N+2** **Job Plan** = SGUPGDISTLINE **Related Record** Ref Type=SOG, Value=ckt#	**Work Order – N+2** **Job Plan** = SGFEEDERCAP **Related Record** Ref Type=SOG, Value=ckt#	

Work Order Creation Job Aid SOG WO Creation Job Aid Rev 0.docx **Mass Work Order Creation Tool Job Aid** Mass Work Order Creation Job Aid.doc

4.0 S.O.G. Work Order Description Naming Convention

4.1 S.O.G. Circuit Kickoff (Shell) WO Naming Convention - this Naming Convention is for the Kickoff (Shell) work order that will define SOG circuit scope of work.

➢ **Circuit Kickoff (Shell) Naming Convention**

GIP_SOG_Feeder Number_BACKBONE

- Example: GIP_SOG_T4600B04_BACKBONE
  - SOG work for circuit T4600B04

➢ **I&C Tech/ Equipment Operator Site Evaluation Naming Convention**

GIP_ASD_Feeder Number_BACKBONE _ SITE EVAL_DIS#/Field Tag ID or Lat.,Long.

- Example: GIP_ASD_T4600B04_BACKBONE_ SITE EVAL_ 1DDQ93 or 35.1234,73.456

4.2 Individual Work Orders Under Annually Funded Work Stream (AFWS)

➢ **Automated Switching Device (ASD) Naming Convention (Typically Electronic Reclosers)**

GIP_ASD_(Feeder Number)_BACKBONE_(Field Tag ID or Lat.,Long.)

- Example: GIP_ASD_T4600B04_BACKBONE_1DDQ93 or 35.1234,73.456

➢ **Open Point Recloser/ASD Naming Convention**

GIP_ASD_(Feeder Number)_BACKBONE_(Field Tag ID or Lat.,Long.)_Open Point

- Example: GIP_ASD_T4600B04_BACKBONE_1DDQ93 or 35.1234,73.456_ Open Point

➢ **Circuit Capacity Naming Convention**

GIP _CAP_(Feeder Number)_BACKBONE_(Description and Funding Project ID(if desired))

- Example: GIP_CAP_T4600B04_BACKBONE_N Oak Ave to E Lebanon then Briarclift Rd to Saddle Club Rd

➢ **Substation Capacity Naming Convention**

Transmission Generated

➢ **Connectivity Naming Convention**

GIP _CON_(Feeder Number)_BACKBONE_(Description and Funding Project ID(if desired))

- Example: GIP_CON_T4600B04_BACKBONE_N Oak Ave to E Lebanon then Briarclift Rd to Saddle Club Rd

➢ **Conductor Ampacity Upgrades (driven by new conductor ratings and not SOG)**

GIP _CUPG_(Feeder Number)_BACKBONE_(Description and Funding Project ID(if desired))

- Example: GIP_CUPG_T4600B04_BACKBONE_N Oak Ave to E Lebanon then Briarclift Rd to Saddle Club Rd

5.0 Enterprise Self Optimizing Grid Strategic Program Charging Guide:

Annually Funded Work Stream (AFWS)	Job Plan	Description
Automation & Self Healing	SGSELFHEAL DEF-SGSELFHEALF DEC-SGSELFHEALC DEP-SGSELFHEALC DEO-SGSELFHEALOK DEK-SGSELFHEALOK	This work stream involves installing DSCADA-enabled electronic reclosers on the backbone for segmentation purposes. Recall the design criteria of segmenting the backbone is an average of 400 customers, 3 miles of circuit or 2MW of load. Normally-open reclosers for circuit ties will also be charged to this Job Plan. The Job Plan starts with **SGSELFHEAL** and ends with a unique code for each jurisdiction. Note the change from Specific to a Blanket charging mechanism since the average work request cost for a recloser is generally less than $50,000. Also, all work associated with Self-Healing modeling and testing will be charged to the jurisdiction blankets.
Capacity	SGFEEDERCAP	Circuit Capacity - Projects to increase Circuit Capacity as a result of meeting SOG restoration targets.
	SGAMPACITYUPG (Not SOG Driven)	Conductor Ampacity Upgrades - This effort involves upgrading conductors utilizing the common rating standards now used enterprise-wide.
	SGSYSCAPACT	Substation Capacity - Projects to increase substation capacity as a result of meeting SOG restoration targets. This “inside-the-fence” effort could involve transformer bank increases, new circuit breakers or new substations.
Connectivity (excludes tie device)	SGUPGDISTLINE	Projects to build circuit ties to alternate sources which will allow for reconfiguration options when sustained faults occur. Note the normally-open recloser will be designed under the Automation and Self-Healing AFWS .

Section IV - Circuits not Qualifying for Self Optimizing Grid

Background: Based on estimates, 20% of our customers are on the remaining 40% of our distribution circuits not targeted for full implementation for Self Optimizing Grid. These circuits either do not have enough customers on the circuit or do not have a feasible means for inter-circuit connectivity with an alternate source. These remaining circuits will still be segmented with automated switching devices and utilized by Closed Loop FISR. Work on these circuits will take place in the latter years of the Grid Improvement Plan unless abnormal performance issues drive an accelerated deployment. This section is intended serve as a guide for what should be done on these circuits.

Segmentation – Apply the segmentation rules of Section II

Connectivity (Circuit Ties) –

- The installation of new circuit ties are not required under the Self Optimizing Grid program for non-qualifying circuits. Based on engineering judgment, if a new circuit tie is deemed necessary, the cost should be covered under the Reliability and Integrity Programs in the Grid Improvement Plan. New construction circuit tie work should <u>not</u> be charged to Self Optimizing Grid for non-qualifying circuits.
- Utilize an existing circuit tie only if the conductor on both sides of the tie is 1/0 ACSR or greater.
- Do not upgrade conductors as part of utilizing a circuit tie. Closed Loop FISR (CL FISR) bases restoration decisions on real time load flow circuit models and therefore should not utilize a tie if doing so results in an overload and voltage violation situation.
- Any utilized circuit tie must have a SCADA enabled and controllable device.

Capacity – Does not apply. Existing radial circuits should have adequate capacity. In the event that an automated switch is placed at a circuit tie, Closed Loop FISR will determine the feasibility of automatic restoration and will operate only if doing so does not create an overload or a voltage violation situation.

Automation – Apply the automation rules in Section II

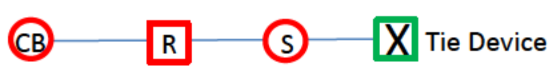
Section V: Self Optimizing Grid Segmentation Device Mode of Operation Guide

General Recommendations: Applies to the feeder backbone of each circuit part of Self Optimizing Grid

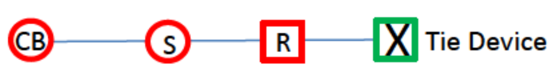
- There will be only one segmentation device setup as a recloser on the feeder backbone. This recloser should be somewhere close to midpoint based on customer count. Use judgment as to which device is setup as the recloser based on circuit characteristics such as large customers or outage probability. There will be reasons in some jurisdictions for which the recloser needs to be closer to the substation due to fault current levels and breaker reach. Exception: If needed to address a reach issue, two reclosers in series is acceptable. Setting up two segmentation devices as reclosers is expected if the circuit has a major load split close to the substation (device setup as a recloser on both sides of the split).
- Any first device downstream of the circuit breaker or the recloser should be setup as a sectionalizer.
- Any second, third, nth device downstream of a breaker or recloser should be setup as a switch. No series sectionalizer between the breaker and the recloser or between the recloser and the tie point. Some jurisdictions have three operations to lockout on breakers and reclosers. As a result, from an enterprise perspective, two sectionalizers cannot be placed in series directly behind the same reclosing device (open point excluded). The number of counts for sectionalizers is a jurisdictional decision. Note: Use judgment as to which device is setup as a sectionalizer based on circuit characteristics such as large customers or outage probability.
- Tie point device can be setup as desired based on jurisdictional preferences.

Theoretical Circuits CB Circuit Breaker S Sectionalizer R Recloser Sw Switch

2 Segmentation Devices



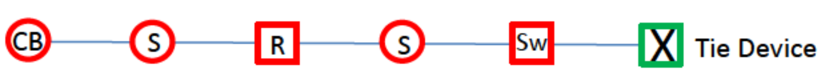
Preferred – Lower MAIFI with single phase trip. Better breaker reach for some jurisdictions.



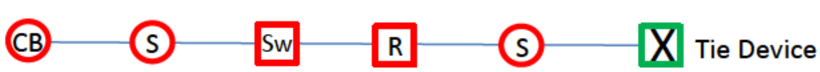
Alternate – May allow larger customers to be upstream of the recloser for fewer blinks.

3 Segmentation Devices

4 Segmentation Devices



Preferred – Lower MAIFI with single phase trip. Better breaker reach for some jurisdictions.

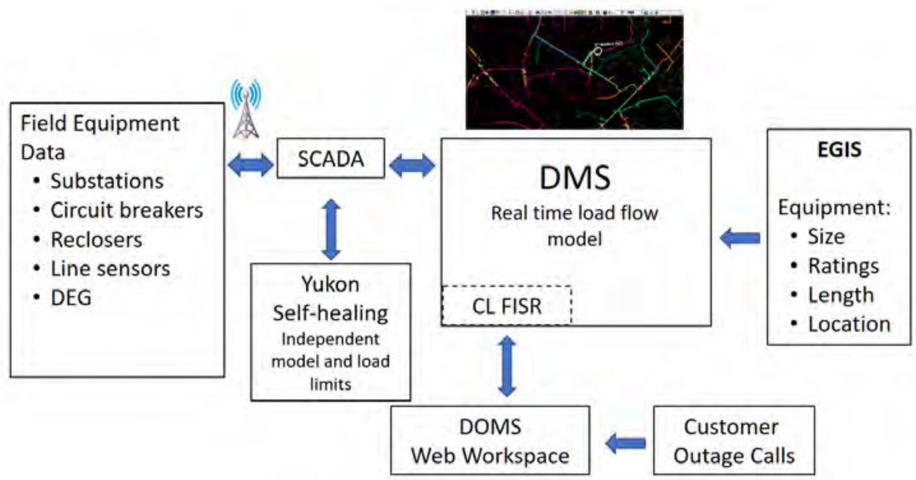


Alternate – May allow larger customers to be upstream of the recloser for fewer blinks.

5 Segmentation Devices

Section VI: FISR and Protection Validation Feature (in development)

Background: Across the enterprise, the Cooper Yukon Feeder Automation (YFA) has been the control system for self healing and S.O.G since 2010. This system has provided excellent operational reliability improvements over the years, but does require independent modeling in parallel to DMS, determination of load limits, data point setup per device, along with significant license and maintenance fees. The GE ADMS system that is being rolled out across the enterprise has an integrated automation system called Fault Isolation and Service Restoration (FISR). This system provides enhanced functionality to gain additional reliability benefits without the added licensing costs or modeling labor. FISR can be ran in two modes. The Open Loop mode means that FISR will provide reconfiguration plans for an operator to execute manually while the Closed Loop mode means the best plan will be selected and reconfiguration is executed automatically. Currently approximately half of the circuits in the Burlington, NC footprint are being controlled by FISR in the Closed Loop mode, commonly referred to as CL FISR. The diagram below shows how FISR resides in DMS and ties into EGIS and DOMS. At some future point, Duke Energy will migrate existing self healing teams from YFA to FISR. There is no set transition date at this time.



FISR Benefits:

- No separate self-healing system – FISR is part of DMS. Reduced O&M costs.
- FISR runs off of a real-time power flow model that estimates currents and voltages even if a device loses communications.
- FISR can estimate what the voltage will be after restoration and stop a restoration if voltage will be in violation.
- FISR determines load limits automatically (how much it can back-feed) because all circuit equipment attributes are in the DMS model such as conductor sizes, equipment ratings, bank capacity, etc.
- FISR can retry operating a device if the trip or close does not go through initially.
- Minimal additional device setup is required to enable automation once setup in DMS/SCADA.
- FISR considers substation bank loading.
- No team concept. The whole system is a team meaning many restoration options.
- FISR automatically disables automation to a circuit when HLT is applied.

Protection Validation Feature - Currently in most jurisdictions, recloser group settings are being changed depending on circuit configuration within self healing/SOG. This is done to accommodate load, maintain coordination and ensure adequate protective reach in all possible scenarios. This is manageable for smaller teams. However, as you begin to build out a network that involves many circuits and devices with many reconfiguration options, this becomes very difficult to maintain. An extreme example is a device in the Burlington FISR footprint that has seven different possible sources calling for four different group settings depending on reconfiguration.

During a reconfiguration, it is highly important that our equipment is not overloaded and protective reach is maintained such that if there is an additional fault, our reclosers can detect it. Maintaining coordination is good to have, but not critical in this temporary configuration. Both YFA and FISR currently have a miscoordination feature such that if two devices see the same fault and lockout at the same time, the upstream device will be closed if automation remains enabled.

Duke Energy is currently working with GE to develop a feature called Protection Validation (PRV) that will check for adequate reach before a restoration occurs. FISR already checks the load against the device trip settings in the lookup table before reconfiguring. The concept is to have a default group setting for all devices in their normal configuration like a typical radial feeder. Discontinue the practice of determining the group setting for all possible scenarios and rely on the Protection Validation (PRV) feature to check for adequate reach. If reach is determined to be inadequate, PRV changes the group settings for all devices in the violating protection zone to a group that maintains reach without tripping for overload. This will result in a potential loss of coordination, but as mentioned, FISR has a miscoordination feature and this would be considered a temporary configuration. This will require a new template that indicates the default group, for "Return to Normal" and the template number DNP data point for FISR to understand the settings in the other groups of the template.

More information will be included in future revisions as this feature is in development and could change slightly upon completion. This feature will be tested on two self healing teams in Ohio before determining future implementation. The PRV feature development completion is expected in the 4th quarter of 2020 with implementation in the two Ohio teams to occur shortly after that.

Section VII: Self Optimizing Grid Cost Based Analysis (CBA)

Background: A SOG Cost Benefit Analysis (CBA) is part of the justification for implementing targeted circuits on an annual basis. This analysis has been performed for all jurisdictions for a 3 to 4 year deployment plan. A substantial portion of the data inputs for costs and projected CI/CMI benefits are obtained from a separate master spreadsheet created for each jurisdiction. This master spreadsheet contains all circuits with information such as the backbone mileage, customer count, load, the estimated amount of capacity work needed and if a tie device exists. This information was used to determine the number of devices needed and the overall costs per circuit which helped determine which circuits will be included in SOG. For the circuits targeted for SOG, the projected CI/CMI benefits were calculated per circuit. SOG circuit selections were based on the criteria in this application guide on page 17. Circuits were prioritized based on cost per CI and CMI savings. Consideration was also given for circuit implementation based on a resource informed plan.

Program Costs:

- Calculated for:
  - Capital Costs – costs to deploy SOG on an annual basis, to include the three key components; automation, capacity, connectivity.
  - O&M Costs – on-going costs to operate and maintain SOG, including IT/Telecom operational support, cellular costs and equipment maintenance.
- Evaluated over the expected asset lifecycle period of 30 years.

Program Benefits:

- Calculated for:
  - Customer savings – The value to the customer based on reduced outage events
    - Outage avoidance savings
      - Estimated cumulative on-going CI and CMI savings based on backbone length, backbone fault rate and circuit customer count.
      - Estimated outage duration based on the calculated CMI/CI/60 (Data input for ICE tool).
      - Utilizes Interruption Cost Estimate (ICE) tool for customer valuation of cost per event based on customer mix and duration per event.
    - Momentary Interruption avoidance savings
      - Avoided momentary interruption impact costs for non-MED outages.
      - Based on 13-years of historical outage information.
      - Utilizes Interruption Cost Estimate (ICE) tool for customer valuation of cost per event.

- Capacity Savings (generation deferral) – The value of increasing capacity for SOG
  - Increasing capacity will reduce line losses, which also reduces voltage drop across the circuits.
  - Less voltage drop will allow IVVC to reduce voltage more, further reducing demand.
  - Reduced load results in less generation and generating facilities needed.
  - Cost deferral is associated with generating facilities.
- Energy Savings – The value associated with energy savings as a result of reduced line losses from capacity increases.
- Environmental Benefits – The value of carbon reductions from less demand and generation.
- DER Enablement (jurisdiction specific) – The value of hosting capacity additions to distribution, which provides energy savings, avoided capacity and CO2 reductions.

- Evaluated over the expected asset lifecycle period of 30 years

Data Required for Cost Benefit Analysis:

- Assumptions:
  - Energy provides value to customers and that energy is an enabling product for our society. Therefore, improvements to power quality have tangible value to customers
  - The ICE Calculator, funded by the DOE, is the industry standard for estimating this value
- Data Inputs:
  - Refer to table below.
- Financial Assumptions:
  - Standard financial assumptions such as cost of capital and escalation rate apply equally across all SOG targets
  - Based on standard financial metrics determined by Corporate Treasury

Data Collected for SOG Cost Benefit Analysis (CBA)	
	Substation
	Outage Events (Greater than 5 minutes) on Substation Devices & Feeder Breakers (excluding MED's)
	Substation Name
	Substation Identification Number
	Substation County
	Substation Bank Rating (derated for limiting factors)
	Substation Bank Peak Load
	Distribution Line
	Circuit Identification Number
	Circuit Name
	Jurisdiction of Circuit ID
	Location of Circuit ID by US State
	Operations Center Responsible for Circuit ID
	Voltage Rating (kV) of Circuit ID
	Distribution Planning Summer Peak (KW) of Circuit ID
	Distribution Planning Winter Peak (KW) of Circuit ID
	Maximum Load Limit (Rating) of Circuit ID
	Self-Healing Network (SHN) or SOG Team Number (if applicable)
	Miles of OH 3-phase Primary on Feeder Backbone
	Miles of UG 3-Phase Primary on Feeder Backbone
	Wire Sizes of OH 3-Phase Primary on Feeder Backbone by Circuit ID
	Wire Sizes of UG 3-Phase Primary on Feeder Backbone by Circuit ID
	Length of Wire Sizes of OH 3-Phase Primary on Feeder Backbone (Miles)
	Length of Wire Sizes of OH 3-Phase Primary on Feeder Backbone (Miles)
	Existing Automated Switching Devices (ASD) on Circuit
	Total Number of ASD's Needed for Average 2MW Load per Segment on Feeder Backbone
	Total Number of ASD's Needed for Average 400 Customers per Segment on Feeder Backbone
	Total Number of ASD's Needed for Average 3 Miles per Segment on Feeder Backbone
	Existing Feeder Tie Points
	Physical Location of Existing Feeder Tie Points in Relation to Circuit
	Wire Size on Circuit 1 at Feeder Tie Point
	Wire Size on Circuit 2 at Feeder Tie Point
	Customer
	Total Number of Customers Assigned to Native Circuit ID
	Large Commercial & Industrial (C&I) Customers (%)
	Small C&I Customers (%)
	Residential Customers (%)

Data Collected for SOG Cost Benefit Analysis (CBA) - Continued	
	Reliability
	Average Repair Time (Minutes)
	Average Switching Time (Minutes)
	Projected Base CI without SOG Segmentatation
	Projected CI with MPR's
	Projected CI for Circuit on Existing Self Healing Network
	Projected CI for Circuit 100% Compliant to SOG Guidelines
	Incremental CI Improvement due to SOG
	Incremental CMI Improvement due to SOG
	Average CAIDI
	Typical Outage Duration
	Large C&I Outage Value (Cost per Event)
	Small C&I Outage Value (Cost per Event)
	Residential Outage Value (Cost per Event)
	Large C&I Momentary Interruption Value
	Small C&I Momentary Interruption Value
	Residential Momentary Interruption Value
	PV Data (Rooftop Solar)
	Forecasted PV (Annual)
	Forecasted PV (Cumulative)
	Circuit Limit (with SOG) MW
	Circuit Limit (without SOG) MW
	PV Scaling Factor
	PV Derate Factor

Data Collected for SOG Cost Benefit Analysis (CBA) - Continued
Generation Capacity & Energy Savings
Average CVR Factor
Annual Load Growth Rate
% Load Reduction without Circuit Conditioning (i.e. SOG)
% Voltage Reduction (without SOG)
% Voltage Reduction (with SOG)
Total KW Load on SOG Circuits Enabled with IVVC
Total Load Reduction (KW) on SOG Circuits Enabled with IVVC
Coincident Peak Demand (MW)
Peak w/ IVVC (MW)
MW Reduction with Normal Voltage Reduction Mode
Additional MW Reduction Emergency Mode (without SOG)
Additional MW Reduction Emergency Mode (with SOG)
Total Potential MW Reduction (without SOG)
Total Potential MW Reduction (with SOG)
% Transmission Loss Gross-Up
% Generation Planning Reserve Margin Gross-Up
$/kWYear CT Cost
$/Year Capacity Offset Value
Capacity Factor for Energy Savings
Environmental
CO2 ($/ton)
NOx ($/ton)
SOx ($/ton)
Energy: CO2 Reduction(ton/MWh)
Energy: NOx Reduction (ton/MWh)
Energy: SOx Reduction (ton/MWh)

From the data collected above, the following calculations are completed to provide a net present value (NPV)

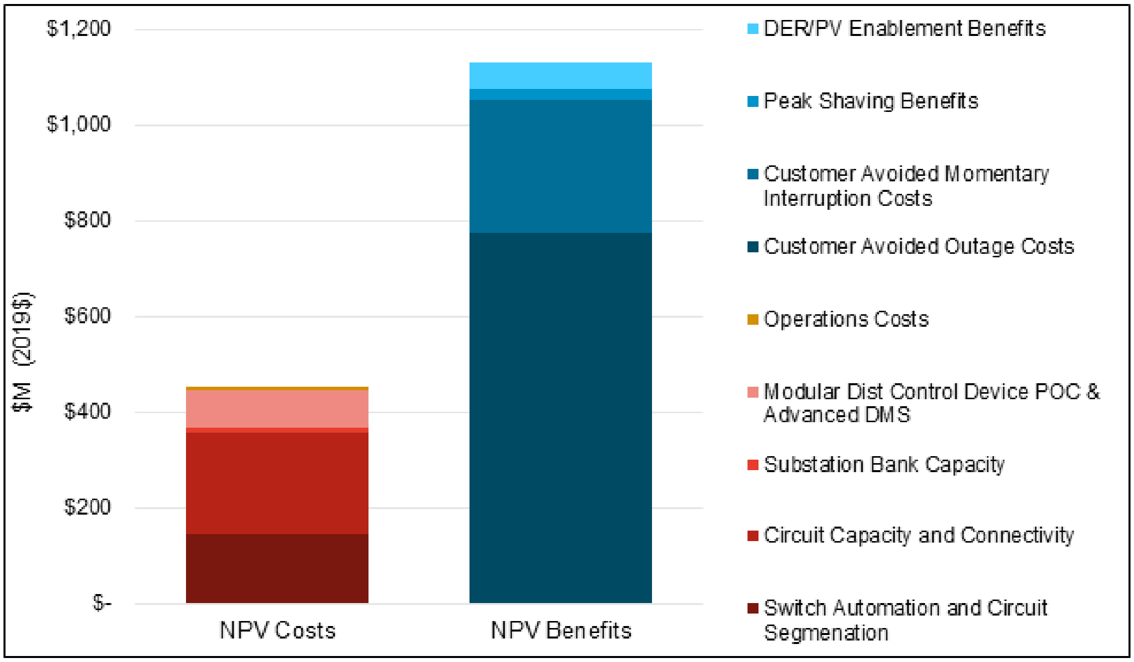
NPV Calculation:

Calculations
Capital Costs
Switch Automation and Circuit Segmenation
Circuit Capacity and Connectivity
Substation Bank Capacity
Modular Dist Control Device POC & Advanced DMS
O&M Costs
Cellular
Operations Support
Maintenance
Benefits
Customer Avoided Outage Costs: Residential
Customer Avoided Outage Costs: Small C&I
Customer Avoided Outage Costs: Large C&I
Customer Avoided Outage Costs
Customer Avoided Momentary Interruption Costs: Residential
Customer Avoided Momentary Interruption Costs: Small C&I
Customer Avoided Momentary Interruption Costs: Large C&I
Customer Avoided Momentary Interruption Costs
Capacity Savings (IVVC)
Energy Savings (IVVC)
Environmental Benefits
Environmental Benefits (IVVC)
Peak Shaving Benefits
DER Enablement: Capacity Savings
DER Enablement: Energy Savings
DER Enablement: Environmental Benefits
DER/PV Enablement Benefits

An example Cost Benefit Analysis is attached here:

Microsoft Excel
97-2003 Worksheet

NPV Bar Chart of Benefits



Cost Benefit Analysis Approval Process

Once the cost benefit analysis has been completed for a predetermined list of target circuits and has demonstrated a positive NPV, the program is reviewed and approved by the Grid Solutions leadership

The SOG annual work plan is based on a resource informed analysis with the intent of aligning targeted circuit work with available resources. Project execution has the autonomy to schedule and manage the approved projects throughout the year based on customer engagement activity needs, resource availability and efficiencies, the right mix of project complexities and easement acquisition (where applicable).

Appendix I - Questions and Answers: This section is intended to provide further clarification on this application guide based on submitted questions.

SOG Analysis and Capacity Related

Question: How does SOG affect existing extra facilities such as a customer paying for an alternate feed with reserve capacity?
Answer: There two angles to this question. If a customer is paying extra facilities for an alternate feeder, this means they are paying for the automatic throw-over and reserve capacity. SOG is not intended to serve as a replacement since there is no guarantee that restoration will take place to all unfaulted line segments as intended. Pre-existing ATO's and the input feeders should not be altered by SOG unless the contract has expired and the customer chooses not to renew. Also, the reserve capacity must be factored in when considering capacity requirements for SOG.

Question: When considering the 75% of projected peak rule for unloading to relief circuits, does that apply to the bank as well? For example, look at the peak load at the relief bank and assume you will be picking up the extra load when the bank is at 75% of its peak.
Answer: Assume the relief bank is at 75% of peak demand as well. Designing capacity to handle additional circuit load at 75% of peak, while considering the bank load at 100% of peak could lead to unintended bank upgrades.

Question: When considering the 2MW segment load target, should that load also be considered at 75% of peak load.
Answer: Yes. All load considerations under SOG should be taken at 75% of projected peak to meet the 90% of the hours in a given year availability rule.

Question: Do we consider load growth while performing SOG circuit analysis.
Answer: In general, do not include load growth. If there is a circuit with or expecting a much higher than normal load growth, this can be considered as part of the circuit analysis. When executing load growth projects, the project should be built to SOG rules. Segmentation device installations as part of this project can be charged to SOG.

Question: Post SOG circuit work, how far is the capacity allowed to be eroded due to load growth before action is taken to regain the original availability target of 90% of hours per year? Do we allow large customers adds without work to redesign the segment or add capacity to meet the original SOG design?
Answer: The original intent was that the business will maintain SOG to original design, post deployment. However, there have been no set rules around when and how this happens. More work is needed to address this question.

Question: If a SOG feeder has multiple ties, should we stop our review when we can unload the SOG feeder at 75 % peak even if that means several ties were not reviewed. If there is a feeder tie that is not selected to be part of the SOG network, should we install an automatic switching device at the unused tie point?
Answer: If there is another feeder tie that is above what is necessary to unload a SOG circuit, engineering judge should be utilized to weigh the benefit of the additional tie. If this additional tie helps to unload a SOG circuit, adds additional switching options, and the conductor is greater than #2 ACSR, the installation of this additional tie is acceptable. Do not install non-essential ties until SOG work is planned on the alternate (relief) circuit. If the tie is between 2 non-SOG circuits, installing an ASD must be funded from a different bucket of money.

Question: How far do we go into the alternate (relief) circuit with SOG principles? SOG the entire circuit?
Answer: If the circuit is in the 10 year SOG plan, analyze the alternate (relief) circuit for connectivity, capacity and automation. If the circuit is not in the 10 year plan, only apply the automation (segmentation) rules. Exception: If the relief circuit is not on the SOG list, but is the only alternate source for circuit part of SOG, the relief circuit should be included in SOG also. In the either case, stop work on the alternate (relief) circuit at circuit ties to a third circuit, i.e. don't add ASD's at tie points on circuits beyond the relief circuit until the scheduled SOG analysis on those circuits.

Question: How should we model capacitor banks for voltage support when performing a SOG circuit analysis?
Answer: Assume that all switched bank capacitors are on.

Question: What conductor ratings should be used in the model?
Answer: Refer to the new conductor ratings published in the enterprise Distribution Standards manual. Per the listed notes below the ampacity chart, legacy ratings can continue to be used on lines constructed before the 2016 publication as long as the legacy ampacity rating was based on a conductor temperature of 185F or less. Legacy ampacity ratings that were based on a conductor temperature greater than 185F are now required to utilize the published enterprise ratings, which includes DEC. There are no longer emergency ratings.

Question: Do we design SOG such that we have bank failure contingency, i.e. be able to pick up the entire load of the bank if there is a failure.
Answer: Although it is desired to have the ability to pick up as much load as possible in most circumstances, requiring a bank failure contingency would lead to the need to upgrade a lot of banks for a very low risk event. Therefore, SOG should be designed for a single circuit contingency.

Question: What are the rules concerning "utilized" circuit ties for a tie in a loop on the same circuit?
Answer: While there may be some benefit, a circuit tie ASD in a loop on the same circuit does not provide benefit if losing most or all a circuit during an event. As a result, it is not a recommended practice. However, if the additional tie allows adherence to the rule of isolating a fault to one segment, while restoring all other customers, this would be allowed. Use engineering judgment.

Question: What are the rules around DER with respect to SOG?

Answer: A general recommendation is to exclude circuits with DER for the first couple of years of the program if possible. The current self healing system software, YFA, can model DER. However, this system does not control regulators, which presents an issue when an upstream line regulator controller is locked on CoGen mode and the regulator is back-fed from a new stiff source. Essentially, the regulator can go into runaway either stepping to max buck or boost. Below are further recommendations per jurisdiction.

DEMW – Include DER as desired. The Midwest uses the M-6200 regulator control that has an auto determination feature eliminating the runaway concern.

DEC – If there is no upstream line regulator(exclude circuit exit regulators), DER can be integrated as desired. If there is an upstream line regulator, avoid if possible. If there is a strong desire to include immediately, a control change-out will be necessary. Contact Rod Hallman.

DEP - If there is no upstream line regulator(exclude circuit exit regulators), DER can be integrated as desired. If there is an upstream line regulator, avoid if possible. A control change-out to prevent the concern is not possible until the full DMS conversion to Alstom.

DEF - If there is no upstream line regulator(exclude circuit exit regulators), DER can be integrated as desired. If there is an upstream line regulator, avoid if possible. If there is a strong desire to include immediately, a control change-out will be necessary. Contact Rod Hallman.

Load Limits and Protection Settings

Question: Is there a plan to coordinate determining protection settings and recloser mode?

Answer: Enterprise-wide, who determines the settings that are put in the reclosers and even how they are setup (recloser, sectionalizer or switch) are not the same. In DEF, DEI, DEO and DEK this is determined by the capacity planners. In the Midwest, these recommendations are installed through DPAC. In the Carolinas, although the capacity planners may look at reach and recommend how they think the device should be setup, determining the protection settings and the device mode is ultimately a DPAC decision. The implementation of SOG was not meant to and should not change this current process of determining reach or protection settings. Recently, an enterprise guide for determining the recloser mode/setup (also called mode of operation) was established and should be used. See Section V. In all jurisdictions, the planner has some level of involvement and should keep in mind the downstream customer type in making recommendations on the setup. For example, if there are multiple ASD's and a larger customer exists close the midpoint, it may be better to setup the first ASD downstream from this customer as a recloser to reduce momentary operations seen by this customer.

Question: Existing SH rule in DEC concerning setting load limits is set with respect to equipment ratings or no higher than 75% of the trip settings of the protective devices in an effort not to cause another lockout. How does SOG affect this?

Answer: Load limits on individual devices are Cooper YFA specific. How they are determined and who makes the determination is a little different across the company. For example, load limits in DEF may be set based on expected conductor sag rather than on equipment ratings and trip protective settings due to tight clearances and larger conductors. SOG should not change the current process for determining load limit or protection settings. Once FISR is in place, load limits settings per device will no longer be needed.

Appendix II: Gang Operated Air Break (GOAB) Switch Replacement Guidance

Objective: Gang operated air break switches exist on the Duke Energy distribution system for the purpose of switching with the advantage of being able to operate, including breaking load if needed, from the ground. However, these switches do need routine maintenance to ensure proper operation and have increasingly failed to operate as expected as they age. This includes both hook-stick operated and down-the-pole operated GOAB switches. In an effort to eliminate maintenance requirements and reduce operational difficulties, a replacement program has been developed to replace these switches with either a standard electronic recloser, a new SCADA capable electronic switch, manual disconnect switches or switch removal. Below is the guidance for determining the replacement option per switch location.

Preface: Beginning in 2022, any new SOG circuit studies will include addressing all GOAB switches present on these circuits. This also includes GOAB switches at tie points between SOG and non-SOG circuits. There is an existing population of circuits currently on SOG, work scope completed to be on SOG and circuits not targeted for SOG (non-SOG). These circuits need to be addressed independently from new SOG circuit scoping work starting in 2022.

GOAB Switch Target Locations

GOAB Target List

Perform the following steps to determine the GOAB switch replacement option for each targeted location: Replace with electronic recloser, electronic switch, manual disconnect or remove

1. Determine if the GOAB switch is currently on a SOG circuit or a circuit targeted for SOG in the future. If so, go to step 2. Otherwise go to step 3. Go to "Important Links" below to make this determination.

2. GOAB Switches on Circuits Part of SOG (currently on SOG or future SOG)

   Normally Open GOAB Switches (Tie Points) – Any GOAB switch at a circuit tie point between two SOG circuits should be replaced with a SOG segmentation device/electronic recloser if utilized for SOG. If the GOAB switch will not be utilized as a tie point for SOG, replace with a manual disconnect. If the GOAB switch is between a SOG and non-SOG circuit and the primary conductor size on both sides is larger than 1/0, replace with a SOG segmentation device/electronic recloser. If the primary conductor size on both sides is 1/0 or smaller, replace with an electronic switch. Background: Most circuits will be part of SOG and even non-SOG circuits that have a viable circuit tie can become a partial SOG/automated circuit at some point in the future and therefore a remotely controlled device is justified.

Normally Closed GOAB Switches – Any GOAB switch on a SOG circuit should either be replaced with SOG segmentation device/electronic recloser, a manual disconnect or removed. Do not replace with an electronic switch. If the switch will not be replaced with an electronic recloser as part of SOG segmentation, determine if switch should be replaced with a manual disconnect or removed. Ideally within a SOG segment, the switch should be located at approximately 50% of the limiting SOG segmentation criteria. However, because the switches are already in place use the following rule of thumb. Ensure that no more than 75% of the line exposure or customer count exists on either side of the GOAB switch between the SOG segmentation devices. Exceptions to this rule include: 1) A very high percentage of the customers or load in a segment exist on one side, while a very high percentage of the line exposure is on the other side. 2) The switch location could assist in the restoration of critical customers. The installation of manual disconnects requires truck accessibility. If there are accessibility issues, it is acceptable to remove the GOAB switch and install a manual disconnect in another truck accessible location. This may require a site visit for confirmation as accessibility is not always clear in MyWorld.

3. GOAB Switches on Circuits **not** Part of SOG (non-SOG circuits)

Normally Open GOAB Switches (Tie Points) - If the GOAB switch is between two circuits not on the SOG Circuit Master List and the primary conductor size on both sides is larger than 1/0, replace with an electronic recloser. If the primary conductor size on both sides is 1/0 or smaller, replace with an electronic switch.

Normally Closed GOAB Switches - Answer the following criteria questions. If any two or more of these questions are yes, replace with an electronic switch. Otherwise replace with a manual disconnect. If replacing with a manual disconnect and there are accessibility issues, it is acceptable to remove the GOAB switch and install a manual disconnect in another truck accessible location. This may require a site visit for confirmation as accessibility is not always clear in MyWorld.

A. Are there critical customers such as a nursing home, hospital, airport or other utilities (water/sewer behind/downstream from the switch)? This assumes there is a viable tie to an alternate source to back-feed this customer(s). If there is not an alternate source, the answer is no.
B. Are there accessibility issues? (Truck setup would result in blocking traffic in a high traffic area or there is poor truck accessibility)
C. Has the device been operated more than 3 times in 1 year? – future link
D. From the substation to the circuit tie point used to back-feed, is there a remotely controlled electronic switch, recloser or breaker on either side of the GOAB more than 3 miles away. If remotely controlled devices on either side are more than 3 miles away, the intent is to reduce drive time for emergency switching during an outage?

Important Links: Circuits already part of SOG and SOG scoping work completed prior to 2022 do not include addressing GOAB switch replacements. Starting in 2022, SOG circuit studies will include GOAB switch replacements. Therefore, it is important to understand which SOG circuits will need to be revisited for GOAB switch replacements, which will need to be addressed independently from future SOG work. Below are links to tracking spreadsheets to help make that determination. GOAB switch replacement decisions on scoped SOG circuits prior to 2022 should involve consulting with the appropriate planner to understand planned circuit work.
DEP DEC DEF DEO/DEK

GOAB Replacement Options:

- **Electronic Switch** - ABB OVR or G&W Diamondback

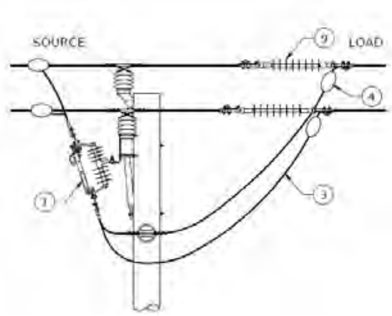
Refer to the Distribution Construction Standards manual, Section 8

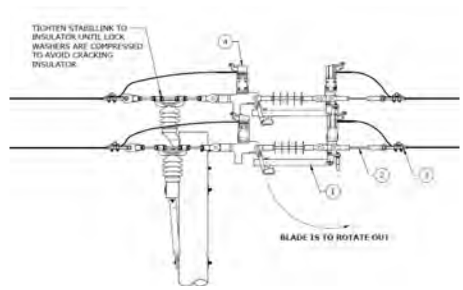
- **Electronic Recloser** – G&W Viper ST (For utilizing at Circuit Tie Points Only as part of GOAB replacements)

Refer to the Distribution Construction Standards manual, Section 8

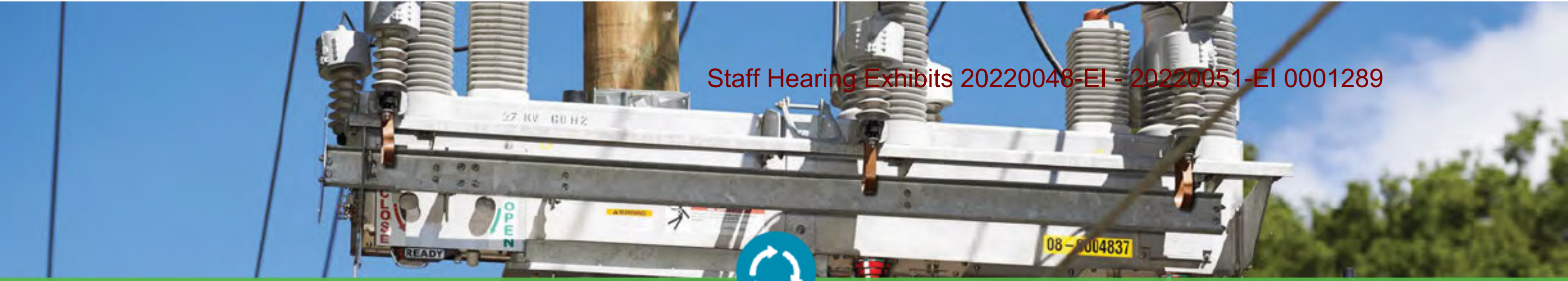
- **900/600 Amp Manual Disconnect Switch** – Single Insulator Style or Inline Tension Disconnects

Both switch types are acceptable





Refer to the Distribution Construction Standards manual, Section 8



Smart-Thinking Grid

A smart-thinking grid uses advanced technology and the power of intelligent information to automatically detect, isolate and reroute power when a problem occurs. Sensors and remote monitoring equipment deliver near real-time information over an advanced communication network from thousands of points along the grid. This information enables the grid to make intelligent decisions to maximize efficiency and restore power faster.

A smart-thinking grid can also better manage the growth of and intermittent power flows from private solar and other renewables, and support the expansion of emerging technologies like electric vehicles, microgrids and large battery storage. And with its advanced monitoring and outage isolation capabilities, the smart-thinking grid can better detect and protect against physical and cyber threats.

Where we are today

Duke Energy's smart-thinking grid comprises more than 350 self-healing networks already installed across our six-state service area, delivering significant benefits to customers. These networks reduce the number of power outages, as well as the duration of outages. If outages do occur on a smart-thinking grid, power is typically restored in less than a minute. In 2017, our self-healing networks operated 330 times to prevent over 330,205 outages. Smart-thinking grid technology helped our customers avoid over 46 million minutes in outage time.

More improvements are planned as part of Duke Energy's multi-state grid improvement initiative. When completed, roughly 80 percent of all customers will be served by a smart-thinking grid.

duke-energy.com/smartgrid

SMART-THINKING GRID CUSTOMER BENEFITS SNAPSHOT

Inception to date*	Self-healing networks	Number of customers saved from outages**	Minutes of customer outages prevented***
Duke Energy Carolinas (DEC)	69	256,185	45,412,339
Duke Energy Progress (DEP)	102	355,858	58,635,137
Duke Energy Indiana (DEI)	22	91,045	10,766,730
Duke Energy Kentucky (DEK)	11	66,092	10,222,904
Duke Energy Ohio (DEO)	38	540,908	72,089,506
Duke Energy Florida (DEF)	117	396,154	32,811,355
Duke Energy Cumulative	**359**	**1,706,242**	**229,937,970**

*DEO values since 2009; DEC, DEI: 2012; DEK: 2013; DEP: 2014; DEF: 2015

**Total number of customers who would have experienced power outages if self-healing technology had not been installed.

***Total number of power outage minutes prevented for customers because of self-healing technology operations.

DUKE ENERGY®

BUILDING A SMARTER ENERGY FUTURE℠

Duke Energy Florida, LLC
20220050-EI
DEF's Response to OPC POD 3 (35-41)
Q39

Documents bearing bates numbers
20220050-DEF-0005285
through
20220050-DEF-005319
are **redacted** in their entirety.

DUKE FLORIDA

2019 POLE FORENSIC ANALYSIS

APRIL 1, 2019

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EXECUTIVE SUMMARY

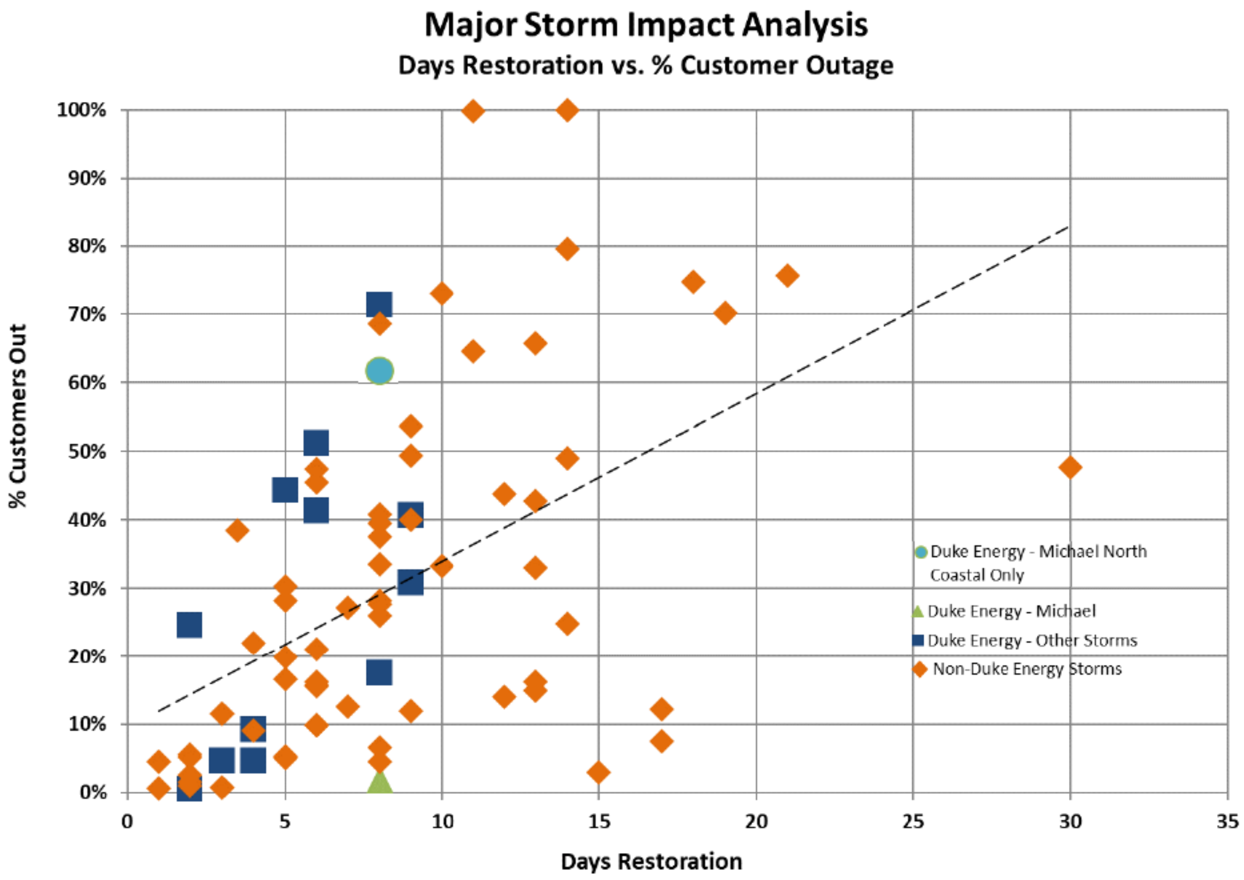
accentureconsulting

EXECUTIVE SUMMARY

- Hurricane Michael impacted Duke Energy Florida (DEF) service territory on October 10, 2018 as a Category 4 storm causing catastrophic damage in the panhandle of the North Coastal Zone
- DEF collected forensic information on the broken poles in the early stages of the restoration and retained Accenture to conduct a statistical and benchmark analysis using the data collected
- Accenture analysis focused on four key components:
  - **Benchmark Analysis** – leveraged Accenture's "storm benchmark database" and compared DEF performance against comparable storms
  - **Forensic Analysis** – used geospatial analysis, descriptive statistics and multiple logistic regressions to assess the cause and effect of pole failures
  - **Storm Hardening Effectiveness** – applied visual and locational analyses to evaluate the association of any broken poles to the hardening program established in 2006
  - **Drone Analytics for Forensic Damage Assessment** – assessed drone usage during Hurricane Michael and recommended process improvements for future major events

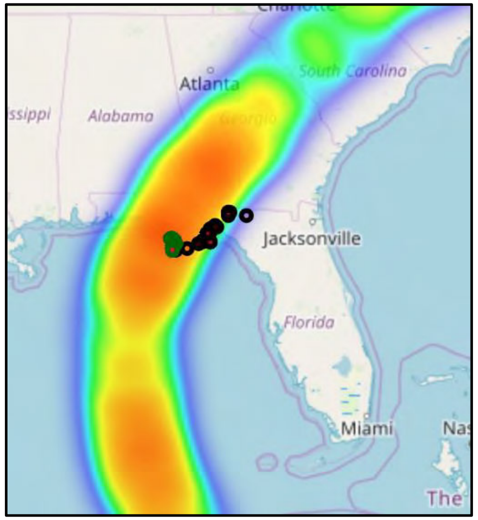
EXECUTIVE SUMMARY – BENCHMARK

- Hurricane Michael impacted the panhandle of DEF's North Coastal Zone causing massive damage to a concentrated area. This area represents approximately three percent (3%) of DEF'S total customer base.
- Sixty-one percent (61%) of DEF's North Coastal Zone was affected by Hurricane Michael with total devastation in the areas of Mexico Beach, Port St. Joe and Cape Sand Blas
- Hurricane Michael was a unique storm for DEF in that the majority of the affected territory was not accessible until 2 days after the storm
- DEF deployed a large contingent of resources to this storm to ensure fast restoration
- The number of poles replaced per customers out at peak was relatively high

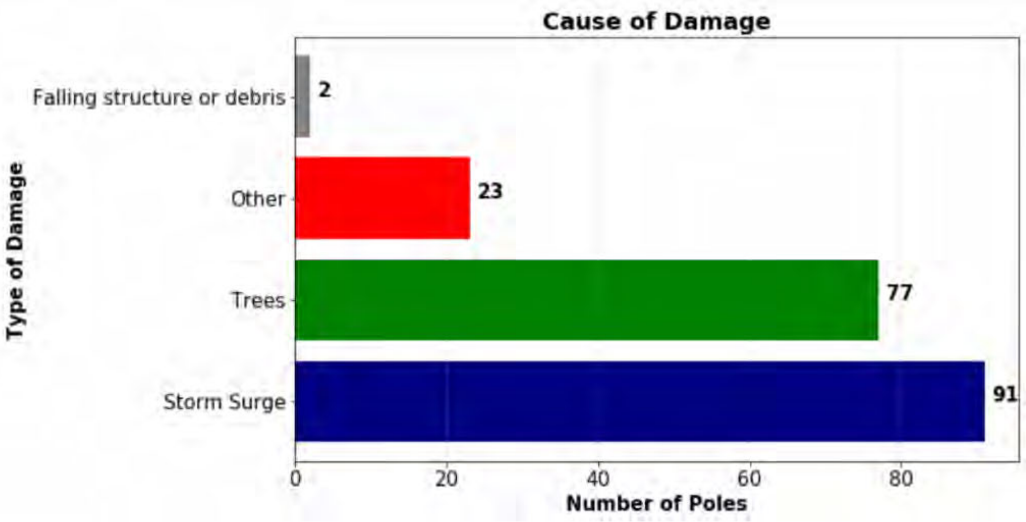


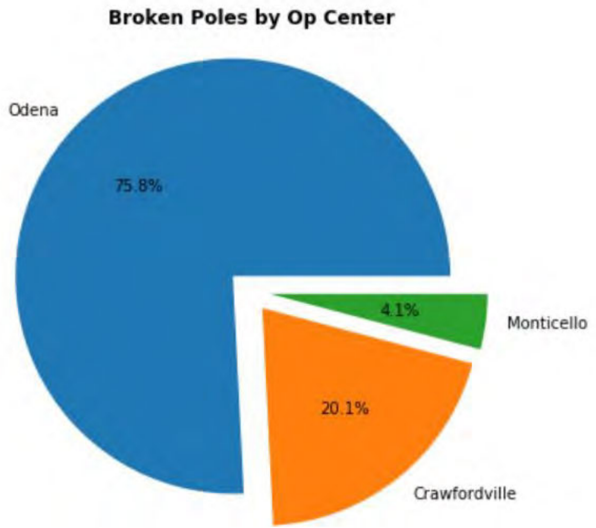
EXECUTIVE SUMMARY – FORENSIC

- Three pronged approach was used in forensic analysis: Geospatial analysis, descriptive statistics and logistic regression.
  - Geospatial analysis showed 16% of poles in the Florida panhandle area were exposed to hurricane force winds. DEF was unable to collect pole data in areas of total devastation.
  - Descriptive statistics on available data showed storm surge as the most common cause of failure with most poles breaking at the base. The Odena Op Center experienced the majority of the pole failures.
  - Results from the logistic regression showed the strongest relationship can be attributed to weather related factors, i.e. storm surge and hurricane force winds; as opposed to pole attributes, i.e., height or year manufactured.



***Higher intensity winds shown as red



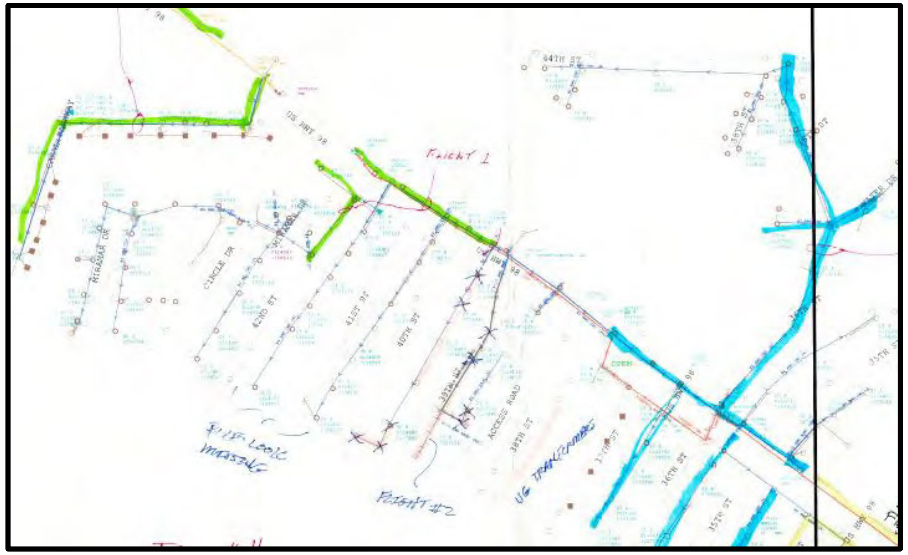


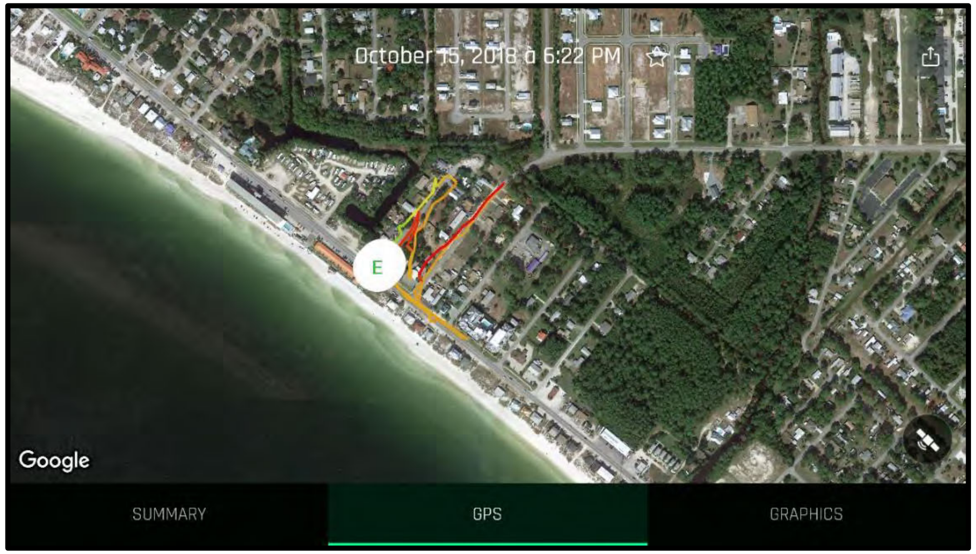
EXECUTIVE SUMMARY – SYSTEM HARDENING

- A forensic assessment of two hundred nineteen (219) randomly selected poles was conducted across DEF's total broken pole population.
- One (1) Class 5 pole was broken and six (6) Class 2 were leaning poles within a storm hardening project Alligator Point Extreme Wind - Phase 2 of 4 (constructed in 2014). Other storm hardening projects experienced no damage.
- Alligator Point experienced tropical storm force windspeeds of 65-75 mph and storm surges of 9-13 ft. As seen in the pictures below the ground gave way and they did not break which shows evidence that extreme wind standards improved their performance.

EXECUTIVE SUMMARY – DRONE USE TO SUPPORT DAMAGE ASSESSMENT

- DEF Forensic Damage Assessment deployed Drone Technology for the first time in the Hurricane Michael response
- This deployment demonstrated the potential for additional benefits to the forensics process by augmenting the existing forensics data collection process with an aerial component
- A total of four hundred forty-nine (449) pictures and forty-two (42) videos were obtained using Drone Technology





OVERVIEW/ PURPOSE

OVERVIEW/PURPOSE

Duke Energy Florida ("DEF") conducted a comprehensive analysis of forensic data on pole failures that the company collected in the aftermath of Hurricane Michael. The purpose of the study is to determine the correlations and major causes of failure. Accenture was retained to perform the analysis and performed the following tasks:

1. MOBILIZED THE PROJECT	2. PERFORMED STORM BENCHMARKING COMPARISON	3. CONDUCTED DATA ANALYSIS	4. REVIEWED AERIAL DRONE FOOTAGE	5. SYTHESIZED AND SUMMARIZED
• Organize the available data into a single electronic database (table) to allow for analysis • Identify any gaps in the data and develop strategies to gather the missing information	• Gather key statistics from the DEF response to Hurricane Michael • Identify the comparable events from Accenture's storm benchmarking database to compare against DEF's response • Conduct benchmark comparison and identify key metrics • Develop conclusions based on the benchmark analysis	• Conduct the regression analysis or apply other analytic methods to allow for statistically valid assessment of the correlations of the different factors • Identify the key drivers or pole failures and determine the overall cause and effect • Develop conclusions based on the statistical analysis	• Understand how drones were deployed and used during Hurricane Michael • Work with DEF team to refine the objectives for use of drone footage during and after major storm events	• Prepare a summary report that describes the methodology and conclusions based on the pole failure data analysis and the benchmark comparison

DUKE ENERGY.
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BENCHMARKING COMPARISON

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BENCHMARKING RESULTS OVERVIEW

- Conducted a Benchmark Survey
  - DEF provided metrics surrounding the restoration efforts of Hurricane Michael
  - Additional surveys were completed by other utilities for storms over the past 25+ years
  - The survey focused on three areas:
    - System Information
    - Storm Magnitude
    - Restoration Performance
- Identified similar category 1 – 4 hurricanes to perform the analysis of DEF's restoration efforts versus other utility companies captured in Accenture's storm benchmarking database from 1989 – 2017
- Highlighted restoration performances from Duke Energy and Progress Energy
- Accenture used numerical redactions to preserve the anonymity of other clients

BENCHMARKING DEMOGRAPHICS

- 26 of 51 utilities included in the benchmarking
- 24 of 57 major events are included in the analysis
- 46 out of 120 distinct restorations

Storm Type	Storm Name	Total
Hurricane Category 1	Fran	2
	Frances	2
	Hermine	1
	Hugo	1
	Humberto	1
	Irene	10
	Katrina	1
	Sandy	5
Hurricane Category 2	Elvis	1
	Georges	1
	Gustav	1
	Gustav + Ike	3
	Juan	1
	Isabel	2

Storm Type	Storm Name	Total
Hurricane Category 3	Ivan	2
	Jeanne	2
	Rita	2
	Wilma	1
Hurricane Category 4	Charley	2
	Hugo	1
	Irma	1
	Matthew	1
	Michael	1
Hurricane Category 5	Floyd	1
Grand Total		**46**

Customers Served Range	# of Companies
0 – 500k	8
500k – 1 mil	2
1 mil – 1.5 mil	5
1.5 mil – 2 mil	2
2 mil – 2.5 mil	6
Over 2.5 mil	3
Grand Total	**26**

BENCHMARKING DEMOGRAPHICS

Company Information	
Total Number of Customers Served	1.8M
Total Number of North Coastal Customers Served	54,484
Total Overhead Distribution Line miles	18,000 miles
Total Underground Distribution Miles	14,000 miles

Storm Description	
Storm Name	Hurricane Michael
Storm Type	Hurricane
Storm Category	4
Start Date	October 10, 2018

Storm Drills	
Number of Storm Drills Per Year	1
Number of Table Top Exercises Per Year	2

Storm Damage Information	
Number of Customers Out at Peak	33,595
Number of Customers Out	71,876
Number of Distribution Poles Replaced	775
Number of Transformers Replaced	351
Number of Conductor Feet Replaced	244,340 feet

Restoration Resources	
Total Line FTEs	3,400
Total Veg. Management FTEs	1,700

Restoration Duration	
Restoration Duration (# Days)	8 days*

Vegetation Management	
Average Tree-Trimming Cycle	3yr backbone / 5yr branchlines

**Excludes 3 distribution circuits that required a total rebuild. These circuits were rebuilt to an extreme wind standard.*

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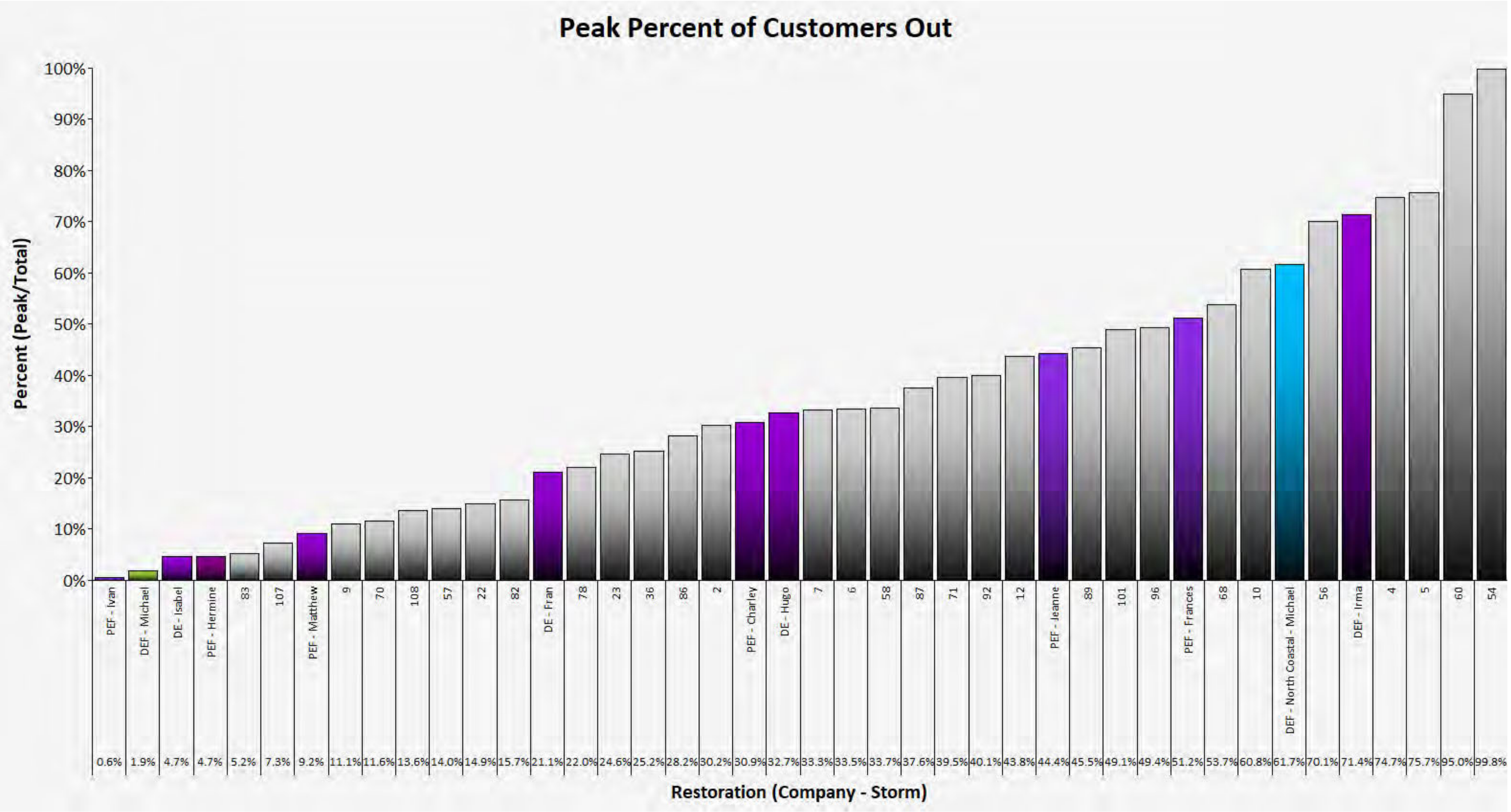
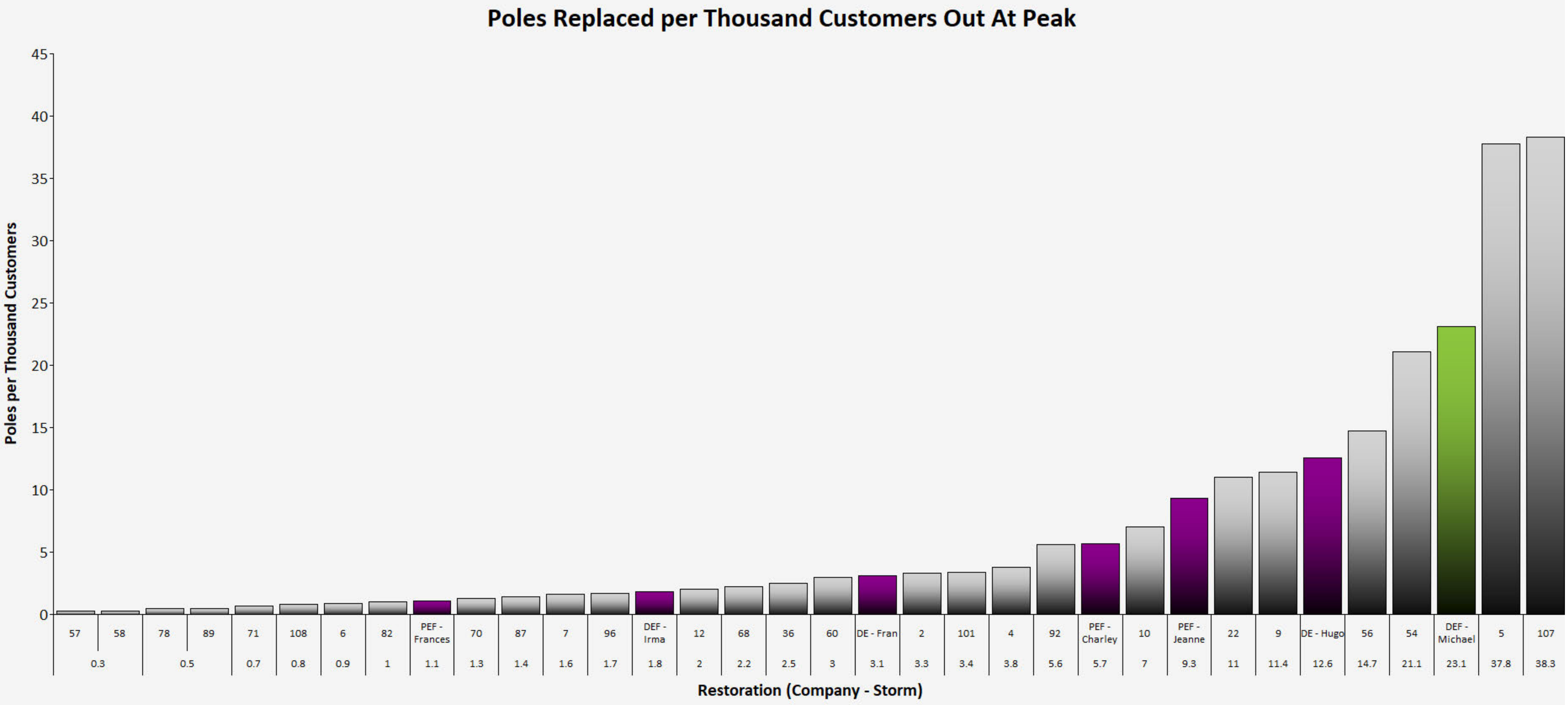
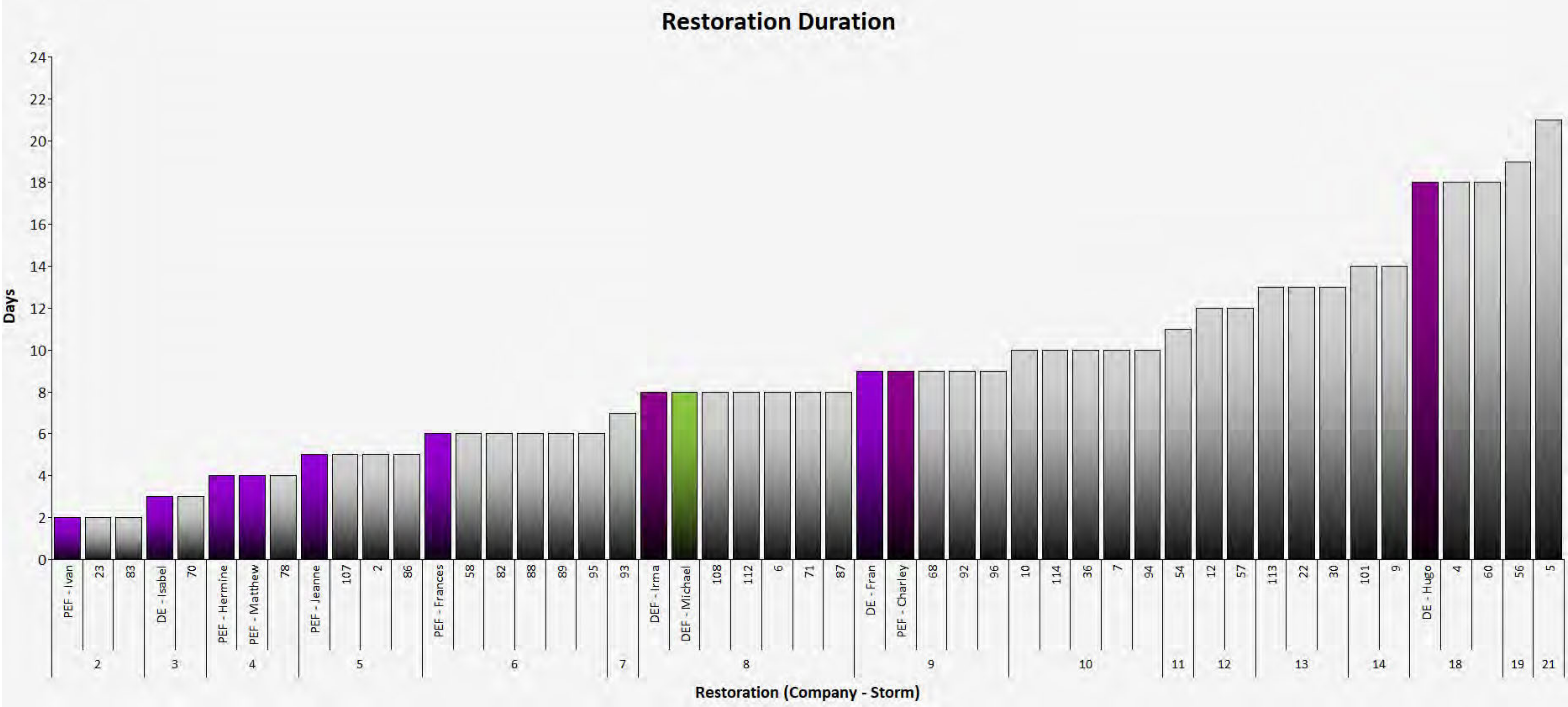
BENCHMARKING RESULTS



BENCHMARKING RESULTS



BENCHMARKING RESULTS



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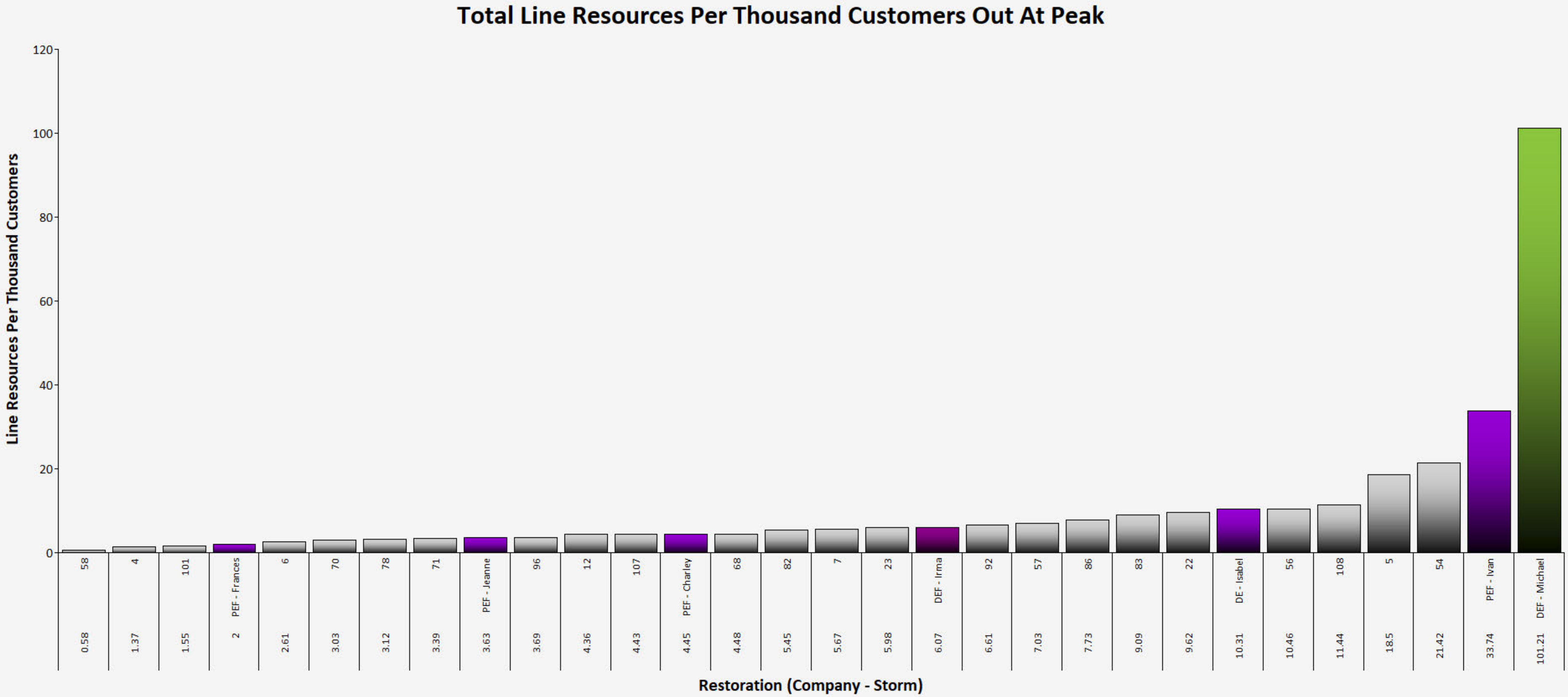
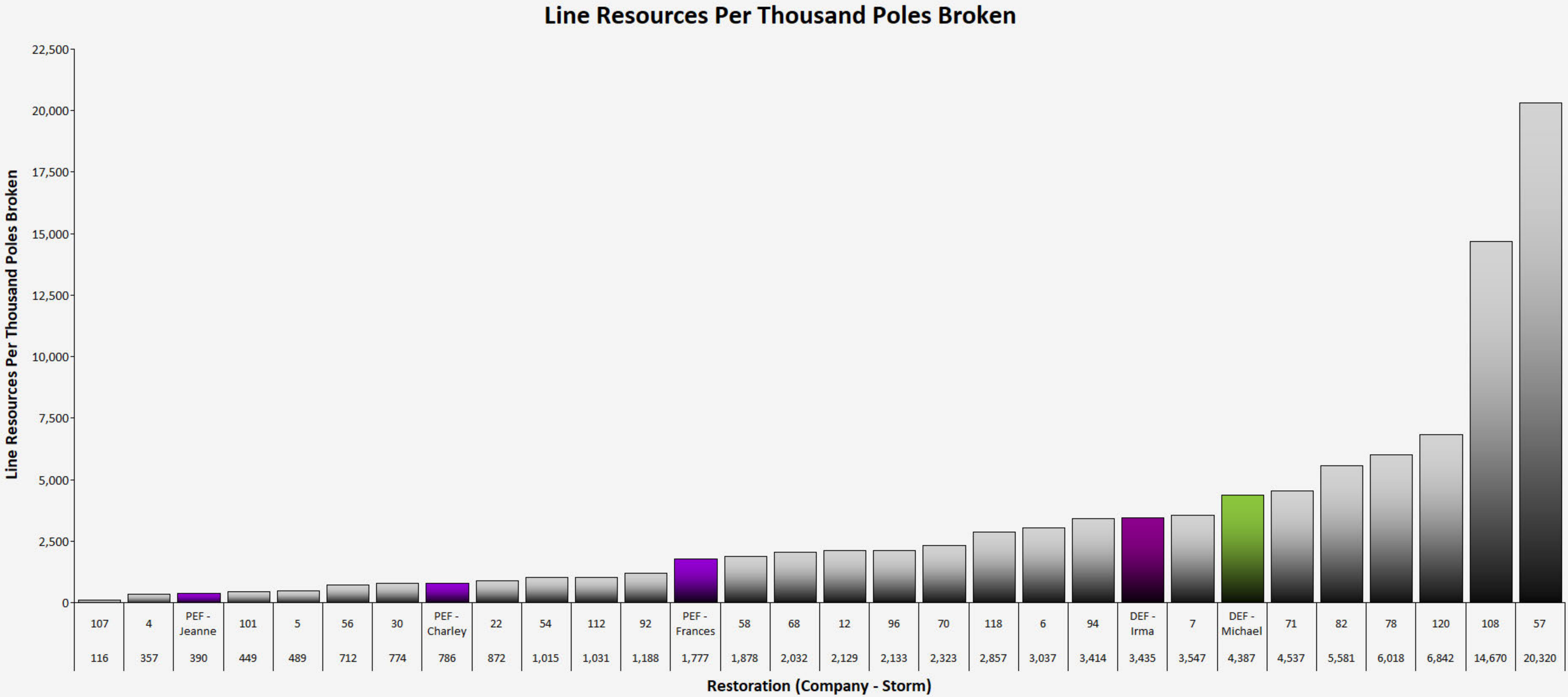
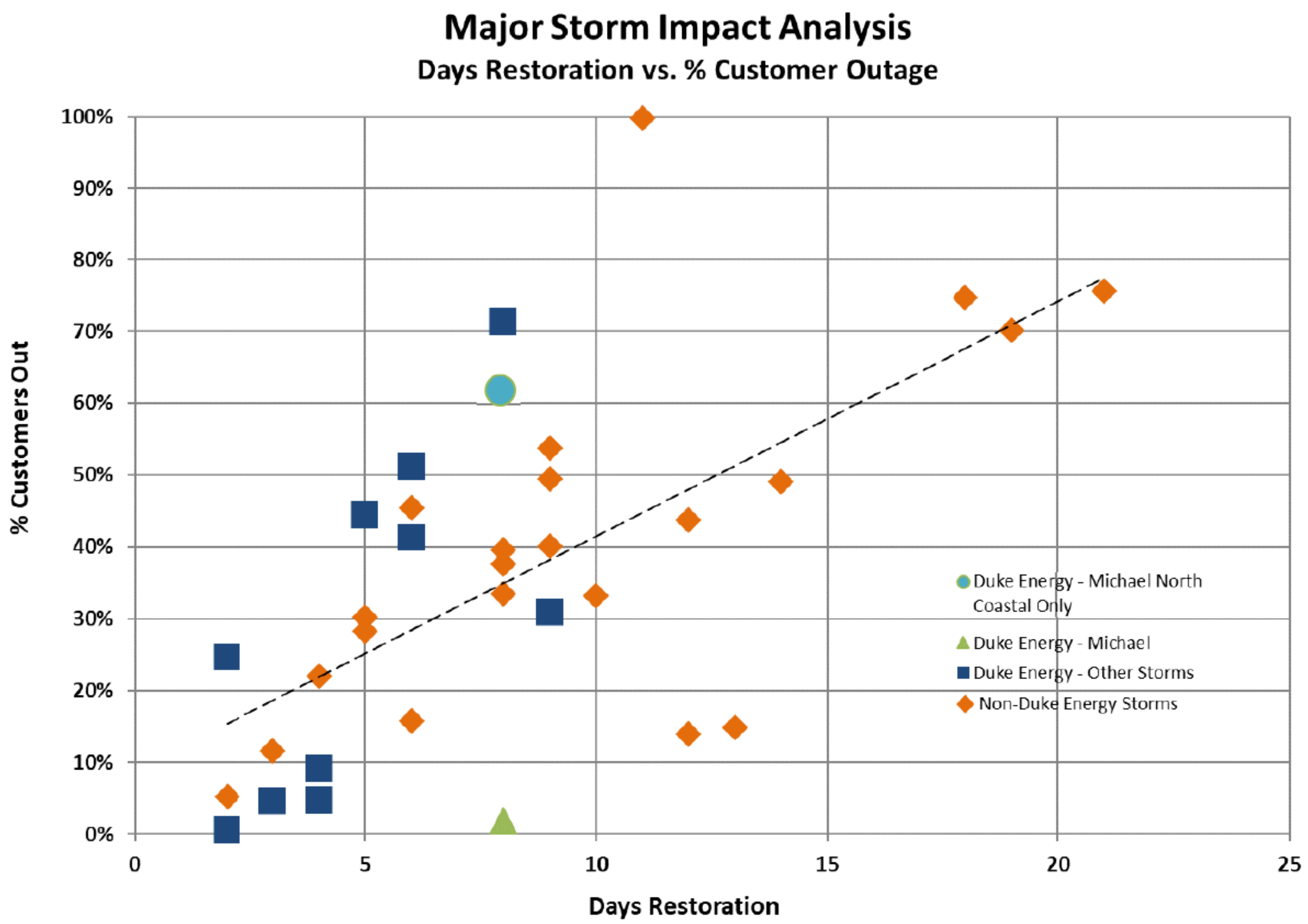
BENCHMARKING RESULTS



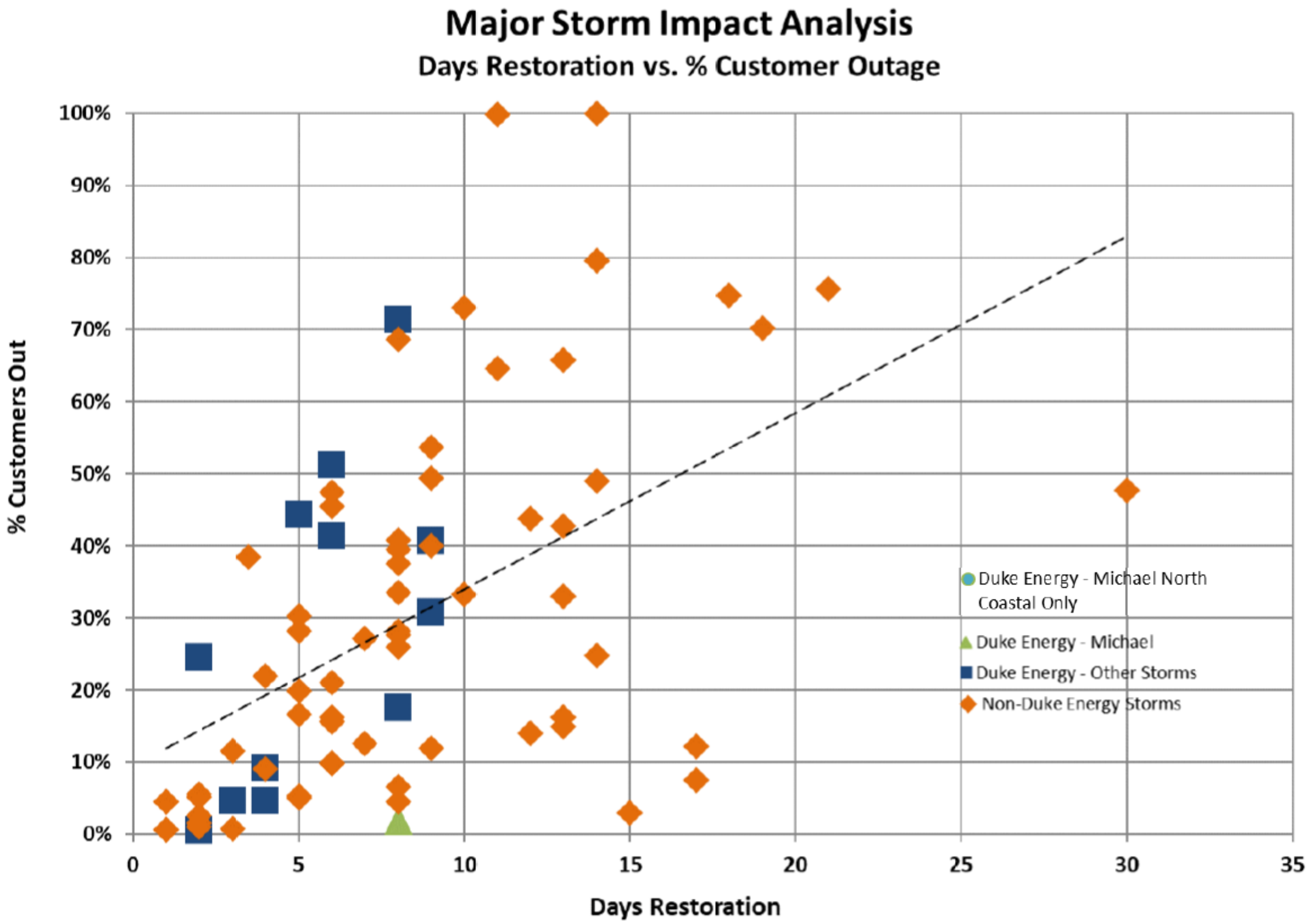
BENCHMARKING RESULTS



BENCHMARKING RESULTS – ALL HURRICANES



BENCHMARKING RESULTS – ALL RESTORATIONS



FINDINGS

BASED ON THE HIGH-LEVEL BENCHMARK ANALYSIS:

- The percentage of customers affected was relatively low when compared to similar events
  - DEF experienced total devastation to its distribution facilities in a concentrated area in the Florida panhandle. Although this area represents approximately three percent (3%) of DEF's customer base, the storm impacted sixty-one percent (61%) of DEF's North Coastal Zone.
  - Number of poles replaced per customers out at peak is relatively high when compared to similar restorations
- DEF took a longer time to restore power to all customers when compared with other storm events
  - Hurricane Michael was a unique storm for DEF in that the majority of the affected territory was not accessible for the first 2 days after the storm. This was due to access bridges requiring structural assessments before vehicles could cross and having to take alternate routes that were indirect and longer.
  - In comparison to other hurricanes in Accenture's database, DEF aggressively deployed a large contingent of resources for this storm.

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FORENSIC ANALYSIS

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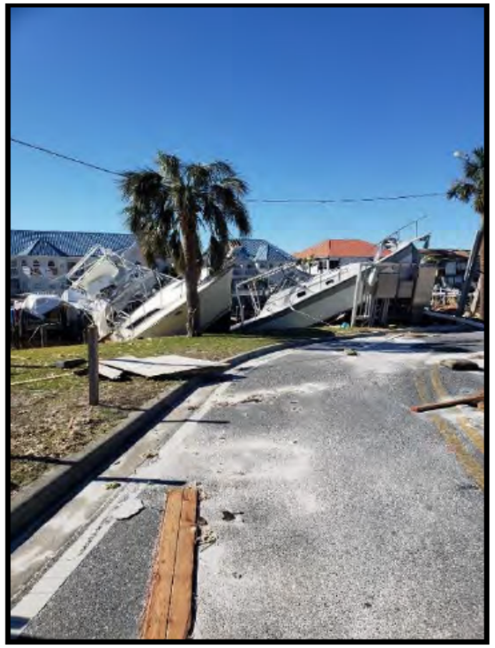
ANALYSIS OF SITUATION

In the aftermath of Hurricane Michael, DEF collected data on 219 broken poles. However, Michael hit several coastal areas where pole failure information could not be assessed or collected due to total devastation. Poles were destroyed and unable to identify, buried underneath other debris, or washed away. As such, this forensic analysis used the available broken pole attribute data. Poles without these data were visually assessed using geospatial analysis.

In response to Hurricane Michael, DEF employed a two pronged strategy:

- Normal restoration of damaged facilities impacted by Hurricane Michael
- Rebuild of 3 distribution circuits in the area of total devastation (Mexico Beach, Port St. Joe)



METHODOLOGY

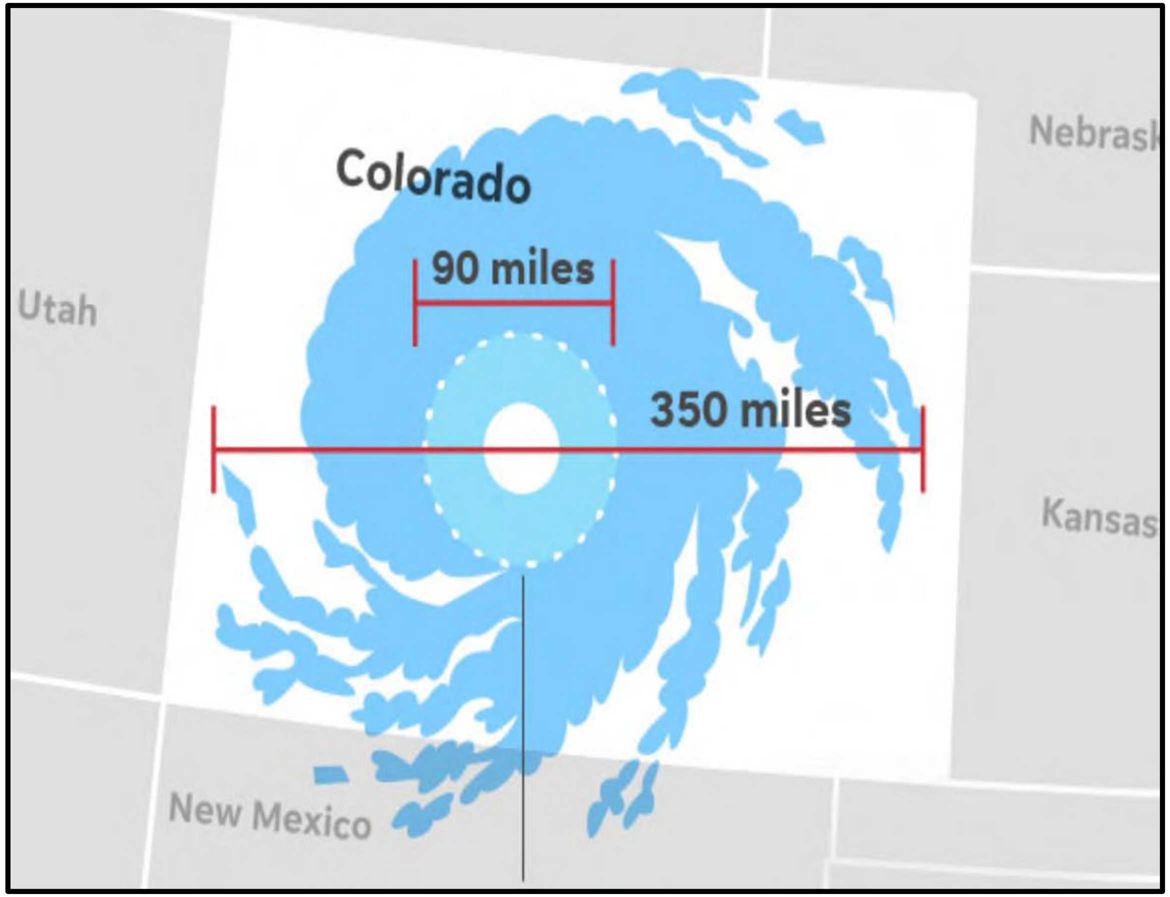
- Created data driven maps to analyze the broken pole population, hurricane path, wind speeds, and storm surge.
- Assessed broken pole properties such as cause of damage and pole height with descriptive statistics
- Identified feature importance using logistic regression

Incorporated Factors:

- hurricane force winds
- storm surge
- manufactured year
- pole height
- barrier land masses
- pole circumference
- treatment

DATA VISUALIZATION

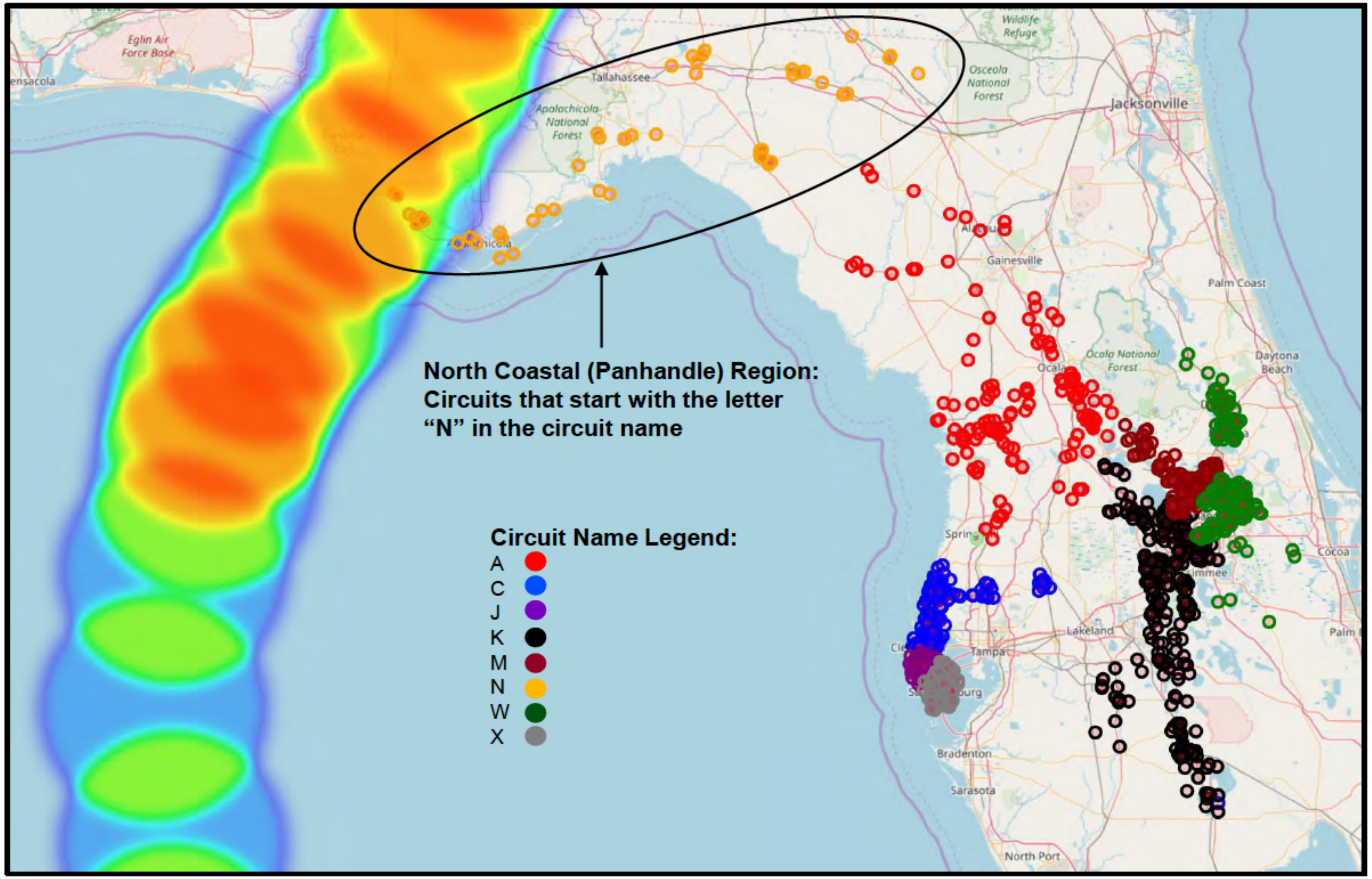
STORM BREADTH



- Hurricane Michael was about 350 miles across. The hurricane-force winds were near 90 miles in diameter and tropical-force winds affected about 96,211 square miles, which is near the size of the entire state of Colorado.

DATA DRIVEN VISUALIZATION

NORTH COASTAL REGION

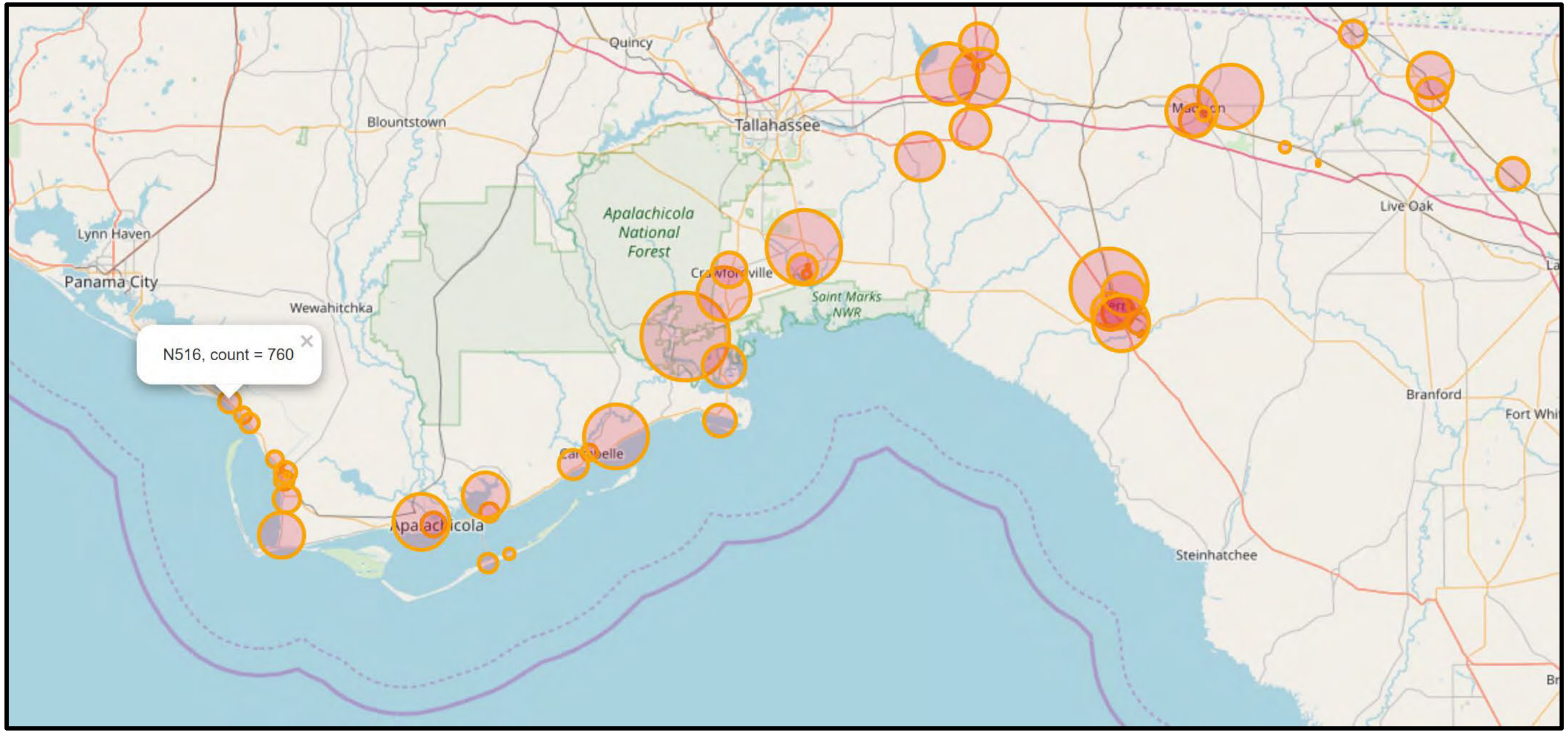


***Higher intensity winds shown as red

- Hurricane path only affected the panhandle of the North Coastal Zone (orange points). In addition, all broken poles were in the panhandle.
- Since the hurricane path only affected the North Coastal Zone, the forensic analysis focused on the pole population within the panhandle of the North Coastal Zone.

DATA DRIVEN VISUALIZATION

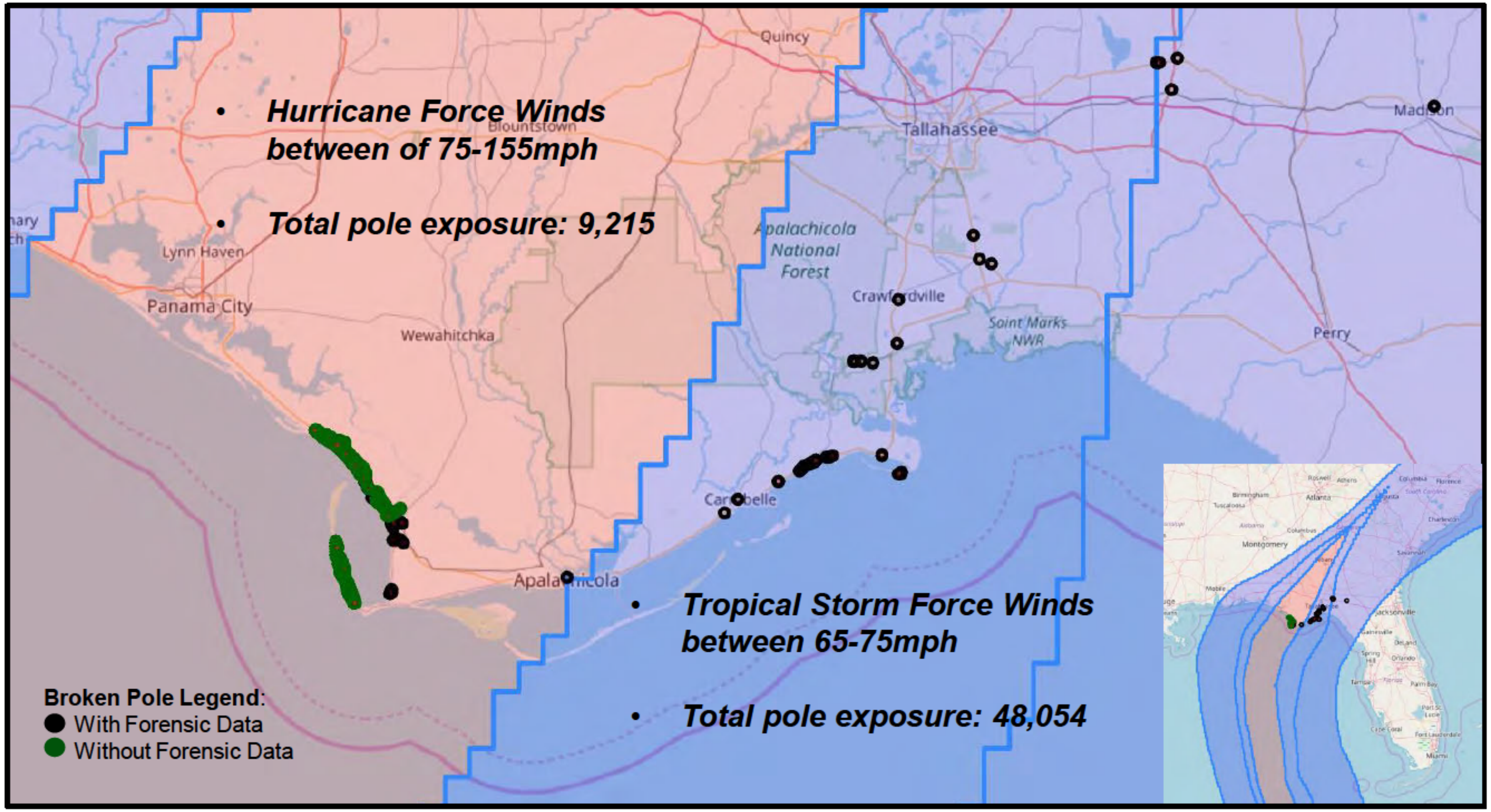
NORTH COASTAL REGION - RELATIVE CIRCUIT SIZE AND EXPOSURE



- The size of orange circles represent the general location and the number of poles on a circuit.
- Circle size is relative to all other circuits. (For example, circuit N516 is comprised of 760 poles and is smaller than circuits comprised of more poles and correspondingly bigger than circuits comprised of fewer poles.)
- This graphic shows pole population exposure and potential risk along coastal areas verses inland areas.

DATA DRIVEN VISUALIZATION

BROKEN POLES AND EXPOSURE



https://www.nhc.noaa.gov/refresh/graphics_at4+shtml/085125.shtml?swath#contents

- Over nine thousand (9,215) poles exposed to hurricane force winds (measured near 155mph at landfall)
- Over forty-eight thousand (48,054) poles were exposed to tropical storm force winds (wind speeds between 65 and 75 mph)

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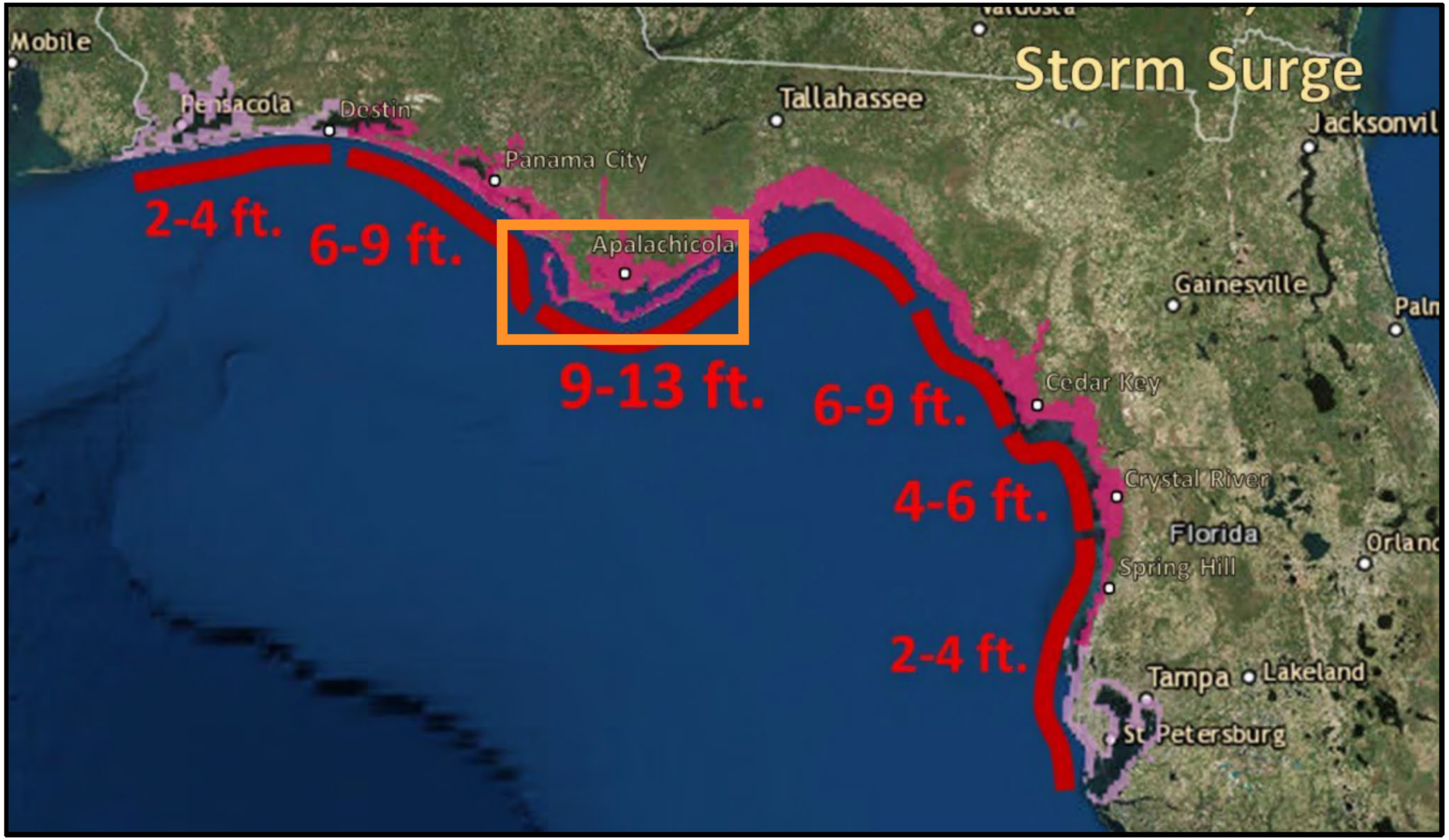
DATA DRIVEN VISUALIZATION

STORM SURGE EXPOSURE



https://twitter.com/NHC_Surge/status/1049770886943924224/photo/1?ref_src=twsrc%5Etfw%7Ctwcamp%5Etweetembed%7Ctwterm%5E1049770886943924224&ref_url=https%3A%2F%2Fwww.wired.com%2Fstory%2Fwhy-hurricane-michaels-storm-surge-is-so-high%2F

- Large areas of the North Coastal Zone were exposed to high storm surge.
- Surge forecasts just prior to Hurricane Michael's landfall identified Mexico Beach as an area of high inundation.
- Poles affected were forecasted to experience between 6 and 13 ft of surge. (Note that some surge sensors recorded approximately 15 ft. of actual surge.)
- The vast majority of DEF's distribution assets are situated along the coastline. As such, they experienced the brunt of the storm surge as well as hurricane force winds.

BROKEN POLE ANALYSIS

AVAILABLE DATA AND DATA ASSUMPTIONS

- Data from 219 poles were used in the descriptive statistic slides to follow, however the total broken pole population modeled was limited to 182 poles due to the following factors:

Final Broken Pole Count:	
Total broken pole population***	219
Unique pole ID unavailable for matching with GIS data source	(11)
Location data unavailable from GIS data source	(18)
Broken poles not: • Owned by Duke • Wood distribution poles	(8)
Final broken pole total	182
*** only includes poles with available forensic data	

USE_CODE
- Primary
- Secondary

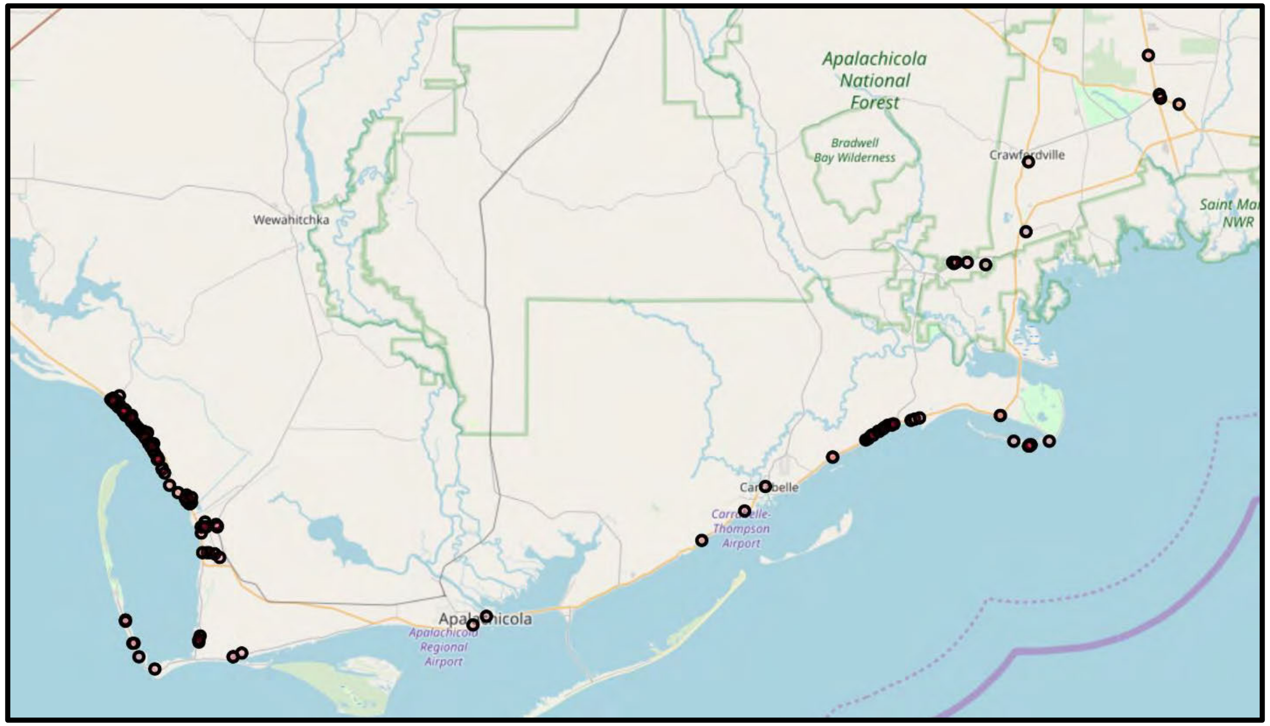
MATERIAL
- Wood

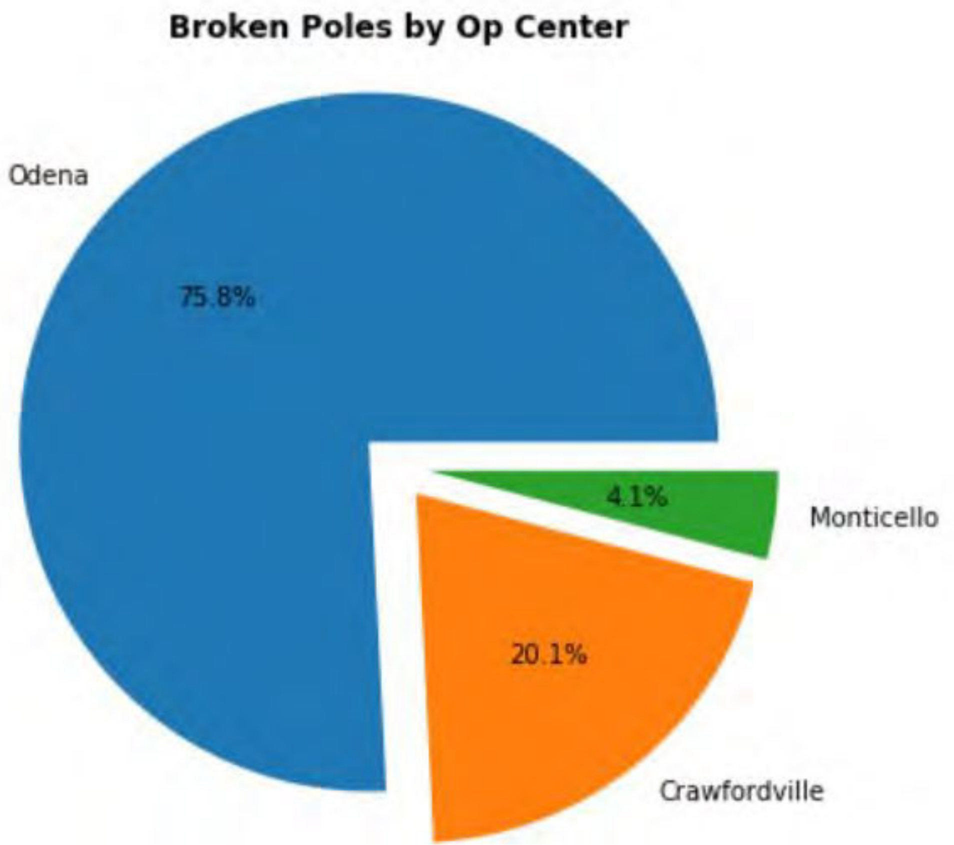
OWNERSHIP
- PEF

OWNERSHIP TYPE
- PGN

BROKEN POLE ANALYSIS

BREAKOUT – POLES WITH DATA

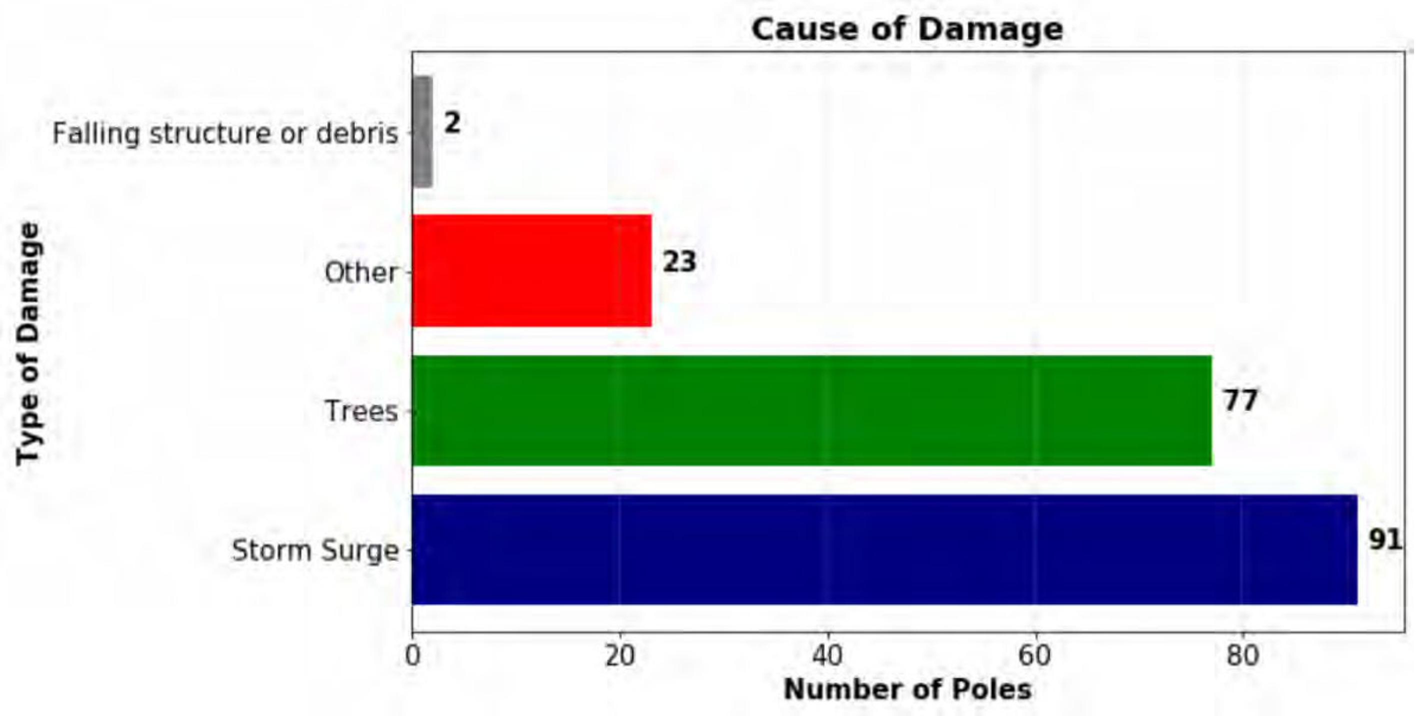


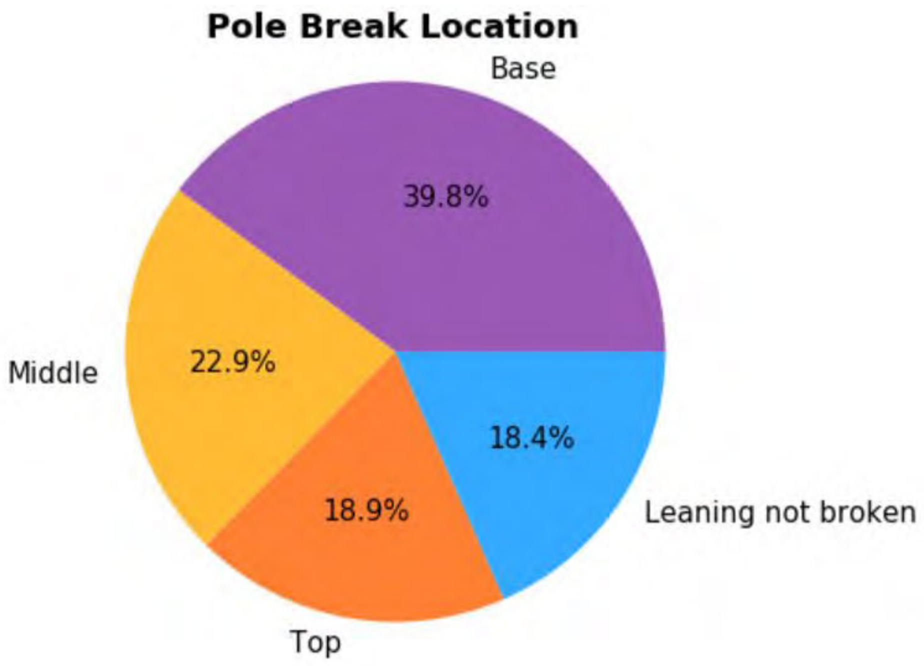


- Graphic depicts only broken poles that have forensic data. The majority of broken poles are in the Odena operating area (75.8%) followed by the Crawfordville operating area (20.1%) followed by the Monticello operating area (4.1%).

BROKEN POLE ANALYSIS

BREAKOUT – POLES WITH DATA





- The predominate cause of recorded damage was Storm Surge (91), followed by Trees (23).
- Twenty-three (23) poles were recorded as 'Other.'
- The majority of broken poles failed at the base of the pole.
- Nearly 20% of poles were not broken, but leaning.

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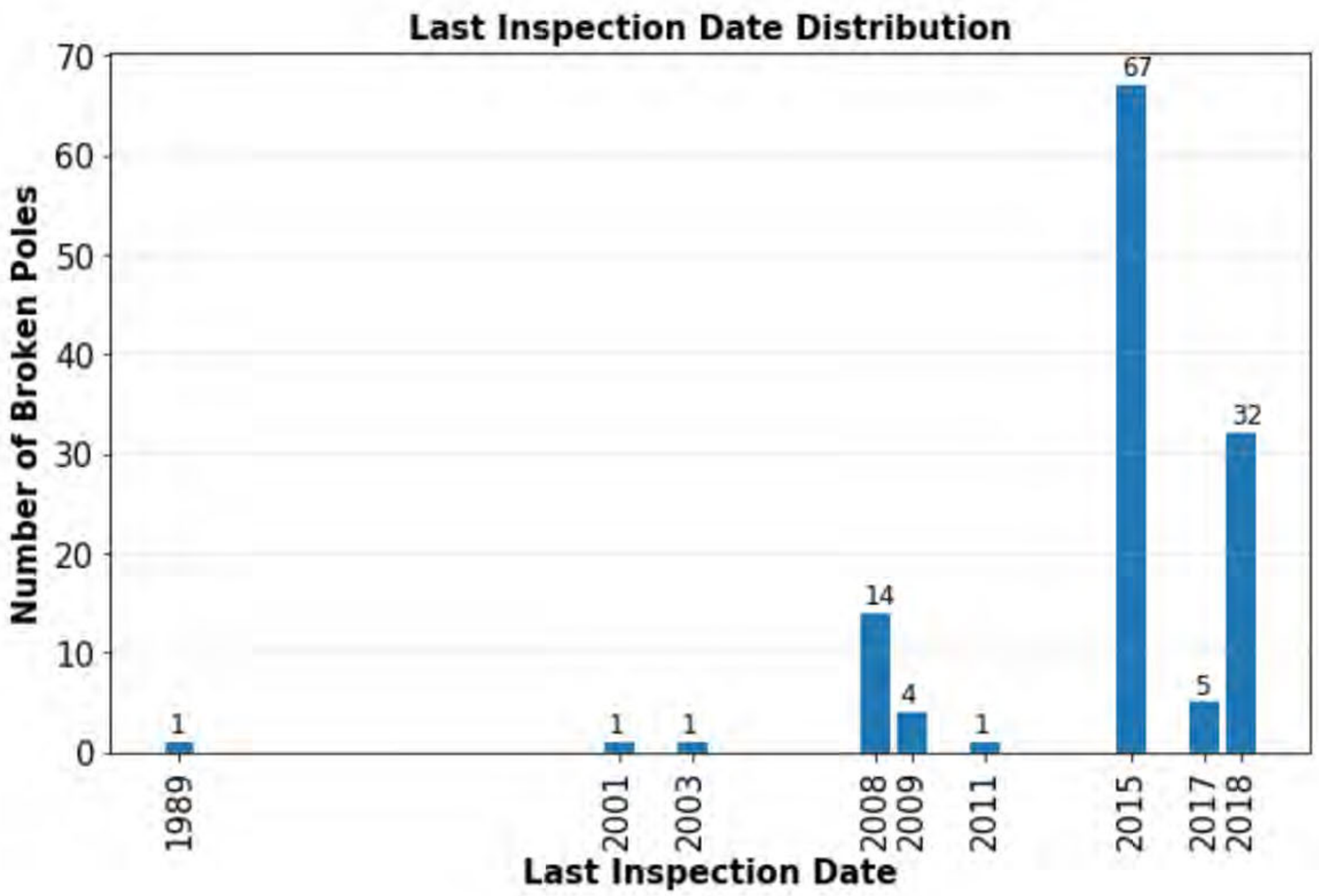
BROKEN POLE ANALYSIS

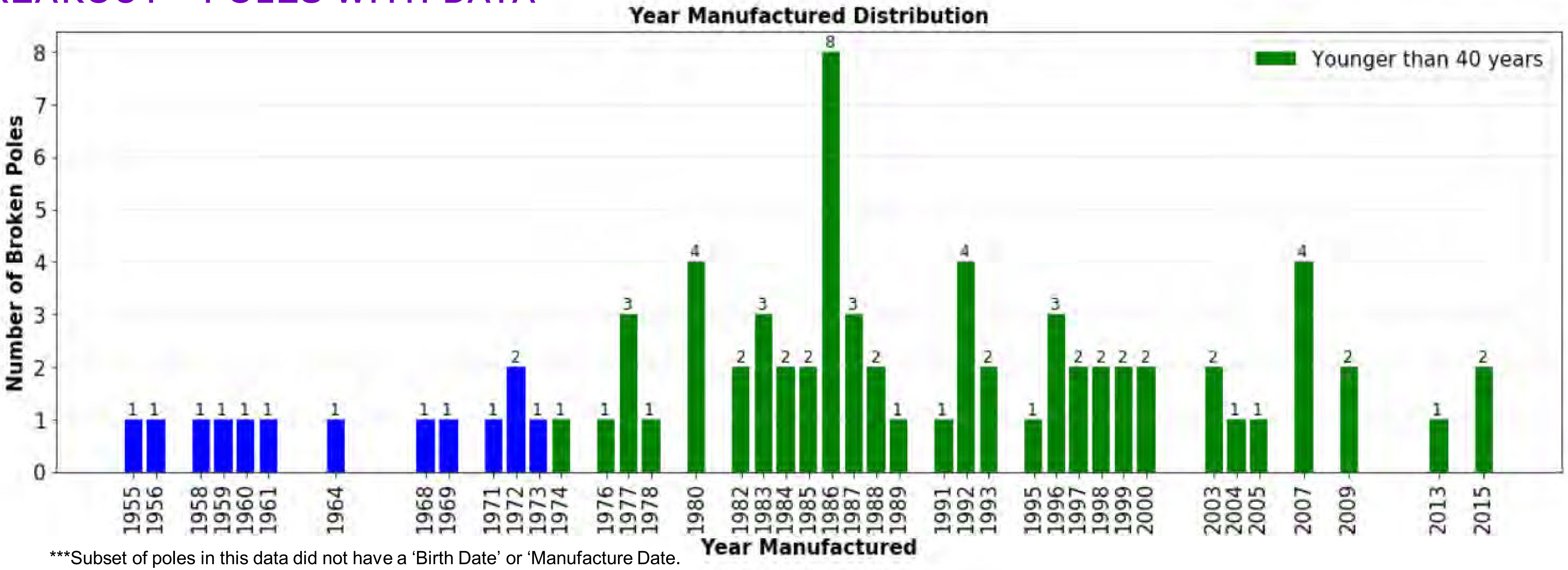
BREAKOUT – POLES WITH DATA



- The majority of the broken poles were last inspected in 2015, 2018 and 2008 respectively.

BROKEN POLE ANALYSIS

BREAKOUT – POLES WITH DATA

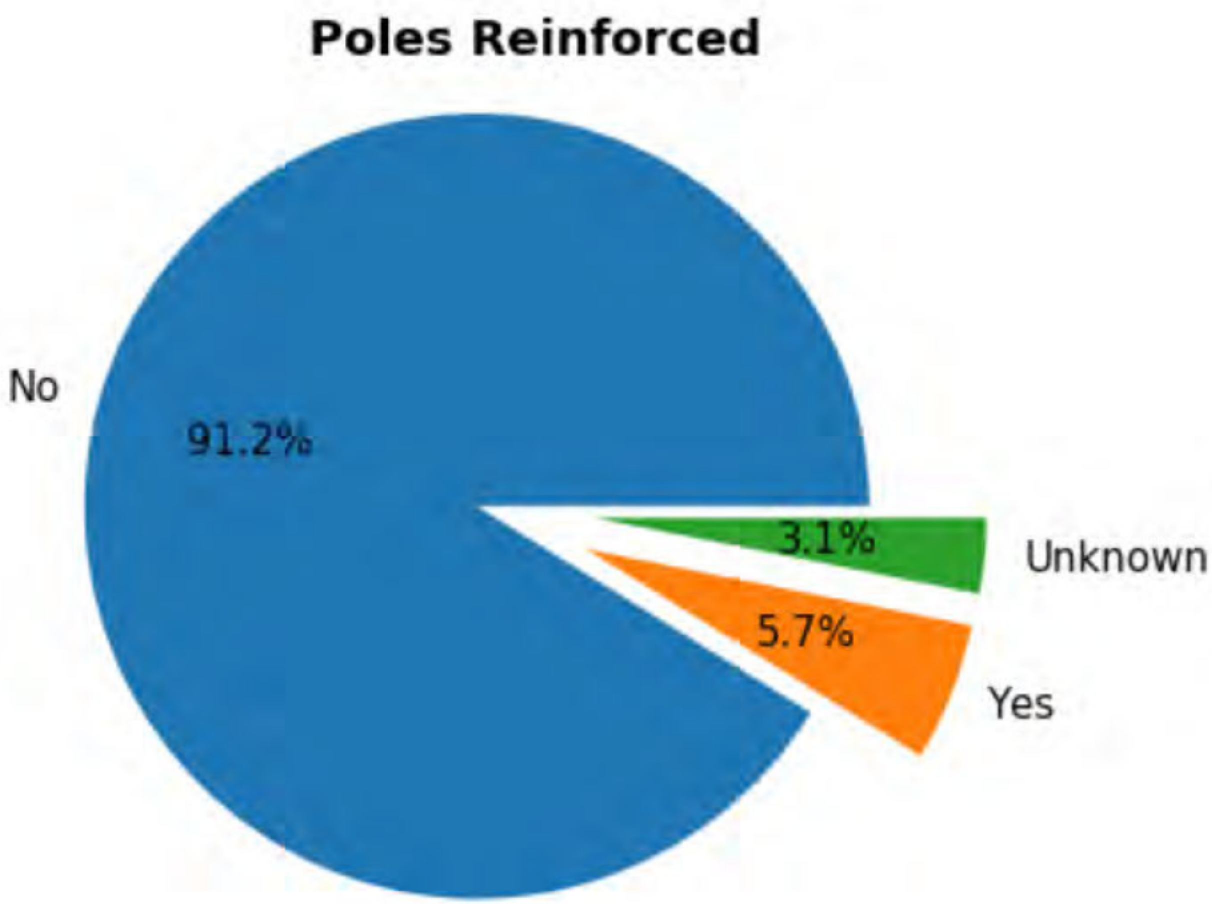


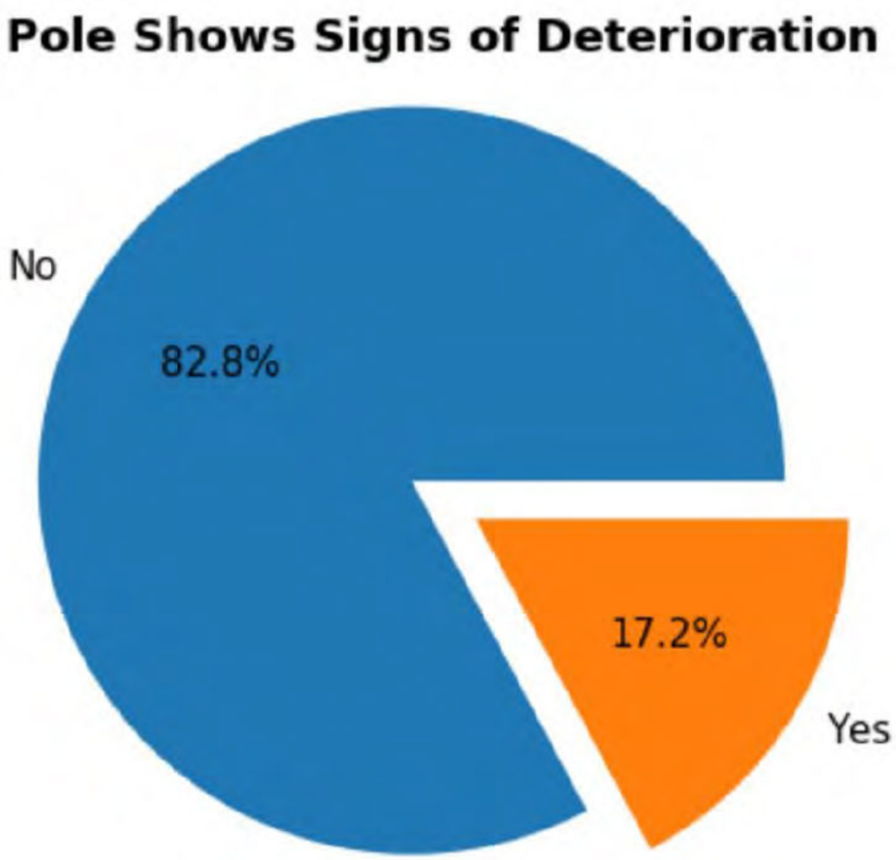
***Subset of poles in this data did not have a 'Birth Date' or 'Manufacture Date.

- From an accounting perspective, the life expectancy of a wood pole is forty-two (42) years. Actual DEF operating experience and Accenture benchmarking data confirms that the expected life of a wood pole is fifty (50) years or more. Additionally, industry research has produced studies that suggest the life expectancy of wood poles can be in the range of ninety (90) years.
- The majority of broken poles were less than 40 years old. The broken poles that were older than forty years did not dominate this distribution.

BROKEN POLE ANALYSIS

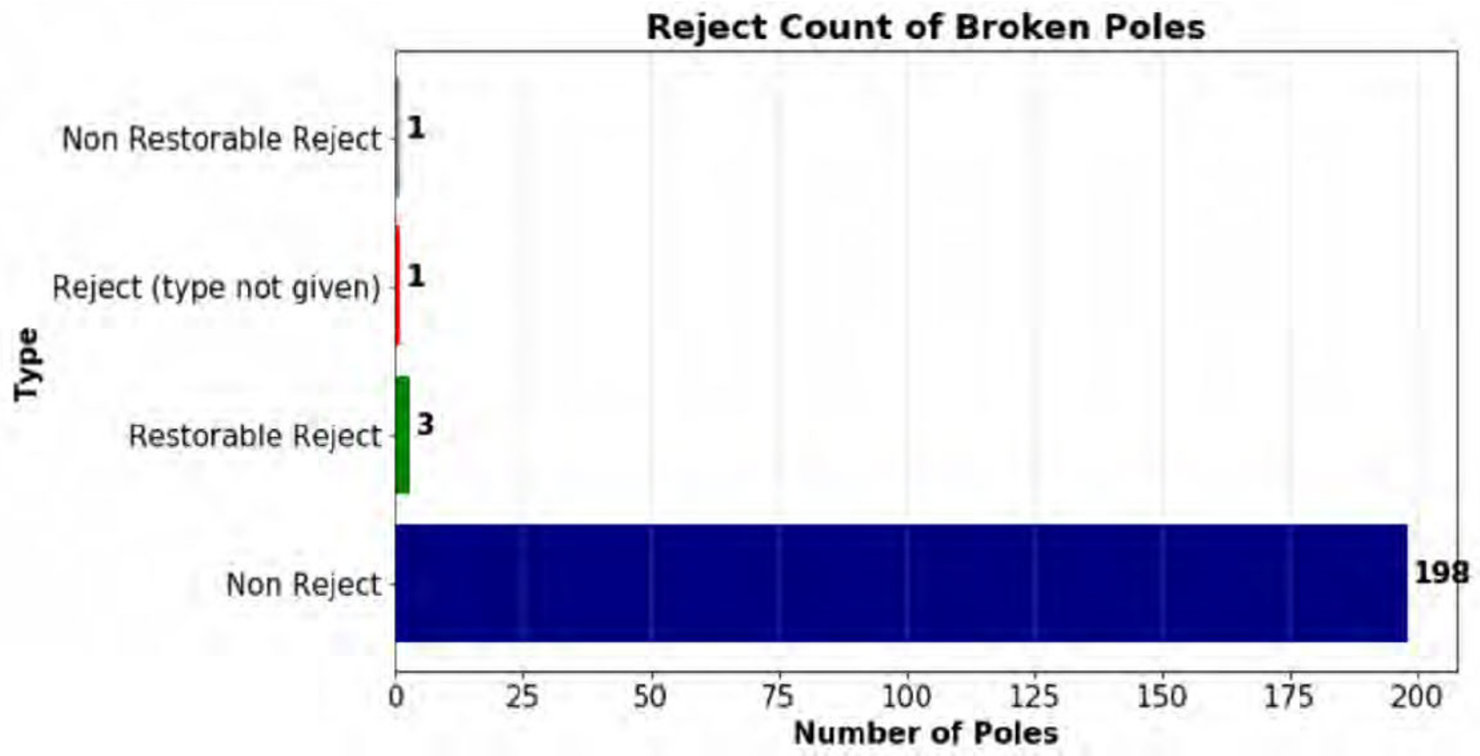
BREAKOUT – POLES WITH DATA

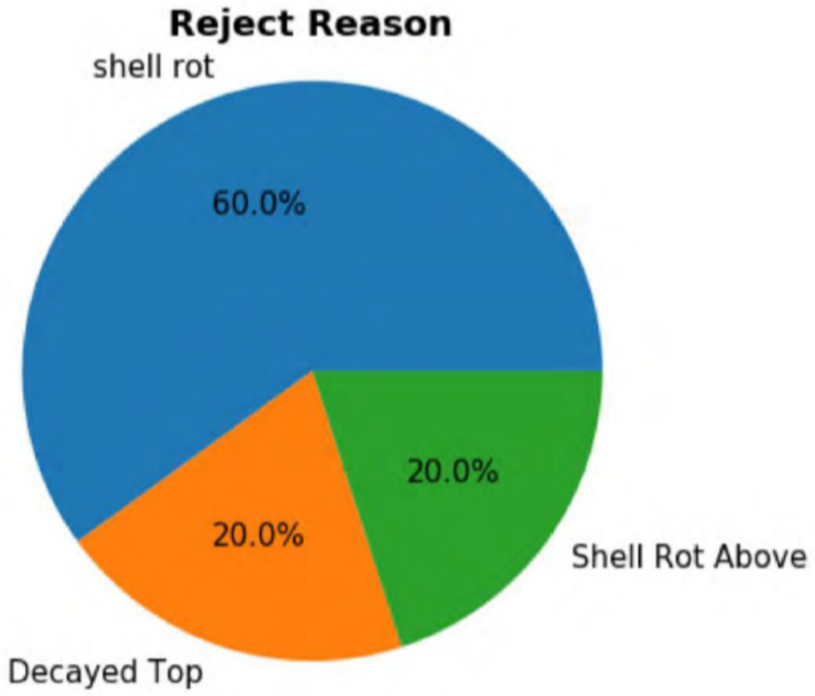




BROKEN POLE ANALYSIS

BREAKOUT – POLES WITH DATA

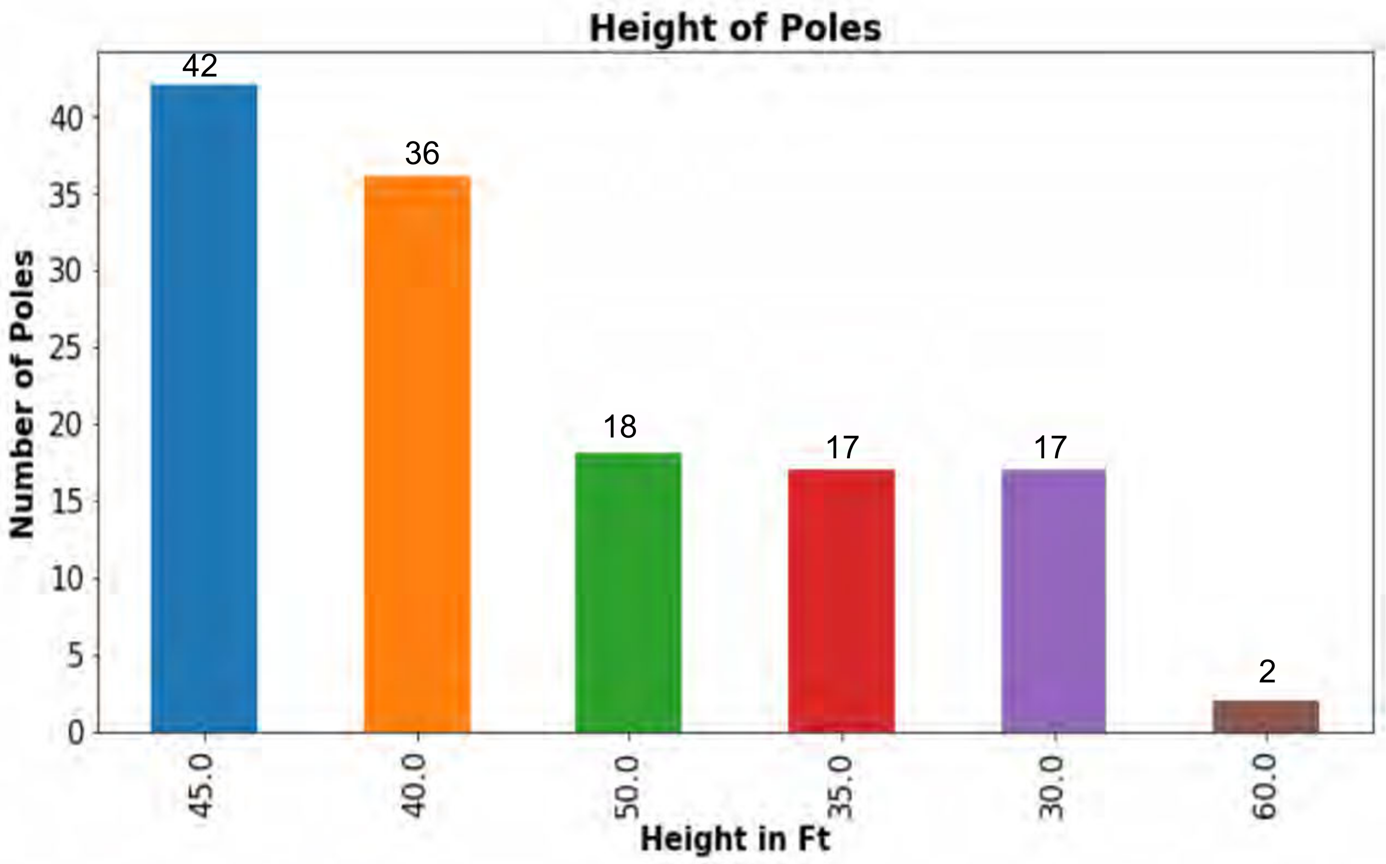


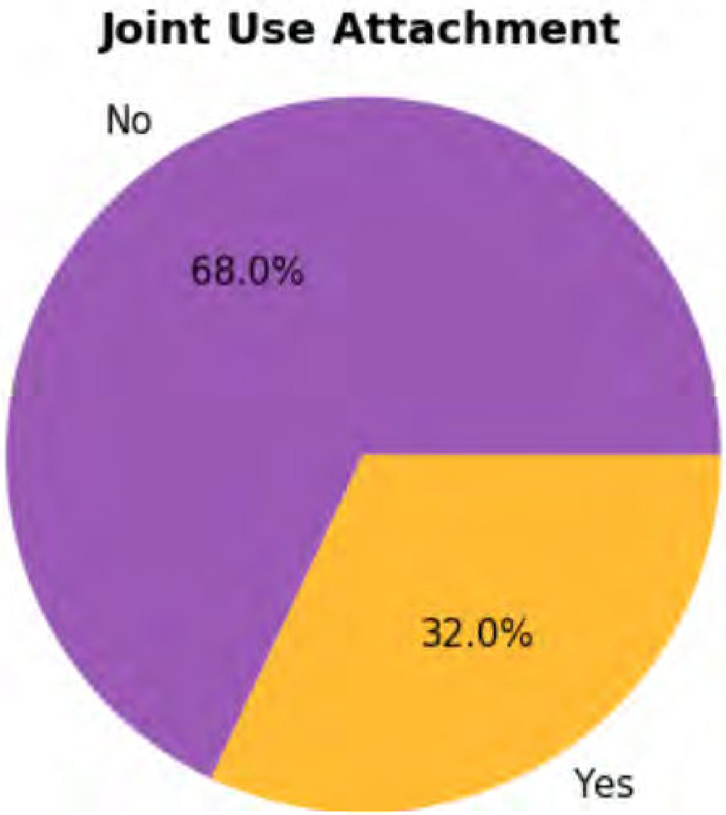


- After reviewing pole inspection data for the 203 broken poles, only 1 pole was not replaced prior to Hurricane Michael. This pole was scheduled to be replaced in January 2019.

BROKEN POLE ANALYSIS

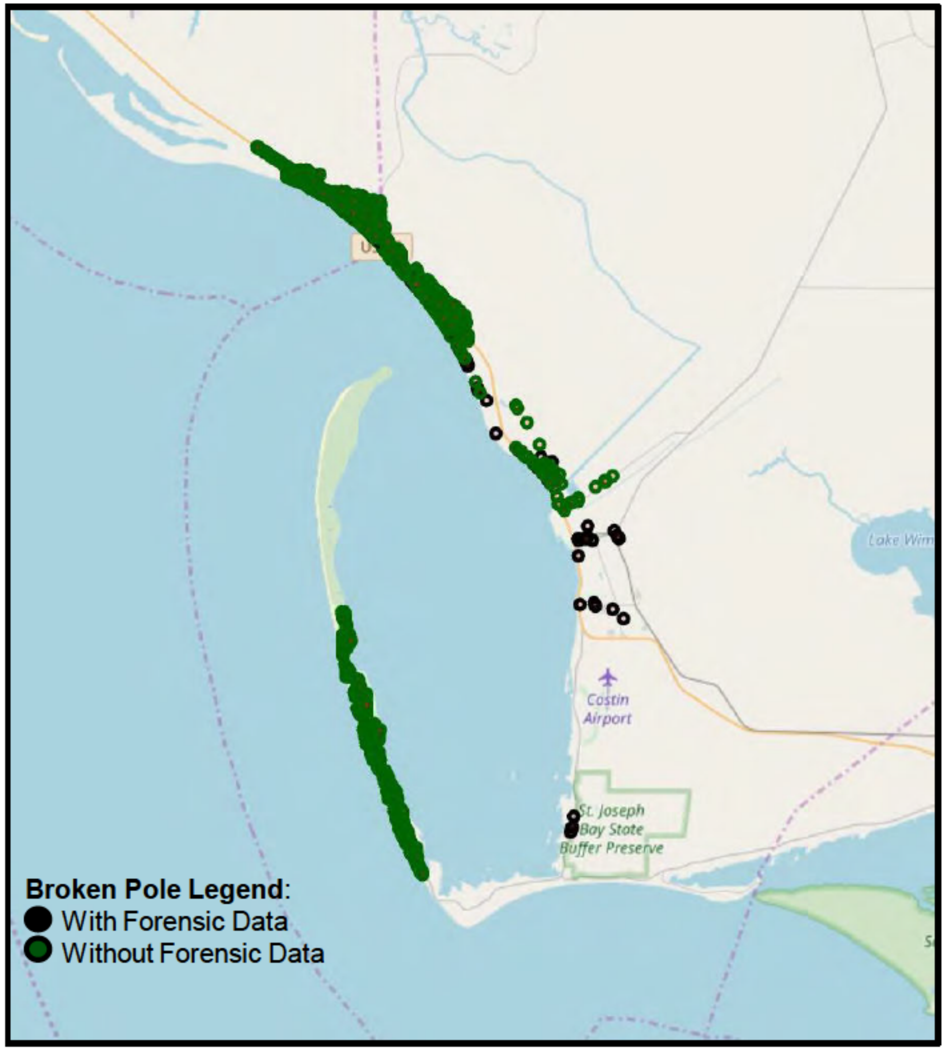
BREAKOUT – POLES WITH DATA





BROKEN POLE ANALYSIS

POLES IN DEVASTATED COASTAL AREA – POLES WITH NO FORENSIC DATA



In addition to broken poles analyzed using forensic data, Accenture also assessed broken poles along the coastline that were totally devastated and were unable to be forensically assessed. These poles are shown in green on the map.

Areas of total devastation include:

- Mexico Beach
- Port St. Joe
- Cape Sand Blas

Circuits within these areas include:

- N516 (760 poles)
- N520 (1 pole)
- N515 (602 poles)
- N527 (680 poles)
- N202 (626 poles)
  - DEF estimated that approximately 10% (63) of these poles on this circuit were broken

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BROKEN POLE ANALYSIS

BREAKOUT – POLES WITH AND WITHOUT DATA

Circuit	Assessed broken poles with forensic data	Assessed broken poles without forensic data ***	Total Assessed Broken Poles	Remaining Poles	Total Poles	Op Center
N327	6	0	6	3,274	3,280	CRAWFORDVILLE
N1	1	0	1	2,414	2,415	MADISON
N48	1	0	1	1,054	1,055	CARRABELLE
N69	1	0	1	2,180	2181	MONTICELLO
N67	6	0	6	2,336	2,342	MONTICELLO
N332	3	0	3	2,807	2,810	CRAWFORDVILLE
N42	1	0	1	608	609	CARRABELLE
N43	17	0	17	2,383	2,400	CARRABELLE
N35	1	0	1	2,032	2,033	CRAWFORDVILLE
N38	12	0	12	1,156	1,168	CARRABELLE
N58	1	0	1	904	905	ODENA
N202	25	38	63	563	626	ODENA
N54	12	0	12	820	832	ODENA
N53	7	0	7	1,029	1,036	ODENA
N516	1	759	760	0	760	ODENA
N515	39	563	602	0	602	ODENA
N527	42	638	680	0	680	ODENA
N556	6	0	6	1,681	1,687	ODENA
N520	0	1	1	0	1	ODENA
	182	1,999	2,181	25,241	27,422	

Circuits completely rebuilt.

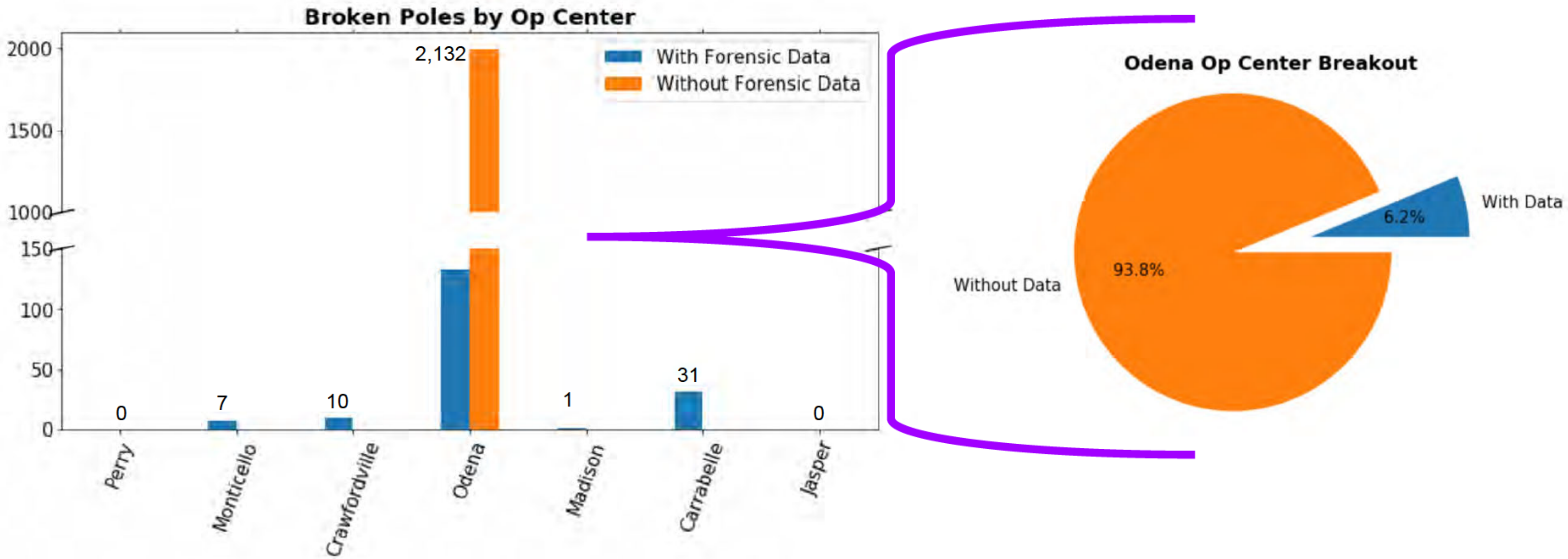
Area of total devastation. Assumed all poles broken.

Area of partial devastation. Assume 10% of poles broken.

***Include poles with incomplete data as well as broken poles in areas of total devastation

BROKEN POLE ANALYSIS

BREAKOUT – POLES WITH AND WITHOUT DATA



- 6.2% of Odena poles have forensic data when combined with poles in devastated coastal circuits.

MODELING

DEVELOPMENT OF LOGISTIC REGRESSION

- Type of classification model that allows to predict a categorical variable from single or multiple input variables
- Predict categorical variables as well as assess other variable importance
  - Produce coefficients and p-values that will be used to ‘rank’ the respective features (inputs)
- Dependent variable
  - Coded as broken(1) / not broken(0)
- Independent variable (inputs)
  - Weather (wind speed)
  - Land barrier protection
  - Storm Surge
  - Manufactured year
  - Pole height
  - Pole circumference
  - Pole treatment

MODELING

INTERPRETING LOGISTIC REGRESSION

There are multiple measures we can look at to understand the results of logistic regression. In this analysis we use:

- **Correlation Coefficient Estimate**
- **P Values** of the estimates
- **Psuedo (Mcfadden) R^2 Value**

Correlation Coefficient Estimate – This describes the size and direction of the relationship between a predictor and the response variable. Here we have standardized our independent input variables by subtracting the mean and dividing by standard deviation. This allows us to compare the size of the coefficients with each other.

P Values– These are probabilities that measure the evidence against the null hypothesis. In our problem, the null hypothesis says there is no relationship between our independent variable (i.e. year manufactured, height, etc.) and our binary dependent variable (broken/not broken.) If we reject the null hypothesis then we accept the alternative hypothesis that there is a relationship greater than chance that the independent and dependent variable are related. A p-value below the 0.05 threshold indicates, low chance of incorrectly rejecting the null, thus we have a statistically significant correlation coefficient estimate.

Psuedo (Mcfadden) R^2 Value – This describes the goodness of fit of the entire model. Similar to R squared typically used in linear regression, this can also be interpreted as more variability in the model is explained the closer R squared is to 1.

The ultimate goal of the above measures in this forensic analysis is to provide insight on the importance of the various factors on pole failure or breakage.

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MODELING

CONSIDERING POLES WITH FORENSIC

Factors	Coefficients	P-Value	Statistically Significant
Pole Circumference	0.0112	0.917	No
Pole Height**	0.3081	0.001	Yes
Year Manufactured***	-0.1948	0.007	Yes
Treatment	-7.1076	0.818	No
Electrical Attachment	0.0685	0.751	No
Storm Surge	2.0946	0.000	Yes
Barrier Island	-0.2841	0.163	No
Hurricane Force Winds	1.3118	0.000	Yes

****Note on Pole Height:**
Accepting pole height as statistically significant may be misleading. The range of heights in this sample is 30-45 ft. 70% of broken poles are at the top end of that range. This artificially gives more weight to taller poles and is due to the small sample size.

*****Note on Year Manufactured:**
Some poles were missing this date and average year manufactured was used as proxy for actual year. Statistical significance of this variable may not be accurate.

Results:

- We have 4 variables that connect in a statistically significant way to the dependent variable of pole breakage. Here, factors where p-values < .05 are Height, Year Manufactured, Storm Surge and Hurricane Force Winds.
  - The size of Hurricane Force Winds and Storm Surge are much higher than Height and Year Manufactured indicating higher likelihood of pole breakage due to surge and winds.
- Pseudo-R^2 for this model is .1501. This may indicate other factors could be involved or more data is needed to increase this models goodness of fit.

MODELING

CONSIDERING ALL POLES

Factors	Coefficients	P-Value	Statistically Significant
Pole Circumference	-0.0820	0.061	No
Pole Height	-0.0128	0.748	No
Year Manufactured	0.0432	0.070	No
Treatment	-15.6123	0.995	No
Electrical Attachment	-0.0280	0.708	No
Storm Surge	2.5870	0.000	Yes
Barrier Island	0.0531	0.346	No
Hurricane Force Winds	4.2273	0.000	Yes

Results:

- We have 2 variables that connect in a statistically significant way to the dependent variable of pole breakage. Here, factors where p-values < .05 Storm Surge and Hurricane Force Winds.
  - The size of Hurricane Force Winds and Storm Surge are the only statistically significant factors in this model, indicating likelihood of pole breakage due to surge and winds.
- Pseudo-R^2 for this model is .4396. This is higher that previous model suggesting higher importance of surge and wind when including poles in devastated coastal areas in addition to pole with forensic data.

MODELING

SUMMARY

Considering broken poles with forensic data

Of the four significant factors in this model, we can place greater importance on Storm Surge and exposure to Hurricane Force Winds as compared to the other statistically significant factors. Coefficients for height and year manufactured were below one, whereas surge and wind were above one, indicating greater contribution to pole failure.

The Pseudo R^2 of 15.01% indicates the involvement of other factors or more data is needed to increase this models goodness of fit.

***The difficulty of gathering forensic data on broken poles has created an extremely small population to model. Due to this lack of data, we should not place emphasis on pole factors that this model is showing as significant.

Considering all broken poles

When we added in poles from the devastated coastal circuits to the poles with forensic data, only Hurricane Force Winds and Storm Surge showed as statistically significant factors.

This appears consistent with intuition. Poles in devastated coastal circuits were most impacted by storm surge. In addition, the greatest wind speed was recorded just upon landfall.

The Pseudo R^2 of 43.96% indicates the fit of this model is better than the first and we can be more confident in relying on the coefficients when compared.

*** Including poles without forensic data increases the size of the dependent variable. This enables the regression to better assess the importance of model input variables.

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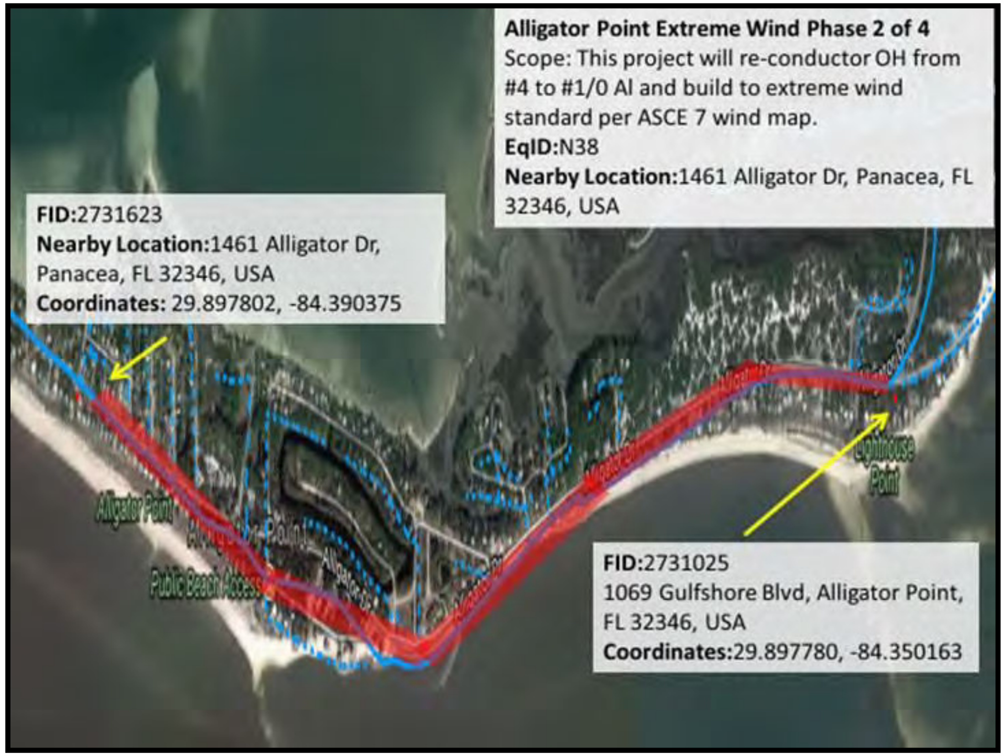
STORM HARDENING

accenture consulting

METHODOLOGY/APPROACH

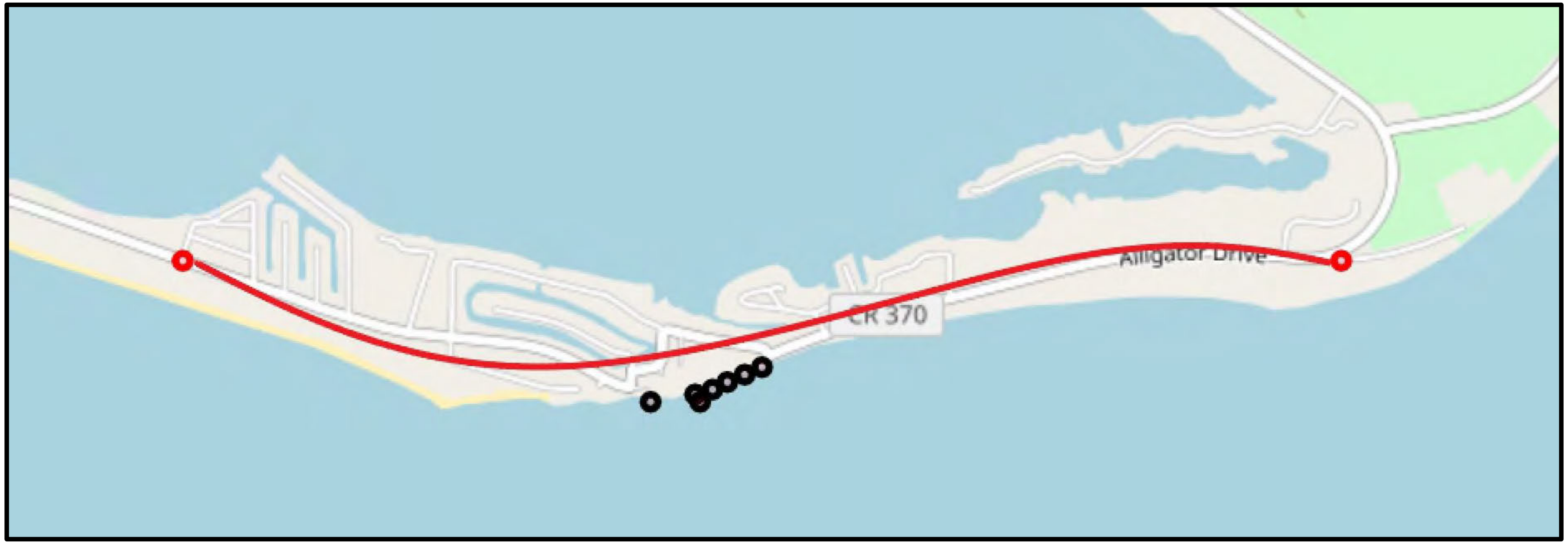
- DEF performed storm hardening on a number of distribution line sections since 2006
  - Selected storm hardening targets that were previously completed from an established repository
  - Traveled to the geotagged location identified for the project
  - Patrolled the entire scope of the project
  - Record any damages to the facilities

- Determined if any poles that failed during Hurricane Michael were a part of the storm hardened circuits by:
  - Mapped broken poles that were reviewed by the forensics team
  - Overlaid storm hardened projects
  - Identified if any broken poles were a part of the storm hardened projects



STORM HARDENED POLES

BROKEN POLE WITHIN STORM HARDENED AREA



- There appeared to be 7 poles within the range of Storm Hardening program labeled Alligator Point Extreme Wind - Phase 2 of 4.
- Of these 7 poles, only 1 broken pole was lying flat on the ground. This pole was class 5 which is smaller than the leaning poles, which were class 2.
- Although this area was impacted by Tropical Storm force winds and not Hurricane force winds, it experienced high storm surge.

STORM HARDENED POLES

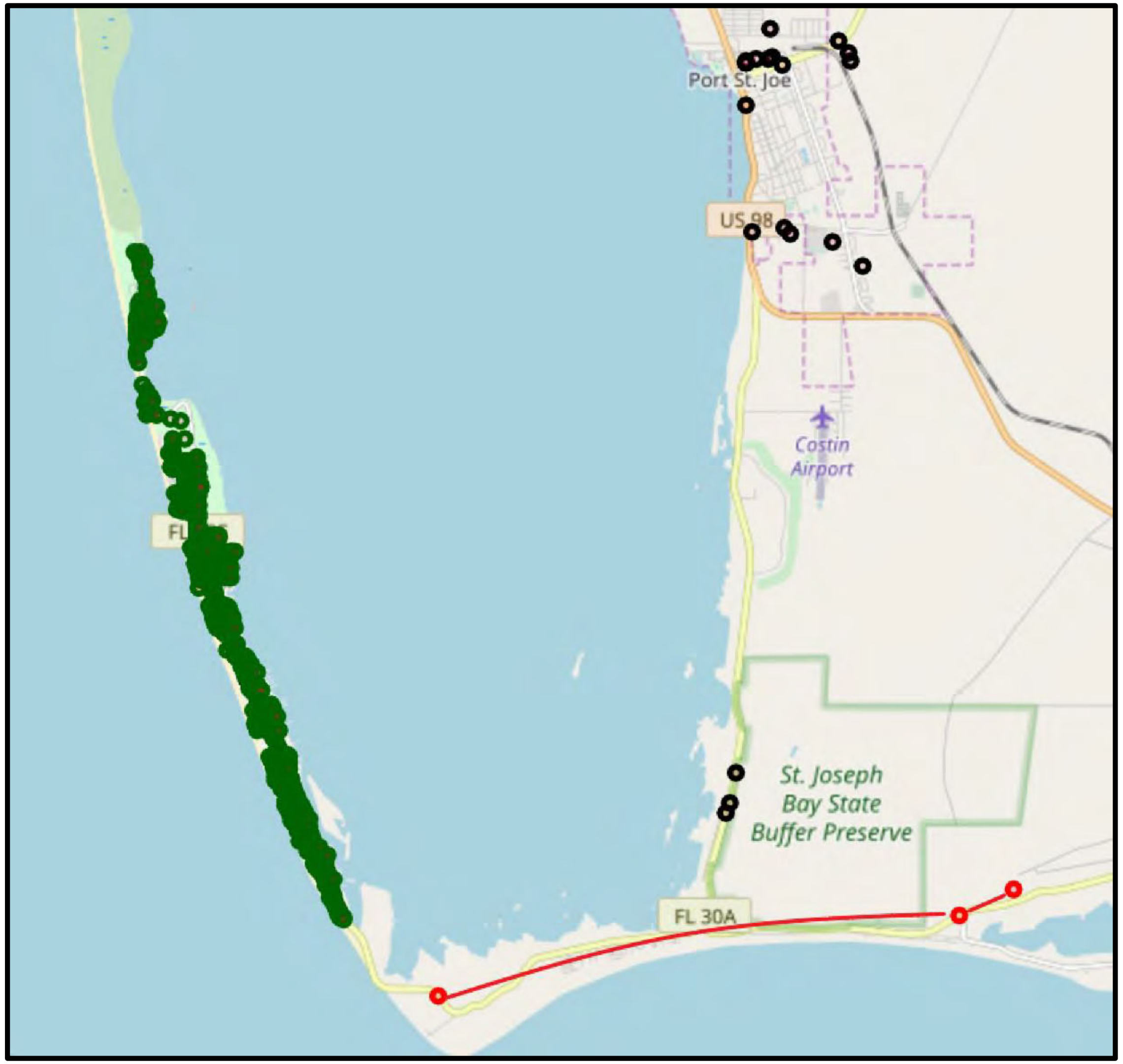
LEANING POLES WITHIN STORM HARDENED AREA

STORM HARDENED POLES

BROKEN POLE WITHIN STORM HARDENED AREA

STORM HARDENED POLES

NO BREAKAGE

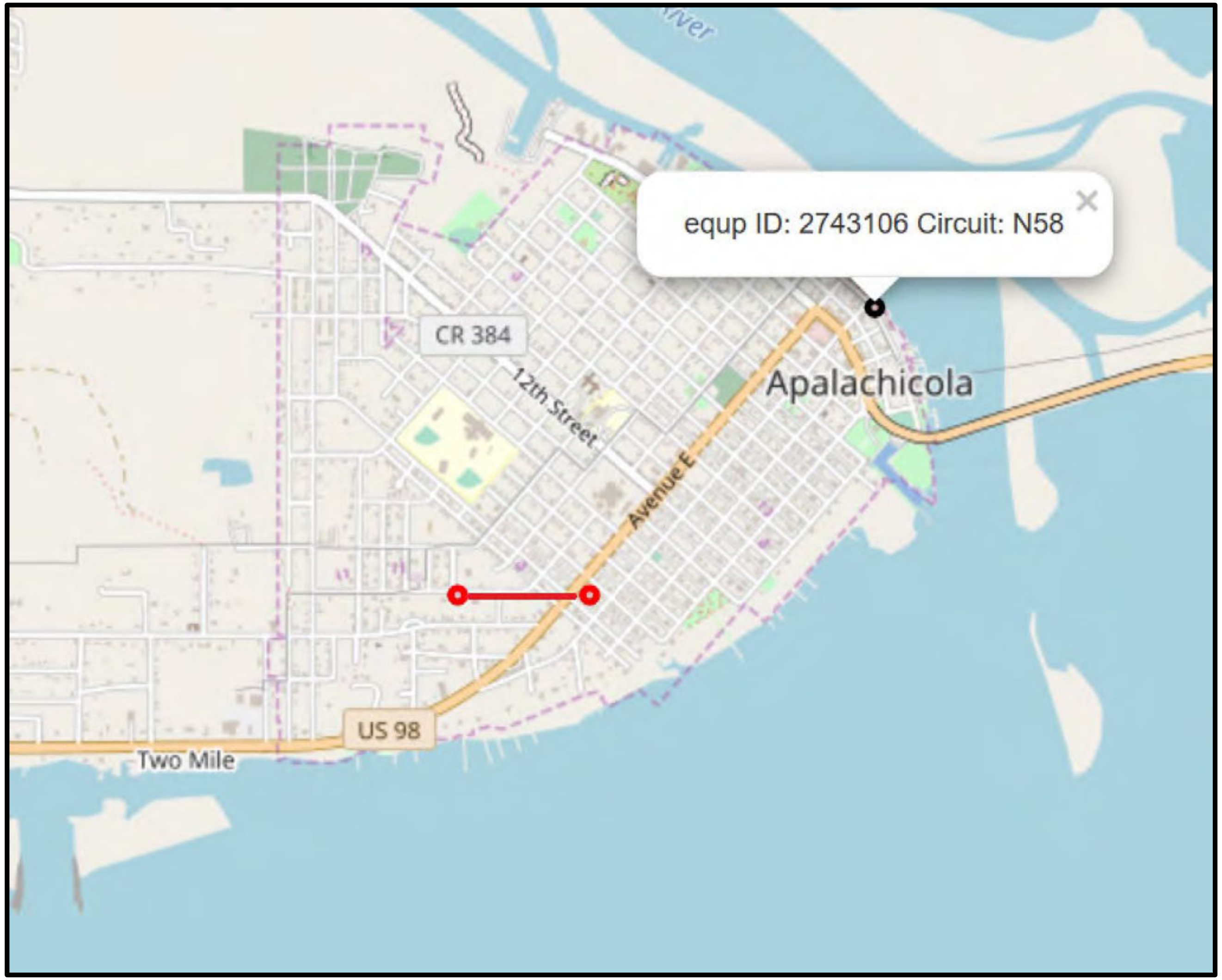


- The area in this map experienced hurricane force winds and storm surge. Although St. Joseph's Peninsula provided some protection, several poles failed.

- The storm hardened poles, in red, experienced similar surge and wind speeds and storm surge. Hardened poles were able to withstand these forces.

STORM HARDENED POLES

NO BREAKAGE



- Although one pole is listed as broken in data, the storm hardening project does not appear to include this broken pole.

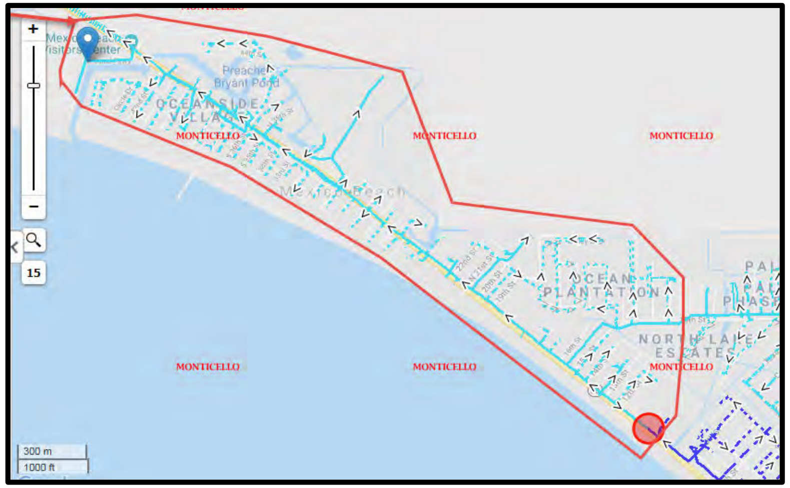
DRONE ANALYTICS FOR FORENSIC DAMAGE ASSESSMENT

accentureconsulting

DRONE ANALYTICS
BACKGROUND / OBJECTIVES

- DEF Forensic Damage Assessment deployed Drone Technology for the first time in Hurricane Michael
- The objective of this deployment was to:
  - Obtain aerial footage in areas of total devastation where there was limited access to foot patrols
  - Obtain aerial footage of Storm Hardening circuits as well as circuits adjacent to Storm Hardening circuits.
  - To assess our ability to acquire broken pole forensic data using drone technology
- A manual drone flight plan strategy was developed and executed
  - The plan was modified based on field discussions and on-site conditions
  - Flight plans were provided electronically, some with and some without META data
  - Video and photo drone footage was uploaded onto a DEF shared drive

DRONE ANALYTICS
BACKGROUND



LOCATION:
- 2MILES ALONG HWY 98. MEXICAN BEACH

- DEF Forensics Damage Assessment deployed drone technology for the first time in the Hurricane Michael response
- This deployment demonstrated the potential for additional benefits to the forensics process by augmenting the existing forensics data collection process with an aerial component

Oct. 13th 2018

Flight 1:
- 18 pics

Flight 2:
- 10 pics

Flight 3:
- 2 videos (total: 2:54)
- 24 pics

Oct. 14th 2018

Flight 1:
- 34 pics

Flight 2:
- 1 video (total: 6:37)
- 25 pics

Flight 3:
- 17 pics

Flight 4:
- 1 video (0:54)
- 20 pics

Oct. 15th 2018

Flight 1:
- 4 videos (total: 4:18)
- 21 pics

Flight 2:
- 1 video (1:25)
- 18 pics

Flight 3:
- 1 video (4:46)
- 32 pics

Flight 4:
- 3 videos (total: 6:41)
- 29 pics

Flight 5:
- 3 videos (total: 3:35)
- 31 pics

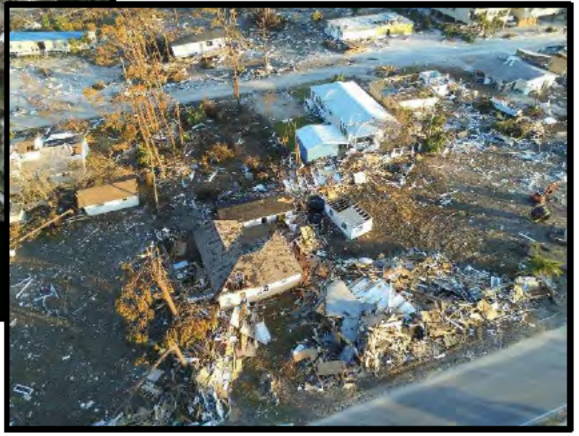
Extra Cape San Blas:
- 8 videos (total: 7:14)
- 44 pics

Extra Mexican Beach:
- 18 videos (total: 17:13)
- 126 pics

Total:
- 449 pics
- 42 videos (55:37)

DUKE ENERGY FLORIDA

DRONE ANALYTICS
AERIAL FOOTAGE



DRONE ANALYTICS
AERIAL FOOTAGE

DUKE ENERGY.
FLORIDA

DRONE ANALYTICS
AERIAL FOOTAGE

DUKE ENERGY FLORIDA

DRONE ANALYTICS
AERIAL VIDEO FOOTAGE