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October 31, 2018

By Hand Delivery
Ms. Lora W. Johnson, CMC, LMMC
Clerk of Council
City Hall - Room 1E09
1300 Perdido Street
New Orleans, LA 70112

Re: Resolution Directing Entergy New Orleans, Inc. to Investigate and Remediate Electric Service Disruptions and Complaints and to Establish Minimum Electric Reliability Performance Standards and Financial Penalty Mechanisms CNO Docket No. UD-17-04

Dear Ms. Johnson:

Please find enclosed for your further handling an original and three copies of Quanta Technology, LLC's Assessment of Entergy New Orleans, LLC's ("ENO") Distribution Reliability Improvement Initiatives. Please file an original and two copies into the record of the above-referenced matter and return a date-stamped copy to our courier.

Thank you for your assistance with this matter.

Sincerely,

Timothy S. Cragin

TSC\rdm

Enclosures

cc: Official Service List (UD-17-04 *via electronic mail*)

Assessment of Distribution Reliability Improvement Initiatives

PREPARED FOR: Entergy New Orleans (ENO)

REPORT DATE: October 31, 2018

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EXECUTIVE SUMMARY

In August 2017 the New Orleans City Council Established Docket UD-17-04 – "RESOLUTION DIRECTING ENTERGY NEW ORLEANS, INC. TO INVESTIGATE AND REMEDIATE ELECTRIC SERVICE DISRUPTIONS AND COMPLAINTS AND TO ESTABLISH MINIMUM ELECTRIC RELIABILITY PERFORMANCE STANDARDS AND FINANCIAL PENALTY MECHANISMS." As part of the effort to cooperate with the City Council's resolution, Entergy New Orleans (ENO) committed to retain the services of a nationally-recognized firm to consult with ENO's distribution reliability team and provide third-party expertise and a national perspective on their current reliability improvement plan. In August 2018 ENO engaged Quanta Technology LLC (Quanta) to perform an assessment of ENO's reliability performance and improvement plans and actions.

Quanta conducted a review of ENO's distribution reliability program and a comparison of its distribution reliability practices versus industry leading practices and those of a selected group of high performing utility peers. ENO's distribution reliability performance had declined in the last five years, and its 2017 key distribution reliability indices (SAIFI and SAIDI) were close to the borderline between 3rd and 4th quartile of the 2017 IEEE Annual Distribution Reliability Benchmark. ENO has increased its reliability spending in the last three years and has planned further investments in key infrastructure, technologies, and systems to stop and reverse this trend and improve reliability performance. As shown in Table 1, these activities are starting to yield positive results and have helped ENO improve its reliability performance during 2018. Year-to-date key indices and overall distribution outage data show a reduction in the number of customer interruptions and customer minutes of interruption.

Table 1 – Actual CI 2017 and 2018 through October 21

ENO System	2017 YTD Actual CI	2018 YTD Actual CI	Actual Diff	Actual % Diff
Distribution View	281,119	204,324	(76,795)	-27.3%
Transmission View	42,387	81,054	38,667	91.2%
Customer View	323,506	285,378	(38,128)	-11.8%

In 2018, ENO has experienced significantly higher customer interruptions due to transmission and substation outages than in the previous two years. Thus far in 2018, transmission and substation outages have accounted for 28.5% of the total CI. Through the same period in 2017, transmission and substation outages accounted for approximately 13.1% of total CI.

The results of Quanta's assessment indicate that ENO's distribution reliability program includes adequate components to continue addressing existing and short-term needs in this area. If investments in distribution reliability and grid modernization continue as planned, it would be expected that ENO's distribution reliability indices improve to 2nd quartile performance. It should be recognized, however, that reliability indices are the outcome of a combination of numerous internal and external distribution system variables. Due to the unpredictability of these variables (e.g., future weather patterns), it is not possible to forecast the exact value of distribution reliablity indices for upcoming years.

The improvements in ENO reliability will not be immediate, since some investments (e.g., BACKBONE program) are essentially needed to stabilize performance and prevent further decline of reliability indices, while others (e.g., deployment of smart reclosers) are largely intended to improve performance, and most importantly, because of the legacy construction and design of ENO's distribution grid coupled with aging infrastructure. The overall effort to achieve reliability improvement on the ENO system should be viewed as a long-term initiative, as opposed to quick fixes.

ENO's proposed reliability program is largely intended to address foundational infrastructure needs (e.g., replace legacy construction and aging assets). These investments, combined with deployment of intelligent infrastructure, and processes enhancements that are part of ENO's grid modernization, AMI (Advanced Metering Infrastructure) and ADMS (Advanced Distribution Management System) programs, are expected to improve ENO's distribution reliability performance. It is worth noting that there is a synergistic relationship between these different programs, i.e., they complement and reinforce each other.

There are important opportunities to improve ENO's reliability program that are described in greater detail in the recommendations section. Specific recommended improvements include considering a broader set of reliability metrics to start preparing to account for forthcoming needs, further deployment of intelligent infrastructure (e.g., smart reclosers/switches), greater utilization of data/grid analytics solutions and techniques to perform more detailed root-cause analyses and enhance asset management, implementation of advanced distribution planning techniques, particularly model-based reliability analysis, and periodic inspection and condition assessment of all its distribution grid assets. It's worth noting that some of these improvements are already being considered and/or implemented by ENO to various degrees as part of its grid modernization, AMI, and ADMS programs. In general, there is a valuable opportunity to accelerate improvement of reliability performance by expediting, to the extent possible within regulatory requirements, the implementation of the components of the reliability program discussed in this report, along with the implementation of these other programs. This needs to be carefully coordinated at project management and implementation levels. It is recommended that ENO evaluates this opportunity if there is a need to achieve reliability improvement objectives faster.

The rest of the report is organized as follows, section 1 discusses project drivers, scope and objectives; section 2 presents a distribution reliability tutorial intended to set the stage, particularly for readers who may not be fully familiar with some of the concepts discussed in the document; section 3 discusses the overall approach used by Quanta to execute the project; section 4 discusses the current state of ENO's system in terms of distribution reliability and assesses the individual components of ENO's reliability improvement program; section 5 discusses industry leading practices pertaining to distribution reliability, including a description of the reliability improvement benefits associated with grid modernization programs; section 6 provides recommendations to improve ENO's distribution reliability program; and section 7 presents the conclusions of this project. Finally, there are five appendices included with relevant technical information about specific topics included in the report.

TABLE OF CONTENTS

List of Figures

List of Tables

List of Acronyms

ADMS: Advanced Distribution Management System

AMI: Advanced Metering Infrastructure

BIL: Basic Impulse Insulation Level

CAIDI: Customer Average Interruption Duration Index

$CEMI_n$: Customers Experiencing n Multiple Interruptions

CI: Customer Interruption

CIS: Customer Information Systems (CIS)

CMI: Customer-Minutes of Interruption

DER: Distributed Energy Resources

FLISR: Fault Location, Isolation and Service Restoration

IEEE: Institute of Electrical and Electronics Engineers

IVR: Interactive Voice Response (IVR)

MAIFI: Momentary Average Interruption Frequency Index

$MAIFI_E$: Momentary Average Interruption Event Frequency Index

MED: Major Event Day

OMS: Outage Management System

PUC: Public Utilities Commission

PV-DG: Photovoltaic Distributed Generation

SAIDI: System Average Interruption Duration Index

SAIFI: System Average Interruption Frequency Index

SCADA: Supervisory Control and Data Acquisition

1 INTRODUCTION

In August 2017 the New Orleans City Council Established Docket UD-17-04 – "RESOLUTION DIRECTING ENTERGY NEW ORLEANS, INC. TO INVESTIGATE AND REMEDIATE ELECTRIC SERVICE DISRUPTIONS AND COMPLAINTS AND TO ESTABLISH MINIMUM ELECTRIC RELIABILITY PERFORMANCE STANDARDS AND FINANCIAL PENALTY MECHANISMS." As part of the effort to cooperate with the City Council's resolution, Entergy New Orleans (ENO) committed to retain the services of a nationally-recognized firm to consult with Entergy's distribution reliability team and provide third-party expertise and a national perspective on their current reliability improvement plan.

In August 2018 ENO engaged Quanta Technology LLC (Quanta) to perform an assessment of ENO's reliability performance and improvement plans and actions. Quanta Technology is a nationally-recognized consulting firm with expertise in all aspects of transmission and distribution operations, reliability, and planning, as well as other technical areas of utility operations and management.

ENO and Quanta reached verbal agreement on the scope of work and contractual terms during the week of August 13, 2018. At that time the Quanta consultants began to develop a list of data requests to be submitted to ENO so that the required information could be collected in advance of an anticipated project site meeting during the week of August 27. The formal contract was executed on August 22 and a project kickoff web conference was held on August 23. The Quanta team then spent several days on site at ENO during the week of August 27 to begin interviews with ENO personnel and to gather additional operational information.

In addition to meeting with ENO personnel, it was deemed appropriate for Quanta to have a discussion with the City Council's Technical and Legal Advisors to review the work scope, project approach and to respond to any questions the Advisors had about the proposed work. A conference call was held on August 31 between ENO, Quanta, and the Advisors for that purpose. In addition to discussion of the work scope, the group reached consensus on the expected timing of a report from Quanta. A final report date of October 31 was agreed.

This report provides information on many aspects of distribution reliability. A brief discussion of the general concepts of distribution reliability is provided as well as detailed discussion of the methods and approach used by Quanta, the current state of ENO reliability programs as assessed by Quanta, industry reliability performance information as determined through industry research, opportunities for reliability improvement as assessed by Quanta, and final conclusions and recommendations. Quanta's ultimate objective in this engagement is to provide a thorough assessment of the current efforts being made by ENO to improve reliability and how those efforts are expected to produce results.

2 DISTRIBUTION RELIABILITY – A BRIEF TUTORIAL

This section is intended to present a brief introduction to distribution reliability in general. The objective is to inform the non-technical reader on basic reliability concepts, metrics, standards, etc. so that the underlying principles of distribution reliability in subsequent sections are understood. Therefore, this section purposely avoids introducing formulae to describe relevant concepts in favor of description of a more narrative description of those concepts. Appendix B of this report includes the respective mathematical formulations, moreover, publicly available technical references on this topic are provided in this section.

2.1 Definition or explanation of the broad concepts of distribution reliability

Distribution reliability studies the impact of service interruptions on the continuity of supply provided to customers, specifically, focusing on analyzing and estimating the frequency and duration of interruptions experienced by customers over a defined period of time, as well as on understanding the underlying root-causes of these interruptions. This is done by collecting and analyzing historical data of distribution system events and calculating and studying performance metrics. An interruption for reliability analysis purposes is defined as the total loss of electric power on one or more normally energized conductors to one or more customers connected to the distribution portion of the system. This does not include any of the power quality issues such as: sags, swells, impulses, or harmonics.

Distribution reliability studies both planned and unplanned interruptions, i.e., interruptions that result from planned and unplanned outages. An outage is defined as the loss of ability of a component to deliver power. Distribution reliability pays special attention to unplanned interruptions to understand, prevent, alleviate and address the root-causes and impacts of these events.

Distribution reliability focuses on studying interruptions caused by outages on distribution facilities, i.e., between circuit breakers and customer revenue meters. This includes primary (medium-voltage) and secondary (low-voltage) lines, service transformers, protective and switching devices, and voltage regulation and control equipment. However, outages may occur on generation, transmission, substations, or customer facilities and result in the interruption of service to one or more customers. While generally a small portion of the number of interruption events, these interruptions can affect a large number of customers and may last for a long time. Utilities collect data from interruptions caused by outages on generation, transmission and substations to understand how they may impact the overall customer experience, and take necessary measures to address them, if needed. Distribution reliability does not include behind-the-meter outages that only affect individual customer facilities.

2.2 Distribution reliability standards and metrics in the US power industry

Distribution reliability can be evaluated through a variety of metrics, commonly known as "distribution reliability indices". Distribution reliability indices evaluate the impact of service interruptions on the continuity of supply provided by a distribution system. The distribution system under analysis may consist of a service transformer, a distribution feeder, a set of feeders served by a substation, or all the feeders in a utility service territory.

Distribution reliability indices evaluate the impact of sustained and momentary interruptions on continuity of supply. Sustained interruptions are defined as those that have a duration greater than a predefined threshold, common thresholds used in North America include 1 min., 3 min., and 5 min. Momentary interruptions are those with durations shorter or equal to these thresholds.

The most common distribution reliability indices evaluate system performance as a function of *customers affected by service interruptions and total number of customers served by a distribution system*. The IEEE Guide for Electric Power Distribution Reliability Indices (IEEE Std. 1366-2012), which is the most widely used reference in this area, defines a variety of distribution reliability indices. The most common reliability indices used by the utility industry are based on the number of customers affected by sustained and momentary interruptions, which are known as customer-based indices. They include[1]:

- Sustained Interruption Indices
    - SAIFI: the System Average Interruption Frequency Index (SAIFI) indicates how often the average customer experiences a sustained interruption over a predefined period of time. Mathematically this is expressed as the sum of Customers Interrupted (CI) divided by the total number of customers served. SAIFI is a normalized metric; its units are interruptions per customer.
    - SAIDI: the System Average Interruption Duration Index (SAIDI) indicates the total duration of interruption for the average customer during a predefined period of time. Mathematically this is expressed as the sum of Customer Minutes of Interruption (CMI) divided by the total number of customers served. SAIDI is a normalized metric; its units are minutes per customer or hours per customer.
    - CAIDI: the Customer Average Interruption Duration Index (CAIDI) represents the average time required to restore service. Mathematically this is equivalent to SAIDI divided by SAIFI. CAIDI units are minutes per interruption or hours per interruption.
    - $CEMI_n$: The Customers Experiencing Multiple Interruptions Index ($CEMI_n$) indicates the ratio of individual customers experiencing "n" or more sustained interruptions to the total number of customers served.
    - ASAI: The Average Service Availability Index (ASAI) represents the fraction of time (often in percentage) that a customer has received power during the defined reporting period.
- Momentary Interruption Indices
    - $MAIFI_E$: The Momentary Average Interruption Event Frequency Index ($MAIFI_E$) indicates the average frequency of momentary interruption events. This index does not include the events immediately preceding a sustained interruption.
- Other indices: there are other reliability indices included in IEEE Std. 1366-2012 that are calculated based on the load affected by sustained and momentary interruptions, which are known as load-based indices, however, they are not commonly used for external reporting. Additionally there are other indices not included in IEEE Std. 1366-2012, but that are used in specific jurisdictions (e.g., some states and municipalities) to evaluate particular aspects of distribution reliability.

It is worth noting that CI and CMI are frequently used as a proxies for SAIFI and SAIDI, particularly when comparing the performance of feeders or the expected benefits derived from reliability improvement projects. For instance, if two feeders have the same SAIFI values, a 10% reduction in this metric may be

[1] This list includes the most commonly used reliability indices. IEEE Std. 1366-2012 includes additional reliability indices that are used in specific cases

interpreted as equally impactful for both feeders. However, if the first feeder has twice the number of customers as the second one, then the 10% reduction in the former will benefit a larger number of customers and, therefore, will be more impactful from that standpoint. This cannot be concluded from the review of SAIFI values only. However, if CI is used instead, the feeder with the greater number of customers will also have larger initial CI and CI reduction values. Therefore, this feeder may be assigned greater priority for implementation of reliability improvement projects. The same also holds true for SAIDI and CMI.

Reliability indices evaluate distribution system performance within "reasonable design and/or operational limits". Events that exceed these conditions are considered "major events" and are excluded from the calculation of reliability indices. IEEE Std. 1366-2012 defines an approach to identify and exclude a Major Event Day (MED), this methodology is commonly known as the "IEEE 2.5 Beta method". The method consists of analyzing the daily SAIDI values for five sequential years to identify a Major Event Day threshold (T_{MED}). Any day with daily SAIDI greater than the threshold value T_{MED} that occurs during the subsequent reporting period is classified as a MED and consequently excluded from the calculation of reliability indices. The reasoning behind this approach is that distribution systems are not designed to withstand extreme conditions associated with major events such as earthquakes, tornados, ice storms, forest fires, major hurricanes, major flooding, etc.

There are other major event definitions used by the industry, examples include[2]:

- A severe storm, flood, or civil disturbance that requires three or more days to restore service
- The following criteria are met: 1) The National Weather Service has issues a severe watch or warning for the area. 2) Extensive mechanical damage has been sustained. 3) More than 10% of customers are out of service at some time during or immediately after the storm. 4) At least 1% of customers are out of service 24 hours after the beginning of the storm.
- A certain percentage of customers in a specific area (e.g., utility service territory) experience an interruption

2.3 Variables in reliability reporting

Reliability reporting is vital to understand distribution system performance, root-causes, and to identify solutions to address relevant issues. Utilities generally prepare daily, monthly and annual distribution reliability reports, the objective of these reports vary in scope. Daily reports are tactical and provide important information to decision makers about the overall operation of the distribution system, which is valuable to manage internal and external relationships with key stakeholders, particularly with customers, local authorities and regulators. Monthly reports are intended to identify system trends, effectiveness of executed and ongoing projects and programs, and may be used to allocate emergent resources and investments to areas that require urgent attention. Finally, annual reports are generally used for planning purposes (e.g., to identify areas of the system that require attention, such as worst performing feeders, and to ascertain needed projects and programs to improve or maintain reliability levels), and for regulatory reporting. For instance, Figure 1 shows the results of a survey of state reporting requirements and practices for utility-reported reliability information.

[2] R.E. Brown, Electric Power Distribution Reliability, 2nd Edition, CRC Press

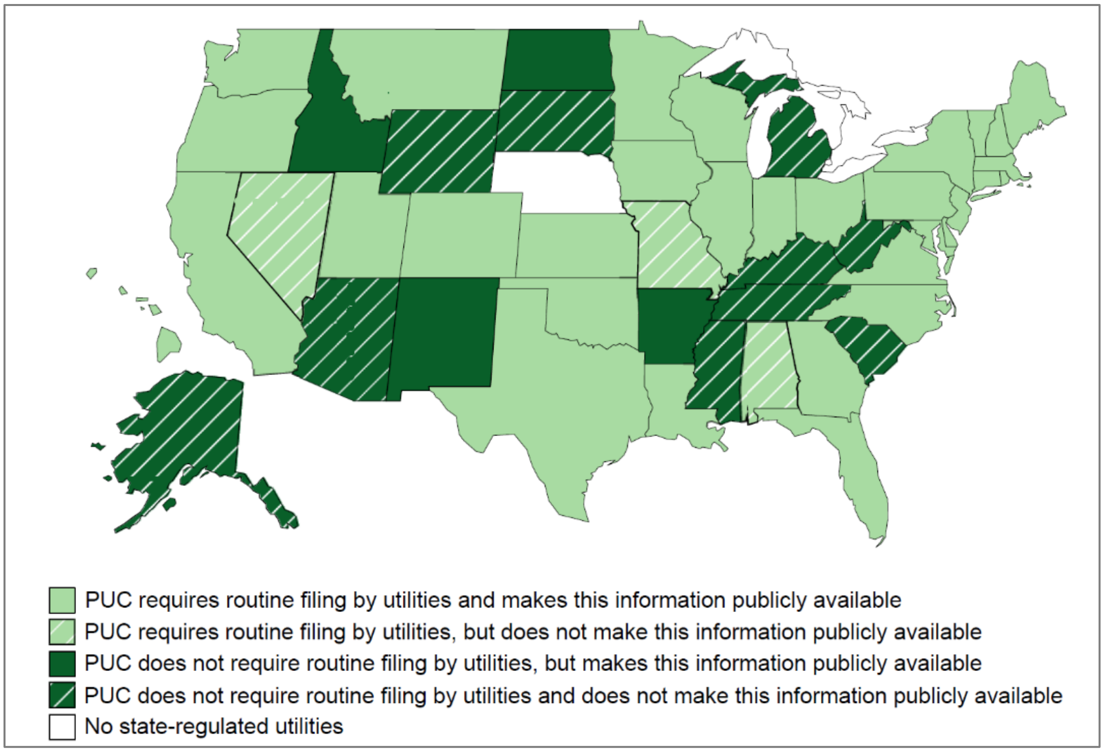


Figure 1 – State Reporting Requirements and Practices for Utility-Reported Reliability Information[3]

Reliability reports usually include the values of key reliability indices used by a utility (e.g., SAIDI, SAIFI, CAIDI, CMI, CI, etc.) for each distribution feeder and overall service territory. Reliability indices included in reports are generally calculated for the period under analysis and preceding periods (e.g., days of the same week/month for daily reports; months of the same year for monthly reports; or last 3 to 5 years for annual reports). Moreover, reliability indices are calculated for various categories of interruption and outage events. Examples comprise:

- All events included: this includes planned and unplanned interruptions, along with major events and interruptions caused by generation, transmission, substation and distribution outages. The purpose of this type of report is to understand the overall customer experience, regardless of root-cause, magnitude and responsibility.
- Distribution events only: this typically includes interruptions caused by unplanned distribution outages, excluding major events. The purpose of this type of report is to understand reliability performance due to outages in the distribution grid that are within reasonable design and/or operational limits.

[3] "35 PUCs, including DC, require that reliability information be reported routinely. An additional four state PUCs receive reliability information from utilities though not in response to a formal reporting requirement. Thirty-seven state PUCs, including DC, make publicly available or summarize in publicly available documents the reliability information they collect from utilities". J. Eto, K.H. LaCommare, Tracking the Reliability of the U.S. Electric Power System: An Assessment of Publicly Available Information Reported to State Public Utility Commissions https://emp.lbl.gov/publications/tracking-reliability-us-electric

Utilities may also include combinations of the aforementioned categories of interruption and outage events, for instance, interruptions caused by planned and unplanned outages, excluding major events, etc. Additionally, utilities may report reliability indices by root-cause category, for instance, CI and CMI (or SAIFI and SAIDI) due to weather events, equipment failures, or vegetation issues. These types of reports allow a utility to identify main root-cause contributors to reliability performance, and to allocate resources and investments to address these issues, if needed. Finally, utilities generally prepare a list of worst performing feeders based on a specific metric (e.g., bottom 5% feeders in terms of SAIFI, SAIDI, CI, CMI, etc.). This report may also include root-cause contribution to reliability performance. The purpose of this type of report is to identify the areas of the system that need urgent attention to allocated needed resources and investments for reliability improvement.

An important aspect to consider when computing reliability indices is the accuracy and uncertainty associated with outage data collection. Historically, outage data collection involved a significant amount of manual work and a variety of data sources with different levels of accuracy and uncertainty. Many utilities are transitioning into automating most of the data collection process through the implementation of grid modernization initiatives and deployment of automated systems, such as Outage Management Systems (OMS), Customer Information Systems (CIS), Interactive Voice Response (IVR) systems, Advanced Metering Infrastructure (AMI), smart phone applications and social media. However, in distribution systems without AMI, customer trouble calls remain an important data source, and therefore, key interruption information, such as start time, may need to be estimated, rather than automatically reported. For this reason, utilities may initially observe an increase in distribution reliability indices after implementing OMS or AMI systems, which help minimize some of the inaccuracies and uncertainties associated with outage data collection.

2.4 How reliability reporting can/should be used in evaluating utility performance

Distribution reliability reports provide important insights regarding system performance. However, since reports generally use average reliability indices, it is important to understand the limitations of these metrics to avoid common pitfalls and misconceptions when using them to evaluate performance[2].

- SAIDI and SAIFI: reductions in SAIFI and SAIDI are proportional to the number of affected customers. Reliability analyses based on SAIFI and SAIDI tend to allocate investments to feeders with greater number of customers, because projects benefit more customers, i.e., the benefit/cost ratio is higher. This can make improvement project justification more difficult on feeders with smaller number of customers.
- CAIDI: CAIDI is calculated as SAIDI divided by SAIFI, therefore, if SAIFI decreases faster than SAIDI then CAIDI will increase. This is counterintuitive, since a reduction in SAIFI and SAIDI represents an improvement in reliability, while an increase in CAIDI would be interpreted by some as a decline in performance. For instance, if SAIDI and SAIFI for a system decrease by 10% and 20%, respectively, then CAIDI will increase by 12.5%. This occurs often when system enhancements, such as reclosers, are installed to reduce the number of customers interrupted by a specific event. By avoiding an outage to the customers that may have been quickly restored, SAIFI and SAIDI are reduced, but CAIDI increases for the resultant outage because the lower number of customers are still impacted by the total outage duration.
- $MAIFI_E$: Like SAIFI and SAIDI, $MAIFI_E$ tends to drive investments to feeders with greater number of customers. Most importantly, it discourages the utilization of some of the most effective solutions for

reliability improvement, such as automatic reclosing, fuse saving overcurrent protection philosophy, and distribution automation, since they increase the occurrence frequency of momentary interruptions, although they are very effective to minimize the effect of sustained interruptions and improve SAIFI and SAIDI. In summary, $MAIFI_E$ will likely increase when implementing these types of solutions, although reliability will improve.

- $CEMI_n$: $CEMI_n$ can only be used in conjunction with other indices, since it addresses the occurrence frequency of interruptions only, and does not account for interruption duration. Therefore, it will assign zero value to reliability improvement solutions that only reduce the duration of interruptions, such as deployment of Faulted Circuit Indicators (FCI). $CEMI_n$ will also assign zero value to solutions that reduce the occurrence frequency of interruptions beyond the $CEMI_n$ threshold. For instance, if a utility uses $CEMI_3$ and reduces the frequency of interruptions experienced by a group of customers from ten to five, $CEMI_3$ will assign zero benefit to this solution, because it still exceeds the $CEMI_3$ threshold of 3 or more interruptions, despite the fact that reliability has undoubtedly improved.

Reliability indices such as SAIFI, SAIDI, and CAIDI have the advantage of being relatively easy to calculate, however, one of their key limitations is that they estimate the average performance of distribution systems, i.e., the same average index is assumed to represent the reliability performance for all the customers served by the system. This means that average reliability indices do not consider the spatial distribution of reliability and the topological features of the distribution grid, i.e., the fact that customers located close to substations are expected to have better reliability than those located at feeder ends. For this reason, reliability indices should be used in conjunction with historical outage and operational data to identify poor-performing areas within feeders (e.g., by pinpointing most frequently operated devices) and properly allocate investments and reliability improvement solutions.

As utilities implement grid modernization programs, deploy AMI, and transition towards the utilization of computational models to analyze distribution reliability, it is expected that the automated calculation of customer-level reliability indices becomes a reality, and the high granularity spatial evaluation of distribution reliability becomes a standard practice. Therefore, while these capabilities become available to utilities, it is advisable to use a combination of reliability indices, e.g., SAIFI, SAIDI, $MAIFI_E$ and $CEMI_n$ to attain a more comprehensive depiction of feeder performance.

Here it is important to recognize the fact that $MAIFI_E$ is in general more difficult to track than more traditional indices such as SAIFI, SAIDI and CAIDI. Partly because of the lack of the monitoring infrastructure (e.g., communications systems, SCADA[4], ADMS[5], AMI, etc.) to accurately collect the data required for its calculation. For instance, a utility may not monitor *all* its reclosing and switching devices (circuit breakers, reclosers, and distribution automation switches) and therefore, may not be able to collect *all* the device operation data needed to accurately calculate momentary interruptions and $MAIFI_E$. However, as utilities transition into a modernized grid, such monitoring infrastructure will gradually become available. Therefore, it is a good practice to collect this type of data for those devices that are already being monitored, and estimate base $MAIFI_E$ indices that can serve as a starting point to evaluate the historical evolution of momentary interruptions. This estimation will become more accurate as more devices are monitored and more data is collected[6].

[4] Supervisory Control and Data Acquisition (SCADA)
[5] Advanced Distribution Management System (ADMS)
[6] This is analogous to the increased accuracy in the calculation of traditional indices (SAIFI, SAIDI) attained through the deployment of AMI.

Reliability reporting is sometimes used to compare performance among utilities, here it is important to consider discrepancies regarding reliability analysis assumptions and practices, and differences in intrinsic features of each utility's service territory and distribution system that affect reliability performance. Examples of differences in reliability assumptions include major event exclusion methodology used in analysis, momentary interruption threshold, consideration of planned interruptions, etc. Examples of important geographic and distribution system features to take into account include lightning flash density, precipitation, temperature, percentage of overhead and underground lines, customer density, etc. It is important to take these factors into account when benchmarking performance to ensure conclusions are relevant and applicable to the reality of the utility under analysis.

It is also important to recognize that reliability indices are the outcome of a combination of numerous internal and external distribution system variables. Due to the unpredictability of these variables (e.g., future weather patterns), it is not possible to forecast the exact value of distribution reliablity indices for upcoming years. Instead, techniques used by utilities aim at estimating trends, ranges of likely values, or expected values of reliability indices. In the specific case of reliability improvement programs, it is expected that reliability indices will show an improving (decreasing) trend for upcoming years after implementation begins. However, these metrics may exhibit noticeable variations in consecutive years. For instance, reliability indices may improve significantly in a year and then only moderately (or even worsen) in the the next one, because part of the improvement is due to the implementation of the reliability program, and the rest is the effect of the inherent randomness of reliability variables. When that randomness leads to "good years" (e.g., years with fewer storm days and/or cool summers) the benefits of improvement programs are likely to become more evident than during "bad years". For this reason, a recommended practice is to analyze the values of reliability metrics over multiyear periods (e.g., 3 to 5 years), rather than over consecutive years. This approach allows to capture the expected mid/long-term improvement trends (instead of focusing on potential consecutive year variations) and to a certain extent account for the effect of randonmness.

3 PROJECT APPROACH AND METHOD

3.1 Scope of Work

The contracted scope of work for the reliability assessment included the following:

A comprehensive benchmarked assessment of the current ENO reliability plan, including programs, processes, practices and implementation.

a) Comparison utilities should have similar features (e.g., urban area, older system, and legacy design issues) and be high performing in reliability or have made large improvements in their reliability.
b) The review should primarily focus on conventional components of reliability, not grid modification, automation or advanced metering.
c) Sharing of the firm's perspectives, based on the firm's research and experience, regarding the potential reliability benefits associated with "Grid Mod" and AMI implementation for a typical utility.
d) Include an assessment of the expected reliability improvement if the plan is implemented as designed, e.g., validating Entergy's planned targets (total CI reduction, etc.)

Quanta was also asked for input and recommendations on other administrative items as part of the work scope, however, those items were beyond the primary area of review of Entergy's reliability improvement plans and practices.

3.2 Approach and Methodology

3.2.1 Project Team

Quanta Technology's approach to any professional engagement begins with ensuring that the appropriate consulting personnel are assigned to the project. In this engagement the core team consisted of three consultants with over 100 years combined experience in the electric power industry as engineers, operational managers, executives and regulators. Additional Quanta personnel performed business oversight to the project as well as contributing to technical scope where appropriate. Short resume's of the team members are included in Appendix A. The team experience includes engagement with utility companies, industry associations, government organizations, regulatory bodies and industrial customers. The geographic scope of engagements includes the US, Canada, Latin America, the Caribbean, Asia, and Europe. The resulting experience and competency of Quanta Technology in distribution operations and reliability is extensive.

An additional qualification of the Quanta team is the current industry participation in the Power & Energy Society (PES) of the Institute of Electric and Electronic Engineers (IEEE). Quanta employees participate in IEEE in various working groups, subcommittees, committees, and executive leadership. Specific to this engagement, it is noted that Dr. Julio Romero Agüero, who serves as the technical lead for the ENO project, is currently the Chair of the IEEE Distribution Subcommittee. Within the PES committee structure the Distribution Reliability Working Group operates as a subset of the Distribution Subcommittee. Dr. Romero Agüero, through his consulting work as well as his IEEE activity, is highly knowledgeable of distribution planning and reliability practices and standards and is widely known for his publications on these topics, as well as the impacts of distributed energy resources on grid operations.

3.2.2 Project Approach & Methodology

At its core, this engagement is considered to be an assessment of practices. It is more qualitative than quantitative in approach and method, as required by both the scope and the compressed schedule. The work scope focused on evaluating ENO's ongoing reliability improvement actions and providing industry comparisons for reliability programs and improvement. From those comparisons, recommendations for additional efforts can be formulated, as identified.

The basic approach to this engagement follows the flow diagram depicted in Figure 2.

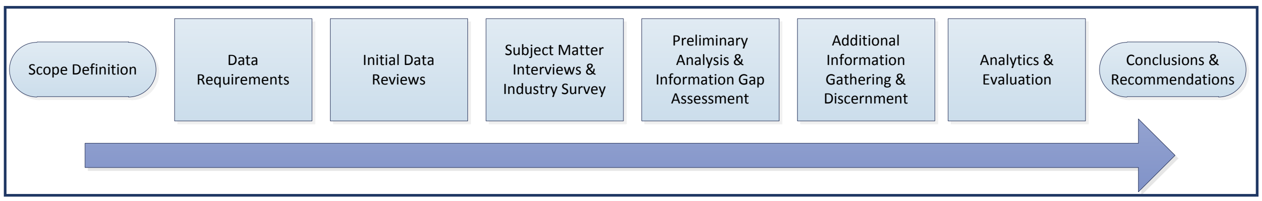


Figure 2 - Project Approach

3.2.3 Data Requests

Prior to initial meetings with ENO personnel, Quanta Technology submitted a comprehensive data request for system information such as:

- Service territory area
- System reliability indices (SAIDI, SAIFI, CAIDI, etc.) without and with MED
- Number of substations
- OMS (Y/N)
- Number of feeders
- Number of customers
- Peak demand
- Installed capacity
- Primary distribution voltage (e.g., 12.47 kV, etc.)
- Miles of overhead and underground lines
- Percentage of urban, suburban and rural distribution
- Reliability indices (SAIDI, SAIFI, CAIDI, etc.) without and with MED

The data request also asked for available information on current reliability improvement plans and reliability practices. The data request included such items as:

- Overall Report/Summary/Strategy
- Reliability data by feeder
- Reliability analysis tool and methodology

- Benefit-cost and prioritization methodology for selection of reliability improvement projects
- Proposed project management metrics and project status report to evaluate implementation of reliability plan
- Proposed metrics to assess effectiveness of reliability plan
- Outage cause classification methodology
- Description of Outage Management System (OMS) capabilities
- Description of outage data collection process (explain what parts of the process are manual, automated, semi-automated, and describe potential sources of error/inaccuracies)
- Reliability indices of interest (SAIDI, SAIFI, CAIDI, MAIFI, CEMI, etc.)
- Definition of sustained/momentary interruptions
- Definition of Major Event Days

Upon receipt of information from ENO, Quanta was able to develop an initial understanding of ENO operations, reliability practices, and programs that are underway for reliability improvement. This initial understanding was then enhanced through on-site meetings and interviews with ENO subject matter experts in operations, reliability assessment, organizational performance analysis, asset management, and other content areas related to the project scope. These meetings were an opportunity for open discussion about ongoing programs and to clarify Quanta's understanding of organization, operations, and performance. As part of the on-site work, the Quanta team also had the opportunity to see areas of the ENO system that have been upgraded or refurbished as part of reliability programs as well as areas yet to be addressed. All of the described activities informed Quanta's understanding of the current practices at ENO to address reliability performance, as well as the infrastructure challenges faced by the company in its efforts.

3.2.4 Benchmarking

A major element of this engagement was to benchmark ENO performance against other companies in the industry that have high performance in reliability and to, where possible, understand what efforts had been made by those leaders to achieve their current levels of performance. The methods used to determine benchmark candidates are explained in detail in Chapter 5 and will not be repeated here.

The benchmark process was used to identify leading practices employed in the industry to achieve, monitor, report and maintain high reliability performance. As with all benchmarking programs, results are varied and unique to the company's providing the information. What works in one location or to address one company's specific problem cannot always be applied by other companies. However, the information obtained through benchmark surveys does allow the requesting company, ENO in this case, to understand how others approach their problems and to take from that understanding anything that can be applied to ENO's specific situation. Those findings and comparisons are discussed in the later chapters of this report.

3.2.5 Analysis, Evaluation, and Conclusions

Applying all the information gathered through the processes described, Quanta then began a process of analytics and evaluation to compare ENO's reliability improvement practices to the industry. The comparative information comes from the benchmark information, publicly available reliability data, Quanta's experience in working with other clients, and the personal experience of the project team members, all of whom have direct experience in utility operations and management. The resulting assessment constitutes the body of this report.

4 DISTRIBUTION RELIABILITY AT ENTERGY NEW ORLEANS

4.1 Current State

The reliability performance at Entergy New Orleans, as measured by standard industry indices, has declined in recent years and has been a cause for concern within ENO and the community. In 2018, ENO is experiencing improvement in SAIFI, the primary reliability measure used by the company. The improvement is largely due to the ongoing distribution reliability efforts the company has undertaken for several years. Comparison of CI by major outage cause codes in the first six months of 2017 and 2018 shows:

- Animal -27.4%
- Conductor -39.4%
- Equipment -40.4%
- Vegetation -12.4%
- Weather -76.2%

The majority of the improvement can be directly related to improvement efforts by ENO, however, more random events that affect reliability, such as weather, also contribute to the overall improvement.

ENO's SAIFI performance for 2016, 2017 and through October 21, 2018 is shown in Table 2. The table provides the overall customer view SAIFI as well as the contribution to SAIFI by distribution operations and transmission operations.

Table 2 - ENO SAIFI as of October 21 Each Year

ENO System	2016	2017	2018
Distribution View	1.3947	1.3809	0.9921
Transmission View	0.1526	0.2082	0.3936
Customer View	1.5473	1.5892	1.3857

The results show that 28.5% of the 2018 customer view SAIFI is due to transmission and substation outages. Individual transmission outages, which include substation outages, while less frequent than distribution outages on any utility system, have a greater impact on reliability indices due to the numbers of customer affected and, in many cases, the extended duration of the outage.

Distribution (DLIN) performance metrics as presented in June 2018 testimony filed with the City of New Orleans are shown as Table 3. Prior to 2016 the company's reliability indices were considerably better as compared to the industry. A notable decline occurred in 2016-17 which now is showing evidence of having been arrested and reversed.

Table 3 – ENO Year End DLIN Reliability Indices

ENO'S SAIDI AND SAIFI (2013-2017)					
	2013	**2014**	**2015**	**2016**	**2017**
SAIDI	92	121.3	128	167.9	179.8
SAIFI	1.04	1.209	1.234	1.61	1.584

Source: Entergy New Orleans Testimony, T. Patella, June 2018

As shown in Table 1 in the Executive Summary, distribution (DLIN) customers interrupted (CI) is down from 2017. Correspondingly, SAIFI is currently tracking at ENO target levels for the year and significantly improved from the same time in 2017.

Figure 3 provides a 2017 versus 2018 SAIFI comparison through October 21. As shown, 2018 has had a consistent performance in reliability while in 2017 there was a significant SAIFI increase in the month of June. Data review shows that 25% of the total CI attributed to weather in 2017 occurred in the month of June. The significant 2017 increase demonstrates the challenge of maintaining reliability performance throughout the year and that it can change significantly due to a small number of events.

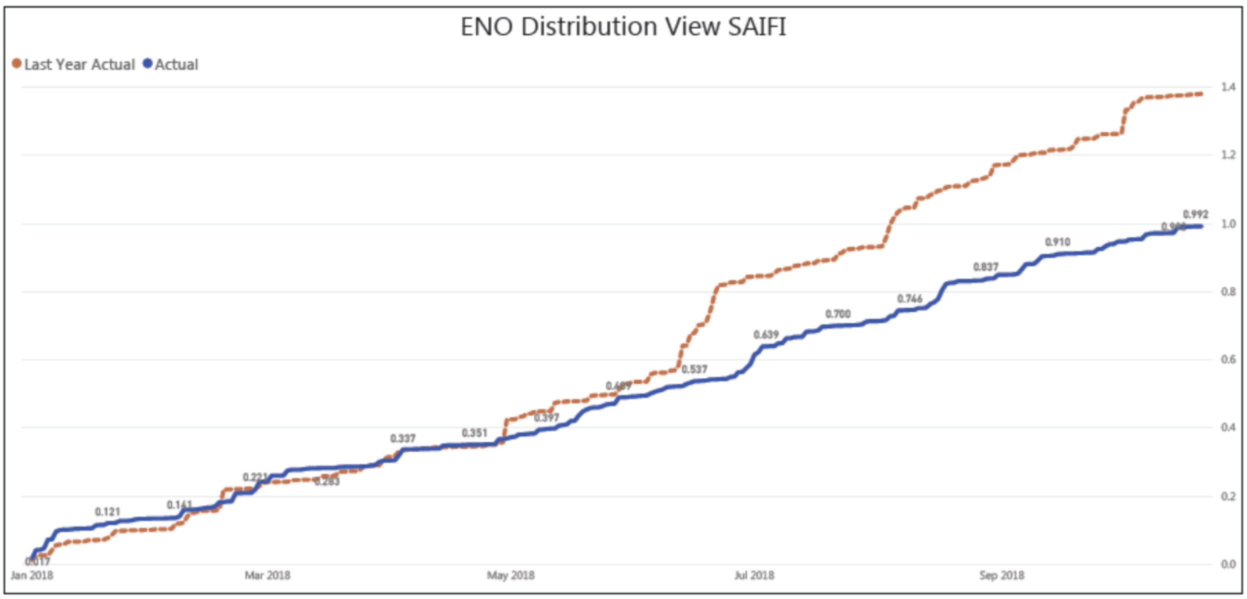


Figure 3 - ENO 2018 Distribution SAIFI Performance - As of 10/21/2018

Source: Entergy

Distribution reliability performance improvement is a high priority at ENO and has been a priority for several years, as indicated by the various programs and initiatives that have been instituted and are discussed in this report.

Consistent improvement in system wide distribution reliability performance is seldom a quick fix. Many variables, controllable and uncontrollable, contribute to reliability performance. In this evaluation, Quanta Technology has reviewed years of performance metrics, interviewed many stakeholders and participants in the ENO efforts, performed a field visit to view the physical infrastructure of the company, all to gain an understanding of the efforts made to improve performance and the challenges faced in those efforts.

The following sections include: Quanta's observations and findings regarding the challenges faced by ENO in improving distribution reliability, both general and specific; information on the current efforts to address the challenges and improve overall performance; and an assessment of the effectiveness of the ongoing efforts.

4.1.1 Legacy Distribution Design

The electric distribution grid in New Orleans is made up of aged facilities built to a design standard from many decades ago, as shown in Figure 4. Areas of the system date to the 1920s and while age does not equate to a lack of functionality, there are certain aspects of the legacy system that do not contribute positively to reliability performance. Much of the fundamental design of the ENO distribution system is based on industry standards developed in the mid-twentieth century. Distribution system design in that era was focused on power delivery and not reliability. The following excerpt from the book Aging Power Delivery Infrastructures (second edition 2013) makes the point:

"Any reasonable layout style, conductor size set, switching zone, and conductor sizing rule base will result in a distribution system that does its basic job as interpreted from the traditional perspective: route power from substations to customers without violation of voltage, loading, or power factor standards. However, this interpretation of the distribution system's job is obsolete and incomplete. It looks at the distribution function only from the perspective of moving power and neglects its role in and capability for improvement of customer-service reliability. Very few primary distribution systems are planned and engineered to make maximum use of the distribution system as a resource for customer reliability."[7]

The legacy design standards and criteria were developed to distribute power in an economical manner that did not violate voltage or loading standards, as detailed in the preceding excerpt. The emphasis was on economics and operating criteria. This resulted in a system built with multiple circuits (primary feeder, laterals, open-wire secondary) on common structures. This made maximum use of fewer distribution transformers and more poles, crossarms and conductors, which was the most cost effective construction at the time. The primary benefit was a level of redundancy in service to customers that resulted in high availability. The downside, being experienced in recent years, is a higher level of collateral damage when a single component such as a crossarm fails and impacts more circuitry than would be in place on a single pole under today's standards. The age of the design, as well as the age of the infrastructure, have compounding effects. ENO is challenged with a legacy design that has many more components than a modern design would use, the age of the components, and the urban environment that makes infrastructure upgrades more complex and therefore more expensive.

Quanta Technology performed a field patrol of the ENO system in September 2018, which highlighted areas of the legacy design in operation. Multiple circuits on a single structure were observed, including the combination of feeder circuits (large conductor) and a lateral (small conductor) beneath it. The more conductors that are in operation for the same number of customers results in increased exposure and ultimately a higher level of outages. This field patrol confirmed the issues related to the legacy design of the system. An example is shown as Figure 4.

Grid modernization projects throughout the industry today include a large component of infrastructure upgrades and application of "advanced distribution planning" principles. The planning and design concepts being used in grid modernization efforts are based on using the full capability of a distribution system to provide availability, which was the primary objective of legacy designs, and reliability, which is the focus of most utility customers today.

[7] H. Lee Willis and R.R. Schreiber, Aging Power Delivery Infrastructures, Second Edition, CRC Press

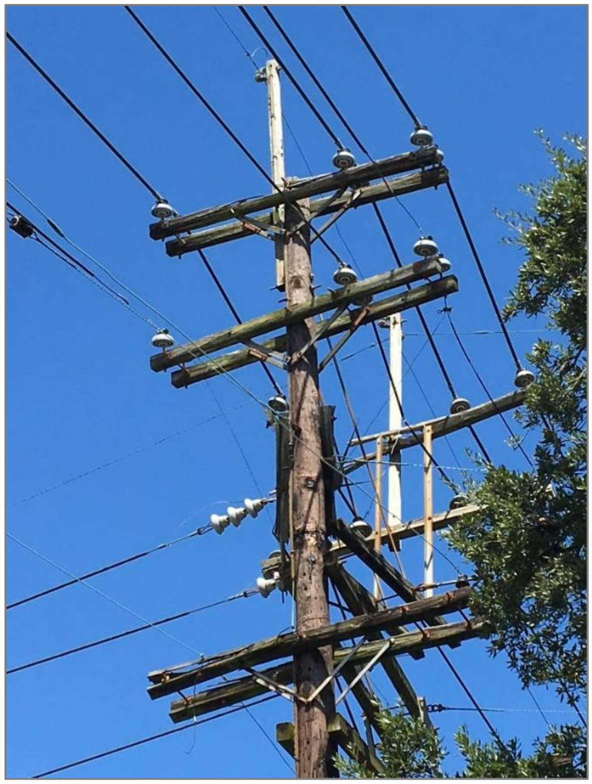


Figure 4 – Example of Deteriorated Legacy Construction[8]

As with any older, urban utility system, there are areas of the distribution system in need of upgrade. Entergy's reliability improvement programs, discussed later, are aimed at addressing many of the issues created by the legacy design and aged infrastructure. The efforts include upgrading system components to the company's current design standards as individual reliability issues are addressed. Entergy's current standards include improvements such as:

- Increased pole loading criteria – Entergy designs many poles to the NESC extreme wind criteria which exceeds the minimum requirements for the service territory.
- Crossarm material – Entergy is currently installing fiberglass crossarms as replacements for failed or aged wood crossarms. Fiberglass arms have higher strength and resiliency and require less maintenance.
- BIL standards – Standard design ensures that appropriate BIL values are met in new construction.

These items as well as other design and infrastructure improvements are addressed in more detail in Section 4.2.

[8] Source: Field inspection conducted by Quanta Technology as part of this project

Implementing new design standards is the right approach and has already had positive effects in arresting the trend of declining reliability. Comprehensive infrastructure upgrades must continue to affect continued improvement, which can be further enhanced with automation technology.

4.1.2 Infrastructure

Similar to many urban utility companies in the United States, ENO has a high population of aged equipment. In the utility industry, age does not mean that equipment is no longer functioning as designed. In fact, some older equipment designs and manufacture are much more robust than new equipment. Older facilities do, however, represent increased risk of failure simply due to approaching end of normal service life.

Entergy's current asset information does not allow for an in-depth analysis of age of a class of equipment or other analysis often done in review of equipment failure situations. Some data on the distribution line transformer and wood pole population at ENO was obtained and is basis for discussion of those asset classes.

4.1.2.1 Distribution Overhead Transformers

Table 4 shows the age distribution of ENO's service transformer population.

Table 4 –Distribution Transformers

In Service Transformers		
Decade Installed	Count	% In Service
1920	1	0.003%
1930	-	0.000%
1940	70	0.224%
1950	1,326	4.251%
1960	2,333	7.479%
1970	6,887	22.077%
1980	3,954	12.675%
1990	4,802	15.393%
2000	7,186	23.035%
2010	4,572	14.656%
Unknown	65	0.208%
	31,196	100.000%

Source: Entergy data

Between 2013 and the present, 2,531 transformers (8% of population) have been removed. In service failures accounted for 1,261 of the units removed (4%) and all others (1,270 or 4%) were removed as no longer in service (idle account) or changed/upgraded for additional load. The 5 year failure rate of 4% or average annual rate of 0.8% is within industry norms for this class of equipment. Table 5 provides an industry reference for the failure rate.

Table 5 – Transformer Failure Rates

Transformer Type	Failure Rates		
	Median Failure (50%)	95% Failure	ENO Actual
Distribution Transformers	0.3	1.8	0.8

Source: EPRI, Estimating Reliability of Critical Distribution System Components, Technical Report 1001703, 2003

The age distribution of the population shows that 34% of the in-service units were installed before 1980 indicating a minimum number of years in service for this portion of the population of 38 years. Expected life of distribution service transformers has been found in some studies to range from 40 to 50 years with many examples of even greater service life. As with all assets, the actual service life depends upon many variables including load, geographic location, and environmental factors, to name a few. Failure rate estimates vary widely as a result.

4.1.2.2 Distribution Wood Poles

Other equipment classes at ENO where some data has been obtained is poles and crossarms. Age data is not readily available, but a reasonable estimation of the total population and number of failures is shown as Table 6.

Table 6 – ENO Equipment Failures 2013-17

Equipment Class	Approximate Number in Service	Failures	5 yr Failure Rate	Annual Failure Rate
Poles	90,000	166	0.2%	0.04%
Crossarms	500,000	731	0.1%	0.03%

Source: Entergy

Wood pole service life varies widely in the industry based on geographic location, type of wood and original treatment, and the ongoing inspection and treatment regimen, if any. Geographic factors represent risks as indicated in Figure 5 – Decay Hazard Zones, a map of the wood deterioration zones of the US. The ENO service territory experiences high humidity and high rainfall, as well as having a high water table. Risk to the condition of wood poles is highest in this region of the country. Nonetheless, wood poles have been shown to have usable service life well in excess of fifty years in many companies and as high as 90 years in some. The average age of the ENO wood pole population is not known, but is expected to be at and beyond the 30-40 year service life that is considered a reasonable minimum for wood poles.

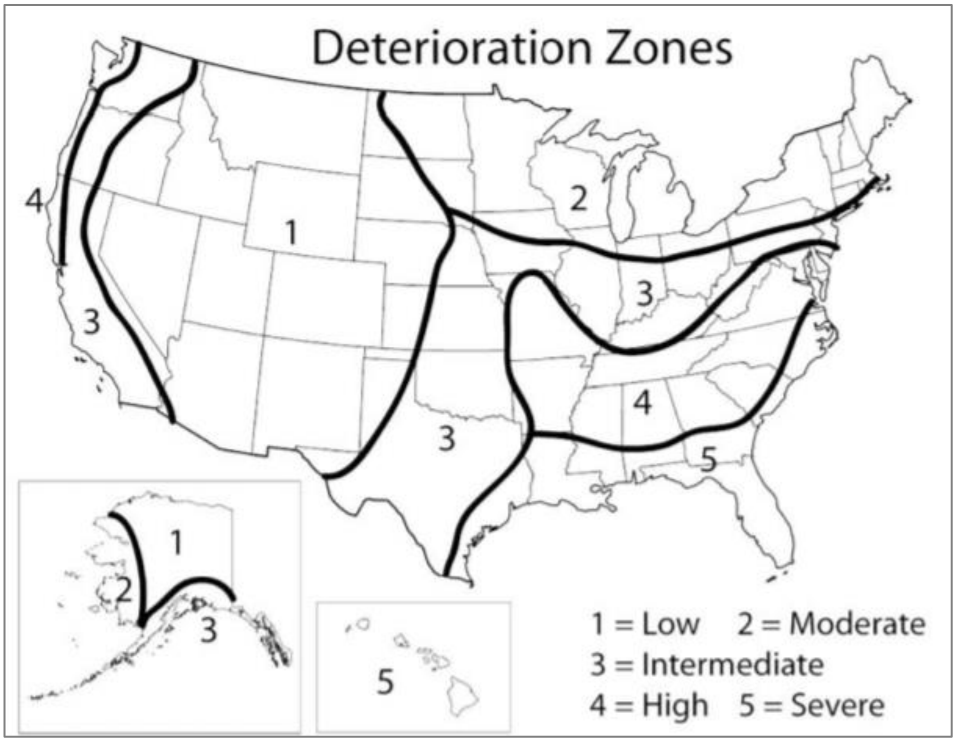


Figure 5 – Decay Hazard Zones[9]

The ENO failure rate, as shown in Table 6, is again within industry expectations despite the high hazard area. A 2013 survey by Oregon State University of 86 utility companies reported a wood pole replacement rate of 0.56%.[11] This rate included all poles replaced for any reason, not only failures. That study estimated that approximately one-half to two-thirds of the poles replaced were not restorable, which would equate to an approximate "failure" rate in the range of .28% to .38%. The ENO wood pole failure rate is approximately 0.04%.

Failure data on crossarms alone has not been obtained, however, it is reasonable to expect similar rates, or lower rates, than poles.

ENO has in place a wood pole inspection program that is consistent with practices in the industry. The cycle time for ENO pole inspections is twelve years, which results in 8.5% of the population being inspected each year. As part of the ongoing reliability improvement efforts, however, ENO in 2017 accelerated pole inspections to cover approximately 50% of the pole population. The inspection process used was an intrusive inspection which included excavating the pole base to examine condition below ground line. This inspection resulted in approximately 800 identified for pole replacement and 3000 poles identified for reinforcement. This intense effort to assess pole condition provides ENO confidence that the condition of the pole population is known and that pole failure hazard is reduced.

[9] Estimated Service Life of Wood Poles, North American Wood Pole Council, Technical Bulletin 16-U-101, February 2016

Two things are noteworthy from the data presented on transformers and poles:

- Failure rates by equipment class are within the industry norms
- The number of crossarms per pole (average of 5+) is very high, a function of the legacy design

These equipment examples are provided to demonstrate that while failures are occurring in these classes of equipment, the rates of failure are not beyond what should be expected for the specific equipment classes.

In general, ENO is challenged with an aging infrastructure in an urban environment that experiences deterioration risk from environmental factors as well as age. Failure rates do not seem excessive at this time but the legacy design features of the system along with high customer density and a congested urban environment do, in many cases, contribute to higher CI and CMI.

4.1.3 Metrics and Outage Data

As discussed in Chapter 2 – Distribution Reliability Tutorial, commonly used interruption indices in the industry are SAIDI, SAIFI, CAIDI, CEMI, and ASAI. It was also noted that CI (customers interrupted) and CMI (customer minutes of interruption) are often used as proxies for SAIFI and SAIDI, respectively. Internally, ENO focuses on CI and CMI as the primary operating metrics to track reliability. This practice gives more emphasis to the "customer experience" than SAIFI and SAIDI which are often regarded as external reporting metrics.

ENO's focus on CI and CMI is evident in their internal reporting and practices. The ongoing reliability improvement programs are built around impact to CI and CMI and employees are well-versed in the status of CI and CMI against targets. As previously shown in Table 3, SAIFI and SAIDI and their respective proxies CI and CMI have trended upward from 2013 through 2017. Table 2 and Figure 3 however, indicate improvement due to many of the initiatives that have been implemented by ENO over several years.

4.1.3.1 2013-2017 CI and CMI Increase Evaluation

In 2013 ENO was a solid 2nd quartile performer in both SAIFI (CI) and SAIDI (CMI). The upward trend since that year has been reviewed above. For distribution line (DLIN) outages, the 2013 to 2017 increases in customers interrupted (CI) and customer minutes interrupted (CMI) are shown as Figure 6.

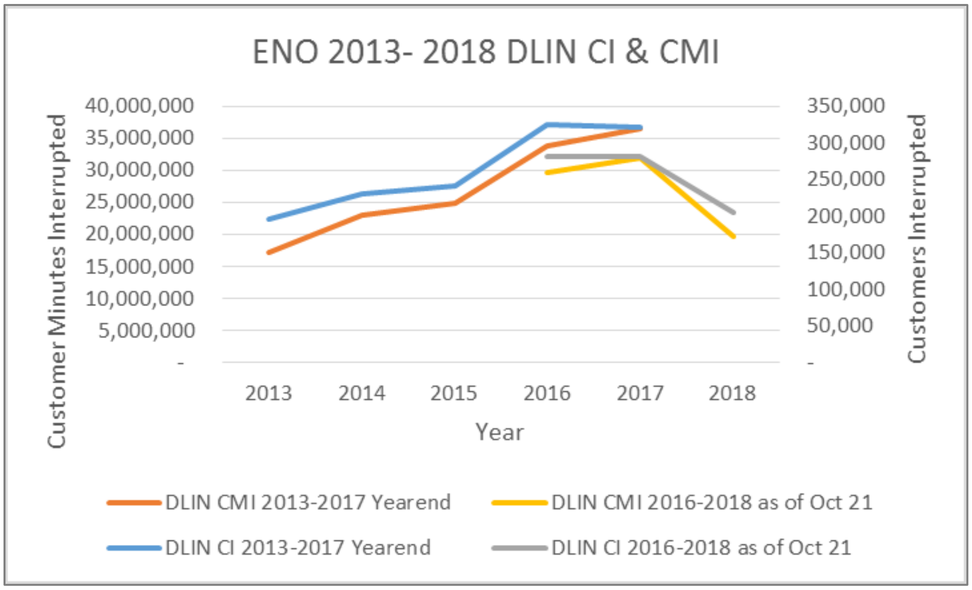


Figure 6 – CI and CMI Trend

As indicated, 2017 CI was 65% higher than 2013. In addition, 2017 CMI was 112% higher than 2013. The CMI increase is primarily due to the CI increase of 65%. The remaining reason for the CMI increase is due to an increased average minutes for restoration. The average duration has increased by about 25 minutes, or 28%. This figure also provides the 2016-2018 year-to-date performance as of October 21, for both CI and CMI. As shown here and previously stated, 2018 performance year-to-date has improved.

For distribution line (DLIN) outages, the 2013 to 2017 proportional increases in customers interrupted (CI) and customer minutes interrupted (CMI) are shown by reported cause in Figure 7 and Figure 8. Analysis of ENO outage records indicates that 64% of the CI increase between 2013 and 2017 is due to three cause codes: equipment (41%), conductor (12%), and vegetation (11%). The same cause codes contributed 61% of the CMI increase between 2013 and 2017: equipment (42%), conductor (12%), and vegetation (7%).

Within the Equipment cause, the two highest increases were recorded as crossarm and pole related outages. Pole and crossarm outages explain to a large degree any increase in restoration times. Once again, legacy design features contribute to the time required to replace poles and arms. It is not uncommon to find that multiple poles may need to be changed due to one pole failure. Consistent with one of ENO's ongoing reliability improvement programs, ENO attempts where possible, to rework associated circuits to achieve a less complex and congested circuit layout.

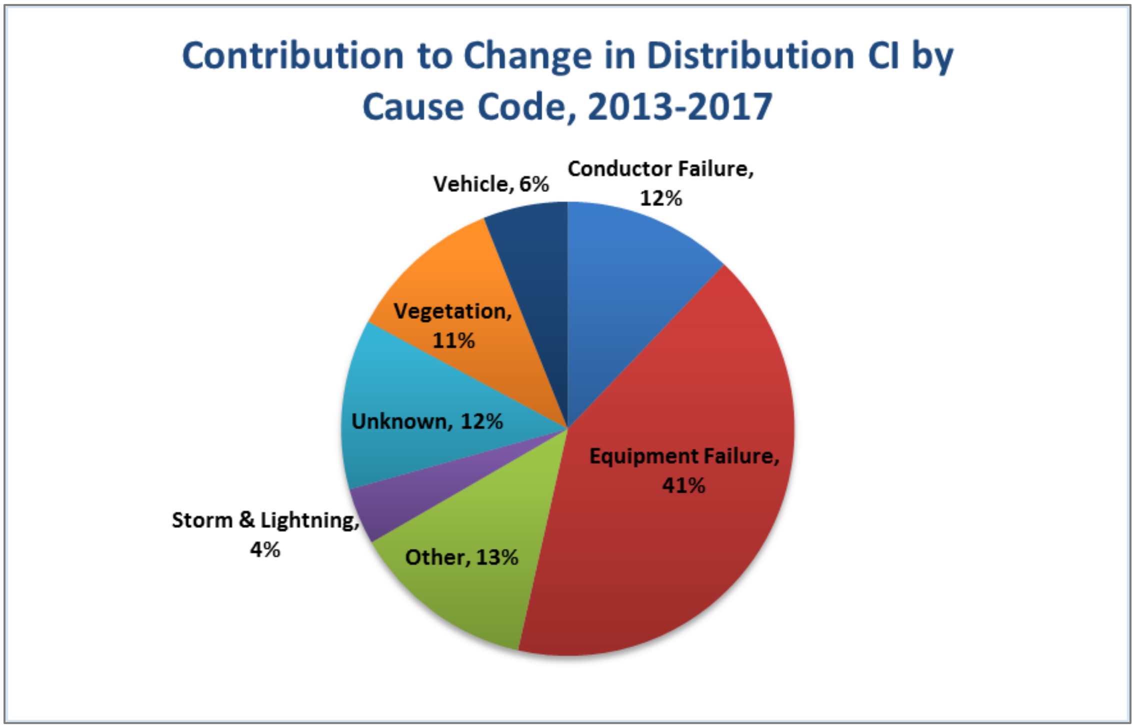


Figure 7 – Proportional DLIN CI Increases

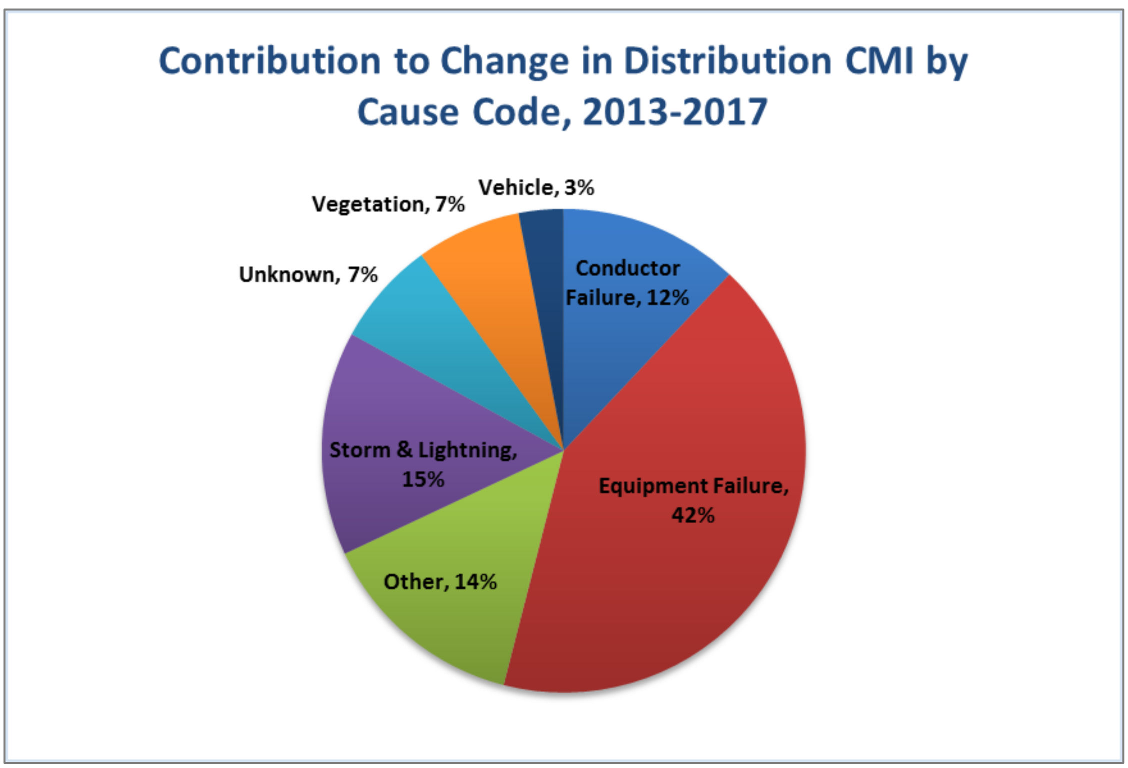


Figure 8 – Proportional DLIN CMI Increases

While "Equipment Failure" was found to be the highest summary category used to code outage events, it is somewhat misleading. A deeper look into the outage records indicates many events being coded as equipment failure when the root cause was something external to the infrastructure, such as weather or tree interference. For example, the outage code for a blown distribution line fuse is summarized under equipment failure. A blown fuse, however, is not a failure of equipment; it is in fact the proper operation of the equipment. In examining outage reports, it is found that many blown fuse outages are due to an identified root cause that should be captured under the appropriate category for that cause, e.g. vegetation, weather. ENO is working as part of their reliability awareness efforts to ensure that proper outage codes are used. Historical data, however, does not reflect that more recent emphasis.

4.1.3.2 Current Reliability Data- Outages and Events

ENO has previously provided the City with outage and reliability data including number and causes of outages, duration, dates, times, etc. Quanta has worked with the same raw data during this review. One observation on the collection of outage data that has been made has to do with how outage events are counted during a step restoration process.

Currently, when an outage occurs, ENO tracks the data on a per restoration step basis. For example, when a tree contact results in a substation breaker operation, that outage may be restored in a series of steps to minimize the duration of the outage to as many customers as possible. The restoration steps include field switching to restore power to areas that can be fed from sources not affected by the initial outage cause. In order to accurately track CI and CMI each step in that restoration process is counted as a separate outage event. Entergy's current outage management systems do not have the capability to ultimately aggregate the multiple steps into a single outage event. For example, if the breaker outage resulted in 3 restorations steps, the records will list them separately and will indicate 3 outages instead of 1, as well as 3 tree events instead of 1. This results in a higher number of outage events than what actually occurred. This process does not impact the accuracy of the CI and CMI data.

The extent of the impact of this practice is not known and is not anticipated to be highly significant, however, it does artificially inflate the number of outage events that have occurred. The impact of the practice is on the ability to develop accurate failure rate data that is based on actual number of outage events, such as outages per line mile. To the extent the practice exists in the industry, it is commonly being addressed as utility companies upgrade outage management systems to have capability to aggregate the multiple events. Entergy is implementing a new ADMS which should have the capability needed to address the issue.

4.2 Primary Reliability Improvement Programs and Initiatives

As has been reported in testimony by Entergy personnel, there are a number of ongoing reliability improvement programs and initiatives within ENO. Ongoing maintenance and inspection programs such as vegetation management, pole inspection, and cable replacement continue. Initiatives such as FOCUS, BACKBONE, and R1 have been implemented to bring additional emphasis to improving distribution reliability through design, construction, maintenance, and cultural change within the organization.

4.2.1 FOCUS Program

ENO currently has multiple efforts underway to improve the safety, reliability and resiliency of their distribution system. The FOCUS program is one of their major improvement efforts. This program is based on reviewing previous outages and addressing the root cause. In this regard, the program is considered to be a reactive practice as it addresses previously occurring issues. Quanta has reviewed the processes around the program and feels that it is effective in properly addressing the outage cause issues identified in Figure 7 and Figure 8. A brief review of the program follows.

Process Flow Diagram

The FOCUS flow diagram shown in Figure 9 indicates the overall process.

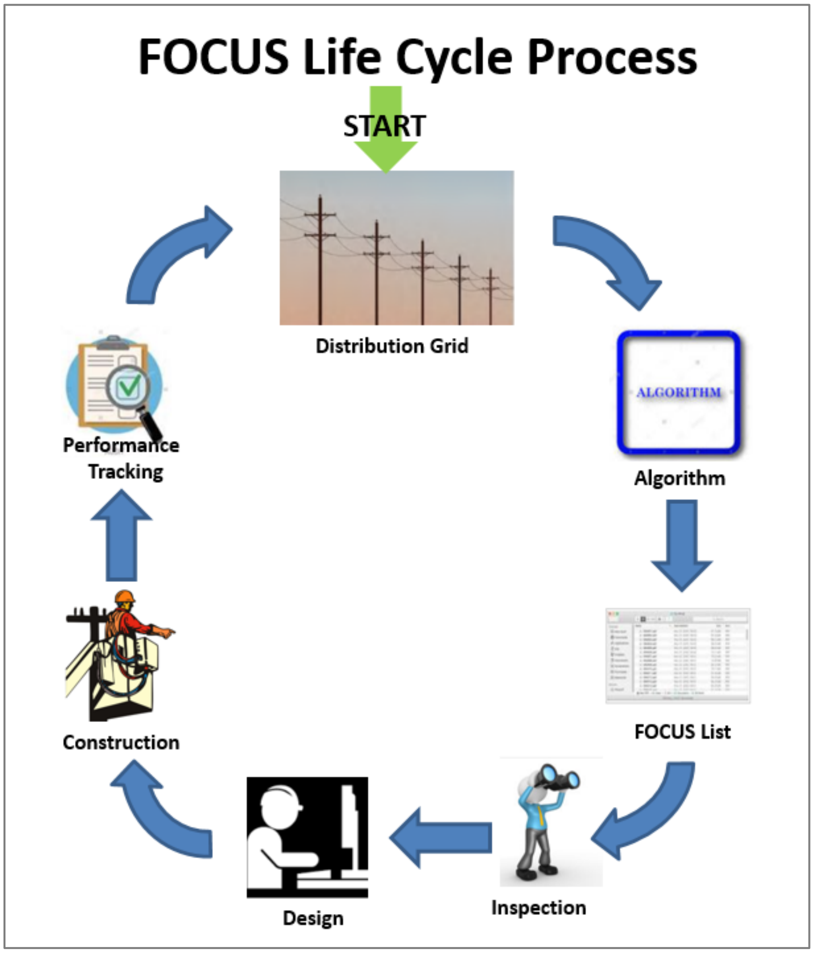


Figure 9 - FOCUS Life Cycle Process

Project Identification

FOCUS project identification begins with the Algorithm method described in Figure 10. This shows that projects implemented into the program are based on historical CI performance, which is a reasonable approach. Once identified, the projects are added to the FOCUS list.

Targeted Device Flagging Algorithm

- Exclude "unavoidable" cause codes
- Exclude BLACK and RED events
- Devices experiencing multiple events in a 24 hour period are only counted once

- The new flagging algorithms based upon:

"number of customers" with "number of outages" over a "period of time":

  - 1000 Cust's and greater, 3 outages, 18 months
  - 1000 Cust's and greater, 4 outages, 2 years
  - 500-999 Cust's, 3 outages, 15 months
  - 500-999 Cust's, 4 outages, 2 years
  - 200-499 Cust's, 3 outages, 12 months
  - 200-499 Cust's, 4 outages, 2 years
  - 75-199 Cust's, 3 outages, 9 months
  - 75-199 Cust's, 4 outages, 2 years
  - 20-74 Cust's, 3 outages, 6 months
  - 20-74 Cust's, 5 outages, 2 years
  - 1-19 Cust's, 3 outages, 4 months
  - 1-19 Cust's, 5 outages, 2 years

- Algorithms designed to trigger larger CI devices much faster and allow smaller CI devices **that have significant "quiet" times** the opportunity NOT to trigger.

Figure 10 - FOCUS Algorithm Method

<u>Inspections</u>

Once identified and included in the FOCUS list, that circuit segment gets a visual detailed inspection. The inspection personnel are ready and equipped to immediately resolve problems that may soon cause a reliability problem.

The inspections take into consideration multiple problem categories including:

- Bad poles
- Bad crossarms
- Bad crossarm braces
- Bad connections
- Damaged Insulators
- Loose guys
- Bad anchors
- Damaged arrestors
- Vegetation problems

Additionally, based on established ENO criteria, potential infrastructure changes are identified including:

- Install, relocate, remove lightning arrestors
- Relocate fused switch

- Remove and install grounds
- Install fuses on laterals
- Install animal guard
- Resolve slack and/or damaged conductors
- Improve Basic Insulation Level (BIL)

ENO has placed emphasis on the BIL ratings and upgrades of the distribution system to enhance its resiliency against lightning events.

Design and Construction

Following the field inspection, the results are reviewed. If no conflicts exists, the project is then designed and sent to construction.

Performance Tracking

Once implemented in the field, the performance of the circuit segment is monitored and compared to past performance. The expectation is that CI will be improved by 70% based on historical evaluation. The 70% improvement value is common to all Entergy operating companies.

The FOCUS program uses an approach that is common in the industry for addressing reliability performance. Other companies may refer to the effort as a "worst performing feeder" program or a program to address CEMI (customers experiencing multiple interruptions). The FOCUS program includes elements of both approaches and addresses sections of circuits that have experienced high CI and CMI. As the name implies, FOCUS is focused on addressing known areas of reliability problems with priority.

4.2.2 BACKBONE Program

The BACKBONE program has a similar approach to the FOCUS project with a key difference. While FOCUS is considered reactive based on reliability performance, BACKBONE is proactive. Inspections are based primarily on time elapsed since the feeder was last inspected. The BACKBONE program inspection is focused on the line segment from the substation breaker to the first sectionalizing device as shown in Figure 11.

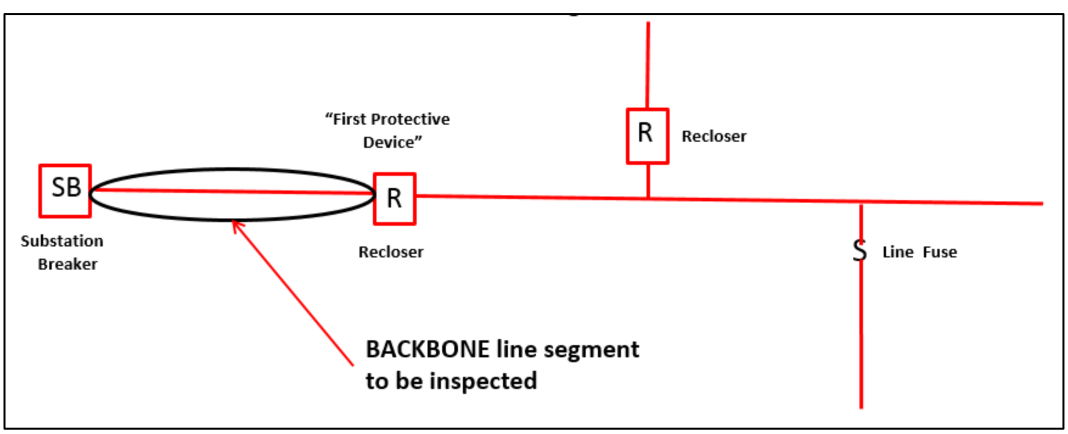


Figure 11 – BACKBONE Inspections

This inspection is comprehensive and includes detailed visual inspection and infrared or thermographic inspection to identify potential equipment issues. Using this approach, the BACKBONE program supports the avoidance of entire circuit outages, which normally have the highest CI impact and has been effective in identifying issues that were addressed and outages avoided. The following Figure 12 is taken from an internal ENO report and provides a status of projects, as of 10/25/18, that are being worked in 2018 under the FOCUS and BACKBONE initiatives. The avoided customer interruptions is based on estimates developed as part of each individual project scope.

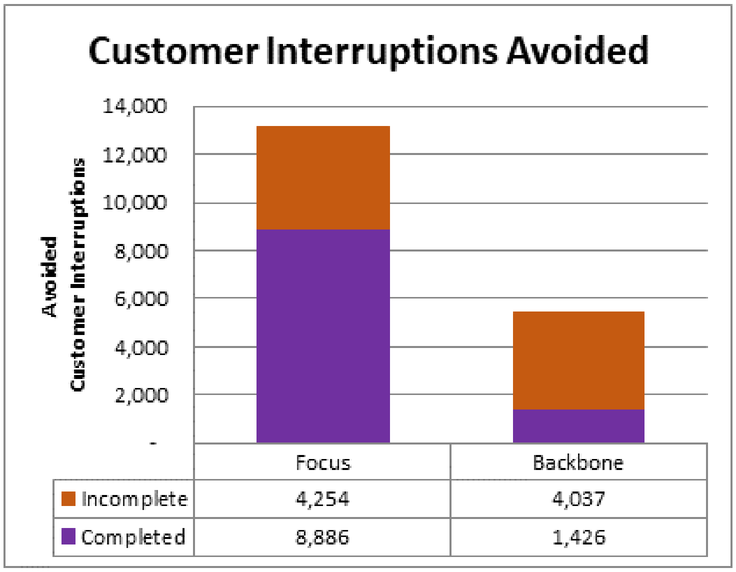


Figure 12 – Reliability Projects

4.3 Other Efforts to Improve Reliability

4.3.1 R1 Program

The purpose of the R1 Program is to improve reliability every time a crew performs work on the primary system. The applied phrase to provide guidance is "Build it Right the First Time". Besides the work already being done, reliability is further improved by taking corrective action on identified issues that would likely result in an outage. Key R1 efforts include ensuring the structure meets the enhanced BIL ratings, all visibly damaged equipment is resolved, ensuring structure spacing is maximized, and resolving vegetation issues, either by them or by a follow-up crew depending on the extent of trimming required.

The list of items to be addressed in each of the areas mentioned (BIL, structure, vegetation, visible damage) is comprehensive and effectively ensures that the infrastructure under repair is brought up to current standards as opposed to being repaired to the original standard to which it was designed. This is in effect a piece by piece inspection and rebuild of the infrastructure. It is effective, but it is also time consuming, which affects CI and CMI where outages are required to perform the work.

4.3.2 Pole Program

With the aging legacy infrastructure, the condition of poles and its equipment is important for reliability. ENO has the Pole Program, which is a cyclical proactive inspection, treatment, and preventative maintenance program.

The Pole Program requires a visual inspection of the pole and its installed infrastructure, such as crossarms and insulators. To validate the condition of the pole, an excavation is performed where possible. The program's excavations have been more successful than prior methods at identifying poles in need of follow-up. The process includes pole loading analysis to ensure a pole has the required strength based on pole condition, equipment on the pole, and desired level of wind resiliency. Depending on the overall results, the pole may be determined to be in satisfactory condition, may need treatment to maintain its health, may require re-enforcement, or may need to be replaced. As noted earlier, the standard pole inspection cycle for ENO is twelve years or 8.5% of the population per year. Recent inspections have been accelerated as part of the ongoing reliability emphasis. Pole inspection cycles within the industry vary, typically from eight to twelve years with some as high as fifteen and some companies having no formal program at all.

The National Electric Safety Code (NESC) provides utilities infrastructure installation requirements. Per NESC Rule 250B, 60 foot poles in ENO territory are required to withstand 60 MPH winds. Most distribution poles are less than 60 feet, in height but for enhanced pole strength, ENO is instead using a wind speed rating of 110 MPH for both pole replacements and new poles, resulting in higher class poles where physically feasible and cost effective, or where considered necessary due to criticality of the circuit or a specific customer. Based on engineering analysis, ENO is now installing Class 1 poles, where feasible, in areas where under NESC requirements Class 3 poles would suffice. Class 1 poles can be rated anywhere between 20% and 50% stronger than Class 3 poles depending upon the specific application.

4.3.3 Infrared Inspections

ENO is utilizing infrared inspections to identify potential failures on the distribution system. Infrared cameras detect elevated temperatures which likely indicates an imminent failure**.** The infrared findings are prioritized based on the severity of the elevated temperature along with other observations on that specific equipment. The infrared inspections are used for all applicable equipment including connectors, switches, connections where the overhead transitions to underground, and jumpers.

4.3.4 Underground Cable Renewal Program

The Underground Cable Renewal Program improves reliability by identifying cables that do not meet performance criteria. Those identified are targeted for replacement. This includes replacing full underground cable segments as opposed to repair of failed segments by splicing.

Aging underground cable is and has been an issue throughout the industry for a number of years. Proactive replacement of full cable segments or half loops, as done at ENO, is practiced by many in the industry, as splicing cable faults has been proven to be a short-term fix in many cases.

4.3.5 Vegetation Management Program

The ENO Vegetation Management Program is both proactive and reactive. On the proactive side, it has a cyclical approach based on trim cycles that are evaluated annually based on multiple factors including growth rates, vegetation type, and density. It is also evaluated using the impact on reliability.

Currently, the average cycle is 1.4 years which is considerably shorter than industry averages for trim cycles. The short cycle time is driven by the limited trim clearances allowed within the City. The majority of the trees trimmed are between the street and sidewalk and are City owned trees. With City owned trees, ENO is allowed to trim a maximum of 4 feet from primary conductors, with no allowance for secondary conductors, street light wires, and down guys.

Entergy's internal vegetation clearance standards are shown as Table 7. Clearances of 6-10 feet are expected depending on tree species to maintain safety and reliability. The City's requirement does not allow ENO to trim to the standard used in the rest of the Entergy system.

Table 7 – Entergy Vegetation Clearance Specifications

Minimum Acceptable Tree to Primary Wire Clearances – Below and Side Clearances			
Rate of Tree Growth	Urban (ft.)	Rural (ft.)	Example Tree Species
Slow	6	10	live oak, eastern red cedar, southern magnolia
Fast	10	15	sugarberry (hackberry), sweetgum, elm, water oak, sycamore, willow, Chinese tallow. pecan, maple, ash, hickory, black cherry, pine

On the reactive side, vegetation clearing is performed based on reports from ENO personnel or the public.

4.3.6 Basic Insulation Level (BIL) Enhancements

Lightning is one of the biggest causes for outages on the ENO distribution system. To improve the performance during these weather events, ENO has upgraded its standards related to the Basic Insulation Level (BIL). The BIL has been enhanced by modifying the insulator placements and pole framing configurations. The BIL enhancement is accomplished by increasing the air and wood path distance to a grounded conductor. Guidance under the R1 program is to ensure the structure BIL is 300kV or higher. To further increase the BIL when a shield wire is present, Hendrix cable is utilized.

4.3.7 Sectionalizing Program

The Sectionalizing Program strives to mitigate the impact of outages by reducing the number of customers impacted and reducing the outage duration time. This is performed by the installation of automatic isolating devices, such as reclosers. These devices quickly sectionalize the circuits into smaller segments with fewer customers. By immediately isolating the faulted section, the remaining section can potentially be more quickly restored.

For 2018, ENO plans to install an additional 30 reclosers on its circuits. The installations are selected and implemented based on the expected impact to both SAIFI and SAIDI.

4.3.8 Storm Hardening

The primary goal of the Storm Hardening program is to improve the resiliency of the circuits serving Critical Customers. Critical Customer examples include public safety and health facilities, civil defense facilities, and facilities important to ENO's restoration process. Other criteria used for project selection include the overall number of customers served as well as findings from other reliability programs inspections. The primary method used in the storm hardening program is increased pole strength as previously discussed. Storm hardening efforts throughout the industry are primarily focused on pole integrity through strength rating, pole condition management, and vegetation management. Methods used in the industry to increase pole strength include using larger wood poles, using poles of other materials (concrete, steel), and shortening span lengths, as examples. ENO is primarily using larger wood poles in their strengthening efforts.

In the case of ENO, storm hardening has also included an element of circuit reconfiguration. This approach is based in both storm resiliency and everyday reliability improvement. As discussed, legacy design issues are a contributor to reliability performance at ENO and circuit reconfiguration is an important element to addressing the legacy issues. This effort will improve operational reliability as well as enhance the system resiliency to severe weather as redundant facilities are removed and a more efficient design is implemented.

4.3.9 Internal Program

The purpose of the Internal Program is to address findings that are not compliant with the National Electric Safety Code and Entergy Service Standards. Internal Program projects are normally identified by internal parties such as the Region Manager, Operations Manager, Line Supervisors, and Design Managers. Projects identified in this program often deal with updating legacy design issues.

4.3.10 Cross-Company Reliability Improvement Collaboration

Reliability improvement at ENO is clearly a high priority with multiple efforts in progress. As part of these efforts different groups meet to coordinate and communicate new projects, schedule, status, and issues to resolve. Examples of those groups are Network Reliability, ENO Reliability Docket, and the Reliability Steering Committee. Each of these currently operating internal groups has a specific area of focus as part of the reliability improvement efforts. Additionally, enhanced reliability reporting tools have been developed and implemented to effectively and timely communicate reliability performance.

ENO has instituted a dedicated reliability crew. The crew is composed of the reliability service men (RSM) previously assigned to the individual networks. In that capacity their role was to identify emergent or high priority work that was expected to have an immediate impact on reliability. However, as individuals, the impact they could have was limited. By combining the RSMs into a crew covering ENO, they can now resolve emergent high priority issues and perform proactive inspections in addition to the already existing programs.

The Entergy "Reliability Champion Guidebook" is also an example of the extensive collaboration. Some of the key content in the Guidebook includes:

- Key Behaviors of a Reliability Champion- Includes holding regular face-to-face meetings to review topics such as recent outages, training, and performance reports
- Metrics Definitions – Includes SAIFI, SAIDI, CI, CMI, Average Outage Duration

- Metrics Calculations- How CI, CMI, and duration are determined
- Asset Management Programs- Includes FOCUS, BACKBONE, and R1-Build it Right the First Time
- R1 Key Actions- Includes detailed listing of R1 actions
- Reliability Meetings- Includes required and optional attendees as well as recommended agenda
- Reliability Reports- Explains the reports contents and the value
- Data Scrubbing- Explains how to validate that the acquired outage data is correct
- Causal Codes- Explains how to select the right code and the value

This is regarded by Quanta Technology as an excellent program to engage all employees in the subject and emphasis of achieving and maintaining system reliability. The program has been effective in identifying situations that could cause outages and in working to avoid those outcomes.

5 INDUSTRY PERFORMANCE AND TRENDS

Quanta Technology conducted a review and benchmark of the distribution reliability practices of ENO and selected electric utilities. The benchmark consisted of four activities: 1) a review of publicly available data (from industry and regulatory reports and publications) regarding distribution reliability performance and trends of US electric utilities, 2) the selection of utilities with good distribution reliability performance and distribution systems with similar characteristics as ENO, 3) review and application of prior Quanta Technology industry surveys and data collection, and 4) the comparison of ENO's distribution reliability practices versus those of the selected utilities via a survey questionnaire and other applicable information. The objective of the benchmark was to identify potential gaps, areas for improvement, and lessons learned that could be used by ENO as a reference to improve its distribution reliability practices. This section describes the methodology used to conduct the review and benchmark, and the main findings and conclusions from these tasks.

5.1 Reliability reports and metrics

Distribution reliability is a topic of great interest in the industry, therefore, there are various organizations that periodically collect, analyze, and publish important reliability reports that have become key references for the utility industry. The most well-known documents are the annual reports and benchmarks published by the IEEE Distribution Reliability Working Group[10], the Energy Information Agency (EIA)[11], the American Public Power Agency (APPA)[12], and the National Rural Electric Cooperative Agency (NRECA)[13]. These documents provide important insights regarding reliability performance for Investor-Owned Utilities (IOU), public power utilities, and rural cooperatives. Table 8 shows an example of a summary benchmark of distribution reliability indices using 2015 EIA's data; the results are categorized based on utility ownership (IOU, public power, cooperative, and all utilities) and type of reliability standard being used (IEEE 1366-2012 or other Results include average SAIDI and SAIFI values with and without MED.

[10] http://grouper.ieee.org/groups/td/dist/sd/doc/Benchmarking-Results-2017.pdf

[11] https://www.eia.gov/electricity/data/eia861/

[12] https://www.publicpower.org/reliability-tracking/distribution-system-reliability-and-operations-survey-and-report

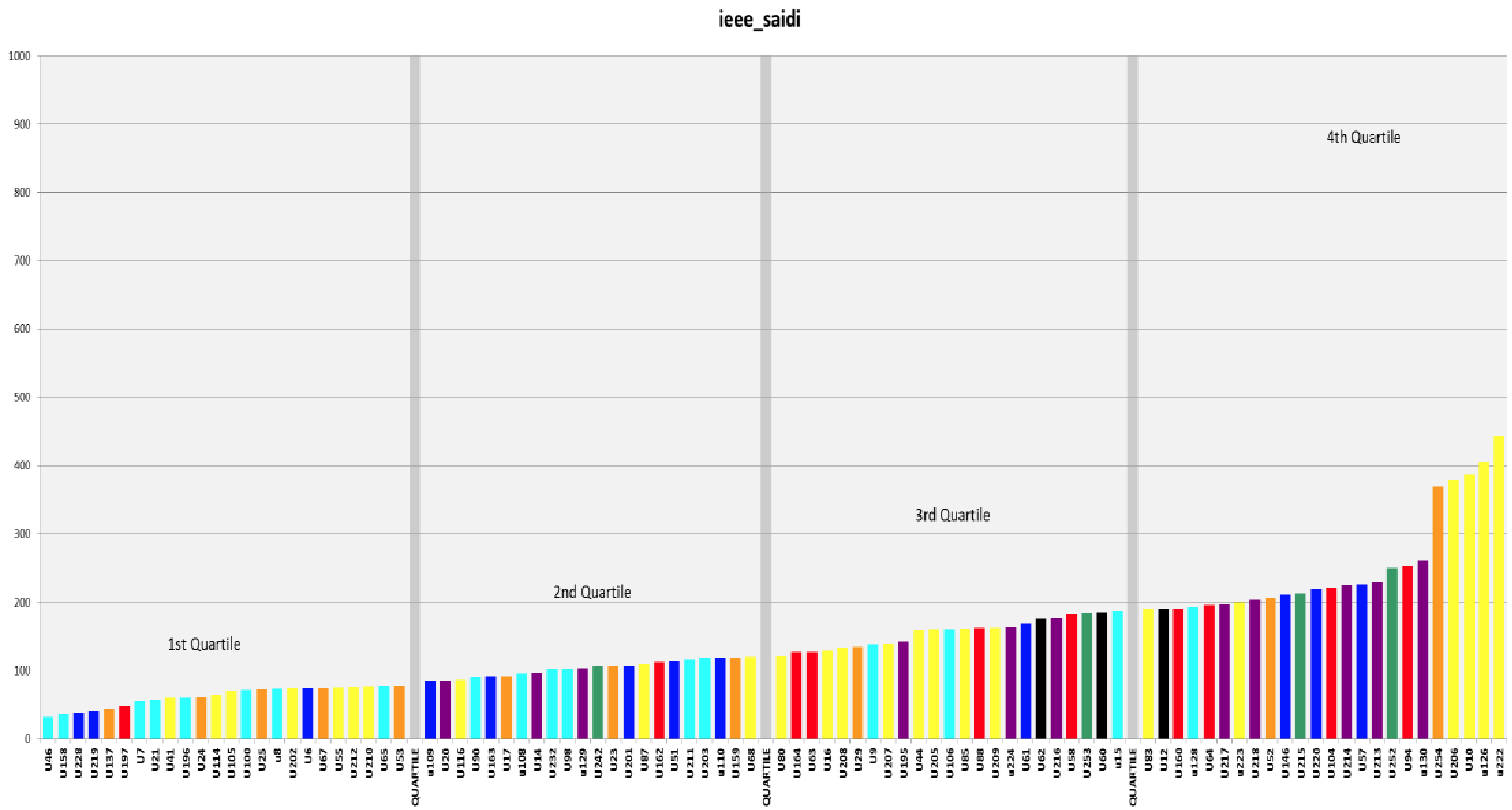
[13] http://grouper.ieee.org/groups/td/dist/sd/doc/2019-07-19%20NRECA%202016%20Distribution%20Reliability%20Study%20Results%20-%20Tony%20Thomas.pdf

Table 8 - Summary of Distribution Reliability Indices based on EIA Data (2015).[14]

National Data	>100,000 MWh	2015			
Number of Utilities Submitting Data Nationally:		**All**	**Coop**	**IOU**	**Public Power**
		1045	173	512	360
National Reliability Metrics (IEEE Standard)		**All**	**Coop**	**IOU**	**Public Power**
Average of SAIDI With MED (IEEE)		243.72	302.03	234.91	124.95
Average of SAIDI Without MED (IEEE)		131.96	161.57	133.65	59.52
Average of SAIFI With MED (IEEE)		1.96	2.75	1.38	0.93
Average of SAIFI Without MED (IEEE)		1.52	2.05	1.15	0.73
National Reliability Metrics (Other Standard)		**All**	**Coop**	**IOU**	**Public Power**
Average of SAIDI With MED (Other)		202.48	321.85	222.78	90.67
Average of SAIDI Without MED (Other)		114.41	171.89	88.92	53.19
Average of SAIFI With MED (Other)		2.87	2.11	1.54	3.65
Average of SAIFI Without MED (Other)		1.63	1.56	1.00	1.84

Figure 13 (pp. 33-34) was extracted from the 2018 IEEE distribution reliability benchmark (which includes 2017 results for 93 utilities). The plots show the sorted SAIFI and SAIDI values for participant utilities without MED. Utilities are identified by a confidential code number unique to each participant and have been grouped in quartiles, which is a terminology typically used in the industry to describe performance. Each quartile represents 25% of the total sample. High performing utilities (e.g., those with SAIFI and SAIDI values under 1.03 int/cust-yr and 78 min/cust-yr) are typically referred to as being "1st quartile", i.e., the top 25% of the survey data set. Similarly, 2nd quartile performance represents the subsequent 25% of the sample (between 25% and 50% of the total data set), and so on. Bar colors indicate the region of the US and Canada where participant utilities are located: Northeast (orange), Mid-atlantic (yellow), Southeast (green), Midwest (light blue), South (purple), Northwest (red) and Southwest (dark blue).

[14] http://grouper.ieee.org/groups/td/dist/sd/doc/2017-07-19%20APPA%20Reliability%20Update%20-%20Hoffman.pdf


ieee_saidi
1st Quartile
2nd Quartile
3rd Quartile
4th Quartile
QUARTILE
QUARTILE
QUARTILE

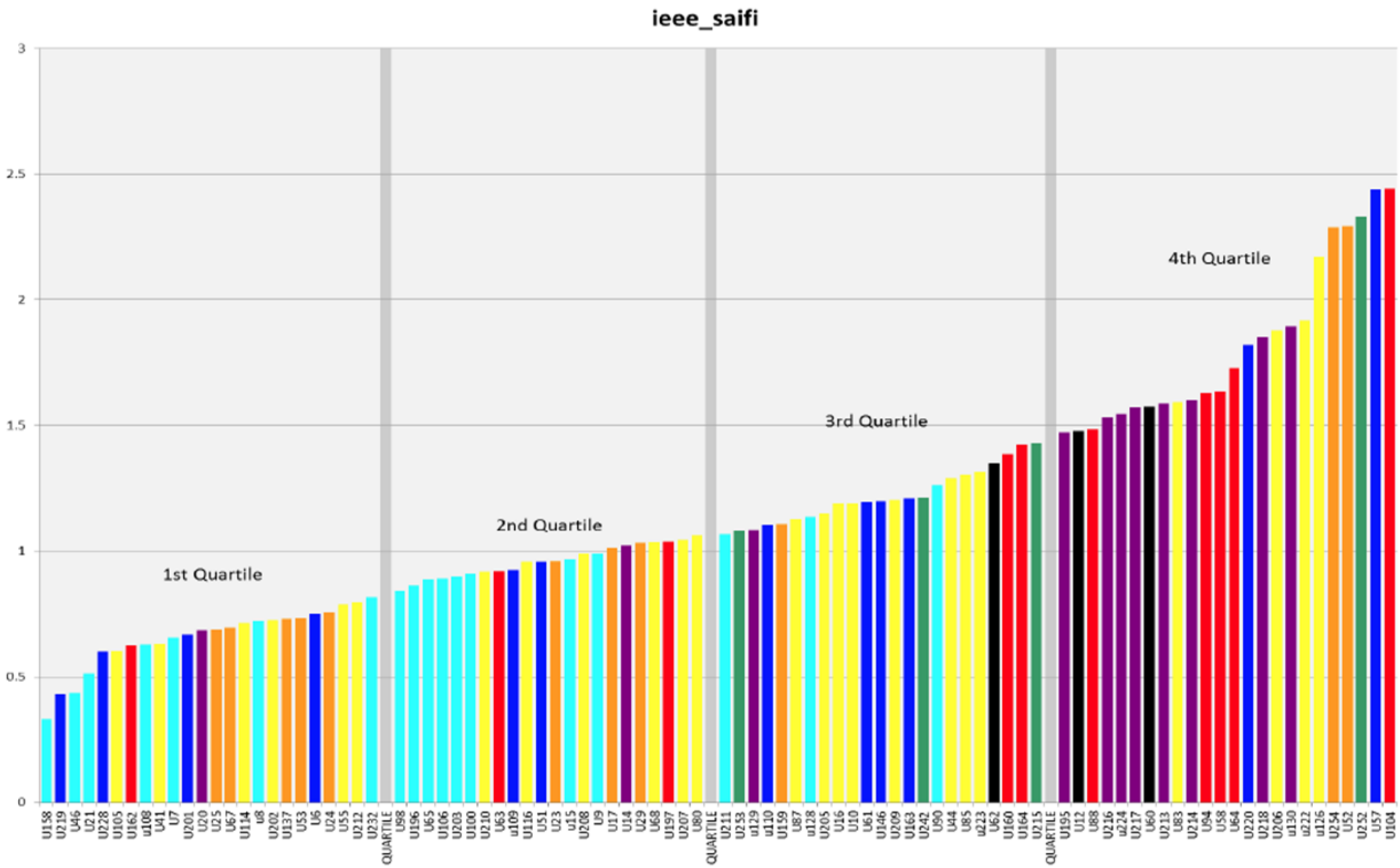


Figure 13 – SAIDI and SAIFI Quartiles from 2018 IEEE Annual Benchmark (without MED).

Figure 14 and Figure 15 show the historical evolution of the boundaries between quartiles for indices calculated without and with MED, respectively. Figure 14 plots show the boundaries between quartiles for the SAIFI and SAIDI values of the annual IEEE benchmarks from 2005 to 2017. Results show that the boundary between 1st and 2nd quartiles (without MED) has oscillated between 78 and 109 min/cust-yr for SAIDI, and 0.82 and 1.11 int/cust-yr for SAIFI. Figure 15 plots include MED and show that the boundary between 1st and 2nd quartile has oscillated between 107 and 202 min/cust-yr for SAIDI, and 0.9 and 1.33 int/cust-yr for SAIFI.

Table 3 in Section 4.1 shows ENO's historical reliability performance. Those results show that ENO's reliability performance for 2017 is close to the borderline between 3rd and 4th quartile in the IEEE benchmark.

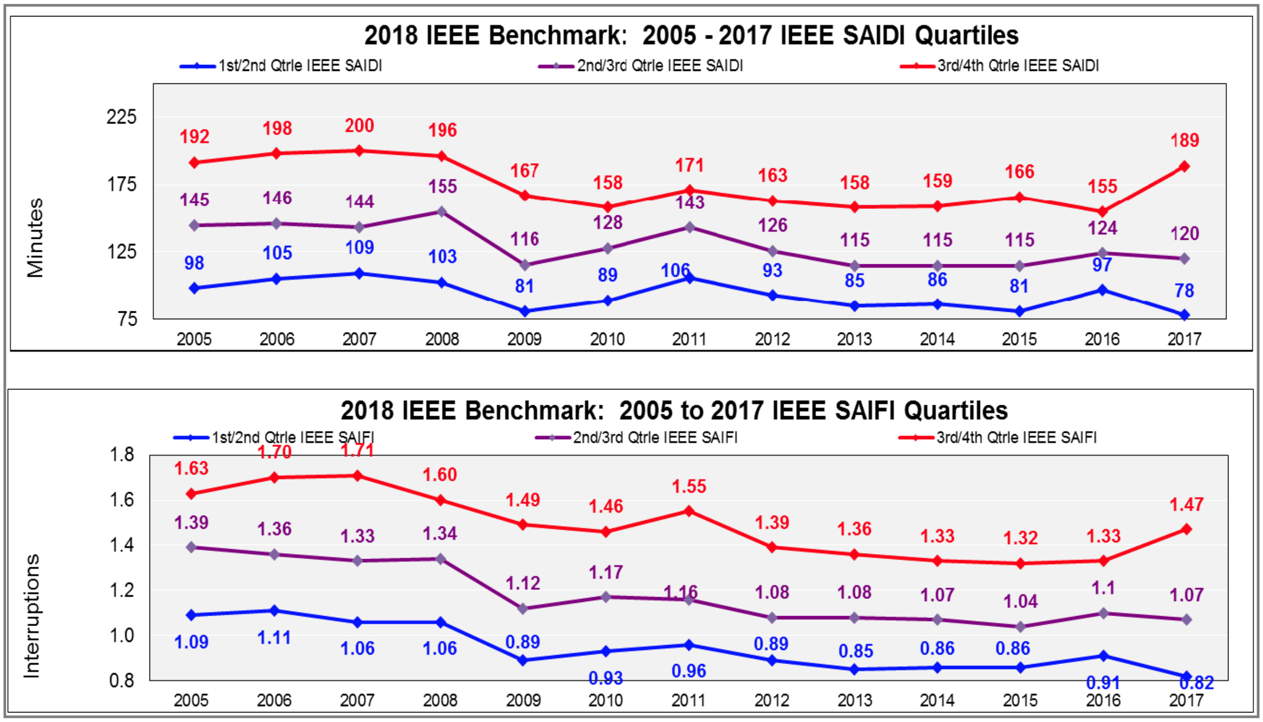


Figure 14 – Historical SAIDI and SAIFI Quartiles from 2018 IEEE Annual Benchmark (without MED).

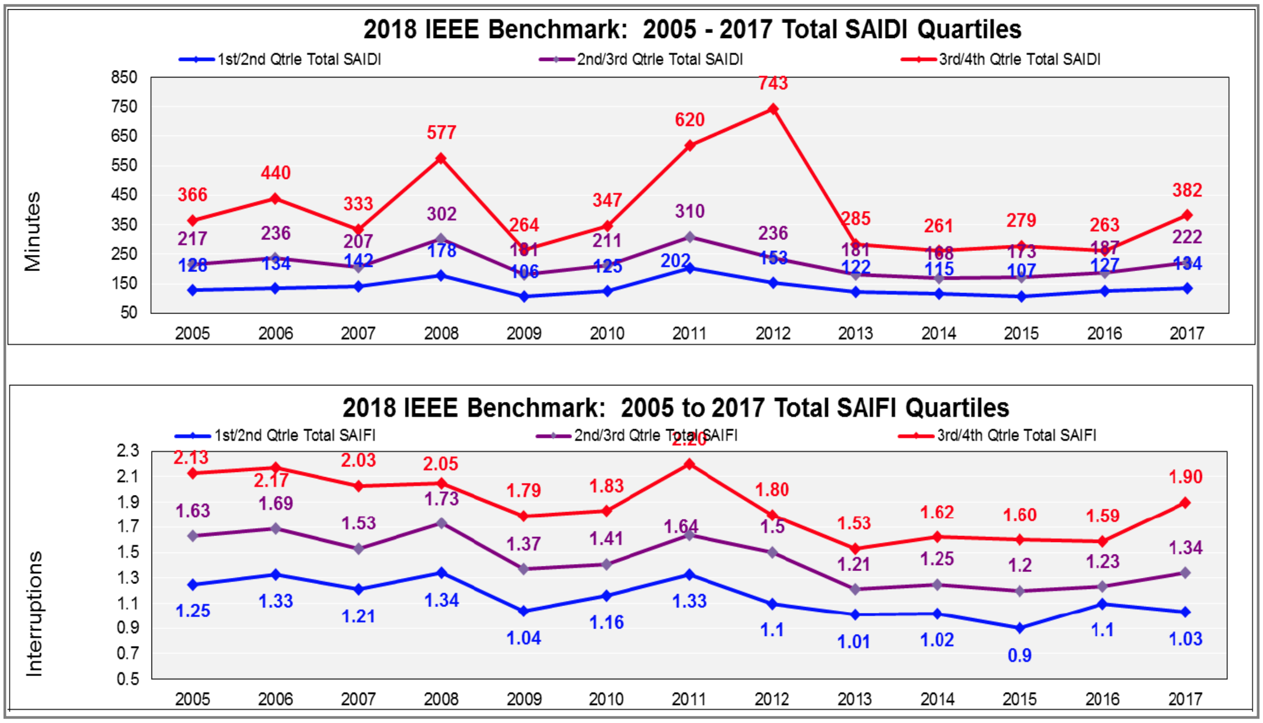
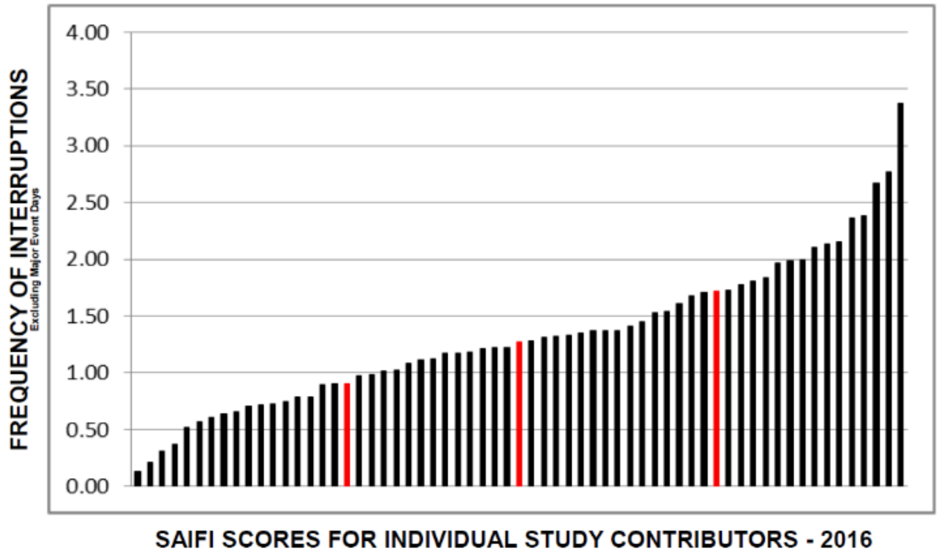
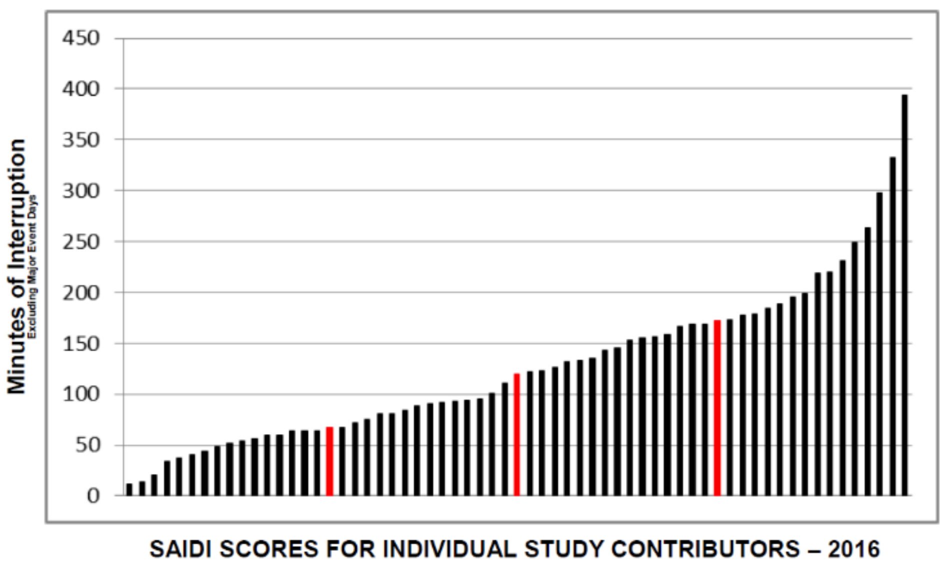


Figure 15 – Historical SAIDI and SAIFI Quartiles from 2018 IEEE Annual Benchmark (with MED).

Finally, Figure 16 shows the sorted SAIFI and SAIDI values and respective sample quartiles for participant utilities included in the annual NRECA reliability survey of 2016. Results include SAIDI and SAIFI values for all participant utilities (excluding MED), each bar represents a utility (no utility names are included). Utilities are grouped by quartiles, each quartile represents 25% of the sample of participant utilities, 1st quartile represents top reliability performance and 4th quartile represents poorest performance from the sample. The corresponding table with each plot shows boundary values between quartiles, minimum and maximum reported values, and average value of the sample.



Min	0.13
1st Quartile	0.91
2nd Quartile	1.27
3rd Quartile	1.72
Max	3.37
AVG:	1.32



Min	11.28
1st Quartile	65.55
2nd Quartile	119.91
3rd Quartile	170.51
Max	394.01
Avg	126.92

Figure 16 – Historical SAIDI and SAIFI Quartiles from 2016 NRECA Annual Benchmark (without MED).

5.2 Benchmark of distribution reliability practices

In order to evaluate ENO's distribution reliability program versus leading industry practices, Quanta Technology conducted a thorough review of the proposed components of the program, and a benchmark of ENO's distribution reliability practices versus those of utilities with similar features as ENO and top reliability performance. The objective of benchmarking versus high performing utilities was to identify potential gaps, areas for improvement and lessons learned that could be considered by ENO in its distribution reliability program. It is worth noting that ENO's distribution system and service territory features are unique, consequently, it is difficult to identify utility peers to make a one-to-one comparison. Therefore, the aim of this task is to identify utilities that are sufficiently similar, so their distribution reliability practices, success stories, and lessons learned can be relevant for ENO. This section describes the methodology used to conduct the benchmark. The studies described in this section were made through a combination of quantitative and qualitative analyses, heuristics, and Quanta Technology's expertise. All the data used in the process was obtained from publicly available sources, such as industry and Public Utility Commission (PUC) reports, websites, etc.

The distribution reliability benchmark data from surveys such as those conducted by IEEE, APPA and NRECA are provided by utilities using automated online software tools and kept confidential. Distribution reliability data is publicly available in some PUC websites, since some states require utilities to make annual filings of distribution performance. The EIA annually collects and makes distribution reliability data available via their website, specifically as part of its Form EIA-861 report. This data set is very comprehensive and includes information from IOU and public power utilities (including ENO), as well as from rural cooperatives.

Quanta Technology used the 2016 reliability data from the EIA report to identify and preselect a subset of 28 utilities[15], based on high reliability performance[16] (e.g., Consolidated Edison, Madison Gas and Electric), geographic similarities to ENO's service territory (e.g., utilities located in the Gulf of Mexico area, such as Mississippi Power, Alabama Power, and Gulf Power), and knowledge of the implementation of important initiatives pertaining to reliability practices (e.g., storm hardening work at Florida Power and Light, distribution automation deployment at ComEd). The objective of this preselection was to reduce the search space to be considered in the benchmark to a reasonable amount, given the level of effort required to collect data, and the fact that high performing utilities were the main target of the benchmark.

Then, a prioritization approach was used to rank the preselected utilities. The approach consisted of calculating a total similarity metric for each utility, based on the following variables:

- Reliability indices (SAIFI and SAIDI)
- Customer density (customers/square-mile)
- Average electricity price ($/kWh)
- Grid design (percentage of overhead and underground lines)
- Weather (average temperature, lightning flash density, precipitation, and relative humidity)

The variables customer density, average electricity price, grid design, and weather were selected due to their evident impact on reliability performance. For instance, areas with higher customer density tend to have better reliability performance, since cost-effectiveness analyses of proposed investments tend to favor projects located in those areas. There is also a correlation between electricity price and reliability, higher electricity prices are generally a reflection not only of generation costs, but also of investments levels in transmission and distribution infrastructure, which are recovered through rates. Similarly, areas with high percentage of underground grid tend to have better reliability performance due to the reduced overhead exposure and vulnerability of distribution lines and equipment, i.e., underground distribution is

[15] The majority of utilities (76%) included in this list calculate their reliability indices as per IEEE Std. 1366-2012, the remaining utilities use other methodologies (e.g., defined by their respective PUC)
[16] Defined for the objective of this benchmark as SAIFI and/or SAIDI within 1st and lower 2nd quartile performance of 2017 IEEE Benchmark

intrinsically more reliable (lower failure rates) than overhead distribution, this is also shown graphically in Figure 17.

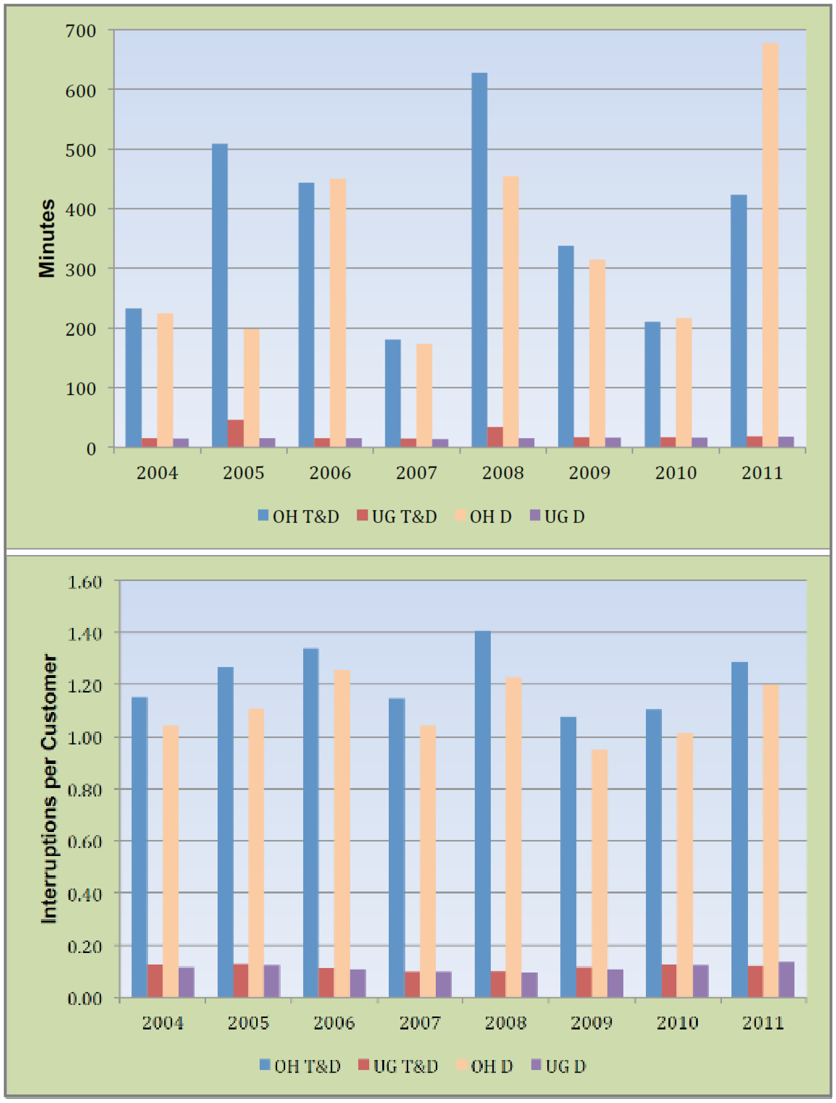


Figure 17 – SAIDI and SAIFI values for overhead (OH) and underground (UG) transmission and distribution systems.[17]

Finally, weather parameters such as temperature, lightning flash density, precipitation and relative humidity have a direct effect on various aspects of distribution reliability performance[18]. Figure 18 shows examples of the reliability performance of the subset of 28 preselected utilities and ENO, as a function of

[17] Out of Sight, Out of Mind 2012, An Updated Study on the Undergrounding of Overhead Power Lines, Edison Electric Institute (EEI), Jan. 2013 http://www.eei.org/issuesandpolicy/electricreliability/undergrounding/Documents/UndergroundReport.pdf

[18] For instance, among several relevant findings, the 2015 report "Assessing Changes in the Reliability of the U.S. Electric Power System" by Lawrence Berkeley National Laboratory found that (if major events are not included) a 10% increase in the number of customers per line mile is correlated with a 4% decrease in SAIFI. The report also found that (if major events are included): a) a 10% increase in the percentage share of underground line miles is correlated with a 14% decrease in SAIDI, b) a 10% increase in annual lightning strikes is correlated with a 2% increase in SAIFI, and c) a 10% increase in annual precipitation—above the long-term (generally, 13-year) average—is correlated with a 10% increase in SAIDI https://emp.lbl.gov/sites/all/files/lbnl-188741.pdf

customer density, percentage of underground distribution and average electricity price. The results show that although ENO's customer density is higher than that of most peer utilities, its distribution reliability indices are also higher. This is influenced by the fact that the percentage of ENO's distribution grid that is underground is smaller than that of the majority of peer utilities. These features, combined with the unique weather patterns and physical vulnerabilities of the area, make reliability improvement at ENO a challenging and complex task.

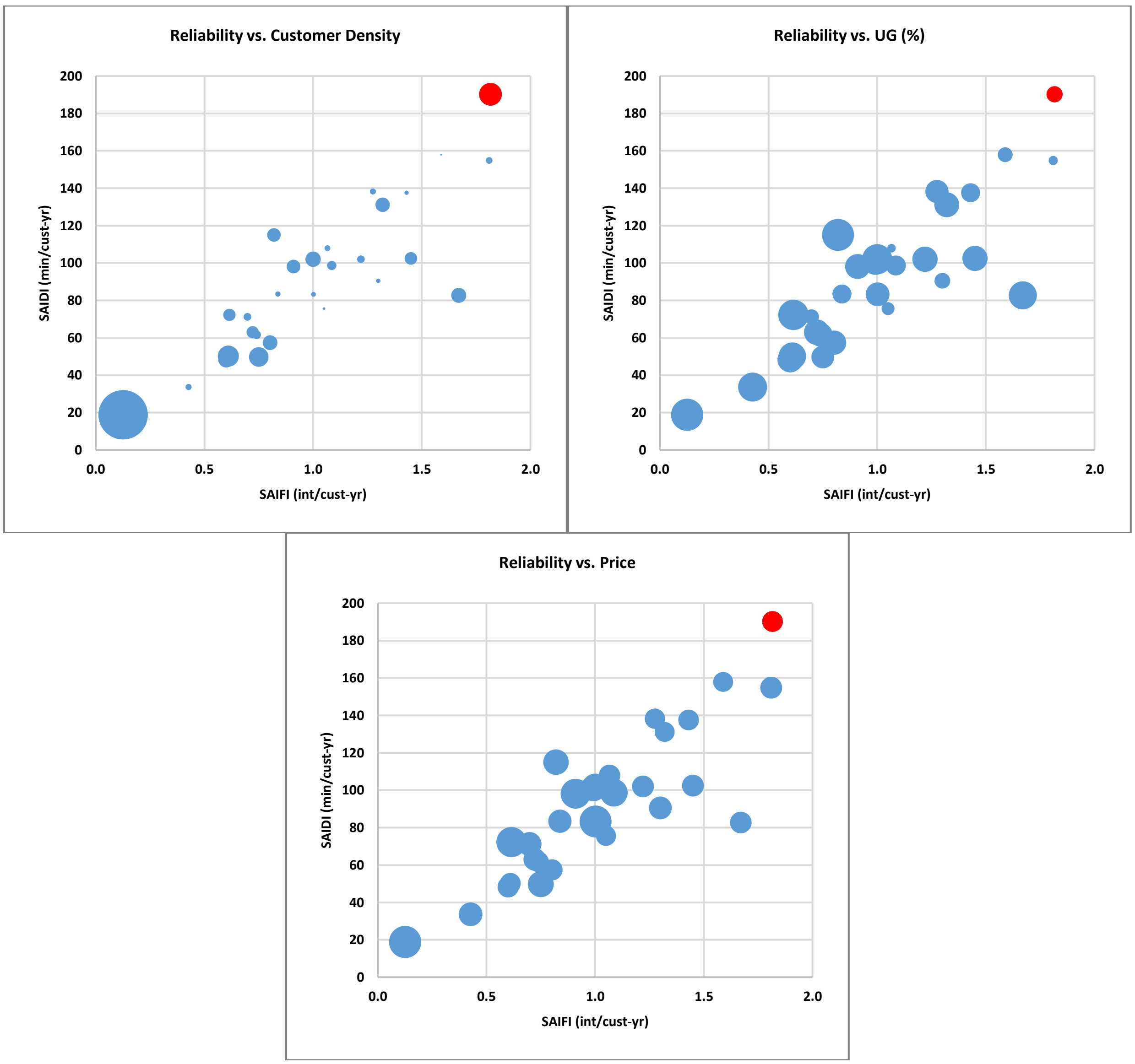


Figure 18 – Benchmark Comparisons.

(Reliability (SAIDI and SAIFI) versus customer density (customers/square-mile), percentage of underground distribution, and average electricity price ($/kWh) for the subset of 28 preselected utilities. Bubble size shows the variable of interest (customer density, percentage of underground distribution, and average electricity price). ENO is shown in red. Results were calculated using 2016 data compiled by the U.S. Energy Information Agency (EIA). The results show that although ENO's customer density is higher than that of most peer utilities, its distribution reliability indices are also higher. This is influenced by the fact that the percentage of ENO's distribution grid that is underground is smaller than that of the majority of peer utilities.)

The total similarity metric evaluates how similar ENO and each utility are. The smaller the total metric for a specific utility is, the more similar ENO and that utility are. The total metric was calculated as the weighted sum of five metrics, as follows[19]:

- The individual metrics for the variables customer density and average electricity price were calculated as the absolute value of the difference between the respective normalized values of ENO and those of each utility
- The individual metric for the variable grid design was calculated based on the sub-variables percentage of overhead and underground construction. The grid design metric was calculated as the Euclidean distance between the respective normalized values of ENO and those of each utility.
- The individual metric for the variable weather was calculated based on the sub-variables average temperature, lightning flash density, precipitation, and humidity. The weather metric was calculated as the Euclidean distance between the respective normalized values of ENO and those of each utility.
- The individual metric for reliability indices (SAIFI and SAIDI) was calculated as the inverse of the Euclidean distance between the respective normalized values of ENO and those of each utility. That way utilities with high reliability performance were assigned a small value and utilities with poor performance were assigned a large value.

(The similarity metric formulae are included as Appendix C).

Finally, utilities were prioritized based on their total similarity metric from minimum to maximum. The top 20 utilities with smallest total similarity metrics, which are shown in Table 9, were selected to participate in the benchmarking of distribution reliability practices. Quanta Technology invited contacts at those utilities to participate in the benchmark by answering a confidential online questionnaire. A copy of the questionnaire is included in Appendix D of this report. Five utilities agreed to participate and completed the online questionnaire. Quanta Technology complemented the results from the survey by reviewing and extracting relevant data from publicly available sources, specifically, from reliability reports published by the PUCs of Florida[20], Illinois[21], Pennsylvania[22], and Texas[23].

[19] The respective formulae and data are included in Appendix B of this report
[20] http://www.psc.state.fl.us/ElectricNaturalGas/ElectricDistributionReliability
[21] https://www.icc.illinois.gov/Electricity/utilityreporting/ElectricReliability.aspx
[22] http://www.puc.state.pa.us/consumer_info/electricity/reliability.aspx
[23] https://www.puc.texas.gov/industry/electric/reports/sqr/default.aspx

Table 9 - Prioritized list of utilities to benchmark based on results of similarity analysis

Rank	Utility
1	Mississippi Power
2	Gulf Power
3	South Carolina Electric & Gas Company
4	Orlando Utilities Commission
5	PPL Electric Utilities
6	Florida Power & Light Co
7	CPS Energy
8	Austin Energy
9	Public Service Electricity & Gas
10	Alabama Power
11	Commonwealth Edison
12	Duke Energy Florida
13	Atlantic City Electric
14	Georgia Power
15	Tampa Electric
16	JEA
17	CenterPoint Energy
18	Virginia Electric & Power (Dominion Energy)
19	Madison Gas & Electric
20	NSTAR Electric Company
21	Delmarva Power
22	Hawaiian Electric
23	Baltimore Gas & Electric
24	Potomac Electric Power
25	AEP Texas Central Company
26	San Diego Gas & Electric
27	Cleco Power
28	Consolidated Edison

5.3 Peer comparisons

5.3.1 Metrics

The results from the benchmark show that peer utilities use SAIDI, SAIFI, CAIDI, CEMI, MAIFI and $MAIFI_E$ for evaluation of reliability performance (other indices used by peer utilities include L-bar and CELID[24]). Some of these indices are used for internal control and others for regulatory reporting. SAIFI and SAIDI are the most widely used reliability indices in the industry, as shown in Figure 19. For instance, these indices are being used for regulatory reporting by ENO, Austin Energy, CenterPoint, Duke Energy Florida, Florida Power and Light[25], Gulf Power, Tampa Electric, and Pennsylvania Power and Light, among others. Another popular combination is SAIFI and CAIDI, which is being used for regulatory reporting by Commonwealth Edison and Consolidated Edison, among others. However, as discussed in previous sections, CAIDI can provide misleading results and MAIFI is difficult to track accurately (since it counts every momentary interruption, rather than momentary interruption events, which are tracked by $MAIFI_E$).

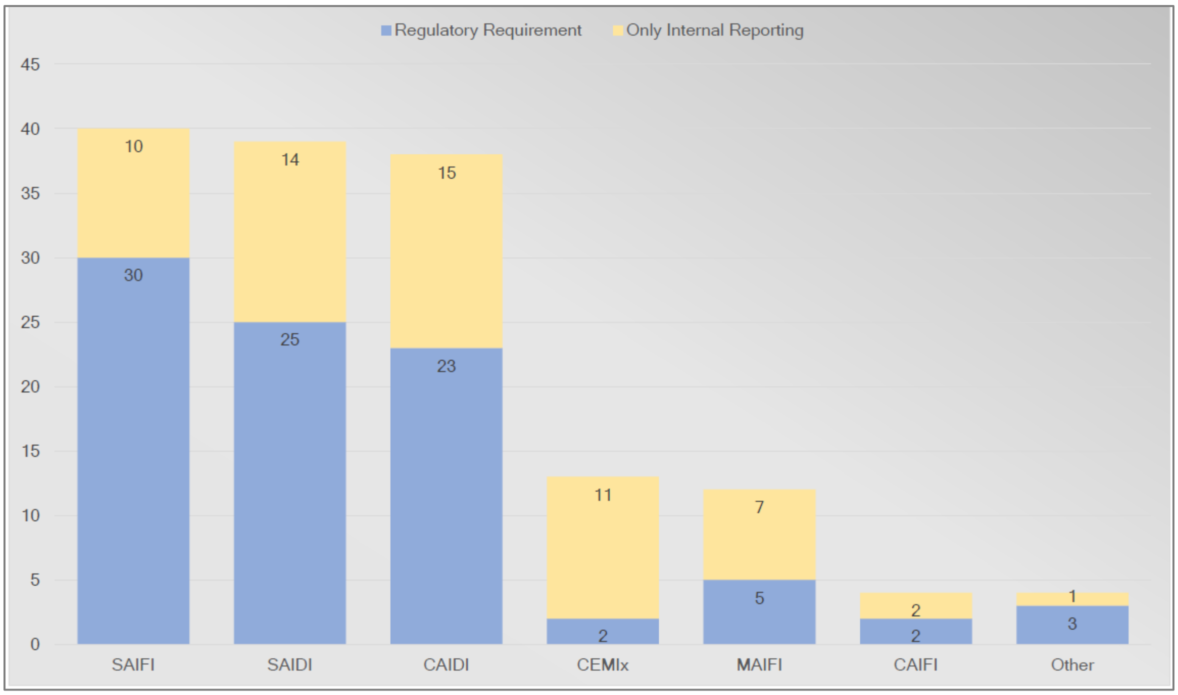


Figure 19 – Survey of Reliability Metrics used for Regulatory and Internal Reporting.

(Numbers inside each bar show the number of participant utilities that selected each option. Results show that SAIFI, SAIDI and CAIDI remain the most common indices for regulatory reporting and that $CEMI_n$ and MAIFI are becoming

[24] As per IEEE 1366-2012 Customers Experiencing Long Interruption Durations (CELID) indicates the ratio of individual customers that experience interruptions with durations longer than or equal to a given time. That time is either the duration of a single interruption (s) or the total amount of time (t) that a customer has been interrupted during the reporting period.
[25] Florida Power and Light tracks CEMI-3, CEMI-5, CEMI-8, CEMM-35, CEMM-50 and CME ("Customer Momentary Experience")

popular for internal reporting. Results show that out of the less traditional indices, MAIFI is the most common one for regulatory reporting. [26])

$CEMI_n$ and $MAIFI_E$ are becoming increasingly popular reliability indices. The utilization of this set of indices is expected to provide a more complete assessment of distribution reliability for reporting purposes and also for evaluation and allocation of investments (e.g., benefit-cost analysis). For instance, as shown in Figure 20, $CEMI_5$ and $MAIFI_E$ are being used for external and regulatory reporting by JEA[27], Duke Energy Florida, Florida Power and Light, Gulf Power, and Tampa Electric[28]. $CEMI_n$ (or jurisdiction-specific indices that are similar to $CEMI_n$) are also reported by other utilities not included in Table 9, for instance, the IOUs in California (Southern California Edison, Pacific Gas and Electric and San Diego Gas and Electric)[29], Potomac Electric Company (Pepco), Avista, and IOUs in Illinois, Delaware, Maryland, New Jersey, Connecticut and North Dakota[30]. Similarly, in Pennsylvania, electric distribution companies are required to report MAIFI data provided the equipment capability is available to obtain relevant data (momentary interruption threshold used by utilities in Pennsylvania is 5 minutes). Furthermore, PPL Electric has a program to address CEMI, under this program all customers have their interruption count monitored on a rolling 12-month basis and appropriate remediation strategies are developed[31].

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[26] S. Martino, 2017 EPRI General Reliability Survey, Preliminary Results, 2017 IEEE PES General Meeting, Jul. 2017, Chicago, IL http://grouper.ieee.org/groups/td/dist/sd/doc/2017-07-18%20EPRI-IEEE%20Survey%20Results%20-%20Sal%20Martino.pdf

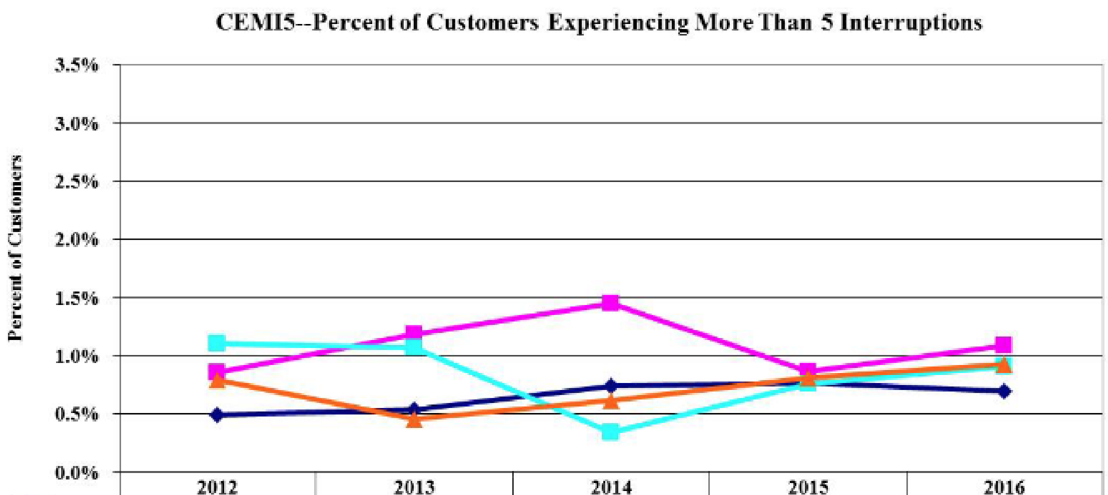
[27] https://www.jea.com/about/electric_systems/reliability/cemi-5/

[28] Review of Florida's Investor-Owned Electric Utilities 2016 Service Reliability Reports, Florida Public Service Commission, Division of Engineering, Nov. 2017 http://www.psc.state.fl.us/ElectricNaturalGas/ElectricDistributionReliability

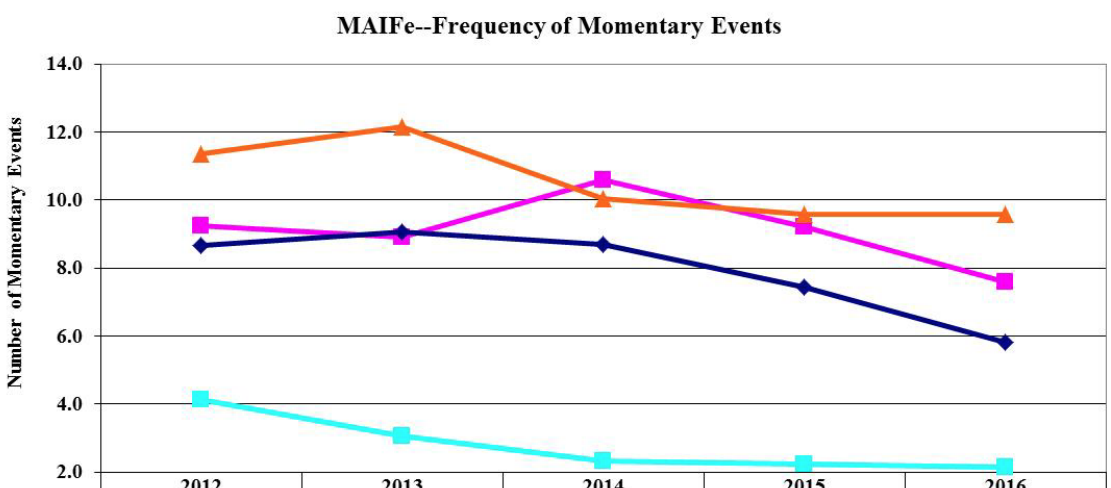
[29] M. Kurtovich, M. Zafar, California Electric Reliability Investor-Owned Utilities Performance Review 2006-2015, CPUC, May 2016 http://www.cpuc.ca.gov/uploadedfiles/cpuc_public_website/content/about_us/organization/divisions/policy_and_planning/ppd_work/ppd_work_products_(2014_forward)/ppd%20reliability%20review.pdf

[30] Customer Specific Reliability Metrics: A Jurisdictional Survey https://www.oeb.ca/oeb/_Documents/EB-2010-0249/OEB_Customer_Specific_Reliability_Metrics_Report.pdf

[31] Electric Service Reliability in Pennsylvania, Pennsylvania Public Utilities Commission, 2016



	2012	2013	2014	2015	2016
DEF	0.9%	1.2%	1.5%	0.9%	1.1%
FPL	0.5%	0.5%	0.7%	0.8%	0.7%
Gulf	1.1%	1.1%	0.3%	0.8%	0.9%
TECO	0.8%	0.5%	0.6%	0.8%	0.9%



	2012	2013	2014	2015	2016
DEF	9.3	8.9	10.6	9.2	7.6
FPL	8.7	9.1	8.7	7.5	5.8
Gulf	4.1	3.1	2.3	2.2	2.1
TECO	11.4	12.2	10.0	9.6	9.6

Figure 20 – Adjusted $CEMI_5$ and $MAIFI_E$ reported by IOUs in Florida

Figure 20 presents information from Duke Energy Florida, Florida Power and Light, Gulf Power and Tampa Electric. Results show the percentage of total number of customers that experienced more than 5 interruptions per year, and the annual frequency of momentary interruption events experienced by an average customer in the service territory of these utilities.

Reliability indices and $MAIFI_E$ in particular are certainly influenced by the choice of sustained and momentary interruption threshold. The shorter the threshold the greater the share of interruptions that are considered as *sustained* and counted by the traditional indices (SAIFI and SAIDI). Figure 21 shows the results of a survey conducted by Lawrence Berkeley National Laboratory (LBNL) among 123 utilities regarding their practices for defining sustained interruptions. The results show that 5 minutes, which is the threshold recommended by the IEEE 1366-2012 Std. is the most common value used by this utility sample, and is the value that ENO is currently using as threshold for sustained/momentary interruptions[32]. ENO uses the IEEE 2.5 Beta method for identification of MED. As shown in Figure 22, this is an industry leading practice that has been adopted by many PUCs and utilities. As discussed in previous sections, some utilities use exclusion methods defined by their state PUCs.

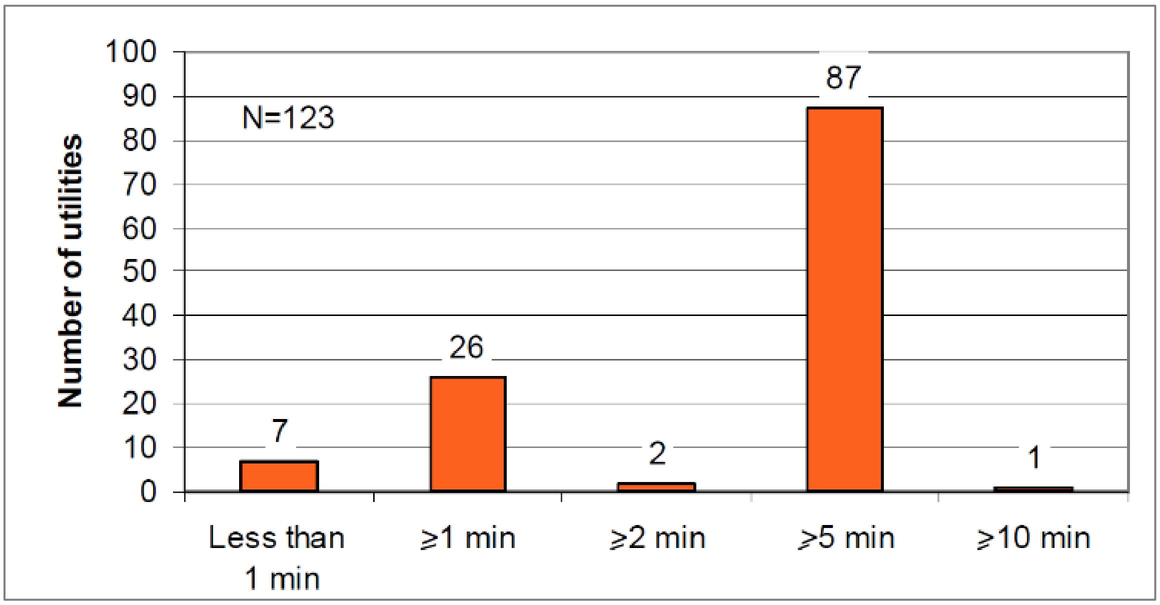


Figure 21 – Utility Practices for Defining Sustained Interruptions. [3]

[32] Surveys conducted by the APPA among public power utilities show an increase from 38% to 48% from 2013 to 2015 in the number of utilities that use 5 min. as the threshold for momentary and sustained interruptions

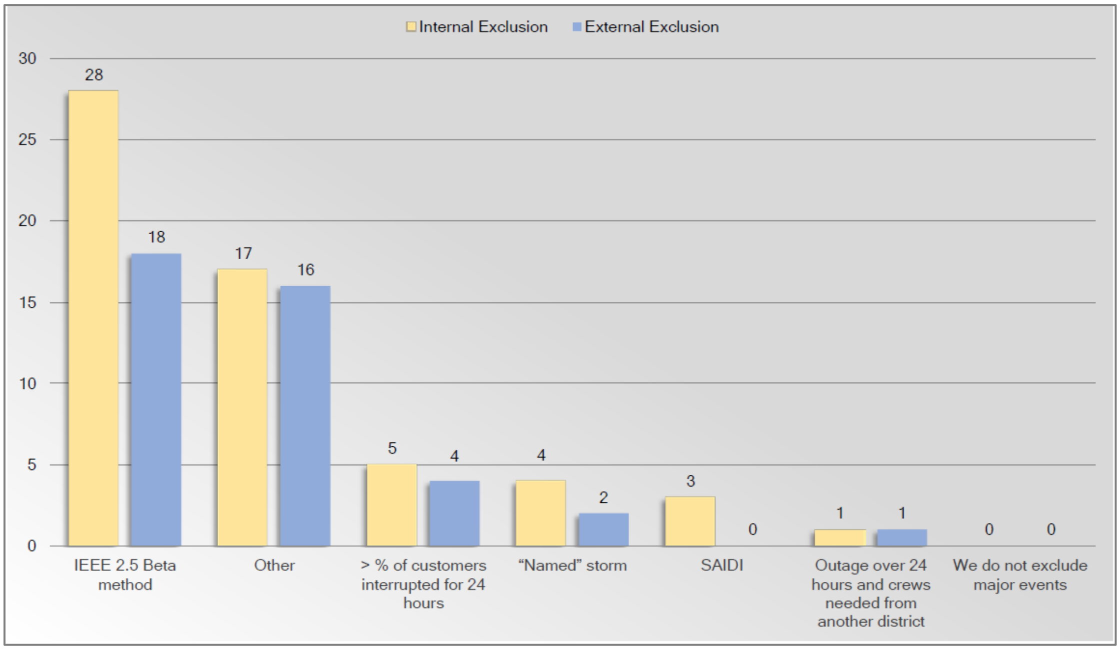


Figure 22 – Major Event Identification and Exclusion Methodology. [30]

5.3.2 Reliability programs

Effective reliability programs strive to improve reliability by achieving the following:

- Fewer outage events
- Fewer customers interrupted per outage
- Shorter outage duration.

To maximize the value achieved, analytics should be performed. The net result would be a benefit/cost (B/C) metric. With this metric, proposed projects can then be prioritized to achieve the highest value for the same investment.

Customer minutes interrupted (CMI) is often used for benefits estimate since it includes the three categories shown above, while customers interrupted (CI) does not include duration. If SAIFI is the driver, then customers interrupted (CI) is instead used.

To estimate the benefit, the basis is the current reliability performance using either historical average CMI or CI. Another effective approach is to use failure rates for the infrastructure. Infrastructure failure rates can be grouped in multiple ways depending on the available data. A simple common approach is to estimate failure rate on a per mile basis, such as outages per mile-year. Estimated outage durations is also necessary. Once the base case is established, then the improvement can be estimated based on the work performed, which should improve the failure rates and/or the outage duration. The difference between the before and after cases establishes the expected reliability benefit. The methodology to perform this analysis varies across the industry.

Not all utilities have a formal budgeted and scheduled roadmap for achieving significant reliability improvements. If a utility is already in one of the top two industry quartiles, a formal roadmap may not be necessary.

Conventional reliability improvement programs are very consistent across the industry in the approach used and the methods applied to address reliability issues. Data from two independent surveys confirm this point.

Table **10** presents information from the American Public Power Association's survey of distribution system reliability and operations practices among 112 of its members. The numbers associated with each item are the number of respondents (out of 112) that use that method of addressing reliability.

Table 11 presents findings from a Quanta Technology survey of 12 utility companies regarding distribution reliability practices and spending. The items in this table are ranked by total spending for each initiative among the 12 utilities surveyed. This survey is dated (2008) but correlates highly with APPA 2015 data confirming the point that conventional distribution reliability practices have changed little. Grid technology and automation implementation offer additional tools to address reliability but the traditional methods (vegetation management, animal guards, inspection and maintenance, etc.) still apply.

Table 10 – Reliability Improvement Initiatives[33]

Vegetation Management/ Tree Trimming	93
Animal/Squirrel guards	86
Routine distribution inspection and maintenance	74
Thermographic circuit inspections	68
Review of worst performing circuit	54
Lightning arresters	53
Converted overhead to underground	46
Transformer load management	28
Covered wire	27
Root cause analysis	23
Circuit rider program	22
Other (please explain):	18

Table 11 – Reliability Improvement Survey of 12 Utilities[34]

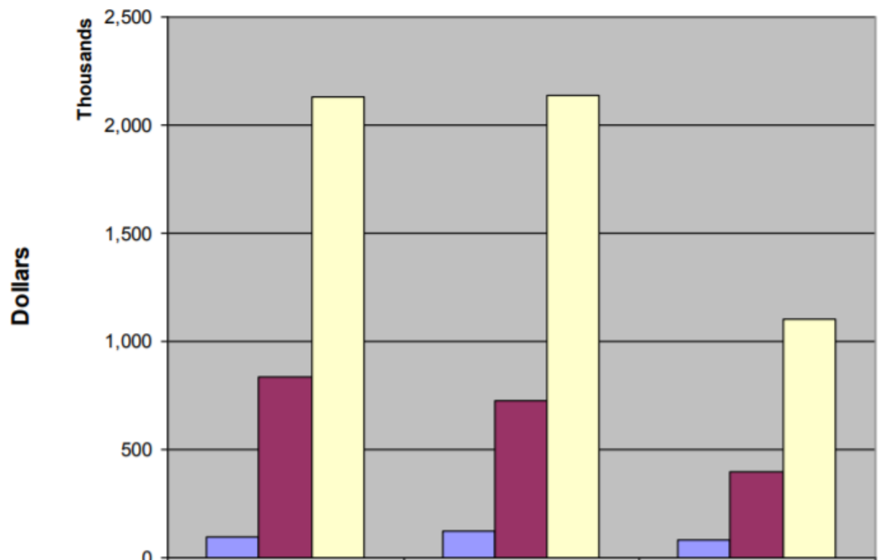
[33] American Public Power Association (APPA), Evaluation of Data Submitted in APPA's 2015 Distribution System Reliability and Operations Survey

[34] Quanta Technology Survey of Utility Methods and Spending on Distribution Reliability

Vegetation management
Overhead to underground conversion
Proactive cable replacement
Pole inspection and maintenance
Worst circuit improvement
Distribution hardening
Non-automated line devices
New automated line devices
Visual feeder inspections (no infrared)
Small wire replacement
Faulted Circuit Indicators
Visual/Infrared feeder inspections
Improved lightning protection
Animal guards
Cable rejuvenation

The application of this information for this report is to compare these common and proven reliability improvement methods to actions currently being taken by ENO. ENO is currently using the outage prevention programs and assessments listed in Table 10 and Table 11. The level to which each program is used varies among all utilities depending upon the specific needs of that company's system. The one area where ENO is less active is overhead to underground conversions.

Underground conversion in the New Orleans area has been reviewed and discussed often as a method to prevent outages during major storm events. A number of prior industry studies have shown the difficulty in showing economic justification for major underground conversion in any environment. One of the most notable of those studies is the EEI report "Out of Sight, Out of Mind"[19] previously referenced in this report (Figure 17, Section 5.2). That 2013 report was an update of previous versions of the same study. The EEI report presented average cost data for underground conversion which is shown as Figure 23.



	Urban	Suburban	Rural
Min Value	93,202	120,000	80,000
Average	832,383	723,692	395,874
Max Value	2,130,000	2,138,400	1,100,000

Figure 23 – Cost per Mile: Converting Overhead to Underground Distribution[19]

In 2013 as part of an engagement to review system performance and emergency response to Hurricane Isaac, Quanta Technology developed OH to UG cost estimates for Orleans Parish. Those estimates are shown as Table 12. The estimated costs at that time were considerably higher than the averages shown by the EEI study and were based on a system model specific to the New Orleans area that considered all the variables associated with conversion to UG in the City. Without doubt, UG conversion within the City of New Orleans would be extremely expensive due to congested infrastructure, lack of space for a utility corridor for underground vaults and other facilities, and difficulty of construction in the urban environment.

Table 12 – Estimated Costs to Convert OH to UG in New Orleans[35]

Area	Overhead Circuit (miles)	Cost ($000s)	$ / Mile ($000s)
East New Orleans	466	$2,547,510	$5,467
Tulane	560	$3,305,068	$5,902
West Bank	145	$745,108	$5,139
Totals	1,171	$6,007,647	$5,625

[35] Quanta Technology, "Reliability of the Electric System in Orleans Parish" 2013.

As an approach to improving and maintaining reliability, there are many more cost effective methods which ENO is currently pursuing. However, a practice of targeted undergrounding for new facilities and perhaps some existing facilities should be included as part of an overall infrastructure management strategy. This has been exhibited in ENO's approach to storm hardening where targeted undergrounding and alternative resiliency/reliability improvement measures have been considered and compared. Considering the high cost of underground conversion in the ENO territory, it is highly likely that more improvements can be achieved on the overhead system for the same level of expenditure.

Other industry practices from the five utilities benchmarking assessment conducted with this project are as follows:

- Less than half the utilities had regulatory performance metrics with economic impacts. ENO reports its results, but currently they do not have an economic impact.
- Majority of utilities have multi-year reliability performance targets, including ENO.
- Majority of utilities, including ENO, use technology to enhance outage data gathering
- Most common outage causes listed were equipment failure, vegetation, animals, and weather related, similar to ENO.
- More than half the utilities use grid analytics to determine failure rates and performance. ENO has analytics for determining performance but does not have the data for failure rates analysis.
- Three utilities provided outages per mile per year: One utility provided 0.4 outages per mile per year combined for overhead and underground; another provided 1.32 for overhead, and 0.59 for underground; and the third provided 0.72 for overhead, and 0.25 for underground. ENO does not have the data for that failure rate.
- Reliability improvement is largely proactive but also poor performing circuits are identified for improvement. ENO is both proactive and reactive.
- Majority of the utilities prioritize projects based on either CI improvement/cost or CMI improvement/cost. ENO prioritizes primarily based on estimated CI improvement.
- For the benefit/cost analysis, different methods are used including software tool and internal spreadsheet based models. ENO uses CI algorithm for prioritizing improvement efforts.
- Common efforts to improve reliability include: modern reclosers, fusing, FLISR, circuit re-configuration, aging infrastructure replacement, vegetation clearance, hardware inspection and replacement. This includes ENO.
- Different departments are involved in project identification and implementation. Project results are tracked using reliability indices. This also applies to ENO.
- Majority of the utilities do not have a full distribution system inspection and maintenance program. This also applies to ENO.

The compressed schedule of this project limited the time available for responses to the benchmark survey, however, the items listed above are consistent with surveys conducted by other organizations, Quanta Technology's experience in the industry, and the current survey. Overall, ENO's distribution reliability practices are similar to the other utilities included in the survey. The primary difference is related to the failure rate analysis which is not possible at this time, but is expected to be available in the future as new systems are implemented.

5.3.3 Asset management

Management of utility assets and in particular aging assets is an important element of overall distribution system operations and reliability. There are many methods by which the management of utility assets can be achieved ranging from internally developed spreadsheets and analytics to commercially available systems designed specifically for use in the utility industry. In the end, the method or system used for asset management is simply a tool; the important element is the philosophy and practices of the asset owners.

It is common in today's electric utility industry for companies to use asset management software as a system of record for all assets. A basic asset registry that includes nameplate data from equipment is fundamental to the asset management system. The systems are also used as the repository for all inspection and maintenance records for individual assets. This information gives the users the capability to perform analytics on classes of asset by various attributes: age, manufacturer, voltage, location, etc. This information is used in overall asset management for purposes of determining operational risk in the event of multiple failures of a particular class of asset, developing a manageable asset replacement strategy, and ensuring inspection and maintenance requirements are met, to name a few examples.

Asset management programs and systems are becoming the norm as more utilities attempt to move from time-based maintenance programs to reliability-centered or condition-based practices. These practices provide for maintenance to be performed based on data analytics and condition monitoring capabilities. As opposed to a time-based maintenance schedule, use of resources is optimized to perform inspections and maintenance when data indicates that apparatus or equipment are approaching higher risk of malfunction or failure. This of course requires a comprehensive asset information capability to track performance of a class of assets and develop failure statistics to drive maintenance.

A true condition-based maintenance program also includes a significant capability in real-time, monitoring of equipment status, which is often included, where feasible, as part of an overall grid modernization program. In reality, continuous monitoring of the condition of distribution assets is not economically justifiable due to the volume of devices, relatively low cost of devices or apparatus, and the overall design and operations philosophy of distribution systems, which limit the number of customers exposed to individual line device outages. Implementation of AMI, however, does provide the capability for distribution transformer loading to be monitored to determine if there are overloaded units in service.

Benchmarking responses confirm what Quanta has found to be typical in the industry today:

- Distribution asset philosophy remains primarily "run to failure" with trends and initiatives moving toward preventive and/or condition-based maintenance. Run to failure, while most cost effective in distribution asset management, is becoming a less desirable approach as companies work toward improving the "customer experience" by minimizing unplanned outages.
- Preventive and condition-based practices are often most common in evaluating underground cable condition and implementing proactive cable replacement measures. Partial discharge and other diagnostic testing of cables are the common condition assessment methods.
- Most utilities have in recent years implemented a resiliency or weather hardening initiative. The scope of the projects varies widely based on the specific risks being mitigated (wind, ice, floods,

etc.) and the design criteria being used by the utility. In all cases, however, the utility considers a weather hardening program as part of an overall reliability improvement strategy. While weather hardening programs are primarily intended to increase mechanical strength of the infrastructure to withstand extreme conditions, the result is also a benefit to everyday reliability. Some of the methods used in weather hardening programs include increasing pole size/class, changing pole materials (steel, concrete), replacing small gauge conductor, and targeted conversion of overhead conductor to underground.

- Asset management databases are used in determining failure rates of asset classes and also to perform predictive analytics for reliability improvement and system resiliency.

5.4 Grid Modernization – Industry Trends and Activities

Electric power systems around the world are undergoing an unprecedented transformation. In the US, this evolution has been clustered and described under various terms, including smart grid, grid of the future, grid modernization, and utility of the future. Despite slight differences among these terms, all of them recognize that the status quo is no longer able to fulfill the changing needs and growing expectations of end users, while providing electric utilities and other industries with the opportunity to thrive in a dynamic and modern market; therefore, they have encouraged the introduction of new paradigms. The terms "smart grid," "grid of the future," and "grid modernization" emphasize the need to build an intelligent grid that can be monitored and controlled in real-time to allow for providing a reliable, safe, and secure service and empower customers to actively participate and benefit from greater and more diverse market opportunities and services.

Building this intelligent grid is a monumental task (particularly on the distribution and grid-edge[36,37] sides, which are vast and heterogeneous) that has led to the emergence of new concepts, technologies, and paradigms. Examples of this include debates regarding future grid architecture (a distributed, hybrid, or centralized grid); advances in grid modeling, simulation, and analysis; the introduction of the microgrid concept as an alternative to enhance resiliency and facilitate the DER integration; and the convergence of information and operations technologies (IT/OT).

The idea of the utility of the future, on the other hand, has a broader connotation and encompasses the need for all aspects pertaining to the utility industry to evolve and adapt to this new and dynamic customer-centric reality. This includes business and engineering processes, regulation, policies, rate design, asset ownership, service diversification, and relationships with customers. Although grid technology related aspects are challenging and complex, changes and solutions in this area are at a more advanced stage than those needed to address emerging regulatory, policy, and business problems and needs (some of which are being triggered or enabled by technology developments). In summary, addressing the business, legal, regulatory, and policy side of the utility of the future is an area where significant work is required[38].

An important point to emphasize is that the pace of the transition toward a modernized grid, particularly on the distribution side, is a function of the existing and expected system conditions and trends of every utility system and market, e.g., existing and forecasted DER penetration levels. For instance, utilities operating in states such as Louisiana[39] (where DER adoption is rapidly becoming a reality) must continue this evolution toward a modernized distribution grid at a faster pace than utilities operating in emerging DER markets. Otherwise, DER proliferation will lead not only to significant operations, planning and engineering challenges and inefficiencies, but also will prevent utilities (and ultimately customers and society in general) to attain the potential benefits derived from the adoption of these technologies.

Furthermore, since even larger-scale adoption of DER is inevitable, given the imminent (or existing) achievement of grid parity by Photovoltaic Distributed Generation (PV-DG) in US markets, additions in

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[36] The interface between the customer and the electric power supply https://www.tdworld.com/grid-opt-smart-grid/grid-s-edge

[37] The varying hardware, software and business innovations that are increasingly enabling smart, connected infrastructure to be installed at or near the "edge" of the electric power grid https://www.ase.org/blog/so-what-exactly-grid-edge-thing-anyway

[38] J. Romero Agüero; A. Khodaei; R. Masiello, The Utility and Grid of the Future: Challenges, Needs, and Trends, IEEE Power and Energy Magazine, Sep/Oct 2016, pp. 29-37 http://ieeexplore.ieee.org.prox.lib.ncsu.edu/document/7549242/

[39] For instance, Louisiana moved from the 45th position in 2017 to the 35th position in 2018 in the Solar Energy Industry Association (SEIA)'s state ranking of installed capacity of solar generation (13,740 installations and 307 MW of additional capacity expected to be added over the next 5 years) https://www.seia.org/state-solar-policy/louisiana-solar

grid modernization infrastructures and systems should largely be considered “required” rather than “optional” investments to enable the normal operation of modern and future distribution systems. It is worth noting that utilities operating in states with incipient penetration levels of DER, recognize the imminence and urgency of preparing for the transition to this new paradigm, and are actively working on modernizing their distribution grids and overall practices so that they are suitable for operation in this new reality[40,41].

The industry is currently involved in numerous grid modernization proceedings, for instance, Figure 24 shows the results from the latest grid modernization state index published by GridWise Alliance[42], based on a wide range of grid modernization policies, practices and investments. The index is calculated based on a wide range of grid modernization policies, practices and investments. The top 10 states shown have the greatest number of grid modernization initiatives in place.

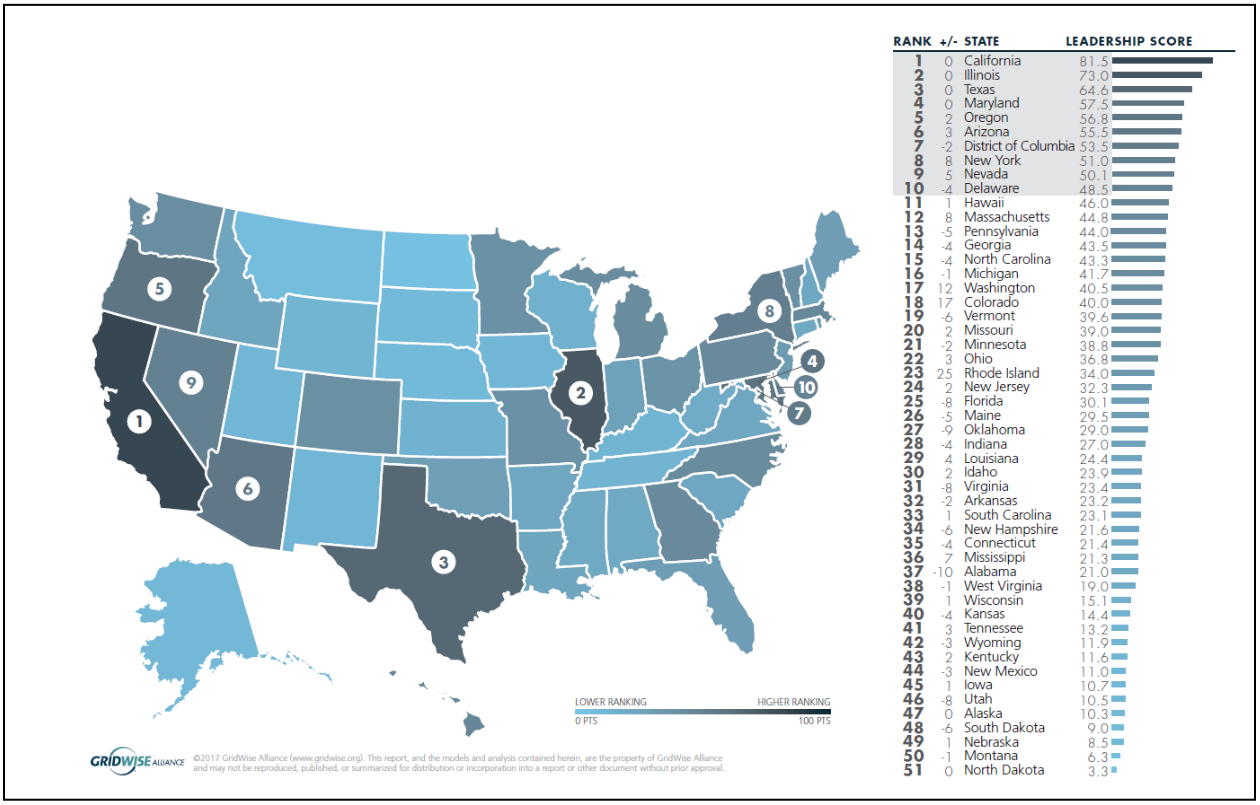


Figure 24 – Grid Modernization Index by State[42]

[40] Illinois Moves Up to #2 in the Nation for Electrical Grid Modernization https://www.comed.com/News/Pages/NewsReleases/2016_01_25.aspx
[41] J. Romero Aguero et al., Modernizing the Grid: Challenges and Opportunities for a Sustainable Future, IEEE Power and Energy Magazine, Vol. 15, No. 3, pp. 74-83
[42] Grid Modernization Index 4, GridWise Alliance, Nov. 2017

Similarly Figure 25, Figure 26, and Table 13 show a recent summary of heterogeneous actions related to grid modernization being implemented by US states, such as studies, business models and rate reforms, deployments, etc.[43]

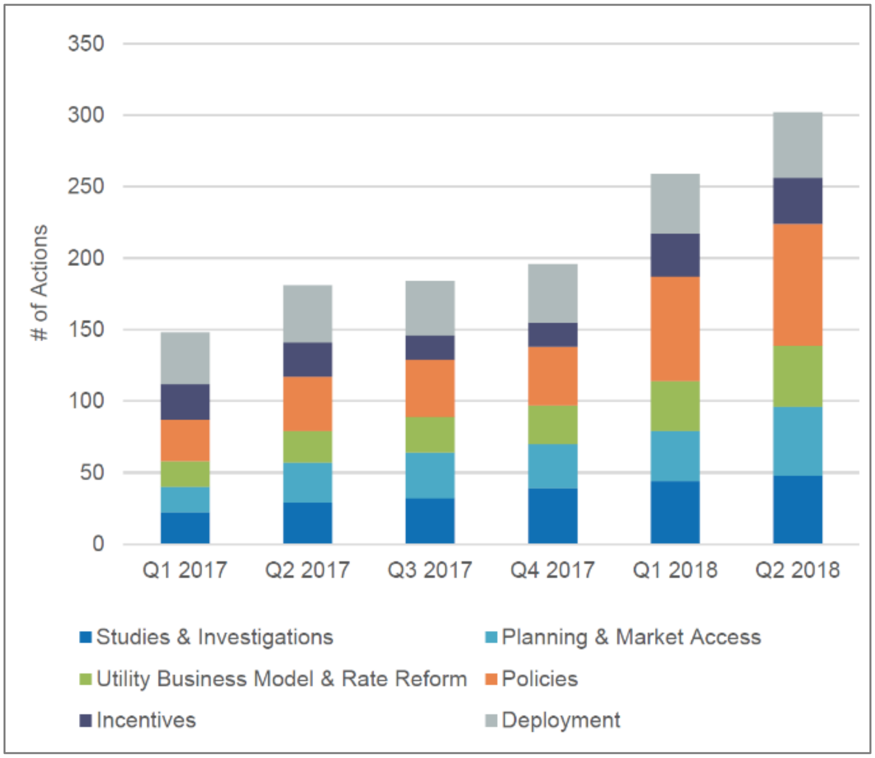


Figure 25 – Total Number of Grid Modernization Actions by Quarter.[36]

[43] 50 States of Grid Modernization, Q2 2018 Quarterly Report, NC Clean Energy Technology Center, Aug 2018 https://nccleantech.ncsu.edu/wp-content/uploads/Q2-18-GridMod-Exec-Final-1.pdf

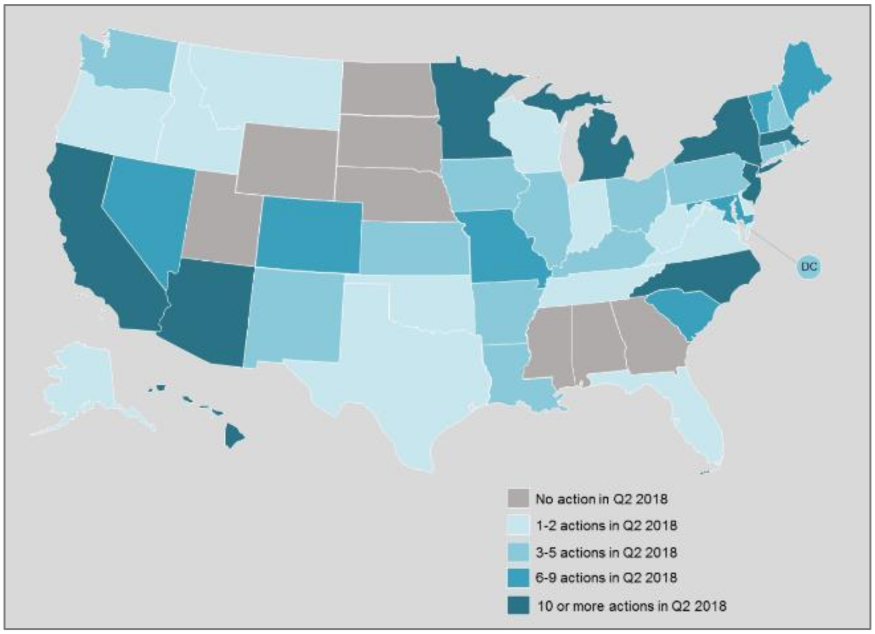


Figure 26 – Legislative and Regulatory Grid Modernization (Q2 2018). [36]

Table 13 - Summary of Grid Modernization Actions (Q2 2018).[36]

Type of Action	# of Actions	% by Type	# of States
Policies	85	28%	31 + DC
Studies and Investigations	48	16%	27 + DC
Planning and Market Access	48	16%	19 + DC
Deployment	46	15%	24
Business Model and Rate Reform	43	14%	19 + DC
Financial Incentives	32	11%	11
Total	**302**	**100%**	**42 States + DC**

5.4.1 Grid Modernization – Reliability Benefits

Quanta Technology conducted a review of grid modernization and smart grid programs implemented or proposed by selected utilities. The review included an assessment of key initiatives included within each program (with focus on those that are relevant for distribution reliability), and their estimated benefits in terms of distribution reliability improvement. There is a variety of technologies and concepts that are key elements of grid modernization that are discussed in more detail in Appendix E of this report. Specific technologies of interest for this section includes deployment of distribution automation solutions, specifically, smart reclosers and switches operating in FLISR schemes, such as the ones proposed by ENOin its grid modernization program. This section discusses the findings and conclusions of that review. This task consisted of an assessment of publicly available documentation from selected utilities, industry reports, and Quanta Technology's expertise on the subject. Some of the reviewed programs were implemented or proposed by utilities included in the selected list for benchmark shown in Table 9.

Grid modernization and smart grid programs include a variety of technologies to address specific needs of utilities. Some of these technologies have a direct impact on improving distribution reliability, specifically decreasing SAIDI and SAIFI through the reduction of CMI and CI. Examples of solutions and technologies included in grid modernization programs are shown in Figure 27, the technologies that have direct impact on distribution reliability are highlighted under the category "Automated Outage Management and Service Restoration" and "Grid Visibility and Diagnostics" and include FLISR, AMI and ADMS, which are technologies that ENO has also planned to deploy.

Features of Smarter Energy Infrastructure						
Grid Modernization Technologies	Energy Grid Optimization	Optimized Power Quality & Power Flow	Data Systems Integration	Grid Visibility & Diagnostics	Automated Outage Management & Service Restoration	DER Integration & Management
AMI	○		●	●	●	○
Power Flow Management Technologies						
Smart Inverters	●	●	○	●	●	●
VOLT/VAR Management	●	●		○		○
Power Line Monitors	●	●		●	○	○
Distribution Management and Outage Management Technologies						
OMS	○		●	●	●	
DMS	○	○	●	●	●	○
WMS			○	●	●	
FLISR	○	○	●	●	●	
ADMS	●		●	●	●	○
DERMS	●	●	●	○	○	●

Key	
Primary Benefit	●
Secondary Benefit	○

Figure 27 – Smarter Energy Infrastructure Features & Grid Modernization Technologies.[44]

[44] J. Blansfield, A. Cooper, Grid Modernization Technologies: Key Drivers of a Smarter Energy Future, The Edison Foundation, Institute for Electric Innovation, May 2017 http://www.edisonfoundation.net/iei/publications/Documents/Final_Grid%20Modernization%20Technologies_IEI%20White%20Paper.pdf

Figure 27 shows that grid modernization technologies have significant benefits in terms of improving grid visibility, diagnostics, outage management and restoration, which directly impact distribution reliability

Figure 28 provides a detailed breakdown of devices and systems typically included as part of FLISR deployment and their impacts on distribution reliability. The figure demonstrates that most Distribution Automation (DA) technologies have significant benefits in terms of reliability improvement

DA Technologies and Systems		DA Applications			
		Reliability and Outage Management	Voltage and Reactive Power Management	Equipment Health Condition Monitoring	DER Integration
Devices	Remote Fault Indicators	•	•		
	Smart Relays	•			
	Automated Feeder Switches (or Reclosers)	•	•		
	Automated Capacitors		•		•
	Automated Voltage Regulators		•		•
	Automated Feeder Monitors	•	•	•	•
	Transformer Monitors			•	
Systems Integration	Communications and Backhaul Systems	•	•	•	•
	SCADA Systems	•	•		
	DMS	•	•	•	•
	Integration with AMI/Smart Meters	•	•	•	•
	OMS, GIS, CIS, Workforce Management Integration	•			

Figure 28 – Devices and Systems that Support Distribution Automation Applications.[47]

Figure 29 offers a conceptual description of FLISR operation, and Figure 30 shows the distribution reliability benefits (reduction in interruption duration) that can be achieved from centralized[45] FLISR implementation as a function of the selected operation mode (manual, semi-automated and fully automated).

[45] Controlled by an Advanced Distribution Management System (ADMS)

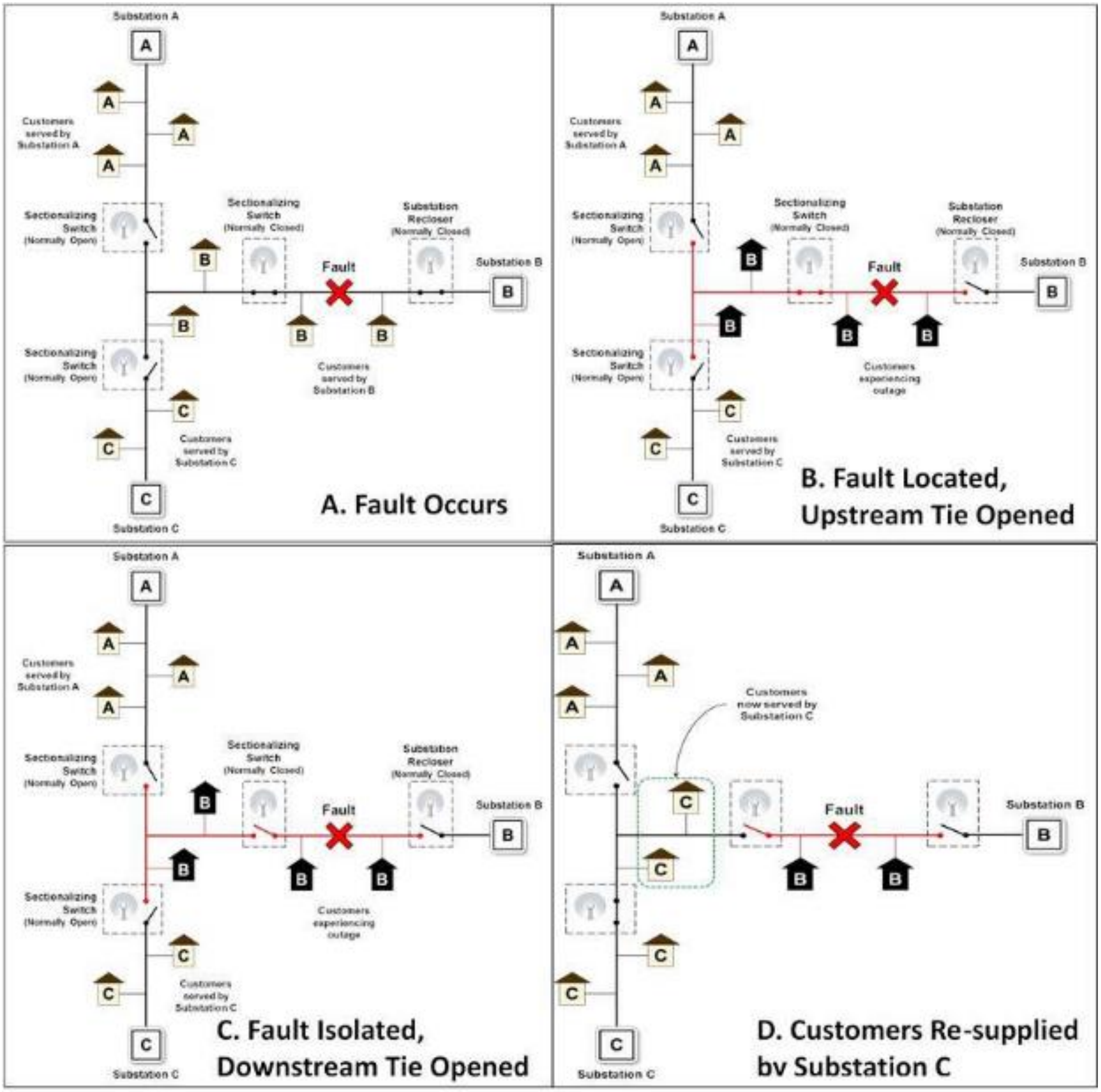


Figure 29 – Conceptual Example of FLISR Operation.

Figure 29 shows how after a fault occurs (A), FLISR helps automatically locate (B) and isolate (C) faulted sections of a feeder (which allows to restore service to customers located upstream from the fault), and then restore service to customers located downstream from the fault by automatically transferring those sections to a neighbor feeder (D)[47]

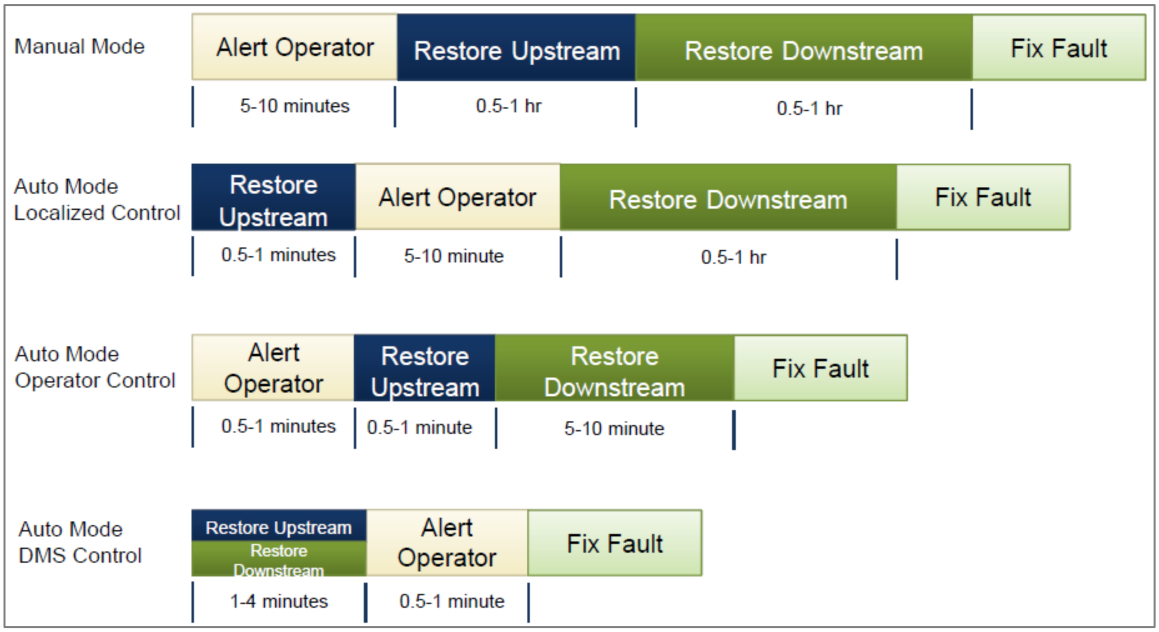


Figure 30 – Comparison of Fault Recovery Timelines for Different Operation Modes in FLISR Implementation.

Figure 30 conceptually shows the total fault location, isolation and restoration time for: manual outage management and restoration, and for three operation modes of FLISR (for various participation levels of the distribution system operator)[46]

It is worth noting that distribution automation and particularly FLISR are now established technologies that have been deployed by numerous utilities and there is an abundant body of work and documented experiences regarding their expected benefits from a reliability improvement perspective. For instance, the US Department of Energy (DOE) published a report in 2016 that summarizes the results from the implementation of distribution automation projects included in the Smart Grid Investment Grant (SGIG) program[47]. This report summarizes the distribution reliability benefits (improvements in SAIFI and SAIDI) achieved by 62 utilities[48] due to the deployment of a variety of technologies, including smart reclosers and switches as part of distribution automation schemes, such as FLISR.

Figure 31 describes the nearly 82,000 DA field devices installed under the SGIG, and Figure 32 shows a summary of the main findings and results from the program. The results show that the deployment of FLISR led to up to 45% reduction in the number of CI and up to 51% reduction in CMI.

[46] http://www.energypa.org/assets/files/2017/March%20Event/Presentation%20Papers/Smart%20Grid%20Automation%20&%20Centralized%20FISR%20-Colby.pdf

[47] Distribution Automation - Results from the Smart Grid Investment Grant Program, US DOE, Sep. 2016 https://www.smartgrid.gov/document/SGIG_Results_for_Distribution_Automation_2016.html

[48] Distribution Automation investments in the electric distribution system totaled about $2.19 billion—including Recovery Act funds from DOE and cost share from the utilities—accounting for 27 percent of the total SGIG investment

DA Asset	Total # Devices Installed	# of SGIG Utilities Deploying	Range of Installments by SGIG Utilities (Least to Most)
Remote Fault Indicators	13,423	17	3 – 4,755
Smart Relays	11,033	27	4 – 4,755
Automated Feeder Switches	9,107	39	2 – 2,193
Automated Capacitors	13,037	30	2 – 2,098
Automated Voltage Regulators	10,665	21	2 – 3,339
Transformer Monitors	20,263	8	2 – 17,401
Automated Feeder Monitors	4,447	19	2 – 1,583

Figure 31 – DA Asset Deployments by Participating Utilities Under SGIG Projects.[47]

Additionally, Figure 33 shows the CMI reduction from projects implemented by 15 utilities that participated in the SGIG program, although the period of data collection is not identical for all utilities, the results show significant benefits in terms of reliability improvement.

Reliability can be further improved when combined with refurbishment of foundational infrastructure and enhanced maintenance practices (e.g., replacement of aging assets, weather hardening, vegetation management, etc.) and deployment of additional intelligent systems (e.g., AMI, ADMS, etc.). It is worth noting that the specific improvement is a function of a variety of variables, such as system configuration, overhead and underground construction ratio, customer density, asset condition, etc. The overall results from the DA SGIG program are consistent with the expected distribution reliability improvements estimated by ENO due to the deployment of its grid modernization program[49].

[49] Direct Testimony of Erica H. Zimmerer on behalf of Entergy New Orleans, LLC., Application of Entergy New Orleans, LLC for a Change in Electric and Gas Rates Pursuant to Council Resolutions R-15-194 and R-17-504 and for Related Relief, July 2018

Primary Aim	• Fewer and shorter power disruptions for customers • Improved reliability performance, as measured by standard reliability indices (such as SAIFI and SAIDI)—which may be tied to utility performance standards			
Smart Grid Function	Remote fault location and diagnostics	Fault location, isolation, and service restoration (FLISR) and automated feeder switching	Outage status monitoring and customers notifications	Optimized restoration dispatch
Description	Without DA, utilities rely primarily on customer calls to identify outages. With DA, operators receive field telemetry from fault indicators, line monitors, and smart meters to rapidly pinpoint and diagnose issues.	FLISR operations quickly reconfigure the flow of electricity and can restore power to many customers who would otherwise have experienced sustained outages.	DA provides operators with comprehensive and real-time outage information, and alerts customers with more timely and accurate information about restoration.	By integrating distribution, outage management, and geographic information systems, utilities can precisely dispatch repair crews and accelerate restoration.
Key Impacts and Benefits	• Overall reduced customer minutes of interruption (CMI) • Shorter outage events with fewer affected customers • Lower or avoided restoration costs • Faster response, dispatch of repair crews, and prioritization of repairs	16 utilities reported reductions of about **146 million customer minutes of interruption** over three years For an outage event, FLISR operations showed: • Up to **45% reduction in number of customers interrupted** • Up to **51% reduction in customer minutes of interruption** About **270,000 fewer customers experienced sustained interruptions** (of >5 minutes) compared to estimated outcomes without FLISR One utility reported repair crews spent approximately 560 fewer hours annually assessing outages		

Figure 32 – Reliability and Outage Management Results from DA Investments from the SGIG program.[47]

Seq. #	Utility	CMI Avoided	Period of Data Collection
1	Indianapolis Power & Light (IPL)	1,541,049	10/2013 – 09/2014
2	Eversource (formerly NSTAR)	18,831,841	10/2012 – 03/2015
3	Pepco—Washington, DC	1,813,656	04/2013 – 03/2015
4	Pepco—MD	4,914,654	04/2013 – 03/2015
5	Southern Company	17,194,770	04/2013 – 09/2014
6	Duke Energy Business Services	8,971,792	04/2013 – 03/2015
7	CenterPoint Energy	14,488,820	04/2013 – 09/2014
8	Electric Power Board (EPB)	42,848,905	10/2013 – 03/2014
9	Avista Utilities	35,609	08/2013
10	Atlantic City Electric	50,011	10/2013 – 03/2014
11	Duke Energy (formerly Progress Energy)	28,688,810	01/2012 – 08/2013
12	Sacramento Municipal Utility District (SMUD)	705,510	04/2013 – 09/2014
13	City of Leesburg	125,694	09/2014
14	PPL Electric Utilities Corporation	2,400,000	10/2012 – 09/2013
15	Burbank Water and Power (BWP)	4,411,791	07/2010 – 08/2014
	Total	**147,962,153**	

Figure 33 – CMI Avoided by DA Operations.[47]

The results from the SGIG program are also consistent with others reported in the literature, such as those published by Commonwealth Edison (ComEd) as part of the benefits of its Energy Infrastructure Modernization Act (EIMA). ComEd reported that as of March 2017, grid modernization investments (including the deployment of 3,100 smart switches operating in distribution automation schemes, along with significant investments in foundational infrastructure[50]) led to 7.6 million avoided customer interruptions since 2012, with outages reduced by 44% and duration of outages reduced by 48%[51]. The implementation of ComEd's grid modernization program has provided important benefits in terms of overall system reliability and customer satisfaction, for instance, Figure 34 and Figure 35 show the evolution of ComEd's system SAIFI and customer reliability complaints in the last five years, during the same period its grid modernization program was implemented. The results show a reduction of about 39% in SAIFI and a reduction of about 80% in the number of annual customer reliability complaints (with respect to the average value from the 2007-2011 period, respectively).

[50] A. Dahwan, Overview of Energy Infrastructure Modernization Act (EIMA), Jun. 2014 https://www.eesi.org/files/Anil-Dhawan-061814-original.pdf

[51] Delivering on Smart Grid, Five-Year Capstone Report https://www.comed.com/SiteCollectionDocuments/AboutUs/ComEdProgressReport2017.pdf

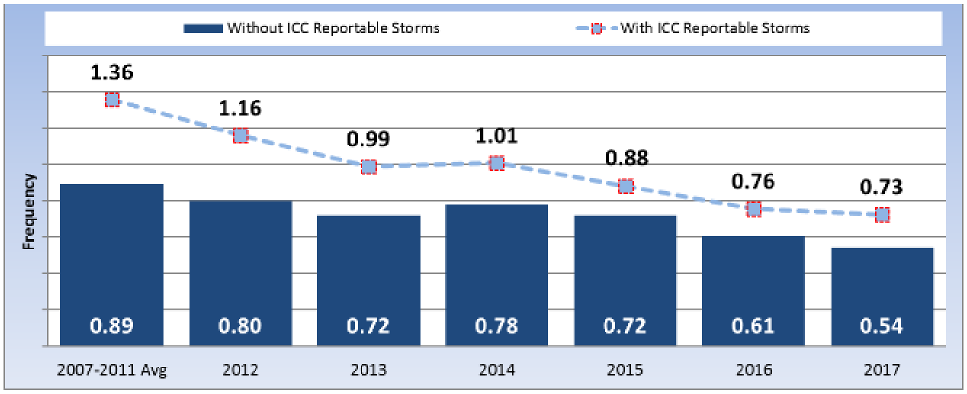


Figure 34 – ComEd System SAIFI improvement since the beginning of the implementation of grid modernization program[47]

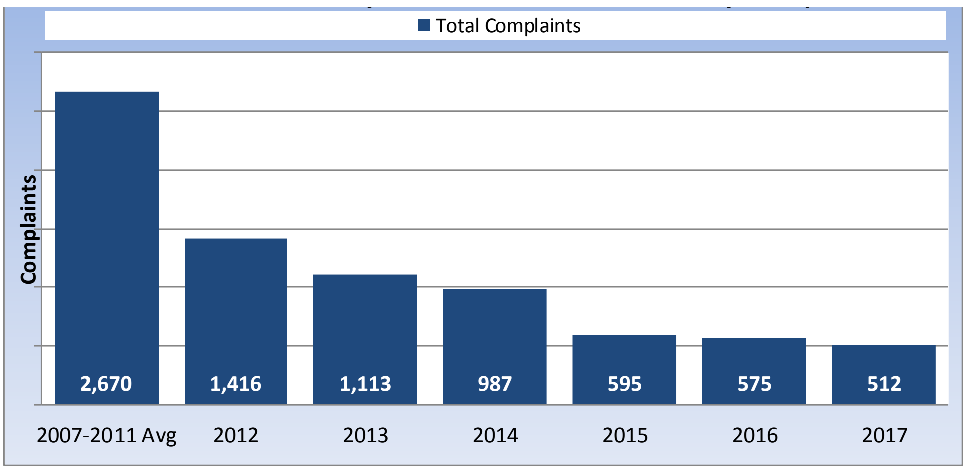


Figure 35 – ComEd System Customers Reliability Complaints decrease since implementation of grid modernization program [47]

Additional benefits associated with this type of grid modernization initiatives include operations and maintenance efficiency and savings, and improved customer satisfaction and public awareness. An important benefit to consider is customer savings in terms of avoided interruption costs, for instance, Dominion Energy has estimated $2.0B in savings for customers over a 20 year period from reliability improvement (SAIDI)[52] due to the implementation of the Grid Transformation and Security Act of 2018 (GTSA)[53].

[52] Savings estimated using the Interruption Cost Estimate (ICE) Calculator developed by Lawrence Berkeley National Laboratory (LBNL) https://eaei.lbl.gov/tool/interruption-cost-estimate-calculator
[53] https://www.dominionenergy.com/library/domcom/media/about-us/electric-projects/grid-transformation/gtsa-072418.pdf?la=en

6 ENO RELIABILITY PERFORMANCE IMPROVEMENT

The primary causes for CI increases since 2013 are related to infrastructure issues such as crossarms, conductors, and poles. The reliability programs currently underway are effectively addressing these issues on a per project basis.

6.1 Current Reliability Program Results to Date

DLIN SAIFI has increased from 1.04 in 2013 to 1.584 in 2017. This resulted in enhancing current activities as well as implementing new ones to improve reliability. Overall there has been significant expenditures since 2016 to improve reliability. Table 14 shows expenditures for FOCUS, BACKBONE, Reliability Blitz, and Storm Hardening, 2016 through mid-year 2018.

Table 14 - 2016 thru Mid-2018 Reliability Expenditures

	2016	2017	2018	Grand Total
Grand Total	$13,834,476	$23,025,913	$15,604,026	$52,464,415

Source: Entergy New Orleans Testimony, T. Patella, June 2018

Post construction evaluations have indicated a significant decrease in CI for sections improved with the current efforts such as FOCUS and BACKBONE. The current efforts under those programs appropriately address areas of known problems and areas with potential for highest CI and CMI impacts. Once the immediate areas of concern are addressed focus should turn to more proactive inspection and repair. This effort will take time.

Based on SAIFI thru September 2018, additional improvements, and on-going aging, ENO has developed a 2018 year-end projected SAIFI of 1.65.

6.2 Potential Impact of Current Initiatives

With the multiple efforts underway to improve its distribution reliability, ENO has developed an appropriate methodology to estimate the SAIFI reduction by year taking into consideration the capital and O&M costs. A key component is a “dollars per CI reduction” metric which was developed using recent experiences. The method has been used to develop a separate metric for its FOCUS, BACKBONE, and DA (Distribution Automation) programs. With the different cost/benefit metrics, a projected SAIFI improvement can be estimated for each of the programs and then combined for an overall expected result on an annual basis with an established budget.

Also, since aging infrastructure has been an on-going issue and will continue indefinitely, it is also taken into consideration for the estimate of its future SAIFI. The values of the metrics used in developing estimates (dollars per CI and infrastructure rate of deterioration) have not been evaluated as part of this report. Nevertheless, the overall approach at estimating the future SAIFI based on level of costs and aging is appropriate.

6.3 Potential Improvement Efforts

As is normally the situation in most reliability improvement efforts, enhancements to the process are an on-going opportunity. Quanta Technology has identified multiple recommendations that can help expedite achieving the desired reliability improvement.

6.3.1 Metrics

ENO is currently keeping track of SAIFI and SAIDI for internal and external reporting purposes. ENO's reliability indices for 2017 are close to the borderline between 3rd and 4th quartile of industry performance, as defined by the 2017 IEEE Distribution Reliability Benchmark. The calculation of reliability indices is largely performed according to IEEE Std. 1366-2012. Benefit-cost analyses and prioritization of reliability improvement projects are performed based on CI reduction. This approach is adequate, and can be enhanced to address the specific aspects associated with average reliability indices discussed in section 2.3. This section provides recommendations in that regard.

Recommendation

1. It is recommended that ENO consider using SAIDI, along with SAIFI, as part of the metrics used in the benefit-cost analysis for evaluation and prioritization of reliability improvement projects. Consideration of $MAIFI_E$ and $CEMI_n$ is also recommended to the extent these indices can be applied with the currently available data gathering technology.
   a. It is recommended that ENO consider SAIDI (along with CMI and $/CMI metrics[54]) to account for projects that improve reliability by reducing interruption duration (such as deployment of Fault Circuit Indicators (FCI) and sensors, manual switches, etc.), but that do not reduce interruption frequency. Using both indices would allow ENO to have a more complete perspective of the benefits derived from the implementation of its proposed reliability improvement projects, and to use this information to prioritize selection and deployment.
   b. It is recommended that ENO consider using $MAIFI_E$ to evaluate the effect of momentary interruptions, and the balance between sustained and momentary interruptions when identifying and evaluating distribution reliability improvement projects. The calculation of $MAIFI_E$ will become particularly important as more distribution automation (FLISR) schemes are implemented in ENO's system. As discussed in section 2.4, the accurate calculation of $MAIFI_E$ requires monitoring infrastructure that may not be fully available to ENO at present, however, a base estimation using existing monitoring infrastructure can help obtain preliminary reference values to assess the historical evolution of this index. This estimation can be progressively refined as the required monitoring infrastructure becomes available.
   c. It is recommended that ENO consider using $CEMI_n$ (e.g., $CEMI_5$) to help identify worst-performing customer pockets within feeders, regardless of customer density. This would help ENO identify and target needed investments to poor performing areas within feeders with

[54] Other utilities have used CMI reduction and $/CMI to evaluate intelligent infrastructure investments, for instance Southern California Edison (SCE) used this metric in its 2018 Rate Case, specifically SCE used $2.32/CMI to assess the cost savings associated with CMI avoided http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/F3C79866183D17BB8825814100830540/$FILE/SCE18V10.pdf

average SAIFI and SAIDI indices. The limitations of effective use of $CEMI_n$ were noted in earlier discussion and should be acknowledged if used. It is worth noting that ENO is already following a similar approach as part of its existing FOCUS project. Using $CEMI_n$ will facilitate benchmarking with peer utilities for performance assessment purposes, and serve as a starting point for the potential calculation of greater granularity indices (e.g., at customer level), once the required infrastructure is available (e.g., AMI).

2. It is recommended that ENO consider accelerating the implementation of a data analytics program, to the extent possible within regulatory requirements. An analytics program will provide the required data for the implementation of advanced distribution planning applications.

   The utilization of additional reliability indices for benefit-cost analysis and prioritization is a more complex activity that involves simulations using specialized software, such as the reliability assessment module in Synergi. ENO is already working on developing guidelines for advanced distribution planning applications, which includes the utilization of this type of software solutions. It is recommended to accelerate the adoption of this advanced distribution planning process (as it pertains to distribution reliability assessment using Synergi) to evaluate the implementation of conventional (e.g., asset replacement) and advanced solutions (e.g., FLISR schemes) for distribution reliability improvement. Currently, ENO is using a combination of spreadsheet-based and model-based approaches to identify and prioritize investments. The utilization of spreadsheet-based approaches is still common in the industry, however, more utilities are transitioning toward the utilization of model-based approaches, including predictive reliability[55]. This is considered an industry leading practice that ENO is recommended to continue adopting.

3. It is recommended to consider estimated customer benefits due to outage cost reduction. As discussed in section 5.4.1, other utilities have included this type of analysis (e.g., using the ICE tool) in the benefit-cost evaluation and prioritization of distribution reliability improvement projects/programs, particularly for those that require large investments. ENO has explored this concept as well. The inclusion of customer and societal benefits have proven to be valuable to justify this type of investments.

6.3.2 Reliability Programs

6.3.2.1 Outage Data and Benefit/Cost Prioritization

ENO has an effective approach at selecting areas for improvement. There are opportunities for enhancing the overall prioritization process. As described earlier, the current method of collecting outage data only provides the impact beyond a device involved in the restoration process. It does not sum the overall CI and CMI for individual outages nor does it indicate it is from a single cause. While the issues of data collection are secondary to addressing infrastructure issues, accuracy of data ultimately is needed for measuring performance improvement and ultimately for predictive reliability analytics.

[55] J. Romero Aguero, L. Xu, Predictive Distribution Reliability Practice Survey Results, 2014 IEEE PES JTCM, Jan. 2014, New Orleans, LA, http://grouper.ieee.org/groups/td/dist/sd/doc/2014-01%20Predictive%20Distribution%20Reliability%20Practice%20Survey%20Results.pdf

Recommendations

1. The process for recording outage events needs to be modified to aggregate the multiple restoration events into a single outage. Although this is being pursued as part of the ENO Grid Mod/ADMS project it should be evaluated for a change in the near future. This will reduce the number of outages reported, will provide the ability for establishing failure rates, and will ensure that when ADMS is implemented that process will be aligned properly.
2. Currently ENO is reporting outage count based on the number of events which includes scheduled outages. With a count in excess of 2000 that number appears excessive for a utility the size of ENO. The industry norm is to not include scheduled outages, thus ENO should consider excluding those (or reporting scheduled outages separately) when the overall outage count is provided externally.

Improvement opportunities in data collection and management are discussed in more detail:

Outage Count for Failure Rate Data

The actual outage count will be less than the quantity identified by summing the multiple restoration steps. Without detail review of thousands of events, an actual outage count may not be possible at this time. Without knowing the actual number of outages, the preferred method of benefit/cost analysis is not doable.

Effective predictive analytics is dependent on "before and after" failure rate values on either a per mile basis or based on specific equipment. The before failure rates are determined by quantifying the number of failures for different types or categories of infrastructure and comparing it to the quantity of that type of infrastructure. For example, if a utility has 2000 miles of overhead primary lines and it has on the average 200 outages per year on the overhead system, the average failure rate would be 0.1 outages per mile per year. Similarly, failure rates for different types of equipment can be evaluated. If a system is re-built, then a revised failure rate would need to be determined to predict the enhanced performance.

Also, if devices such as reclosers are applied, predictive analysis can provide estimated benefit. As a simplified example, if a feeder had 10 miles of overhead line (0.1 outages/mile-year) with 2000 customers evenly distributed, the before analysis would indicate an average of 1 outage per year for the 2000 customers. If a recloser is to be installed on the circuit, then the predicted CI and CMI improvement can be determined based on where it is installed.

Reported Outage Count

Without an actual outage count, ENO has been reporting the number of events which is higher than the actual outage count. In addition, scheduled outages are included in that count. Instead of 2800+ outage events reported, the actual number of forced outages is less, although the number has not been determined.

6.3.2.2 Prioritization of Enhancement Projects

The FOCUS and BACKBONE program are an effective approach at identifying and resolving infrastructure issues. It will take time to make a significant impact on reliability. To maximize the benefits sooner, an enhancement of the prioritization method needs to be considered. More effective prioritizing can result in having more improvement sooner for the same level of effort and costs.

Currently, FOCUS identifies projects based on the CI beyond devices, such as breakers, reclosers, switches, and fuses. Since the outage tracking process does not capture the entire outage impact, this is a reasonable approach. When a project is added to the FOCUS list it is generally prioritized based on projected CI reduction, as opposed to a detailed benefit/cost calculation. The projects that do get implemented are typically based on the level of funding provided to those types of projects.

Recommendations

1. With Current Outage Data- Before both design and construction, some level of prioritization should be pursued. Currently a 70% CI improvement is estimated. Since that value is based on overall Entergy, a value for ENO should be pursued. Once the inspection has been performed and expected enhancements identified, a ballpark cost should be developed for a benefit/cost (B/C) metric. With that metric, it can be determined if the project is reasonable to be designed. Once designed and a more accurate estimate is determined, then the benefit/cost can also be re-done to ensure the highest B/C value projects move forward.

2. With Aggregated Outage Data- Once the multiple outage events can be aggregated, analysis can be performed to determine infrastructure failure rates. Including a before and after. These results would provide an enhanced B/C analysis.

6.3.2.3 Outage Duration

ENO has not pursued reduction of outage duration at a significant level due to potential impacts on crew safety. Field crew safety does supersede outage duration impact. Crews must be allowed to perform the work safely at the proper pace. Nevertheless, there are efforts that can be pursued to reduce the average outage duration without impacting crew safety.

Recommendation

1. Outage durations should be evaluated for potential enhancements. With the increase in SAIFI, SAIDI has increased by a larger proportion indicating that average outage durations have also increased. A large proportion of the SAIDI impact during an outage often occurs before the crew is on site for repairs. The average duration for the customers impacted can be reduced via sectionalizing devices that expedite partial restorations, as well as outage response from the time the outage began until repairs have been made.

6.3.2.4 Feeder Sectionalizing Plan

ENO's distribution system has 195 radial feeders and 155 reclosers, ENO is already deploying smart reclosers in new locations and replacing existing reclosers with newer microprocessor-based technology. There is an opportunity to further increase the number of smart reclosers and distribution automation schemes (e.g., FLISR) in the system to reduce the number of customers by switching/protection zone. As discussed in section 5.4.1, this is a very effective practice for distribution reliability improvement.

Recommendation

1. It is recommended that ENO evaluate the additional implementation of distribution automation schemes (FLISR) to complement ENO's grid modernization program and reduce the system average amount of customers within each switching/protection zone to 500 customers. This is an industry leading practice that is gradually being adopted by other utilities.

   For example, a feeder that provides service to 2,000 customers and has a normally open-tie to a neighbor feeder would be allocated 3.5 reclosers (a recloser in the normally-open tie would be shared with its neighbor feeder). This type of initiative could be implemented proactively by ENO to complement its proposed deployment. As discussed in the examples provided in the report, the distribution reliability improvements derived FLISR implementation can be significant (e.g., about 45% reduction in CI and 51% reduction in CMI based on results reported by the Smart Grid Investment Grant program).

2. It is recommended that ENO explore the implementation of advanced reclosing solutions that are available in modern microprocessor-based reclosers (e.g., single-phase reclosing/tripping and lockout).

   As discussed in Appendix E, this is a technology that has proven to be very effective when implemented in suitable locations (e.g., instead of fusing in three-phase laterals serving only single-phase loads). Similarly, the utilization of advanced reclosing solutions will also give ENO the flexibility to use fuse saving and fuse clearing overcurrent protection philosophies in a customized manner, depending on the application. In general, fuse saving provides greater reliability improvement than fuse clearing, since it allows temporary faults to self-extinguish, and events that otherwise would be sustained interruptions become momentary interruptions. For this reason, it remains the recommended practice to minimize the effect of temporary faults (which represent the majority of events in distribution systems). In the last decades, the utilization of fuse saving has experienced a decrease[56], largely due to the growing interest in the industry in limiting the effect of momentary interruptions. Modern remotely-controlled microprocessor-based reclosers, ADMS and advanced FLISR schemes, allow utilities to customize the overcurrent protection philosophy used by each device. When this is combined with single-phase tripping and distribution automation applications, it provides utilities with a tremendous variety of options to improve distribution reliability by minimizing sustained interruptions, while monitoring and controlling the effect of these advanced reclosing and distribution automation schemes on momentary interruptions.

3. It is recommended that ENO consider accelerating, to the extent possible within regulatory requirements, the implementation of its grid modernization, AMI and ADMS programs, which will provide some of the foundational and intelligent infrastructure and systems (e.g., FLISR schemes)

[56] R. McCarthy, R. O'Leary, D. Staszesky, A New Fuse Saving Philosophy, DistribuTECH 2008 https://www.sandc.com/globalassets/sac-electric/documents/sharepoint/documents---all-documents/technical-paper-766-t84.pdf

needed to improve distribution reliability, including the ability to automate outage data collection and analysis.

6.3.2.5 Corrective Maintenance Program

The FOCUS and BACKBONE are effective projects to pursue upgrades of the distribution system. However, their implementation will take time and may not address significant potential safety or reliability events on sections of circuits not being pursued.

Recommendation

1. ENO should pursue a corrective maintenance program that is based on a 100% inspection of the entire distribution system within an identified cycle, such as every 5-8 years. This would be similar to an expansion of the BACKBONE program in that the effort is to identify and fix specific problems and not perform an extensive rebuild. For example, if a broken crossarm or excessive leaning pole is identified, that needs to be fixed soon. As part of this effort, an overall standard practice should be developed specifying the requirements. Elements of a system inspection currently exist in the reliability programs currently underway at ENO. Full distribution inspection programs are not common practice in the industry, however, the current efforts by ENO offer a good start toward such an effort.

6.3.2.6 Vegetation Clearance Requirement

The 2013 versus 2017 CI and CMI comparison identified vegetation as one of the leading contributors to the overall increase. Infrastructure rebuild is not immune to tree contacts and will still result in outages and infrastructure damage depending on different circumstances.

Recommendation

1. An overall evaluation of the current ENO vegetation program should be performed to review current trim cycles, clearance requirements, trimming obstacles, and the different types of vegetation outages. ENO currently operates with highly restrictive vegetation practices within the City and deeper evaluation of the impact of those restrictions is warranted. That information can then be used to determine the need for improvements in the program and whether regulatory support will be required.

6.3.2.7 Transmission Reliability Evaluation and Improvement Plan

Earlier in the report, the 2018 SAIFI results thru 10/21/2018 showed that transmission performance contributed to 28.5% of the customer view SAIFI. Although a comparison of transmission versus distribution reliability was not part of this overall evaluation, Quanta Technology's perspective is that the transmission impact is disproportionally high for 2018.

Recommendation

1. An evaluation of the transmission reliability should be performed combined with a plan to improve the transmission reliability.

6.3.2.8 Internal Audit Program

There is no information indicating established procedures are not being followed within ENO. It is ultimately in the best interest of the utility as well as the departments responsible for various programs to have a regular review of processes and procedures to ensure compliance with internal standards and expectations.

<u>Recommendation</u>

1. An Internal Audit Program should be pursued to ensure current and new processes are effectively pursued and implemented. The level of an internal audit can vary, but should ensure that committed requirements are being followed. As a first step, requirements should be documented. Examples of validation audits are:

    a. Outage data
    b. Prioritization process
    c. Corrective maintenance program
    d. Tree trim clearance
    e. Pole inspections

6.3.3 Asset Management

Improvement in overall asset management capability is an identified need within Entergy at the corporate level. Currently at Entergy, asset management is located organizationally as a corporate services function supporting all Entergy operating companies. In order to implement a comprehensive asset management capability, Entergy is in process of implementing an enterprise asset management solution. The company has selected the IBM Maximo software product, which is a well-known and respected asset and maintenance management system. Maximo has been used in the utility industry for many years as a computerized maintenance management system (CMMS). The software has been continually enhanced with capabilities that now constitute a fully functional enterprise asset management system.

Implementation of Maximo will give Entergy the ability to track all classes of assets, including basic nameplate information, maintenance history, outage and failure records. This database will then be available for detailed analytics that will provide the company with ability to perform failure analytics, predictive analytics, condition-based maintenance scheduling, and other analysis that ultimately makes the company more efficient operationally and provides information to support optimal reliability improvement efforts.

As part of the overall systems improvement capability, Entergy will also implement new work management and GIS platforms, all integrated with the asset management system. Once implemented and fully functional, the asset and work management capabilities, coupled with the new ADMS and AMI systems as they are currently specified and anticipated, will give Entergy an industry leading capability in operations and asset management.

7 CONCLUSIONS

Quanta Technology conducted a review of ENO's distribution reliability program and a comparison of its distribution reliability practices versus industry leading practices and those of a group of high performing utility peers[57]. ENO serves a high customer density and compact service territory that is very vulnerable to weather events[58] with a distribution system that consists of mostly overhead legacy design and construction, and a customer base with one of the highest poverty rates in US metro areas[59].

ENO's distribution reliability performance has declined in the last five years, and its 2017 key distribution reliability indices (SAIFI and SAIDI) were close to the borderline between 3rd and 4th quartile of the 2017 IEEE Annual Distribution Reliability Benchmark. ENO has increased its reliability spending in the last three years and has planned further investments in key infrastructure, technologies and systems to stop and reverse this trend and improve reliability performance. These activities are starting to yield positive results and have helped ENO improve its reliability performance during 2018. Year-to-date key indices and overall distribution (DLIN) outage data show a reduction in the number of customer interruptions and customer minutes of interruption. Transmission outages in 2018 have, however, increased and mask the DLIN improvements when looking at the customer view reliability indices.

The results of Quanta Technology's assessment indicate that ENO's distribution reliability program includes adequate components to continue addressing these pressing needs. If investments in distribution reliability continue as planned it would be expected that ENO's distribution reliability indices improve to 2nd quartile performance over the next few years. These improvements would not be immediate, since some investments are needed to prevent further decline of reliability indices (slow down the trend) and others are intended to improve performance (reverse the trend), and most importantly, because of the legacy construction and design of ENO's distribution grid coupled with aging infrastructure. The current practices will affect incremental improvement in system reliability. Implementation of distribution automation technology coupled with the ongoing conventional reliability efforts offers more immediate improvement.

There are important opportunities to improve the program that are described in greater detail in the recommendations section. The following are examples and highlights from that section:

1. Metrics: along with more detailed recommendations, it is recommended that ENO consider additional reliability indices (SAIDI, $CEMI_n$ and $MAIFI_E$), along with SAIFI, to identify and prioritize the implementation of distribution reliability improvement projects, and that eventually adopts these indices to evaluate and keep track of performance. A recommended practice is to analyze the values of reliability metrics over multiyear periods (e.g., 3 to 5 years), rather than over consecutive years. This approach allows to capture the expected mid/long-term improvement trends (instead of focusing on potential consecutive year variations) and to a certain extent account for the effect of

[57] Given the uniqueness of ENO's distribution system a one-to-one comparison is not possible, utilities peers in this comparison are *sufficiently* similar to ENO on various important features of its service territory and distribution system, but not all.
[58] New Orleans is the wettest city in the US https://www.iweathernet.com/educational/u-s-cities-with-the-most-extreme-weather and has a tree cover of over 30% (D.J. Nowak, E.J Greenfield, Tree and Impervious Cover Change in U.S. Cities, Urban Forestry & Urban Greening, Volume 11, Issue 1, 2012, Pages 21-30, https://www.nrs.fs.fed.us/pubs/40114)
[59] http://www.labudget.org/lbp/2018/09/new-orleans-poverty-rate-tops-among-u-s-metros/

randonmness. This is the tactic that ENO is recommended to use to monitor and evaluate the effectiveness of its reliability program.

2. Processes: it is recommended that ENO enhance the data analytics process associated with counting outage events, this will provide ENO with more accurate failure rate information that can be used in cost-benefit and prioritization analyses. Moreover, there is an opportunity to implement an internal audit program to verify and ensure compliance of distribution reliability practices.
3. Infrastructure: it is recommended that ENO consider the further deployment of distribution automation schemes (e.g., FLISR) to reduce customer counts within each switching/protection zone.
4. Inspections: it is recommended that ENO implement an inspection program that covers 100% of the distribution system and conduct an overall evaluation of the existing vegetation program to review trim cycles, clearance requirements, etc.

In general, there is a valuable opportunity to accelerate performance improvement by expediting the implementation of the components of the reliability program discussed in this report, along with the grid modernization AMI and ADMS programs proposed by ENO. As these investments are subject to regulatory requirements, expediting the programs may not be feasible but it should be acknowledged that implementation of these technologies are a key element to long-term reliability improvement.

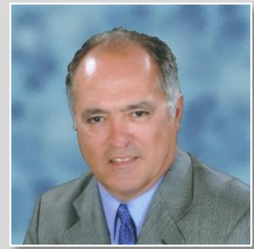
Coordination of the reliability improvement initiative with grid modernization components needs to occur at the project management and implementation levels. The proposed reliability improvement programs are intended to address foundational infrastructure needs. These investments, combined with deployment of intelligent infrastructure and processes enhancements that are part of ENO's grid modernization, AMI and ADMS programs, are expected to improve ENO's distribution reliability performance. It is worth noting that there is a synergistic relationship between these different types of investments and practices. For instance, foundational infrastructure (e.g., condition-based replacement of assets, such as transformers and distribution lines) enables the deployment of intelligent assets (e.g., distribution automation and control)[60], and the latter provides greater visibility and data that allows to accurately and efficiently monitor asset performance to evaluate condition via data/grid analytics solutions. Therefore, both types of investments need to be considered in a comprehensive plan to improve and maintain distribution reliability.

[60] An industry leading example is ComEd's EIMA program, which considers deployment of both foundational and intelligent infrastructure ($1.3B in each one) https://www.eesi.org/files/Anil-Dhawan-061814-original.pdf and has delivered significant distribution reliability improvements over the 2012-2017 period

APPENDIX A: PROJECT TEAM

Vic Romero

Vic Romero, *Executive Advisor, Distribution and Asset Operations,* has over 40 years of utility experience with a broad range of knowledge including operations, engineering, and grid modernization. He has led efforts to initiate and implement grid modernization projects, enhance reliability, and improve business processes. Examples include leading the implementation of ADMS, Borrego Springs Microgrid, reliability strategy, and storm processes.



Executive Advisor
Business Strategy &
Services Management

Areas of Expertise

- Cross functional knowledge of utility processes
- Benefits of Grid Modernization
- Distribution Reliability Analytics

Experience & Background

- Years of experience in the electric power industry 1977–Present
- Executive Advisor- Quanta Technology LLC 2017–Present
- Director, Technology Solutions & Reliability, San Diego Gas & Electric (SDG&E) 2014–2016
- Director, Asset Management & Smart Grid Projects, SDG&E 2011–2014
- Director, Transmission & Substation Construction & Maintenance, SDG&E 2005–2011
- Manager of Operating District, SDG&E 2002–2005
- Electric Distribution Standards Manager, SDG&E 1999–2002

Accomplishments & Industry Recognition

- Registered Professional Engineer, State of California
- A- General Engineering Contractor holder for SDG&E 2009-2016
- 2016 Recipient of SDG&E and PA Consulting's "Reliability One Outstanding Contribution to Reliability Award"

Education

- BS, Electrical Engineering, California Polytechnic State University, 1977

Vic can be contacted at VRomero@Quanta-Technology.com

Julio Romero Agüero, PhD, MBA

Julio Romero Agüero, PhD, MBA, *EXECUTIVE ADVISOR, Vice President, Strategy and Business Innovation,* has been with Quanta Technology since 2007. Julio provides leadership to Quanta Technology in the areas of technology and business strategy, grid modernization, distribution systems analysis, planning and engineering, distributed energy resources, and emerging technologies. He has assisted electric utilities and regulatory boards in the U.S., Canada, Latin America, the Caribbean, and Asia.

Vice President
Strategy &
Business Innovation

Areas of Expertise

- Grid modernization
- Distributed energy resources integration and Smart Grid
- Distribution system analysis, planning and engineering
- Emerging technologies and technology strategy

Experience & Background

- Years of experience in the electric power industry....................1995–Present
- Vice President, Strategy and Business Innovation, Quanta Technology 2007–Present
- Commissioner, National Energy Commission of Honduras....................2006–2007
- Consultant, National Energy Commission of Honduras 2005–2006
- Adjunct Professor, National University of Honduras 2005–2007
- PhD Researcher, National University of San Juan - Argentina 2000–2005
- Operations Manager, National Electric Utility of Honduras....................1999–2000
- Advisor, National Electric Utility of Honduras....................1998–1999
- Regional Manager, National Electric Utility of Honduras....................1996–1998

Accomplishments & Industry Recognition

- IEEE Senior Member
- Chair of IEEE Distribution Subcommittee
- Member of Advisory Committee of DistribuTECH
- Past Chair of IEEE Working Group on Distributed Resources Integration
- Former Editor of IEEE Transactions on Power Delivery
- Former Editor of IEEE Transactions on Smart Grid

Education

- PhD, Electrical Engineering, National University of San Juan, Argentina (UNSJ), 2005
- MBA, North Carolina State University (NCSU), 2013
- BSc, Electrical Engineering, National Autonomous University of Honduras (UNAH), 1996

Julio can be contacted at Julio@Quanta-Technology.com

Bill Snyder

Bill Snyder, *EXECUTIVE ADVISOR, Senior Vice President, Distribution and Asset Operations,* has a broad background in utility operations, management, and change initiatives resulting from over 39 years of experience in the electric utility industry. He has successfully led consulting engagements to review and evaluate operational processes and standards, conducted evaluations of asset condition and value, and led major process change identification and implementation programs in the engineering and operations functions. At Quanta Technology, Bill's consulting engagements range from day-to-day system operations management, including emergency restoration planning and management, to strategic planning and implementation of major process and systems initiatives to improve workforce efficiency and service delivery.

Sr. Vice President
Distribution and Asset Operations

Areas of Expertise

- Field operations planning and management
- Storm plan development and restoration management
- Asset condition assessment and management
- Major business initiative planning, implementation and change management

Experience & Background

- Years of experience in the electric power industry....1979–Present
- Quanta Technology, electric power industry consultant....2007–Present
- Sr. Principal Consultant, KEMA T&D Consulting....2004–2007
- Manager, Service Marketing, Eaton Electrical....2003–2004
- Director, Wind Power Services, ABB Power T&D....2001–2003
- Consultant, Distribution Solutions, ABB Power T&D....2000–2001
- Director/Manager/Engineer (various positions), Progress Energy....1979–2000

Accomplishments & Industry Recognition

- Member – IEEE, Power & Energy Society and Industrial Applications Society

Education

- MBA, Babcock Graduate School of Business, Wake Forest University
- BS, Engineering Operations, NC State University

Bill can be contacted at BSnyder@Quanta-Technology.com

Carl L. Wilkins, PE

Carl L Wilkins, PE, *Vice President, Distribution & Asset Operations,* has extensive experience in the electric utility industry serving in a variety of managerial, research, and consultative roles working with electric & gas utility companies. Combining experience in engineering, sales, marketing, and project management with applied technical skills, he brings a wide array of talents to the Asset Operations team. Carl managed several projects related to T&D storm hardening assessments and emergency preparedness plans for large electric utilities. Carl has led benchmarking studies on transmission maintenance and construction practices. His team performs grid integration studies for wind and solar PV projects and distribution planning studies.

Vice President
Distribution & Asset Operations

Carl served as the Director of Utility Services at Advanced Energy where he managed senior management relationships and the delivery of energy efficiency and renewable energy services to electric utilities. He has worked with utilities in areas of smart grid, plug-in hybrid electric vehicles, policies to address climate change and environmental sustainability.

Carl was the chief architect in the design, coordination, and development of North Carolina's green power program, NC GreenPower, the first state-wide green power program where all electric utilities in the state agreed to collaborate and use one marketing campaign.

Areas of Expertise

- Distributed Generation and Distributed Energy Resources
- Distribution Grid Impact Studies
- Asset Operations

Experience & Background

- Years of experience in the electric power industry 1976–Present
- Vice President, Distribution & Asset Operations, Quanta Technology 2008–Present
- Director-Utility Services, Advanced Energy Corporation 2000–2008
- Manager - Large Commercial Accounts, Duke Energy Progress 1976–1999

Accomplishments & Industry Recognition

- North Carolina Energy Policy Council (2013)
- NC Governor's Energy Advisory Team (2013)
- NC Governor's Scientific Advisory Panel on Offshore Energy & Energy Infrastructure (2011)
- Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) NC Task Force on Offshore Energy

Education

- BS, Electrical Engineering, NC State University
- Executive Education, Harvard Business School

Carl can be contacted at CWilkins@Quanta-Technology.com

APPENDIX B: RELIABILITY INDICES

Distribution Reliability Indices

The following are the definition of the most commonly used distribution reliability indices, as per IEEE Std. 1366-2012

System Average Interruption Frequency Index (SAIFI)

$$SAIFI = \frac{Total\ Number\ of\ Customer\ Interruptions}{Total\ Number\ of\ Customers\ Served}$$

System Average Interruption Duration Index (SAIDI)

$$SAIDI = \frac{\sum Customer\ Interruption\ Durations}{Total\ Number\ of\ Customers\ Served}$$

Customer Average Interruption Duration Index (CAIDI)

$$CAIDI = \frac{\sum Customer\ Interruption\ Durations}{Total\ Number\ of\ Customers\ Interruptions} = \frac{SAIDI}{SAIFI}$$

Average System Availability Index

$$ASAI = \frac{Customer\ Hours\ Service\ Availability}{Customer\ Hours\ Service\ Demand} = \frac{8760 - SAIDI}{8760}$$

Customers Experiencing Multiple Interruptions

$$CEMI_n = \frac{Customers\ Experiencing\ More\ than\ n\ Total\ Interruptions}{Total\ Number\ of\ Customers\ Served}$$

Momentary Average Interruption Frequency Index

$$MAIFI = \frac{Total\ Number\ of\ Customer\ Momentary\ Interruptions}{Total\ Number\ of\ Customers\ Served}$$

Momentary Average Interruption Event Frequency Index

$$MAIFI_E = \frac{Total\ Number\ of\ Customer\ Momentary\ Interruption\ Events}{Total\ Number\ of\ Customers\ Served}$$

APPENDIX C: SIMILARITY METRIC

$$S_i = w^d S_i^d + w^c S_i^c + w^r S_i^r + w^g S_i^g + w^w S_i^w$$

$S_i =$ *Similarity metric between Utility i and ENO*

$S_i^d =$ *Customer density similarity*

$S_i^c =$ *Electricity price similarity*

$S_i^r =$ *Reliability similarity*

$S_i^g =$ *Grid similarity*

$S_i^w =$ *Weather similarity*

$$w^d + w^c + w^r + w^g + w^w = 1$$

$w^d =$ *Grid similarity weight*

$w^d =$ *Electricity price weight*

$w^r =$ *Reliability weight*

$w^g =$ *Grid weight*

$w^w =$ *Weather weight*

$$S_i^d = abs\left(1 - \frac{d_i}{d_{ENO}}\right)$$

$d_i =$ *Customer density of utility i*

$d_{ENO} =$ *Customer density of ENO*

$$S_i^c = abs\left(1 - \frac{c_i}{c_{ENO}}\right)$$

$c_i =$ *Average electricity price (\$ per kWh) of utility i*

$c_{ENO} =$ *Average electricity price (\$ per kWh) of ENO*

$$S_i^r = 1/\sqrt{\left(1 - \frac{SAIFI_i}{SAIFI_{ENO}}\right)^2 + \left(1 - \frac{SAIDI_i}{SAIDI_{ENO}}\right)^2}$$

$SAIFI_i = SAIFI$ *of utility i*

$SAIFI_{ENO} = SAIFI$ *of ENO*

$SAIDI_i = SAIDI$ *of utility i*

$SAIDI_{ENO} = SAIDI$ *of ENO*

$$S_i^g = \sqrt{\left(1 - \frac{OH_i}{OH_{ENO}}\right)^2 + \left(1 - \frac{UG_i}{UG_{ENO}}\right)^2}$$

$$OH_i + UG_i = 1$$

$$OH_{ENO} + UG_{ENO} = 1$$

$OH_i =$ *Percentage of overhead grid of utility i*

$$S_i^w = \sqrt{\left(1-\frac{L_i}{L_{ENO}}\right)^2+\left(1-\frac{P_i}{P_{ENO}}\right)^2+\left(1-\frac{T_i^l}{T_{ENO}^l}\right)^2+\left(1-\frac{T_i^h}{T_{ENO}^h}\right)^2+\left(1-\frac{H_i}{H_{ENO}}\right)^2}$$

$L_i = Lightning\ flash\ density\ of\ utility\ i$

$L_{ENO} = Lightning\ flash\ density\ of\ ENO$

$P_i = Precipitation\ of\ utility\ i$

$P_{ENO} = Precipitation\ of\ ENO$

$T_i^l = Average\ annual\ temperature\ (low)\ of\ utility\ i$

$T_{ENO}^l = Average\ annual\ temperature\ (low)\ of\ ENO$

$T_i^h = Average\ annual\ temperature\ (high)\ of\ utility\ i$

$T_{ENO}^h = Average\ annual\ temperature\ (high)\ of\ ENO$

$H_i = Relative\ humidity\ of\ utility\ i$

$H_{ENO} = Relative\ humidity\ of\ ENO$

APPENDIX D: INDUSTRY SURVEY

Following is the questionnaire that was developed and used as an industry survey. These questions were put into an online survey tool and distributed to companies that agreed to participate in the survey. A sample page from the online survey tool is also shown.

Distribution Reliability Practices Questionnaire

A. Reliability Metrics and Targets

1. What metrics are used by your company (e.g., SAIDI, SAIFI, CAIDI, CEMI, other, etc.) to track and assess distribution reliability performance?
2. What definition is used by your company to calculate distribution reliability indices (e.g., IEEE 1366, internal, defined by regulator, other)?
3. What type of service interruptions are included in the calculation of your company's distribution reliability metrics (unscheduled, planned, generation, transmission, substations, primary/medium-voltage distribution, secondary/low-voltage distribution, etc.)?
4. Does your company keep track of momentary interruptions? If so, what index is used (MAIFI, $MAIFI_E$, other)?
5. What is the threshold for momentary and sustained interruptions (e.g., 1 min., 3 min., 5 min., etc.)?
6. What major event exclusion methodology does your company use (e.g., IEEE 2.5 Beta method, internal, defined by regulator, other)?
7. If applicable, which distribution reliability metrics are only used for internal control by the company, and which metrics are requested by the regulator for official reporting purposes?
8. Does the regulator request your company to comply with a maximum limit for specific reliability indices (e.g., SAIDI and/or SAIFI lower than a specific predefined value)?
9. If applicable, are there any financial (or other) penalties for noncompliance with maximum distribution reliability limits?
10. Does your company have short and long term reliability improvement targets (e.g., reduce SAIDI and/or SAIFI to a specific value by a specific date, etc.)?
11. If applicable, how are these targets calculated (e.g., defined by the company, set by the regulator, other)?

B. Grid Analytics

12. How is interruption data collected (e.g., automatically via ADMS, OMS, CIS and AMI, manually, semi-automatically, etc.)
13. What type of interruption data is collected (status of individual protection/switching devices, individual customers affected by each interruption, etc.)?
14. How accurate is the collected interruption data used for reliability analysis?

15. How accurate are the associated information systems used in reliability analysis (GIS, CIS, etc.)?
16. How many interruption root causes are used by your company?
17. Are root causes divided by sub-categories? If so, how many?
18. What are the most common root-causes in your service territory?
19. Are grid analytics used to calculate failure rates by root-cause and component, worst performing areas within feeders, etc.?
20. Are predictive grid analytics used by your company for reliability analysis? If so, how?
21. How many primary distribution forced outages per mile per year do you have for the overhead and underground system?

C. Reliability Improvement

22. What is your company's approach to reliability improvement/maintenance (e.g., proactive as part of an annual process, reactive in response to regulator request, etc.)?
23. Does your company identify worst performing feeders? If so, what criteria and approach is used to select these feeders?
24. Is distribution reliability assessment part of your annual planning process, or is it a separate process?
25. How are reliability improvement projects selected (e.g., worst performing feeders, proposed by distribution planners, etc.)?
26. How are reliability improvement projects evaluated and prioritized by your company (e.g., using benefit-cost ratio, etc.)?
27. Does your company use a benefit-cost metric to evaluate reliability improvement projects? If so, what metric is used ($/CMI reduction, $/CI reduction, other)?
28. Does your company use a reliability model to conduct benefit-cost analyses?
29. What type of benefits are considered in the estimation to justify improvement projects (benefits for utility, benefits for customers, societal benefits, all of them, etc.)?
30. How are benefits estimated (e.g., using computational models, using planning guidelines, etc.)?

D. Reliability Programs

31. Do you have an official multi-year reliability program to improve SAIDI & SAIFI to a specific value? If yes, what is the target percentage improvement and when is it expected to be achieved?
32. What type of initiatives for distribution reliability improvement have been implemented by your company in the last 5 years (e.g., deployment of microprocessor-based reclosers, deployment of additional switchgear (e.g., disconnect switches, etc.), fusing of laterals, deployment of distribution automation schemes, circuit reconfiguration, component (pole, crossarm, underground cable) inspection and replacement, vegetation management, weather hardening, aging infrastructure replacement, etc.)?
33. What is the scope of these initiatives/program (targeted reliability improvement of selected feeders, targeted reliability improvement of selected areas of the system, system-wide improvement, maintaining – rather than improving – system reliability, etc.)?

E. Program Implementation

34. What organization(s) is responsible for distribution reliability data collection and analysis, including project selection, justification and prioritization (e.g., dedicated reliability organization, distribution operations, distribution engineering, distribution planning, etc.)?
35. If more than one organization is responsible for these activities, where do the responsibilities of each organization begin and end?
36. What organization(s) is responsible for the implementation of reliability improvement projects and programs (e.g., distribution planning, distribution engineering, etc.)?
37. Is there a follow up process to assess the effectiveness of reliability improvement projects and programs? If so, what metrics are evaluated?
38. What type of reports are prepared to assess project/program effectiveness?

F. Grid Modernization

39. Has your company implemented a grid modernization program in the last 5 years?
40. What are the components of the grid modernization program?
41. What are the objectives of the grid modernization program?
42. Is distribution reliability improvement a specific objective of the grid modernization program? If so, what is the expected improvement from the program?
43. Is grid modernization part of an overall reliability program?

G. Aging infrastructure

44. Has your company implemented an aging infrastructure program in the last 5 years?
45. What are the components of the aging infrastructure program (e.g., underground cable replacement, pole replacement, etc.)?
46. How are asset replacements selected and prioritized?
47. Is distribution reliability improvement a specific objective of the program? If so, what is the expected improvement from the program?
48. Is the aging infrastructure program part of an overall reliability program?

H. Vegetation Management

49. What is your company's vegetation management cycle (3 yrs., 5 yrs., other)?
50. What is the scope of the vegetation management program (feeder trunks only, trunks and laterals, primary only, primary and secondary, hazard vegetation only, hazard and non-hazard vegetation, etc.)?
51. What are the regulatory vegetation clearance requirements for the primary distribution system? Does your company have regulatory authorization to trim to that clearance?
52. Is distribution reliability improvement a specific objective of the program? If so, what is the expected improvement from the program?

53. Is vegetation management part of an overall reliability program?

I. Weather Hardening

54. Has your company implemented a weather hardening program in the last 5 years?
55. What are the components of the weather hardening program (e.g., overhead to underground conversion, reinforcement of critical overhead structures, deployment of tree wire or aerial bundled cable (Hendrix), etc.)?
56. How are the hardening areas selected and prioritized?
57. Is distribution reliability improvement a specific objective of the program? If so, what is the expected improvement from the program?
58. Is weather hardening part of an overall reliability program?

J. Asset Management

55. What is your asset management strategy for distribution assets (e.g., run-to-failure, preventive, condition-based, other, etc.)?
56. Has your company implemented a new program in the last 5 years as part of your asset management strategy?
57. What are the components of the program (e.g., real-time monitoring of critical equipment, deployment of data analytics solution, deployment of asset management information system, etc.)?
58. Is distribution reliability improvement a specific objective of the asset management program? If so, what is the expected improvement from the program?
59. Is asset management part of an overall reliability program?
60. Does your company calculate and keep track of equipment historical failure rates of distribution assets?
61. Does your company use predictive methods to develop expected failure rates of distribution assets?
62. Do you have an inspection and maintenance program for the entire distribution system (not solely specific equipment)? If yes, what are the inspection cycle requirements?
63. Is the inspection and maintenance program required by regulations?

Distribution Reliability Practices Questionnaire

* Required

1. Please provide your name, affiliation, and position *

2. What metrics are used by your company to track and assess distribution reliability performance? *

- ☐ SAIDI
- ☐ SAIFI
- ☐ CAIDI
- ☐ CEMI
- ☐ MAIFI
- ☐ Other

3. What definition is used by your company to calculate distribution reliability indices? *

- ☐ IEEE 1366 Standard
- ☐ Internal utility definition
- ☐ Defined by regulator
- ☐ Other

4. What type of service interruptions are included in the calculation of your company's distribution reliability metrics? *

- ☐ Unscheduled
- ☐ Planned
- ☐ Generation
- ☐ Transmission
- ☐ Substations
- ☐ Primary/medium-voltage distribution
- ☐ Secondary/low-voltage distribution
- ☐ Other

APPENDIX E: GRID MODERNIZATION TECHNOLOGIES

There are a number of technologies and concepts that are key elements of grid modernization, examples include:

- Smart reclosers and switches

  Recloser technology has progressed significantly in the last two decades with the introduction of advanced microprocessor-based controllers with capabilities comparable to those of modern relays. This includes the ability to:

  - Store and use multiple protection settings, which allows ensuring coordination for different system configurations and loading conditions, and increasing the number of reclosers that can be installed and coordinated along a distribution circuit. The latter effectively reduces the number of customers affected by faults and improves reliability.
  - Reclose and open individual phases (single-phase tripping) of distribution lines to minimize the number of customers affected by faults and service interruptions. Figure 36 shows a comparison of the reliability improvements achieved by single-phase tripping versus conventional three-phase tripping for a set of 20 circuits for two different types of overcurrent protection philosophies, the results show that single-phase tripping attains greater reliability benefits[61].
  - Monitor, record and provide valuable operational data to distribution operations centers that can be processed by modern ADMS to increase visibility over the distribution grid.
  - Reduce the amount of energy associated with its reclosing operations and reduce the impact on valuable utility assets such as substation transformers and underground cable[62].
  - Operate in sophisticated automation schemes (such as Fault Location, Isolation and Service Restoration (FLISR)) in coordination with other advanced devices (relays, switches, breakers, and sensors). Utilities that have successfully deployed FLISR have multiple sectionalizing points, between three to four locations per circuit to minimize the impacts of outages to customers, and multiple ties to neighbor circuits.
    - Figure 37 shows an example of this type of configuration being used by Commonwealth Edison (ComEd) of Chicago. ComEd has installed hundreds of distribution automation devices since 2012[63,64,65].
    - Another example of an advanced distribution automation loop scheme that uses multiple reclosers and high speed peer-to-peer communications is shown in Figure 38, this scheme was implemented by Public Service Electric & Gas (PSE&G) Company and allows further minimization of reliability impacts from distribution faults. This

[61] J. Romero Aguero, J. Wang, J. Burke, Improving the reliability of power distribution systems through single-phase tripping, 2010 IEEE PES T&D Conference and Exposition, May 2010 http://ieeexplore.ieee.org/document/5484372/

[62] http://www.sandc.com/products/switching-overhead-distribution/intellirupter-pulsecloser/

[63] https://www.comed.com/News/Pages/NewsReleases/2016_06_07.aspx

[64] ComEd has installed more than 3,000 distribution automation reclosers on the 12-kV system and 1,000 switches on the 34-kV system since the mid-1990s.

[65] According to its 2015 Annual Progress Report, "smart switch" distribution automation investments resulted in 1.5 million avoided customer interruptions in 2015, bringing the total to 4.8 million avoided customer interruptions since 2012, with an associated $1.1 billion in societal savings, $976 million of that from distribution automation alonehttps://www.comed.com/SiteCollectionDocuments/AboutUs/Progress-Report-Final.pdf

technology allows a significant reduction (between 77% and 97%) of momentary interruptions with respect to traditional loop scheme applications.

The development of lower cost intelligent reclosers and switches that can isolate faults in smaller sections are needed to support increased flexibility and improve reliability with both traditional and distributed grids. In the future, remote reclosers and switches will be more intelligent and adaptive to distribution system conditions in conjunction with adaptive protection. This is considered a best practice and is capable of operating in a high DER penetration environment.

Despite the notable progress, more work is still needed by the industry to enable widespread adoption and utilization of this technology and the aforementioned applications. This requires not only the further evolution of distribution equipment (reclosers, switches, etc.) but also, and most importantly, the modernization of distribution operations practices to allow distribution automation technologies in general to assist system operators in outage management and restoration activities, especially during multiple contingency conditions such as those typical of major weather events, as well as during normal operation to increase grid efficiency. This is paramount, given the increasing complexity of the distribution grid and the multiple objectives and variables that need to be taken into account, particularly when other goals such as ensuring operation within allowable limits (voltage, power factors, losses, equipment ratings, etc.) are considered.

- Fusing

Traditionally lateral fusing has been an economical way to prevent faults on lateral circuits from causing larger outages on the circuit. However, this also acts to prolong outages on the lateral. Fuses are also exposed to backfeed which under high penetration of DER could exceed ratings. Therefore, it is evident that fuses, which lack adaptability and control capabilities, are not compatible with modern distribution systems, which are intrinsically complex and dynamic. As penetration levels of DER increase, the benefits of using more advanced devices (e.g., single-phase reclosers) for lateral fusing is expected to increase, particularly considering the decreasing prices of these modern technologies. Given the pervasive use of lateral fusing in existing distribution systems, detailed benefit-cost evaluations will be required to estimate reliability and operational improvements and overall feasibility of using advanced devices instead of conventional fuses.

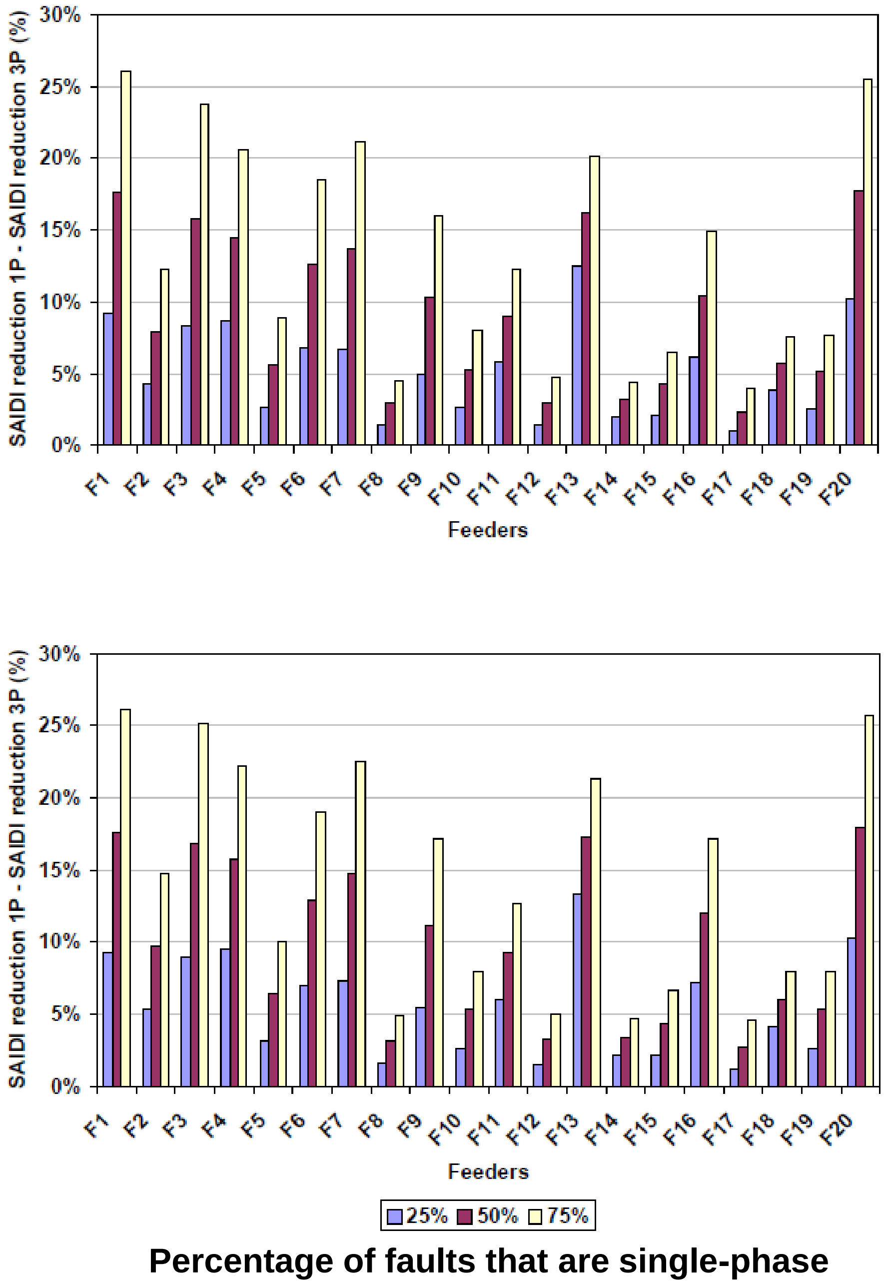
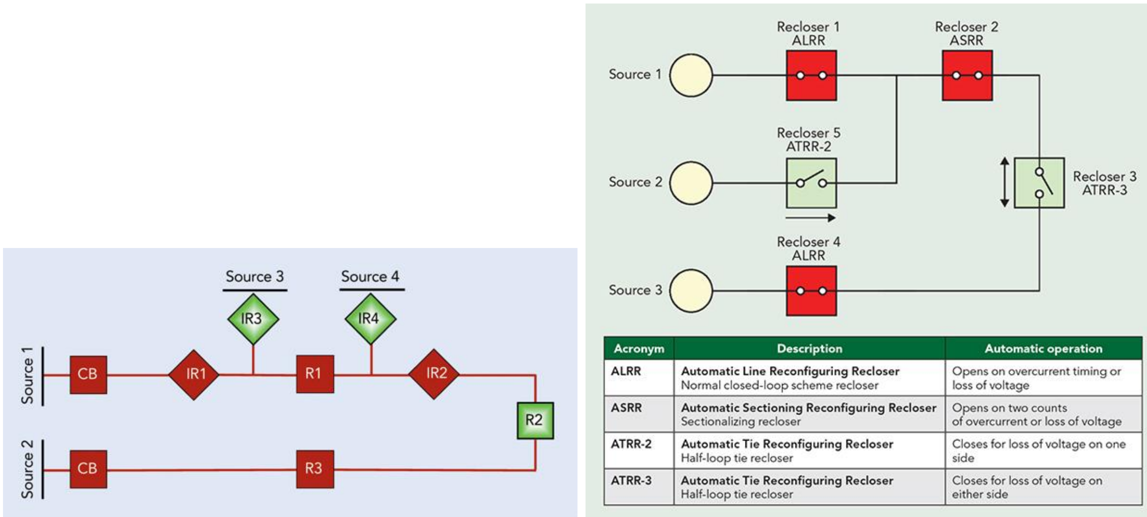


Figure 36 – Reliability benefits (SAIDI reduction) from single-phase tripping

Significant SAIDI reduction is achievable from single-phase tripping versus conventional three-phase tripping for fuse clearing (above) and fuse saving (below) overcurrent protection philosophies. Results show that single-phase tripping achieves a greater reduction in SAIDI (i.e., a greater reliability improvement) than three-phase tripping. Improvement grows as the percentage of single-phase faults in the system increases[61]



Acronym	Description	Automatic operation
ALRR	Automatic Line Reconfiguring Recloser Normal closed-loop scheme recloser	Opens on overcurrent timing or loss of voltage
ASRR	Automatic Sectioning Reconfiguring Recloser Sectionalizing recloser	Opens on two counts of overcurrent or loss of voltage
ATRR-2	Automatic Tie Reconfiguring Recloser Half-loop tie recloser	Closes for loss of voltage on one side
ATRR-3	Automatic Tie Reconfiguring Recloser Half-loop tie recloser	Closes for loss of voltage on either side

Figure 37 – ComEd loop distribution automation schemes using a combination of modern reclosing technologies[66,67]

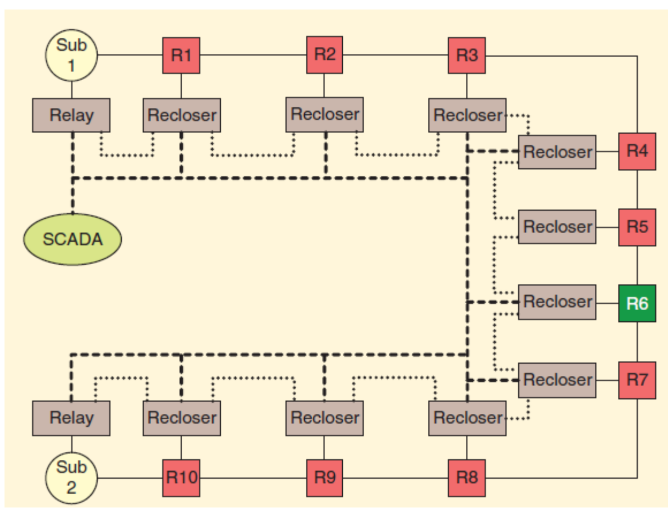


Figure 38 – PSE&G advanced loop scheme using multiple reclosers and high speed peer-to-peer communication[68]

- Distribution Automation

[66] J. Gates, ComEd Advances System Reliability, T&D World Magazine, September 2013 http://tdworld.com/distribution/comed-advances-system-reliability

[67] M. Mondello, A. Dhawan, R. Gupta, ComEd Rolls Out Modern Infrastructure, August, 2014, T&D World Magazine http://tdworld.com/distribution/comed-rolls-out-modern-infrastructure

[68] R. Wernsing, J. Hubertus, M. Duffy, G. Hataway, D. Conner, E. Nelson, Advanced Loop Scheme: Improving Reliability Through Better Operational Methods, IEEE Industry Applications Magazine, Vol. 18, Issue 2, pp. 14 - 22 http://ieeexplore.ieee.org/document/6112292/

On the Distribution Automation side utilities are actively pursuing the implementation of FLISR and Volt-VAR Optimization (VVO) applications that allow improving the reliability and efficiency of the distribution grid. In the specific case of FLISR this implies deploying advanced reclosers and/or switches that allow to automatically locate and isolate faults and restore service via reconfiguration and execution of load transfers to neighbor feeders. This requires not only the ability to monitor and control the grid in real-time to ensure that reconfigurations do not violate equipment and line ratings and voltage limits, but also adjustment of settings of respective protection and voltage regulation/control equipment. A conceptual description of the benefits associated with a FLISR implementation are shown in Figure 39. Accomplishing this objectives requires the utilization of intelligent control algorithms. Leading practices for implementation of FLISR in urban circuits of large metropolitan areas aim at dividing distribution circuits in at least four sectionalizing or protection zones that allow splitting load and customers into manageable circuit components that can be isolated and/or transferred to neighbor feeders to minimize impacts on system reliability, e.g., approximately 500 customers per sectionalizing/protection zone[69]. This requires having at least two normally open ties per distribution circuit that can serve as backup sources during contingencies. It is expected that in the future such backup sources could include DER operating in islanded mode as part of microgrid implementations. There are numerous examples of successful implementations of distribution automation schemes using reclosers and switches. Table 15 shows a summary of the reliability benefits (measured via SAIFI, SAIDI and MAIFI) achieved by 42 projects (Table 16) implemented via the US Department of Energy (DOE) Smart Grid Investment Grant (SGIG) that included the deployment of automated feeder switching on 1,250 distribution feeders[70]. Here negative values represent reductions in reliability indices attained by the projects (with respect to base case), i.e., reliability improvements. Table 16 shows a list of utilities that participated in this program. The results show the tremendous potential and benefits of distribution automation to improve reliability performance. It is worth noting that FLISR applications is one of the key components of ENO's grid modernization program.

[69] K. Tweed, New Switches Cut 80,000 Outages for ComEd, Greentech Media, http://www.greentechmedia.com/articles/read/new-switches-cut-80000-outages-for-comed

[70] Reliability Improvements from the Application of Distribution Automation Technologies – Initial Results, US Department of Energy, December 2012 https://www.smartgrid.gov/files/Distribution_Reliability_Report_-_Final.pdf

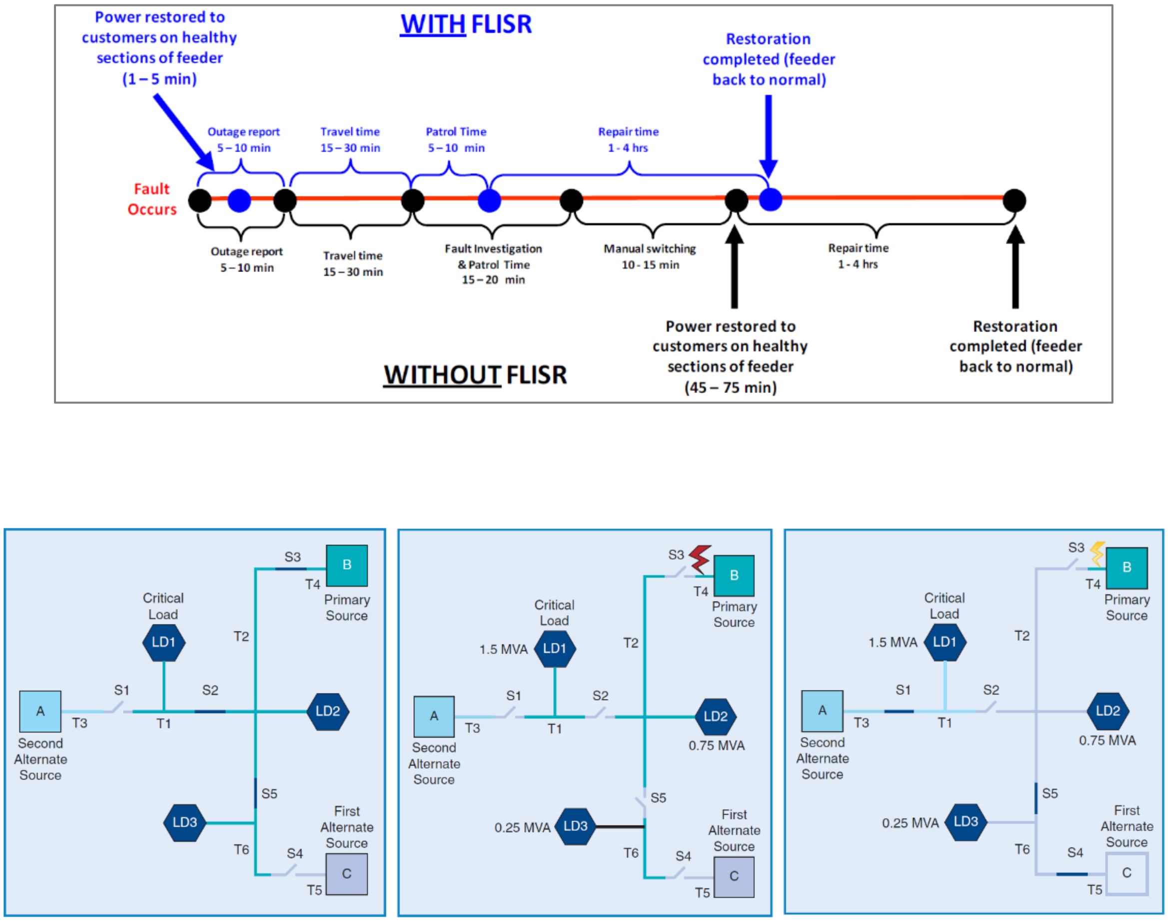


Figure 39 – Conceptual description of the reliability benefits associated with a FLISR implementation.

The first diagram conceptually shows the amount of time required to locate and isolate faults and restore service (without and with FLISR). The set of three plots show how FLISR restores service to most customers supplied by feeder B by automatically transferring loads to neighbor feeders A and C[71,72]

Table 15 – Summary of Changes in Distribution Reliability

Reliability Indices	Range of Improvement % Change	Range of Baselines
SAIFI	-13% to -40%	0.8 to 1.07
SAIDI	-2% to -43%	67 to 107
MAIFI	-28%	9.0

[71] D.M Staszesky, D. Craig, C. Befus, Advanced Feeder Automation is Here, IEEE Power and Energy Magazine, Sep/Oct 2005, pp. 56-63 http://ieeexplore.ieee.org/document/1507027/

[72] J. Romero Agüero, Applying Self-Healing Schemes to Modern Power Distribution Systems, 2012 IEEE Power and Energy Society General Meeting http://ieeexplore.ieee.org.prox.lib.ncsu.edu/document/6344960/

Table 16 – Utilities Deploying Distribution Reliability Devices and Systems as Part of SGIG

Electric Cooperatives	Public Power Utilities	Investor-Owned Utilities
• Denton County Electric Cooperative, Texas • Northern Virginia Electric Cooperative, Virginia • Golden Spread Electric Cooperative, Inc., Texas • Powder River Energy Corporation, Wyoming • Rappahannock Electric Cooperative, Virginia • South Mississippi Electric Power Association, Mississippi • Southwest Transmission Cooperative, Inc., Arizona • Talquin Electric Cooperative, Inc., Florida • Vermont Transco, LLC, Vermont	• Burbank Water and Power, California • Central Lincoln People's Utility District, Oregon • City of Anaheim Public Utilities Department, California • City of Auburn, Indiana • City of Fort Collins Utilities, Colorado • City of Glendale, California • City of Leesburg, Florida • City of Naperville, Illinois • City of Ruston, Louisiana • City of Tallahassee, Florida • City of Wadsworth, Ohio • Cuming County Public Power District, Nebraska • EPB, Tennessee • Guam Power Authority, Guam • Knoxville Utilities Board, Tennessee • Public Utility District No. 1 of Snohomish County, Washington • Sacramento Municipal Utility District, California • Town of Danvers, Massachusetts	• Avista Utilities, Washington • CenterPoint Energy, Texas • Consolidated Edison Company of New York, Inc., New York • Detroit Edison Company, Michigan • Duke Energy, Indiana, North Carolina, Ohio, South Carolina • El Paso Electric, Texas • FirstEnergy Service Company, New Jersey, Ohio, Pennsylvania • Florida Power & Light Company, Florida • Hawaiian Electric Company, Hawaii • Indianapolis Power and Light Company, Indiana • Minnesota Power (Allete), Minnesota • NSTAR Electric Company, Massachusetts • Oklahoma Gas and Electric, Oklahoma • PECO, Pennsylvania • Potomac Electric Power Company – Atlantic City Electric Company, New Jersey • Potomac Electric Power Company – District of Columbia • Potomac Electric Power Company – Maryland • PPL Electric Utilities Corporation, Pennsylvania • Progress Energy Service Company, Florida, North Carolina • Southern Company Services, Inc., Alabama, Georgia, Louisiana, Mississippi • Westar Energy, Inc., Kansas

- Relays and enhanced system protection

  Digital relays are a proven technology today and are already widely deployed (although many utilities still have a large number of electromechanical relays). Relay settings are typically adjusted only by the utility protection department and are rarely modified remotely. Protection settings which are adaptive to system conditions, e.g. DER production or various system configurations (including microgrids) are rarely used in the industry. DERs with inverter technology create various operating scenarios which are not presently addressed by existing protection schemes. Circuit power flows and fault current levels will change based on DER size, output, and location on the circuit. Protection systems should automatically adapt to DER production and circuit conditions. New substation automation applications and new methodologies in protection engineering are needed to address these challenges. It is technically possible to set relays remotely or even to program adaptive settings from the ADMS. In the future, the capabilities of digital relays to support adaptive protection settings (which may be determined at the substation or system level via new applications) will be needed to support protection under high penetration levels of DER and resolve issues such as insufficient fault current, island operation, etc. Additionally, these types of protection schemes can also help with existing safety concerns around increasing the sensitivity to hazardous fault conditions and protection coordination during temporary configurations (e.g., during outage management and service restoration activities). Protection applications such as use of negative sequence values, Direct Transfer Trip (DTT) that depend on sensors and measurements on the circuit instead of at the circuit breaker, as well as use of Synchronized Phasor Measurements, are expected to become more common.

- Advanced sensors

  Advanced sensors provide cost-effective monitoring of key electric variables, including bi-directional power flows, voltages, currents, equipment and DER status, etc., as well as fault information to circuit breakers and other protection devices. Distribution systems are increasingly becoming more complex and difficult to predict, due to the growing variability of DER outputs and loads, and the deployment of distribution automation schemes with the ability to automatically reconfigure the grid to minimize the impact of faults on service reliability. Therefore, there is an increasing need for advanced sensors with higher resolution and time-synchronization capabilities to accurately capture distribution system dynamics. The data provided by these devices will also help detect fault currents at a remote location or high impedance conditions not sufficient to trip normal protection technologies. Implementation of synchrophasor technology in distribution systems and applications based on such may be desirable (as a means to address operational and power quality issues derived from DER variability, for example)[73]. As the cost of these technologies drops over time, and the bandwidth of communications systems used to monitor and control distribution grids increases, synchrophasor technology are expected to become a useful tool at the distribution level, particularly in non-radial distribution configurations.

- Advanced distribution reliability planning

  Modern distribution reliability planning plays a vital role in accomplishing quality of service objectives. For instance, Figure 40 and Figure 41 show an example of the estimated reliability improvement due to the synergistic implementation of a portfolio of projects that include conventional solutions, such as weather hardening, and advanced technologies, including distribution automation and reclosing equipment. This level of reliability improvement cannot be attained by each technology when deployed individually, instead, their combined implementation allows taking advantage of their synergies.

[73] Here it is worth noting that the ability of synchrophasors technology to provide high resolution time-synchronized measurement data is extremely valuable under high penetration levels of DER to estimate the state of the distribution system

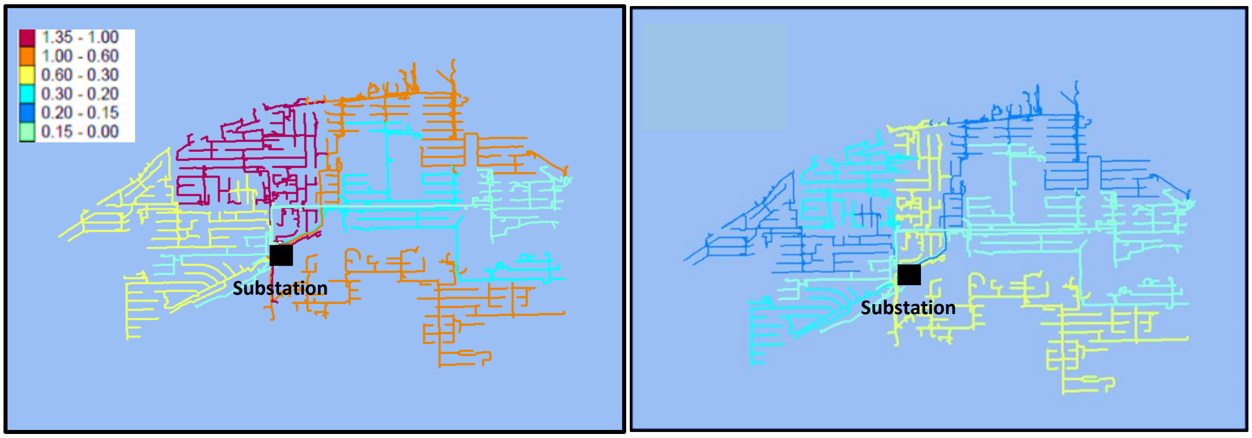


Figure 40 – Expected reliability improvements due to implementation of portfolio of projects

The reliability of the distribution grid represented in Figure 40 is improved through multiple projects including conventional and advanced technology solutions, including distribution automation and advanced sensors. The graphics spatial distribution of SAIDI[74] before (left) and after (right) implementing project portfolio. Red and orange lines have worst reliability performance than green and blue lines.

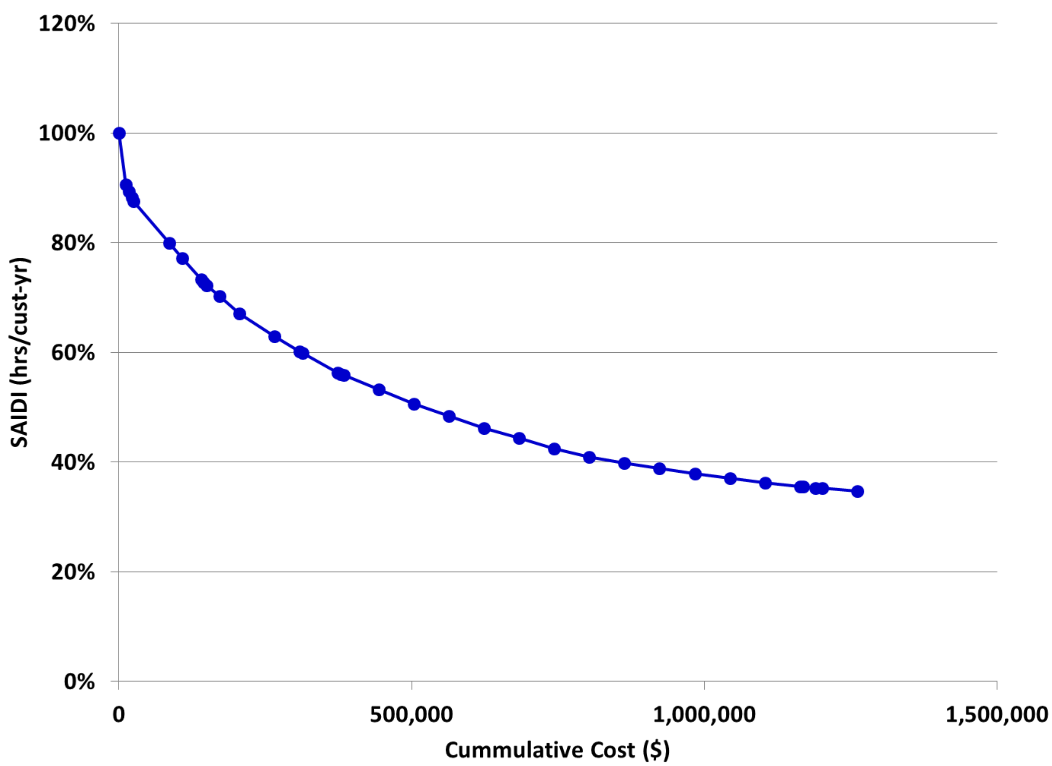


Figure 41 – Project prioritization

[74] System Average Interruption Duration Index (SAIDI) is defined as the average duration of interruptions for customers served during a specified time period and is typically measured in min/cust-yr.

The Figure 41 curve demonstrates project prioritization and expected overall reduction of SAIDI versus portfolio cost for distribution grid of Figure 40. Individual projects have been prioritized based on their expected benefit-cost ratio.

Modern distribution reliability planning techniques, such as the utilization of predictive reliability models using software solutions (Synergi, CYME, etc.), allow estimating benefits and prioritizing and deploying solutions in a cost-effective manner. These technique rely on the utilization of historical reliability and outage data to estimate the existing reliability of the distribution grid and then simulate the implementation of a portfolio of projects for distribution reliability improvement. The simulations consider important system operation constraints, such as equipment ratings and reserve capacity of distribution feeders. Results from the simulations are used to prioritize projects and develop a cost-effective portfolio of solutions to achieve specific reliability improvement targets, such as the one shown in Figure 41. It is worth noting that this type of techniques is being considered as part of ENO's advanced distribution planning initiative.