ELECTRIC POWER
RESEARCH INSTITUTE

# Distribution Grid Resiliency: Modern Grid Technology

2015 TECHNICAL REPORT

# Distribution Grid Resiliency: Modern Grid Technology

EPRI Project Managers
J. Anderson
B. Deaver

ELECTRIC POWER
RESEARCH INSTITUTE

3420 Hillview Avenue
Palo Alto, CA 94304-1338
USA

PO Box 10412
Palo Alto, CA 94303-0813
USA

800.313.3774
650.855.2121

askepri@epri.com

www.epri.com

**3002006783**
Final Report, December 2015

# DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

THIS DOCUMENT WAS PREPARED BY THE ORGANIZATION NAMED BELOW AS AN ACCOUNT OF WORK SPONSORED OR COSPONSORED BY THE ELECTRIC POWER RESEARCH INSTITUTE, INC. (EPRI). NEITHER EPRI, ANY MEMBER OF EPRI, ANY COSPONSOR, THE ORGANIZATION BELOW, NOR ANY PERSON ACTING ON BEHALF OF ANY OF THEM:

(A) MAKES ANY WARRANTY OR REPRESENTATION WHATSOEVER, EXPRESS OR IMPLIED, (I) WITH RESPECT TO THE USE OF ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS DOCUMENT, INCLUDING MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE, OR (II) THAT SUCH USE DOES NOT INFRINGE ON OR INTERFERE WITH PRIVATELY OWNED RIGHTS, INCLUDING ANY PARTY'S INTELLECTUAL PROPERTY, OR (III) THAT THIS DOCUMENT IS SUITABLE TO ANY PARTICULAR USER'S CIRCUMSTANCE; OR

(B) ASSUMES RESPONSIBILITY FOR ANY DAMAGES OR OTHER LIABILITY WHATSOEVER (INCLUDING ANY CONSEQUENTIAL DAMAGES, EVEN IF EPRI OR ANY EPRI REPRESENTATIVE HAS BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES) RESULTING FROM YOUR SELECTION OR USE OF THIS DOCUMENT OR ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS DOCUMENT.

REFERENCE HEREIN TO ANY SPECIFIC COMMERCIAL PRODUCT, PROCESS, OR SERVICE BY ITS TRADE NAME, TRADEMARK, MANUFACTURER, OR OTHERWISE, DOES NOT NECESSARILY CONSTITUTE OR IMPLY ITS ENDORSEMENT, RECOMMENDATION, OR FAVORING BY EPRI.

**THE ELECTRIC POWER RESEARCH INSTITUTE (EPRI) PREPARED THIS REPORT.**

**NOTE**

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

Electric Power Research Institute, EPRI, and TOGETHER…SHAPING THE FUTURE OF ELECTRICITY are registered service marks of the Electric Power Research Institute, Inc.

Copyright © 2015 Electric Power Research Institute, Inc. All rights reserved.

# Acknowledgments

The Electric Power Research Institute (EPRI) prepared this report.

Principal Investigators
J. Anderson
B. Deaver

This report describes research sponsored by EPRI. EPRI wishes to acknowledge the high levels of cooperation, openness, and information sharing by the study participants.

EPRI would also like to recognize the Task Force who supported this effort. The results described in this report would not have been possible without the participation and cooperation of the study participants.

| | |
|---|---|
| Alliant Energy | Rick Potter |
| Ameren Corporation | Tamer Rousan<br>Jim Huss |
| American Electric Power Service Corp. | Paul Thomas |
| Arizona Public Service Co. | Erik Ellis |
| BC Hydro | Cheong Siew |
| CenterPoint Energy Houston Electric, LLC | Walter R. Bartel |
| Central Hudson Gas & Electric Corp. | Franco Bruna |
| Consolidated Edison, Inc./O&R | Matthew Sniffen<br>Sunil Sobhan |
| CPS Energy | Tommy Ross |
| DTE Energy | Richard Mueller |
| Exelon Corporation/BG&E | Aleksandar Vukojevic |

This publication is a corporate document that should be cited in the literature in the following manner:

*Distribution Grid Resiliency: Modern Grid Technology.*
EPRI, Palo Alto, CA: 2015.
3002006783.

| | |
|---|---|
| Exelon Corporation/ComEd | Dan Brotzman |
| Exelon Corporation/PECO | Glenn Pritchard |
| Eversource Energy (formerly Northeast Utilities) | Andrew Kasznay |
| FirstEnergy Service Company | Dean E. Phillips |
| Indianapolis Power & Light Co. | Steve Clouse |
| National Grid | Al LaBarre |
| Pepco Holdings, Inc. | Robert S. Stewart |
| PPL Electric Utilities | David Rossi<br>Chris Menges<br>Robert Markiewicz |
| San Diego Gas & Electric | Jose Carranza |
| Southern Company | Steve Daniel<br>Charlie Vance |
| We Energies | David Nestler |
| Xcel Energy Services, Inc. | Danny Will |

# Abstract

This report describes the results of the modern grid technology task of EPRI's three-year distribution grid resiliency (DGR) initiative. The overall goals of this research were to 1) document the challenges and opportunities that key modern grid technologies present with respect to DGR, 2) gather and document utility practices intended to manage these challenges, 3) communicate and identify opportunities that can be exploited for the benefit of the industry, and 4) identify and scope specific proposals for EPRI research to overcome difficult-to-manage challenges, or further exploit high value opportunities.

The research focused on modern grid technology issues identified during 2012 industry workshops, as follows:

- Configuration and operation of outage management systems (OMS) and distribution automation (DA)/automated restoration systems during severe impact storms
- Hardening of key poles with modern grid technology to mitigate and prevent damage to these expensive assets
- Design and protection standards
- The use of advanced metering infrastructure (AMI) for outage and restoration detection

**Keywords**
Advanced metering infrastructure
DGR
Distribution automation
Distribution grid resiliency
Grid hardening
Modern grid technology
Outage management system

# Executive Summary

EPRI undertook a three-year Distribution Grid Resiliency (DGR) research project to study six tasks of most importance to utilities to enhance distribution resiliency. This report describes the results of the modern grid technology DGR task.

## Background and Objectives

The research focused on modern grid technology issues identified during 2012 industry workshops, including configuration and operation of outage management systems (OMS) and distribution automation (DA)/automated restoration systems during severe impact storms, and hardening of key grid poles with modern grid technology to mitigate and prevent damage to these expensive assets. Additional issues include design and protection standards and the use of advanced metering infrastructure (AMI) for outage and restoration detection.

The overall goals of this research were to 1) document the challenges and opportunities that key modern grid technologies present with respect to DGR, 2) gather and document utility practices intended to manage these challenges, 3) communicate and identify opportunities that can be exploited for the benefit of the industry, and 4) identify and scope specific proposals for EPRI research to overcome difficult-to-manage challenges, or further exploit high value opportunities.

## Results

Building on a literature review and industry scan performed in 2012 and a Modern Grid Technology Grid Resiliency Survey performed in 2013, EPRI identified two major areas of opportunity or gaps where modern grid technologies could potentially support severe storm restoration: 1) maintaining distribution modern grid functionalities during storms, and 2) enhancing existing functionality to improve safety and reduce outage duration. Research commenced to investigate these gaps in present technologies and address them using innovative new solutions or wider scale implementation of solutions that have been demonstrated in the industry.

Following are key insights identified in this research:

- Maintaining and enhancing distribution automation (DA)/automated restoration through various approaches will improve restoration of service to customers through a range of storm severity (minor storm through major storm), but will provide no additional benefit as storms reach catastrophic damage levels.
- Adaptive protection (in the form of fuse saving and additional reclosing) may prevent many transient or temporary faults from becoming sustained outages, reducing the number of restoration jobs during all storms.
- The development, cost optimization, and widespread application of sensors (for example, pole down, line down, and overhead faulted circuit indicators) will reduce damage assessment, fault location, and overall restoration times during all storms.

While a number of recommendations have been developed and can be implemented, the following additional areas offer the opportunity for continuing research and demonstration:

- Cost optimization of pole down and line down sensors
- Development of an application guide for overhead faulted circuit indicators
- Development of the DA battery disconnect switch
- Study of reclosing success rates in different weather conditions
- Improvements in AMI to support outage and restoration detection

# Table of Contents

# List of Figures

# List of Tables

# Section 1: Introduction

This section provides an overview of the Distribution Grid Resiliency (DGR) project, describes the motivation for the Modern Grid Technology DGR task, describes the scope of this task, and outlines the organization of this report.

## Overview of Distribution Grid Resiliency Project

When hurricanes, ice storms, and other significant weather events occur, the electric distribution system is vulnerable to damage and outages. The impacts and costs of these storms can be exorbitant, given the critical nature of electric power systems and their interdependency with other critical infrastructures, such as natural gas and oil, water supply systems, banking and finance, transportation, and others. The frequency and severity of recent storms has focused industry attention on the need to enhance the resiliency of the distribution system so that it will experience less damage during these events. Distribution resiliency improvements can include changes in design standards, construction practices, maintenance and inspection practices, and restoration practices. The appropriate set of activities to harden a distribution system is utility-specific. A significant challenge for utilities is to determine the optimal set of distribution improvements that are acceptable within their regulatory framework, address their particular system parameters and weather characteristics, improve reliability, enhance resiliency, and enable more rapid recovery during and after extreme events.

In response to this challenge, EPRI gathered input and feedback from utility experts on distribution resiliency around the country, and based on this direction, established a three-year research project on grid resiliency.

The overall goal of this research is to create actionable information that utilities can apply to enhance the resiliency of their distribution systems to major weather events. Resiliency can encompass the following forms:

- Damage prevention – Hardening of overhead lines to resist damage, undergrounding, and vegetation management.
- Easier repair – Maintenance, retrofits, or new designs to facilitate damage repair; limit pole damage and cascading failures.
- Isolation and reconfiguration – Isolation of damage to minimize the number of customers affected.
- Recovery – Improved technologies and processes to accelerate restoration.

- Community sustainability – Improved communications with customers and the community (for example, estimated restoration times) and maintaining electric supply to critical infrastructure, such as traffic signals, prisons, hospitals, and cell towers.

The project is organized around the following six DGR tasks (see Figure 1-1):

**DGR Task 1 – Overhead Structures**: The objective of this task is to identify options for improving the resiliency of overhead distribution infrastructure via hardening, graceful degradation, and ease of repair. This task is described in a separate EPRI report [1].

**DGR Task 2 – Vegetation Management**: The objectives of this task are to better understand the mechanisms of vegetation-caused damage to distribution infrastructure during storms; gather and document utility practices related to vegetation management (VM) programs, specifically related to storm damage; and determine if there are new options for VM programs that could result in less system damage during major storms. This task is described in a separate EPRI report [2].

**DGR Task 3 – Undergrounding**: The purpose of this task is to compile representative cost data on the undergrounding of distribution infrastructure so that utilities may better assess this option for improving distribution grid resiliency in major storms, such as wind and ice storms. This task is described in a separate EPRI report [3].

**DGR Task 4 – Modern Grid Technology**: The goals of this research are to document the challenges and opportunities that key modern grid technologies present with respect to distribution grid resiliency; gather and document utility practices intended to manage these challenges, and identify and communicate opportunities that can be exploited for the benefit of the industry; and identify and scope specific proposals for EPRI research to overcome difficult-to-manage challenges, or further exploit high value opportunities. This task is the subject of this report.

**DGR Task 5 – Storm Response Practices**: This task leverages the collaboration that exists among utilities to identify, document, and share leading practices for major storm response. This task is described in a separate EPRI report [4].

**DGR Task 6 – Prioritization of Options**: In this task, EPRI aims to provide utility decision makers with guidance for prioritizing and selecting among the resiliency options identified in the other five distribution grid resiliency (DGR) project tasks. This task is described in a separate EPRI report [5].

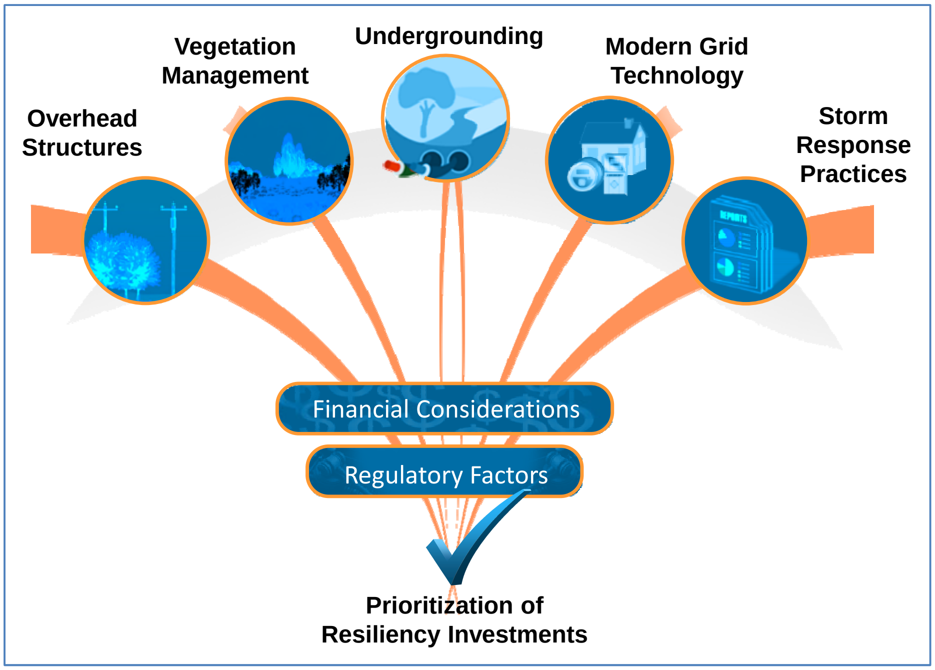


*Figure 1-1*
*The six DGR tasks*

Table 1-1 lists the titles and product identification (PID) numbers for the six DGR reports.

*Table 1-1*
*DGR reports and publication numbers*

| Report | PID Number |
|---|---|
| Distribution Grid Resiliency: Overhead Structures | 3002006780 |
| Distribution Grid Resiliency: Vegetation Management | 3002006781 |
| Distribution Grid Resiliency: Undergrounding | 3002006782 |
| Distribution Grid Resiliency: Modern Grid Technology | 3002006783 |
| Distribution Grid Resiliency: Storm Response Practices | 3002006784 |
| Distribution Grid Resiliency: Prioritization of Options | 3002006668 |

## Motivation for the Modern Grid Technology Task

After the series of severe impact storms affecting North America culminating with Superstorm Sandy (see Figure 1-1), the electric distribution industry and consultants, government agencies, and independent research organizations realized that grid resiliency was an issue that required much attention and research. Given the proximity of the timing of these severe impact storms with the global financial crash of 2008 and the subsequent US Federal Government stimulus investment in the smart grid, industry stakeholders asked the same intuitive question: "What can the smart grid do to improve grid resiliency?"

Many industry outsiders concluded that billions of dollars of investment in smart grid technologies should provide significant benefits to all aspects of running the electric distribution business, including distribution grid resiliency. As the GridWise Alliance workshop correctly pointed out, "Grid modernization technologies alone are not sufficient to increase the grid's ability to withstand very large-scale events" [6].

The DGR project included Task 4 on modern grid technology to study real world, applicable solutions that can have a direct impact on grid resiliency in the short- to mid-term future.

## Scope of the Modern Grid Technology Task

The goals of this research were to:

- Document the challenges and opportunities that key modern grid technologies present with respect to distribution grid resiliency.
- Gather and document utility practices intended to manage these challenges.
- Communicate and identify opportunities that can be exploited for the benefit of the industry.
- Identify and scope specific proposals for EPRI research to overcome difficult-to-manage challenges, or further exploit high value opportunities.

The research focused on these modern grid technology issues identified during 2012 industry workshops:

- Configuration and operation of outage management systems (OMS) and distribution automation (DA)/automated restoration systems during severe impact storms
- Hardening of key poles with modern grid technology to mitigate/prevent damage to these expensive assets

The research also focused on these additional issues:

- Design standards and hardening of modern grid communications assets to maximize their effectiveness during severe impact storms
- Use of advanced metering infrastructure (AMI) for outage and restoration detection

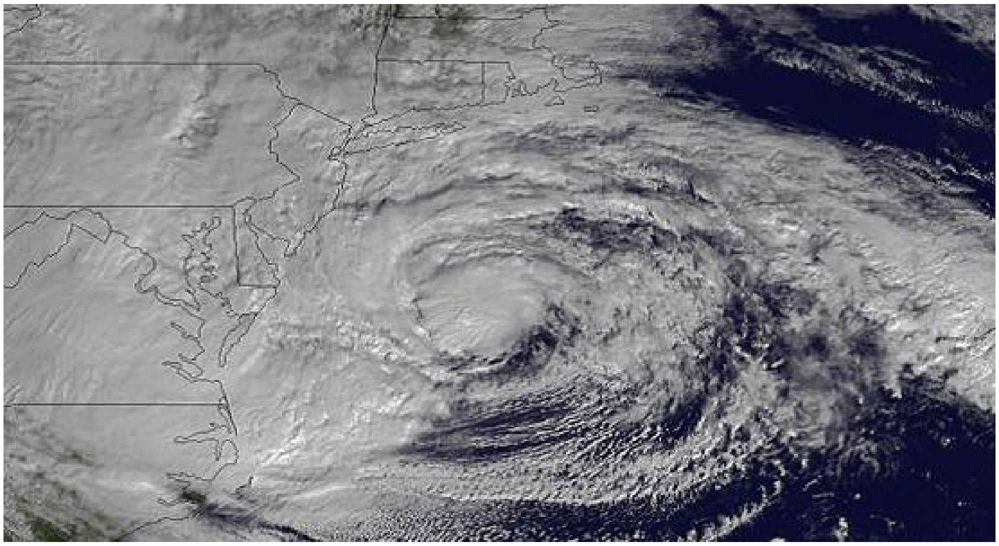


*Figure 1-2*
*Superstorm Sandy - Source: NOAA GOES-13 satellite image, Oct. 29, 2012, showing Superstorm Sandy off the coast of Maryland and Virginia*

EPRI has identified the following two major areas of opportunity where modern grid technologies could potentially support severe storm restoration:

- By maintaining distribution modern grid functionalities during storms
- By enhancing existing functionality to improve safety and reduce outage duration

In general, technology is at the forefront of coping with extreme weather, and post-storm audits over the past decade have increasingly promoted technology-based solutions. Looping systems and DA allow utilities to reroute power and mitigate outages. Geographic information systems (GIS), asset management databases, advanced OMSs, and advanced metering hasten restoration, allowing utilities to generate accurate estimated times of restoration (ETRs), and facilitate data gathering for further analysis. However, technology on its own is not the solution; it must be used in conjunction with traditional hardening and response techniques.

### *Extension of Existing Capabilities*

One challenge is to extend existing capabilities further into the storm recovery. Modern grid technologies provide benefits to the electric distribution utility on a daily basis, whether it is a blue sky day, minor storm day, or severe weather day. These technologies enable utilities to reduce sustained outages and restore service more rapidly, dispatch crews more effectively to trouble locations, determine whether outages have been fully restored, and provide a variety of other useful benefits, as detailed below. However, as a storm progresses, the damage caused may disrupt these technologies, eliminating the benefits they provide. Examples of this type of disruption include the following:

- DA/fault location, isolation, and system restoration (FLISR) automated restoration capabilities may be disrupted for various reasons:
  - DA switch pole damage
  - DA communication disruption
  - DA switch battery failure after long duration outages
  - Multiple contingency outages overwhelming DA control logic
  - Too many feeders locked out to support any useful restoration operations
- Automated metering outage and restoration detection capabilities may be disrupted for reasons including:
  - Too many concurrent outage notifications overwhelming the AMI communications network
  - Outages impacting mesh AMI communications, preventing restoration notifications or ping checks from restored meters
- OMS call analysis algorithms may provide incorrect analysis because of long delays in processing hundreds of thousands of outage calls, and the prevalence of nested outages.

Thus, one goal of this task research is to identify, test, and validate technologies and methods to extend existing capabilities further into the storm.

### *Enhanced Capabilities*

Along with maintaining existing capabilities of modern grid technologies, one of the key aims of this research was to identify, prototype, evaluate, and report on new or enhanced technologies that may offer grid resiliency benefits. These new technologies may range from new methods for the application of existing technologies, to brand new devices or algorithms. Examples of the enhanced capabilities studied in this task include the following:

- Advanced DA/FLISR logic that is able to continue to restore service beyond the first contingency or around communications or device failures to the maximum extent possible given conditions.
- Innovative OMS settings that optimize call analysis results in the face of excessive call volumes, delayed AMI outage notifications, or highly nested outage situations.
- New classes of sensors to detect downed poles by measuring the change in their position.
- New classes of sensors to detect downed conductors by measuring the change in their position.

- Adaptive application of fuse saving settings during storm situations to take advantage of the reduction of sustained outages, without impacting customer satisfaction from excessive momentary outages.
- Adaptive setting of DA recloser and substation circuit breaker reclosing to provide additional attempts at reclosing during high wind or lightning events that may reduce sustained outages, without impacting equipment health due to excessive through faults or customer satisfaction from excessive momentary outages.
- Extended usage of AMI data to track storm progress, localize zones of high outage impact, and eliminate truck rolls related to outage jobs that have already been restored.

## Organization of this Report

Section 2 summarizes the results of an industry scan and a survey that was conducted of the participating utilities to uncover their existing approaches to using modern grid technologies to support resilience. Sections 3 through 15 include one of the following two types of information:

- Some sections include the results of research that was conducted to facilitate the *extension* of existing high value capabilities further into a severe impact storm event. These include Sections 3 through 6 for DA and Section 9 for OMS.
- Some sections include the specific results of research that was conducted to develop *enhanced* capabilities to improve resilience using modern grid technology. These include Sections 7 and 8 for DA, Sections 10 and 11 for adaptive protection, Sections 12 through 14 for sensing, and Section 15 for AMI.

Each of these sections includes the goals of the research, specific research steps taken, research results, recommendations that the research supports, and cost/benefit analyses that support investment in the recommendation.

Section 16 summarizes and compares the costs and benefits of the technologies and approaches described in Sections 3 through 15. Section 17 includes conclusions and recommendations. Section 18 includes references and Appendix A includes acronyms used in this report.

# Section 2: Industry Scanning Activities

This section provides summaries and key outcomes of the industry scanning activities conducted in the modern grid technology task.

## Overview

An exhaustive review of research reports, workshops results, white papers, and demonstration case studies was inconclusive regarding the role of modern grid technology in efforts to improve grid resiliency. In the thousands of pages of reports reviewed, "smart grid" is mentioned frequently in the same paragraph as "grid resiliency." Some of these documents lack substance, recommend future opportunities (for example, microgrids, or using stored power in plug-in hybrid electric vehicles or community energy storage facilities), suggest additional research, or promote concepts that are not realistically applicable. The review surfaced few practical solutions for addressing resiliency challenges.

## Summary of Modern Grid Technology Survey Results

A survey of existing utility practices related to the use of modern grid technology to achieve greater distribution system resiliency was developed and delivered within the first six months of the project. The purpose of this survey was to identify the breadth of existing solutions represented by the DGR project funders, characterize the variations of solutions to similar problems, identify gaps that could be filled by further research, and identify innovative solutions or ideas that could be more broadly shared. The survey was limited to discussions related to DA/FLISR, OMS, AMI and system protection and control.

The survey was developed as a document and sent to each of the participating utilities. Instead of simply requesting that the utilities respond in written form and return the surveys, individual interviews were scheduled with subject matter experts from each utility. This process allowed EPRI staff to delve more deeply into topics of particular interest or experience with the participating utilities, while moving quickly past topics of little interest or experience. In this way, each utility's unique perspectives and lessons learned were captured most efficiently.

The key results of each topic are reviewed in Sections 3 through 15 of this report, as each specific area of research is covered.

The project team conducted a follow-on survey to delve more deeply into the details of utility practices with respect to advanced protection and control functions directed at improving system performance during storms, particularly with efforts to automatically restore as many temporary faults as possible without blowing fuses or locking out reclosers or circuit breakers.

## Outcomes of Industry Scan Activities

Among all of the white papers, case studies, and solid thought into the problem of managing the distribution system in the face of severe impact storms, a few ideas stood out:

- The answer is that there are no easy answers; there is no one solution or magic bullet. The answer is a sequence of small improvements that will results in the ultimate improvements.
- Solid, intelligent preparation is key to making unplannable events more survivable.
- Preventing all impacts from all storms is not feasible, due the very high cost involved.

Two important issues, summarized below, surfaced that require consideration:

- CAIDI metrics
- Turning non-reportable storms into reportable events

### *CAIDI Metrics*

The customer average interruption duration index (CAIDI) is a reliability index commonly used by electric power utilities. CAIDI provides the average outage duration that any given customer would experience. CAIDI can also be viewed as the average restoration time. CAIDI is measured in units of time, often minutes or hours. It is usually measured over the course of a year, and according to IEEE Standard 1366-1998, the median value for North American utilities is approximately 1.36 hours.

$$\text{CAIDI} = \frac{\text{sum of all customer interruption durations}}{\text{total number of customer interruptions}} = \frac{\text{SAIDI}}{\text{SAIFI}}$$

The CAIDI metric does not necessarily reflect the improvements that DA/FLISR provides. This is because DA/FLISR turns some short duration outages into momentary outages. Thus, these outages are removed from both the numerator and the denominator of the CAIDI arithmetic. The following example illustrates this problem:

Without DA/FLISR the feeder experienced the following outages in a calendar year:

- 1200 customers out for 1 hour
- 1200 customers out for 2 hours
- 1200 customers out for 1 hour
- 1200 customers out for 4 hours

CAIDI is calculated as (1200+2400+1200+4800)/4800 = 2.0

With DA/FLISR these outages become:

- 600 customers out for 1 hour; 600 experience a momentary outage
- 600 customers out for 2 hours; 600 experience a momentary outage
- 600 customers out for 1 hour; 600 experience a momentary outage
- 1200 customers out for 4 hours

Thus, this shows the improvement that DA/FLISR provides.

### *Turning Non-Reportable Storms into Reportable Events*

Another unintended consequence of implementing DA/FLISR to improve reliability is beginning to gain notice in the industry. Some state regulators define thresholds in which the storm changes from reportable (meaning it is included in reported reliability performance statistics) to non-reportable (meaning it is excluded from reported reliability performance statistics).[1] Following are a few examples of these thresholds:

- Maryland – 10% of utility customers or declared state of emergency
- Pennsylvania – 10% of utility customers
- New Jersey – 10% of utility customers
- Ohio – 2.5 beta method not counting transmission outages

---

[1] The largest events are often considered non-reportable, as the severity of conditions in these events is considered to exceed the level of design necessary to deliver normal levels of reliability. Regulators often recognize this by allowing utilities to exclude statistics from the largest events so as not to skew reported reliability statistics.

This scan of the industry has uncovered that in at least two utilities, there have been examples in which the reliability improvements directly attributed to DA/FLISR have caused storms to improve from above the non-reportable threshold to below the non-reportable threshold. Without examining the mechanics of a numerical example, it is easy to imagine a situation in which avoidance of 20,000 customer interruptions in a major storm may lead to this condition, ultimately making the reported SAIFI and SAIFI worse than they might have been without DA. Obviously the answer is not to avoid deploying DA, so the industry needs to begin to consider how to clearly communicate this phenomenon to the state regulatory agencies and develop a common approach to gaining credit for reducing the number and duration of outages.

# Section 3: Extension of DA – Backup Power Supplies

## Motivation for this Study

An area of significant potential improvement for maintaining functionality during significant impact storm events is in DA switch power management. Currently, a DA switch, controller, and communications device rely on batteries as a backup power source during an outage, when local power from the circuit is de-energized. Under normal conditions, these batteries need to be replaced every 3 to 4 years. During large storms, depending on their innate functionality and how they are configured, they may drain to the point where they cannot be recharged, requiring utilities to replace all of their DA batteries after restoration, at significant expense of dollars and time.

## Background/Relevant Survey Information

DA switch and recloser controllers and communications devices are typically equipped with a backup power system to allow operation and monitoring of the device during a power outage. In fact, a power outage is "prime time" for DA device operation, when they are required to monitor system conditions, communicate to other DA devices or to the Distribution Control Center DA master station, respond to remote control commands, perform switching operations (open or close), and report their final status. Proper backup power systems (batteries, chargers, and changeover circuits) are critical to ensure that sufficient energy exists to power these functions, ensuring that the maximum number of customers is restored automatically within five minutes.

Typically these backup power systems utilize valve-regulated lead acid (VLRA) batteries as the storage device. The batteries are specified and sized to afford "at least X hours" of backup power under typical operations (powering the controller and communications device with an assumed level of activity). There are wide variances within the industry about how long is sufficient, with some utilities sizing the batteries for 12, 24, or even 48 hours of life after a loss of power, while others are satisfied with only 1 or 2 hours. The background and rationale for these decisions may not be consistent with the present state, as many utilities initially deployed DA in "supervisory control and data acquisition (SCADA) mode" and have since evolved their deployments to “automatic mode.” Fully automatic DA typically requires less “backup time” to complete the FLISR processes than would be required if the utility was using “SCADA mode” and relying on a distribution control center operator to initiate control.

Most of these controllers are designed with a battery test function that attempts to simulate loading of the battery to determine the status of the battery, and alarm if the battery voltage drops below a trigger level or by a trigger percentage. Some controllers are also designed to shed load (for example, the communications device) in an attempt to preserve the battery for critical functions (for example, local control or protection functions). This is important, because there are several examples in recent years when utilities have been forced to replace a significant population of batteries after an extended outage, due to them being deeply discharged and unable to recharge.

A survey of DA switch battery issues conducted in 2014 found that nearly all of the respondents who have a dedicated recloser inspection program also replaced batteries on a fixed cycle. The majority (89%) of survey participants have a dedicated recloser battery replacement program (see Figure 3-1). The time between change outs varied from as little as three years at one utility to seven years at another (see Figure 3-2). Some of the key findings included that several utilities have started tracking their batteries by creating a database that tracks the battery from installation until it is pulled from service. This allows them to not only keep track of when to change out batteries but also identify potential issues with the batteries themselves.

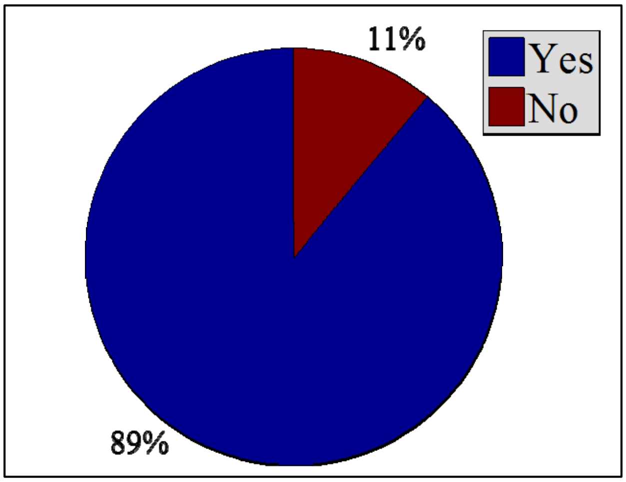


*Figure 3-1*
*Survey results: Does your company have a regular battery replacement cycle?*

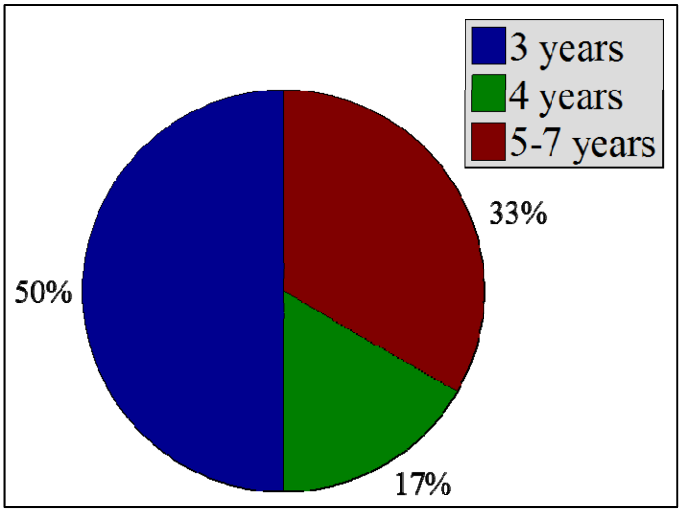


*Figure 3-2*
*Survey results: How many years between battery replacements?*

The survey also addressed how different utilities sized and test their controller batteries. Figure 3-3 shows the minimum length of time that a battery should be sized for an outage.

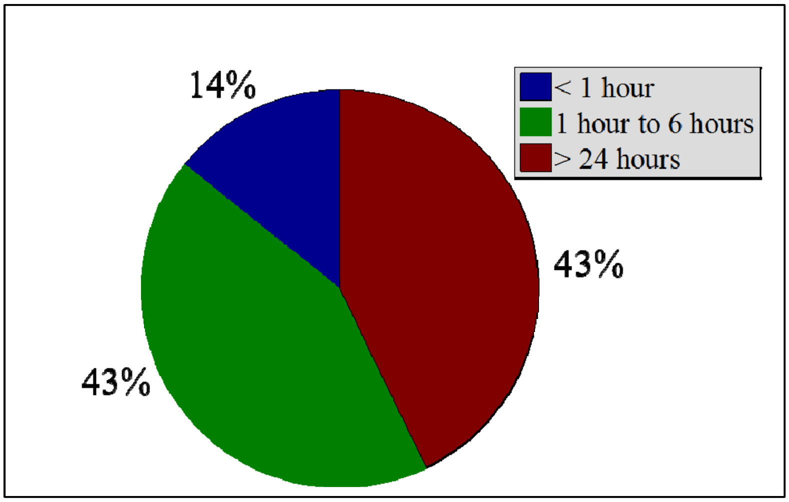


*Figure 3-3*
*Survey results: What would be the minimum amount of time that you would size the battery for?*

## Purpose of this Study

The purpose of this study was to conduct investigations and research to determine methods, practices, and technology solutions that can lead to better DA switch backup power system performance during severe impact storms. Specific goals of this study are to determine solutions that will:

- Prevent the occurrence of wide-scale battery failure following extended outages
- Reduce the number of DA switch failures due to backup power supply failure
- Extend battery life, allowing extension of the battery replacement cycle

## Study Approach

To begin this study, the DGR team characterized how most of the commercially available DA switch controllers operate (see Figure 3-4) [7].

*Figure 3-4*
*Controllers evaluated for backup power functions [7]*

Table 3-1 compares the various controllers' backup power systems.

*Table 3–1*
*Comparison of various controllers' backup power systems [7]*

| Controller | Switching Device | Estimated Battery Life | Routine Battery Test | Can Device Be Operated with No/Dead Battery |
|---|---|---|---|---|
| Cooper Form 5 | Recloser | 4 years | Yes | Yes |
| Cooper Form 6 | Recloser | 4 – 6 years | Yes | Yes |
| Nu-Lec PTCC | Switch | 5 years | No | No |
| S&C 5801 | Switch | 5 years | Yes | No |
| S&C 6801 | Switch | 5 years | Yes | No |
| Schneider Nu-Lec ADVC2 | Recloser<br>Switch | 5 years | Yes | Yes – Recloser<br>No – Switch |
| SEL351-R | Recloser | 4 years | Yes | Yes |
| SEL351-R Falcon | Recloser<br>Switch | 4 years | Yes | Yes – Recloser<br>No – Switch |
| SEL651-R | Recloser | 4 years | Yes | Yes |

Once the existing controllers and backup power supplies were characterized, gaps/opportunities were identified, and solutions were conceived to fill those gaps/opportunities.

## Key Findings

Most of the controllers perform a routine battery test to determine how the battery responds if needed to operate a switching device or power the controls during an ac source loss. Identified factors that contribute to low battery voltage and thus effectively shorten the expected battery discharge time of the battery are:

- Extreme temperatures
- A defective battery
- A battery nearing the end of its useful life
- Number of recloser trip and close operations

One interesting finding is that the battery voltage is higher at colder temperatures and lower at warmer temperatures. This indicates:

- Need for temperature compensated charging circuitry.
- Trickle current charging may not be right answer
- Float charging of the voltage may be a better charging mechanism.

Another interesting note is that a few of the controllers completely disconnect from the battery after a set period of time without ac power.

## Key Outcomes

Two actionable gaps/opportunities identified were:

- Many controllers lack a circuit to disconnect and protect the battery from deep discharge, and potential failure, during an extended outage.
- Batteries are significantly impacted by temperature, and the temperature within the switch controllers that exceed the designed battery temperature.

### *Battery Disconnect Switch*

During the DGR project, one of the issues with DA switch controllers was the post-storm costs of replacing batteries after they have been exhausted and need to be replaced during the restoration process. To prevent this from occurring, some utilities dispatch meter crews to disconnect the batteries in the controller cabinets to prevent permanent damage to batteries. To address this issue, EPRI has initiated design and development of an external battery disconnect switch (see Figure 3-5). During an outage, the switch is programmed to turn off after a specified period of time. When the controller power returns, the disconnect switch senses that ac power has returned and the battery is reconnected.

The intended sequence of operation when an outage occurs is:

1. The battery disconnect circuit detects than an outage occurred by measuring a change in the direction of current flow into the battery and waits X minutes, where X is user-programmable.
2. The battery disconnect circuit also detects when the battery has reached a state of charge of 20%.
3. Once X minutes have passed with no restoration of ac power and the state of charge of the battery has reached 20%, the disconnect switch opens and the battery is completely disconnected from the control.

The battery disconnect switch is designed to reconnect the battery to the controller under the following conditions:

- Field crews press a manual restoration button on the battery disconnect switch.
- When ac power has been restored.
  - The disconnect switch senses the voltage on the controller side until it returns.
  - The disconnect switch then closes, allowing the battery to begin to be charged by the ac power.

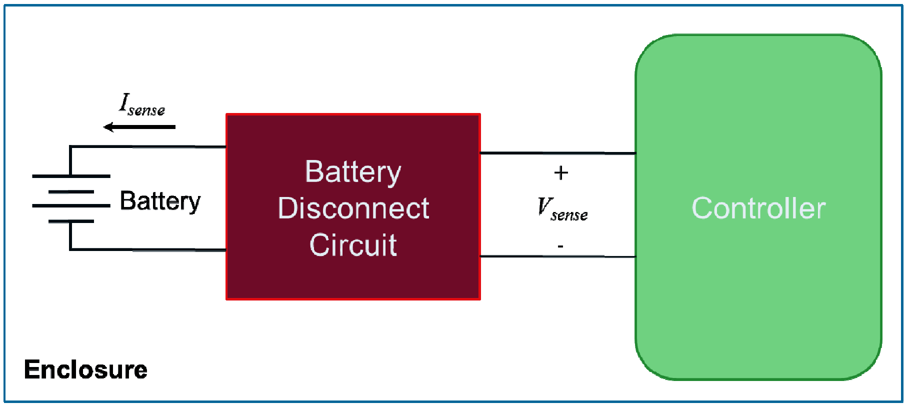


*Figure 3-5*
*Conceptual diagram of battery disconnect switch*

### Controller Temperature Control

Temperature is the enemy of battery life and performance. While most car owners are concerned with the impact of very cold temperatures on battery performance, the significantly high temperatures frequently present within DA switch control cabinets leads to significant reduction in battery life. High temperatures lead to a reduced lifetime for all batteries, and high temperatures cannot always be avoided such as when placed in metal controller enclosures. As a general guideline, for each 8°C rise in temperature, the life of a sealed lead acid battery is cut in half. A valve-regulated lead acid (VRLA) battery that was designed to last for 10 years at 25°C would only last five years if operated at 33°C for its entire life. The same battery would last only 2.5 years if operated at a temperature of 41°C.

The capacity of the battery cannot be restored once it is damaged by heat. Figure 3-6 shows temperature measurements near the processor on a SEL-351R control that is in an enclosure in Greensboro, NC. For a significant portion of the year, the battery operates in a condition that significantly degrades the lifetime of the battery. This temperature may be higher than the temperature at the location of the battery because it is near the control processor. A more in-depth study of enclosure temperatures is underway which may shed some light on one of the major factors in the cause of early battery change outs.

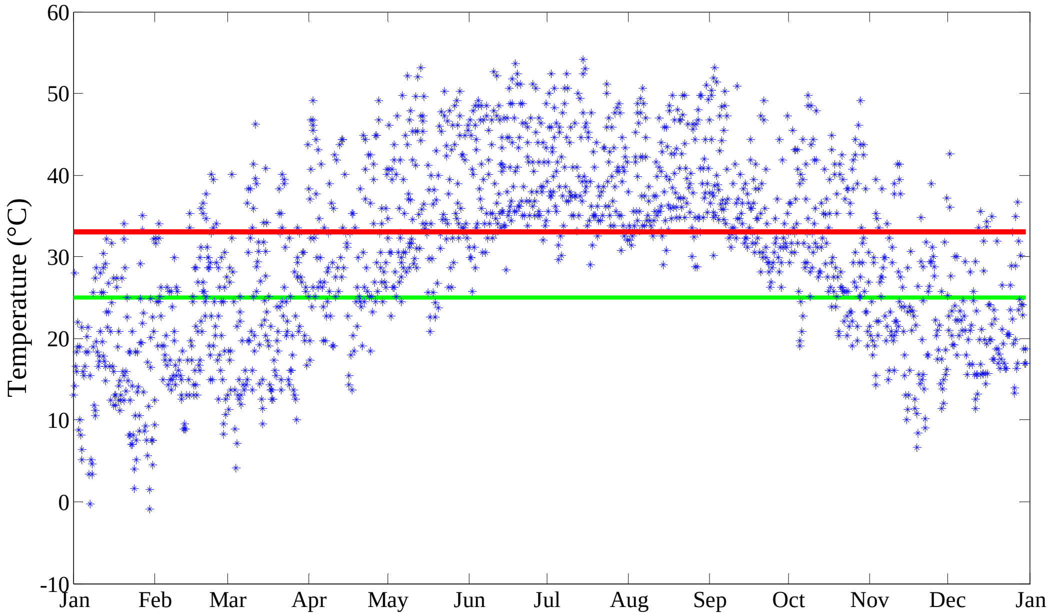


*Figure 3-6*
*Plot of the temperature in a SEL-351R control enclosure that is located in Greensboro, NC, over the period of one year. This temperature was measured by the control itself. The green line is located at 25°C, and the red line is located at 33°C.*

A simple analytical model was developed to determine the effects of using a thermoelectric cooler (TEC) to reduce the temperature of the control enclosure interior. Figure 3-7 shows an example of a TEC known as a Peltier cooler.

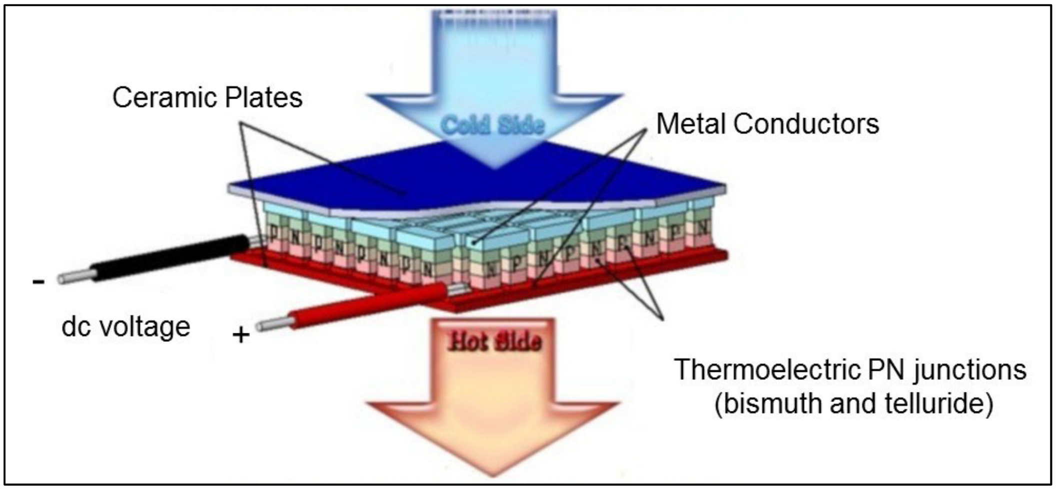


*Figure 3-7*
*Peltier cooler*

Figure 3-8 shows that the analytical model follows the same trend as the measured temperature data when modeled with solar loading on the cabinet from January 2014 to January 2015. This model takes into account the location, time of year, estimated cloud cover, and enclosure mounting including orientation. It also assumes that the TEC is always running and only removes energy. No temperature controls or details of the thermoelectric system were included in the initial model. Figure 3-8 shows that the temperature of the enclosure cabinet can be lowered using a TEC. The location for the model was Greensboro, NC, and the enclosure is mounted on a pole with the back of the enclosure blocked from the sun. The day of the month for which the model is computed is defined as the "characteristic day" for that month.

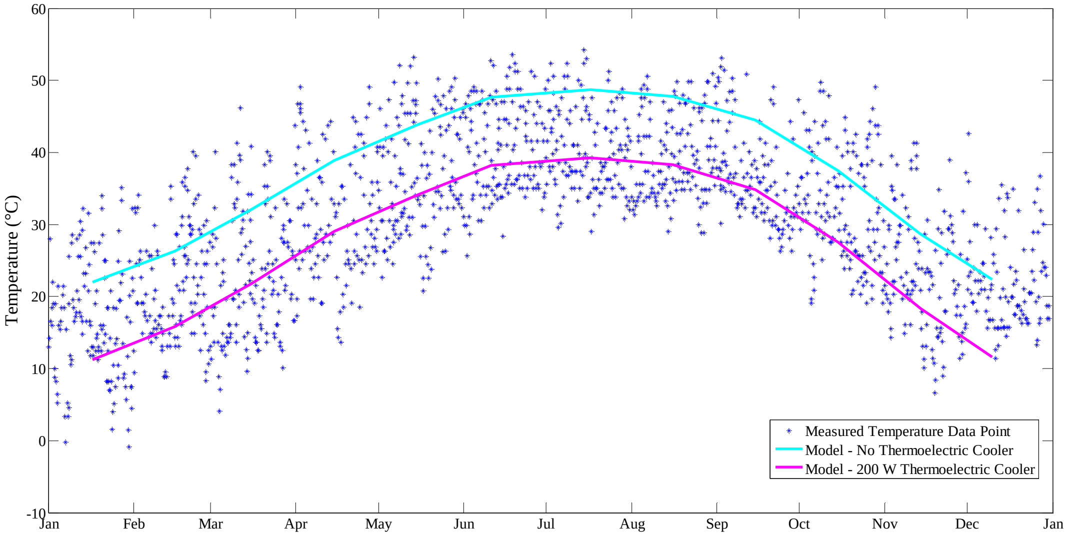


*Figure 3-8*
*Modeled Temperature Impacts of a Thermoelectric Cooler (TEC)*

# Section 4: Extension of DA – FLISR Storm Settings

## Motivation for this Study

The automated restoration aspect of DA, referred to as fault location isolation and service restoration (FLISR), fault detection isolation and restoration (FDIR), or fault isolation and service restoration (FISR), is a new phenomenon in the electric distribution industry. There are a variety of approaches and schools of thought on how these should be operated as a utility progresses from a blue sky day, through adverse weather, minor storms, major storms, and severe impact storms. These approaches may be based on utility specific issues (for example, a higher than normal potential for flooding, the level of dependence of the automation solution on communications, and so on) or more general issues (for example, concern about lack of familiarity with the solution by foreign crews working on the system, desire to keep automatic operations to a minimum when large numbers of personnel are in the field, and so on).

## Background/Relevant Survey Results

A key issue in the architectural design of a DA/FLISR solution is how the solution will operate during adverse weather, minor storms, major storms and severe impact storms. The 2013 survey conducted as part of this research obtained input from participating utilities on how they presently operate their automation during severe impact storms compared to normal operation (see Figure 4-1).

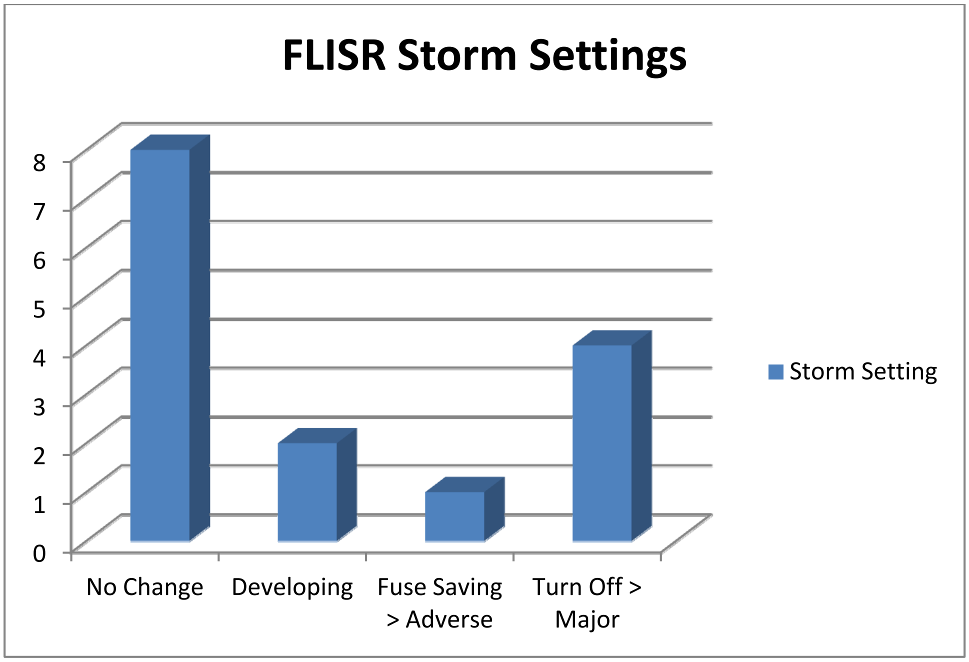


*Figure 4-1*
*Survey results: Storm modification of FLISR settings (Utilities)*

The following responses were received:

- One utility "disables schemes after weather has passed through and damage assessment and restoration efforts are beginning."
- One utility reports that "Right before a major storm hits they 'radialize' their extensive 4-kV grid system by opening reclosers and blocking them open. This step is on the electric operations checklist and is intended to improve safety by reducing the possibility of downed conductors outside of a protection zone due to automated restoration reconfiguration."
- One utility reports that "Depending on the severity of the event, automated reconfiguration will be disabled after the weather system has moved through and restoration work is underway."
- One utility reports that "We don't do anything to turn off the restoration logic. It will continue to work as long as the normal logical conditions are met."
- One utility reports that they "turn automated restoration off once a storm reaches major storm classification, but may also turn it off in a local area that has experienced localized severe storm impacts."
- One utility reports that they "keep automated restoration enabled during all storm situations."
- One utility reports that "Automated restoration is kept active during all storm situations."
- One utility reports that they perform "no changes to the restoration logic; the system will restore what it can until there is nothing left to do."

## Purpose of this Study

The purposes of this study are to expose and investigate all of the utility specific and common issues related to the decision of if and when to disable or modify DA automated restoration logic, and provide decision support for utilities when considering this decision for their own systems.

Specifically, the goals of this study are to:

- Document key issues and the range of decisions and the rationale behind those decisions
- Produce a decision support table to guide utilities in their efforts to make these decisions.

## Study Approach

Because the industry has not settled on a common approach to this issue, the DGR project decided to study the topic and assemble all of the rationales to either disable or maintain DA automated restoration logic, enabling each utility to determine the appropriate decision for their situation.

## Key Findings

The results of the survey were used to determine particular utilities to investigate more thoroughly for insight as to when and why the company decided to make specific decisions regarding automated restoration logic. The results of these investigations are presented in Table 4-1.

*Table 4–1*
*Issues and rationales for disabling or maintaining DA automated restoration logic*

| Issue | Rationale to Disable | Rationale to Maintain |
|---|---|---|
| **Damage Assessment, Standby Crews, Foreign Crews on System** | Safety concern about the large number of personnel on the system who are unfamiliar with DA automated restoration. They may need specific training to recognize and be aware of the automation. | DA automated restoration is no different than other automatic functions (such as fuses blowing or reclosing) that can operate to connect or disconnect the primary. |
| **Abnormal Configurations** | Manual switching may have taken place, changing the configuration in ways not visible to the DA automated restoration logic, resulting in unexpected overloads or unintentional outages. | Normal procedures to specifically disable automatic restoration on feeders that are being switched manually should be followed. |
| **Multiple Contingencies** | The DA automated restoration solution may not be able to perform restoration of multiple contingency events common in severe impact storms. | If the DA automated restoration solution is incapable of performing multiple contingency restoration, nothing further will happen automatically anyway. |
| **Lack of Tie/Restoring Feeders** | When a severe impact storm has passed through the service territory, so many feeders will be affected that the "restoring" feeders may not have the capacity to restore. | If the DA automated restoration logic is sophisticated enough to perceive these situations (through integration with SCADA or OMS), the logic can be left operational, and restoration is decided on a case-by-case basis. Otherwise, it must be disabled to prevent overloading or burning down restoring feeders. |
| **Flooding** | DA facilities are in areas prone to flooding, and the automation (and perhaps the electric service itself) should be disabled to reduce damage and unwanted operations. | If flooding is an issue, disabling may be the only solution. |

*Table 4-1 (continued)*
*Issues and rationales for disabling or maintaining DA automated restoration logic*

| Issue | Rationale to Disable | Rationale to Maintain |
|---|---|---|
| **Preserving Batteries** | There have been examples of DA switches involved in multiple day outages experiencing such significant drain on their batteries that they cannot be recharged and must be replaced. An answer for this is to disable the controller (disconnect it from the battery) after some period of time (for example, 6 hours) to preserve battery life, and restore the controller only after AC has been restored to one side or the other of the DA switch. | As opposed to switching off automation on every DA switch during a severe impact storm, local controller functions (or accessories – see above) may be utilized to manage this on an individual DA switch basis. |
| **Wires Down/High Impedance (HiZ) Faults** | There is concern that DA automated restoration operations may energized downed conductors or restore conductors experiencing high impedance faults – both of which could create safety issues for line workers and the public. There is also concern that restoration switching may extend feeders beyond their zone of protection, increasing the chances of live wires down without tripping a protective device. | Downed conductors should always be considered "live and dangerous" by the public and line workers. This is no different than situations created by reclosing or by DA operations during normal days.<br>Many utilities use reclosers as the tie switch and deploy settings that extend the zone of protection as far as necessary to ensure that all faults fall within a zone of protection and cause a protective device to trip. This practice actually improves the situation from the traditional use of disconnect switches as tie points. |

## Key Outcomes

As planned, this study did not intend to answer the question of whether a utility should disable its DA automated restoration during severe impact storms, and if so, when it should actuate the switch. That decision is best left to each utility considering its specific DA scheme, work practices, feeder design and operating limits, and experience. The key outcome of this study is a set of issues and rationales from multiple utilities that equip each utility with the knowledge to consider its unique situation and make the most appropriate decisions.

# Section 5: Extension of DA – Protecting Critical Infrastructure

## Motivation for this Study

Protecting DA switch poles during a storm event is one straightforward step towards maintaining the functionality further into severe impact storm situations. The loss of a DA pole is far more significant than a normal pole in that the cost to replace the switch, switch controller, communications module and the cost of programming and commissioning the DA switch are quite significant. Additionally, this work requires a number of craft resources over and above a construction crew, potentially including telecommunications technicians, SCADA technicians, and protection/control technicians, depending on the severity of damage. A vice president of a prominent investor-owned utility was not too far off when he suggested a DA switch installation was like installing a “Lexus on a pole.” Along with the cost and complexity of repairs, many of the components have long lead times (3-6 months) and utilities typically do not keep a large stock of spares for maintenance.

## Background/Relevant Survey Results

Several utilities have begun programs to change their design standards to harden DA switch poles. A survey conducted by the EPRI DGR project in 2013 provided the following results, showing about 50% of the utilities surveyed had some sort of DA switch pole hardening in the works (see Figure 5-1).

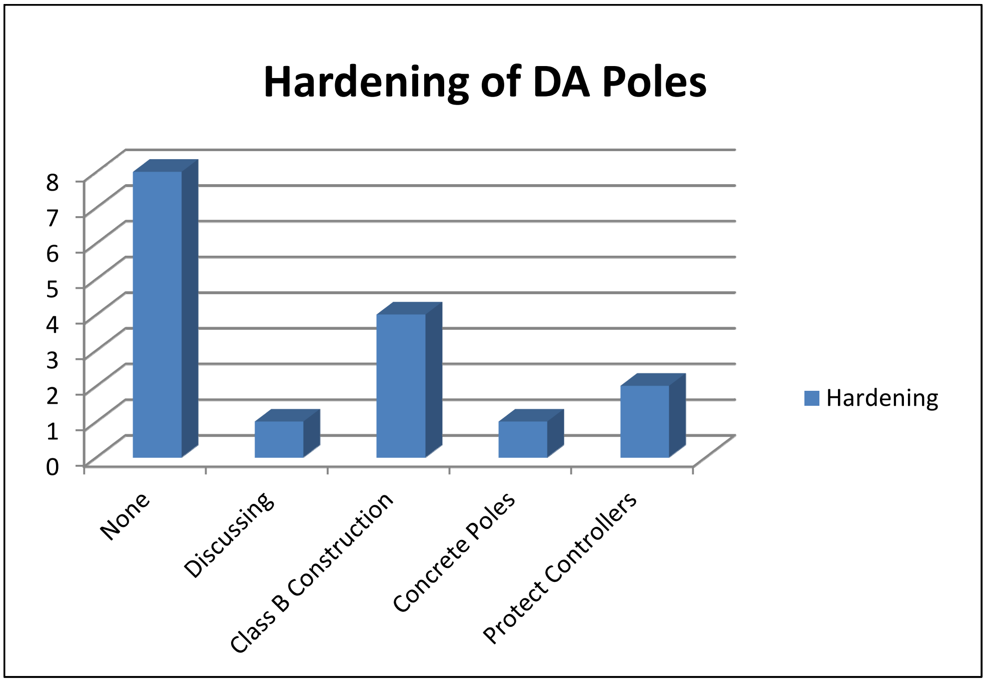


*Figure 5-1*
*Survey results: DA switch pole hardening*

For example, one utility revised its construction standards to improve the reliability of its most critical infrastructure during storm events. The storm hardening revisions were made to ensure that the most important facilities, such as sectionalizing device structures, can withstand a category 3 hurricane (wind speeds of 110 to 130 mph). These updates were not only for new construction, but are being employed on a retrofit basis to the remainder of its system. The utility is hardening its automatic sectionalizing unit (ASU) structures. The key components of this storm hardening effort are as follows:

- The minimum class pole for the ASU installation and its adjacent poles shall be H1 (see Figure 5-2).
- There shall be no major distribution equipment mounted on adjacent poles
- The utility avoids installing ASU structures in locations that are subject to overhanging tree limbs
- The utility limits the number of main telephone company trunk lines (2-in. diameter) to two, on the ASU structure and adjacent structure on each side to minimize pole loading.
- In designing ASU structures, the sum of the angle between the ASU and its adjacent poles shall not exceed 4 inches.

Conductors on the adjacent poles to the ASU structure are double dead ended.

*Figure 5-2*
*New class H1 pole being installed on an existing DA switch location*

Similarly, another utility decided after Superstorm Sandy to increase the size of poles by one level on DA switch poles. For example, if the construction standard called for class 2, the company would upgrade to class 1. This change will be implemented as poles are installed or need to be replaced.

Taking a page from utilities with heavy coastal exposure, another utility has upgraded to concrete poles for DA switches on a case-by-case basis (see Figure 5-3). These poles robustly resist damage from wind, storm surge, and falling trees.

*Figure 5-3*
*DA switch on concrete pole*

## Purpose of this Study

The purpose of this study was to conceive of and test potential approaches to protecting critical DA poles and installed equipment from catastrophic damage as a result of the typical failure modes due to a severe impact storm event. Analysis of available (anecdotal) data indicated that the most likely failure modes were lightning, damage from direct hits from tree limbs or storm debris, and the pole being pulled down by a large tree falling on the lines. The failure mode of DA poles being pulled down by large trees falling on the OH conductors was identified with the highest potential for innovative solutions, in coordination with the work conducted in the DGR Task 1 (aerial structures) project.

The specific goal of this study was to determine solutions that reduce the probability of DA switch pole failure due to trees falling on adjacent lines.

## Study Approach

Building on the specific research of the DGR Task 1 project, the concepts of "hardening by strategic weakening" of OH structures was tested on DA poles. At EPRI's Lenox, Massachusetts laboratory, the DGR team developed and tested a break-away system consisting of sacrificial pole spans on either side of the protected pole (DA switch, AMI backhaul pole, and so on). Connectors designed to disengage wires from poles when impacted by falling trees or other large storm debris were prototyped and installed on both ends of these sacrificial spans, protecting the protected pole from the large stresses that might cause them to break. Figure 5-4 shows the complete design, including a deployment of conductor and pole down sensors, which will be further discussed in a following section. Note that in Figure 5-4, the base station represents the critical DA infrastructure to be protected.

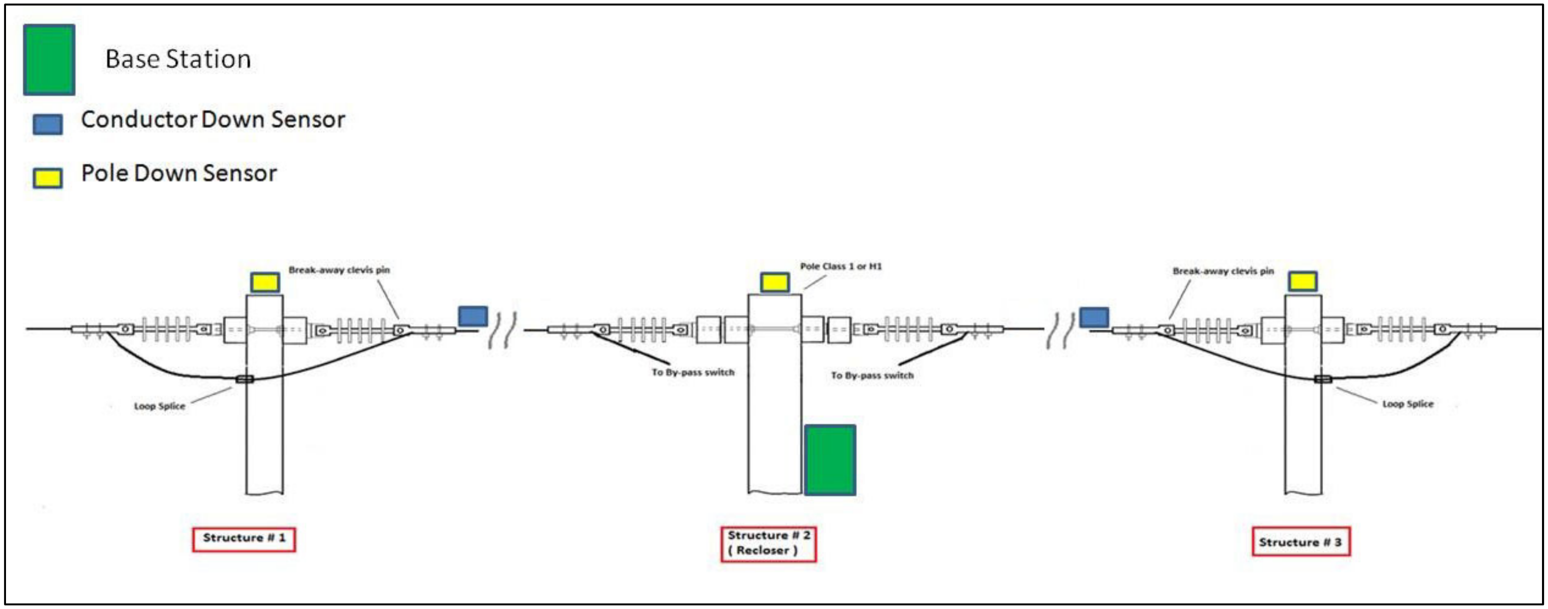


*Figure 5-4*
*Schematic of break-away DA switch pole protection design*

EPRI engineers and technicians conducted four tests using various construction types and connectors to demonstrate the concept that break-away connectors in this configuration could protect the DA switch pole from significant impact due to trees falling on the lines. During the first test, the break-away pins did not function due to misalignment. During the next two tests, the pins did break. Figure 5-5 shows the pins machined (in red) to reduce their strength.

*Figure 5-5*
*Break-away pins*

A control test was conducted using standard hardware that caused visible damage near the ground line of an adjacent pole. During the two successful tests, the sacrificial spans absorbed enough of the energy of the simulated tree falling on the lines, to prevent the protected pole from breaking (see Figure 5-6).

*Figure 5-6*
*OH conductors break after impact of simulated tree on OH lines*

## Key Findings

Figure 5-7 shows the test setup. Comprehensive details of testing (forces, specific construction specs, and so on) of the break-away device is covered in the DGR Task 1 report. Refer to that document for more details [1].

While the concept of break-away connections to protect DA poles was proven, demonstrating the practicality of this solution as a grid resiliency strategy remains a goal. The following issues were identified as challenges to moving forward with this sort of remedy:

- Designing a break-away connector with sufficient strength to meet strength requirements, while being weak enough to break before the DA switch pole was broken remains a challenge. The line components should meet ice- and wind-loading requirements depending on zone, while exceeding those requirements by some margin (say 20%). The right breakaway size will probably be based on general line loading calculations, coordinating with the rest of the mechanical system (similar to fuses and the electrical system).
- Testing in-service DA switches to determine if the violent shaking and twisting forces subjected to the DA pole during the event would damage the bushings, controller, or internal components of the DA switch was outside of the scope of this proof-of-concept testing.

*Figure 5-7*
*Testing of break-away connections to protect DA poles*

## Key Outcomes

This research proved the concept that sacrificial spans could indeed protect critical DA pole installations from being impacted by their poles. Additional work on this concept will continue in future years within the base research of EPRI's Program 180 (Distribution).

# Section 6: Extension of DA – Architectural Considerations

## Motivation for this Study

The choice of control and communications architectures impacts the ability of the DA solution to function during severe impact storms, and also impacts the ability of the distribution control center (DCC) to monitor and manage the automatic DA functions from a central location. The motivation for the study performed as part of this research is to detail these issues, expose the pros and cons of key architectural decisions, and provide decision support into DA architectures that enhance or degrade resilience of the DA system in the face of severe weather events.

## Background/Relevant Survey Information

One of the basic decisions required for any control system is how the control logic is architected. Specifically, this leads to the question of whether the control logic is fully centralized, fully decentralized, or something in between. There are advantages and disadvantages to each of these approaches, which are somewhat different when considering severe impact storm situations than when considering less extreme situations. This background section presents information contained in the EPRI report on *Distribution Management System Planning Guide: How to Run a Distribution Automation Program* [8]. As a result of this DGR research, the advantages and disadvantages have been enhanced and updated to reflect issues specific to severe impact events.

Five distinct types of control logic have been identified that can accomplish the primary goal of FLISR – the successful isolation of the fault and restoration of unaffected sections:

- Stand-alone distributed intelligence
- Peer-to-peer distributed intelligence
- Substation-based decentralized intelligence
- Centralized rules-based intelligence
- Centralized model-based intelligence

The results of the 2013 survey show that a higher proportion of utilities are deploying one of the forms of centralized intelligence control architectures (the final two listed above), but representative samples of each of the other approaches are in full production (see Figure 6-1).

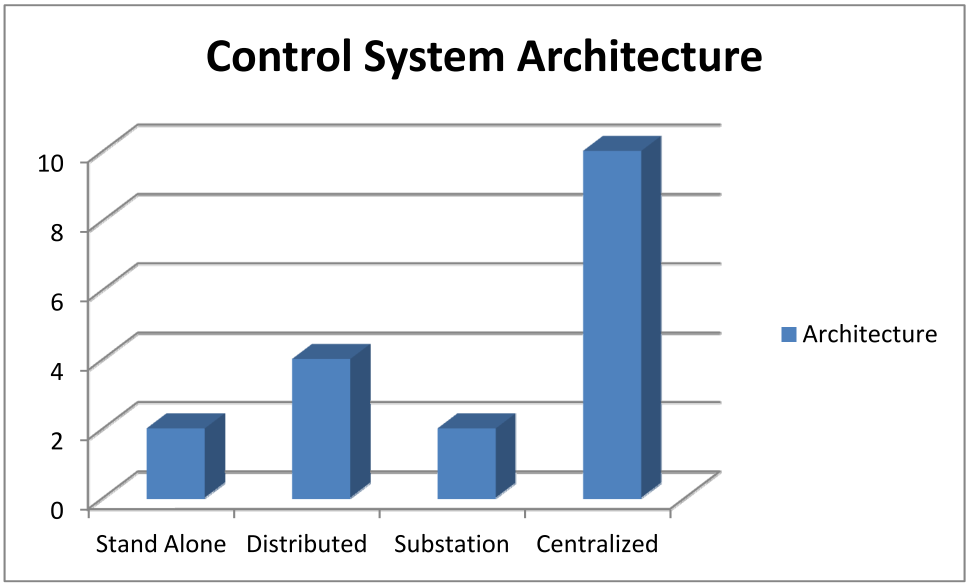


*Figure 6-1*
*Survey results: Control system architecture*

### ***Stand-alone Distributed Intelligence***

Stand-alone distributed intelligence includes schemes that are able to isolate faults and restore service without any communication between field devices. In these schemes, each device has sufficient information with which to determine whether it should open or close. An example is an auto-loop scheme in which two or more feeders are tied together. In an auto-loop scheme, local logic observes the pattern of fault current, loss of load, and loss of potential to determine whether midpoint reclosers should open to isolate the fault and whether tie reclosers should close to restore service. In the three-recloser loop example shown in Figure 6-2, a normal sequence of operations for a fault upstream of recloser R1 is:

1. Breaker B1 senses the fault, goes through its normal reclosing cycle, and locks open.
2. Recloser R1 senses loss of voltage and opens.
3. Recloser R2, the tie recloser, senses loss of voltage on the feeder and closes in. Because R2 can be switching into a fault, normally it is set for one shot; if the fault is there, it trips and stays open.

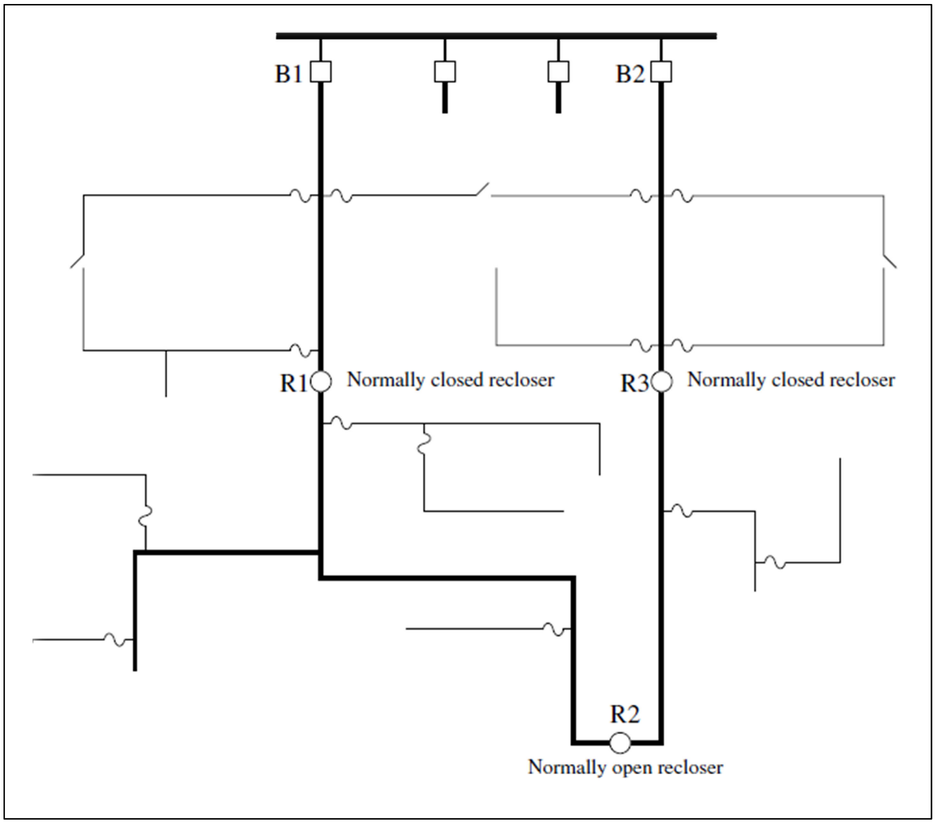


*Figure 6-2*
*Example of an auto-loop scheme*

More reclosers can be added to divide the loop into more sections, but coordination of all of the reclosers is more difficult. Consider the five-recloser loop shown in Figure 6-3. Each feeder has two normally closed reclosers, and there is a normally open tie-point recloser. If feeder 1 is faulted close to the substation, breaker B1 locks out, recloser R1 opens, and the tie recloser closes. This constitutes a long radial circuit with the station breaker in series with four reclosers, which is difficult to try to coordinate. To ease the coordination, some reclosers can lower their tripping characteristics when operating in reverse mode.

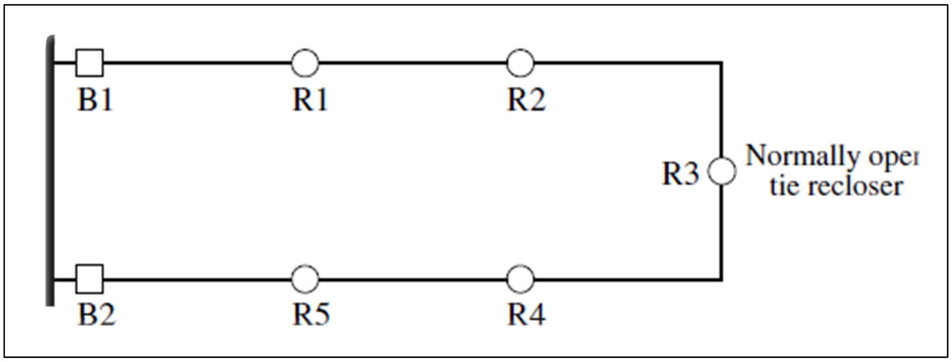


*Figure 6-3*
*Five recloser auto-loop*

In this example, recloser R2 would drop its pickup setting. R2 sees much lower fault currents than it usually does, and R2 should trip before recloser R3 or R4. For a fault between B1 and R1, the five-recloser loop responds similarly to a three-recloser loop:

1. Breaker B1 locks out.
2. R1 opens on loss of voltage.
3. Recloser R2 drops its trip setting.
4. R3 senses loss of voltage on feeder 1 and closes in.

For a fault between R1 and R2, the sequence is more complicated:

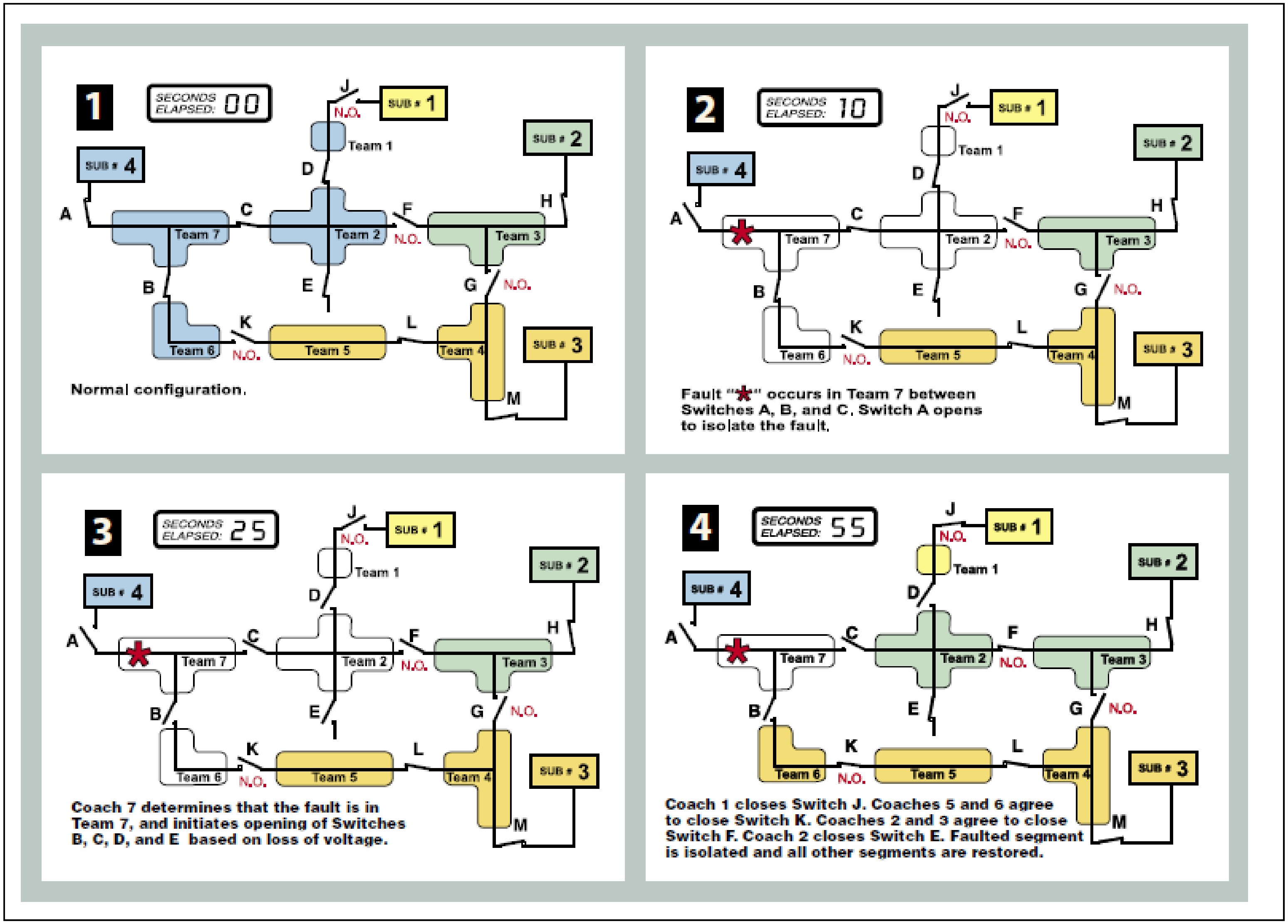
1. Recloser R1 locks out.
2. Recloser R2 drops its trip setting and goes to one shot until lockout.
3. R3 senses loss of voltage on feeder 1 and closes in (and closes in on the fault).
4. R2 trips in one shot due to its lower setting.

In a variation of this scheme, utilities use sectionalizers instead of reclosers at positions R2 and R4. Sectionalizers are easier to coordinate with several devices in series. Remotely controlled switches are another option for automating a distribution circuit. The preferred communication is radio. Remotely controlled switches are more flexible than auto-loop schemes because it is easier to apply more tie points, coordinating protective equipment is not a concern.

### *Peer-to-Peer Distributed Control*

With the fully distributed approach, the main automatic restoration logic resides in controllers that are mounted locally in the field at the automated switches themselves. The decision on whether to open or close a switch is based on local current/voltage measurements and status indications detected at the switch location. This local information is supplemented by information received from nearby switches ("peer" devices) via a high-speed communication network.

Like the centralized and substation centered approaches, the fully distributed peer-to-peer approach automatically detects the fault, locates the fault (between two or more automated switches), opens the appropriate switches to isolate the faulted segment of the feeder, and then restores service to as many customers as possible via the original sources and backup sources without overloading any facilities (see Figure 6-4).



Normal configuration.

Fault "★" occurs in Team 7 between Switches A, B, and C. Switch A opens to isolate the fault.

Coach 7 determines that the fault is in Team 7, and initiates opening of Switches B, C, D, and E based on loss of voltage.

Coach 1 closes Switch J. Coaches 5 and 6 agree to close Switch K. Coaches 2 and 3 agree to close Switch F. Coach 2 closes Switch E. Faulted segment is isolated and all other segments are restored.

*Figure 6-4*
*IntelliTeam operation diagram (Courtesy of S&C Electric)*

### Decentralized (Substation-Based Approach) Control

With the decentralized substation-based approach, logic resides in a smart remote terminal unit (RTU), substation data concentrator, programmable logic controller, or other processor located in the substation (see Figure 6-5). The system uses logical rules along with a basic knowledge of feeder topology to determine the appropriate switching actions. The topology model (which requires information on how devices are connected) is much simpler to maintain than a full power flow model (which requires topology and electrical characteristics for the distribution assets).

*Figure 6-5*
*Substation controller example (Courtesy of Schweitzer Engineering Laboratory)*

In a substation based FLISR scheme, rules-based algorithms are scripted based on pre-engineered evaluation of each automated feeder. Someone, typically an operation support engineer, evaluates the feeder at peak loading conditions and documents a preferred restoration plan for a fault located on each feeder section. These plans are configured in the rules-based logic. When a fault occurs and a DA switch or substation breaker locks out, the rules-based logic is triggered. The rules include checks of substation and feeder loads, voltages, permits/tags, switch statuses, and so on. If all of these checks are successful, the logic proceeds to execute the pre-engineered restoration switching plan.

### Centralized Control

With the centralized approach, the main logic that determines what switching actions to take resides in the control center or other central location (see Figure 6-6). The main application logic can be distribution management system (DMS) model-driven or rules-based logic. With the DMS model-driven approach, feeder reconfiguration actions are determined by applying field measurements and status indications to the as-operated distribution system model. Following is a simplified description of the model-driven FLISR application. A DMS topology processor is used to determine the fault location. The topology processor starts at the feeder extremities (points that are furthest from the source substation) and traces back towards the substation until a DA switch is encountered. If the DA switch indicates that it has seen a fault, then the faulted feeder section is between the DA switch and the feeder extremity. If the DA switch has not seen a fault, then tracing continues until another DA switch is encountered. If the second DA switch has seen the fault, then the faulted feeder section is located between the two DA switches, and the application proceeds with isolating the faulted segment. If the second DA switch has not seen a fault, then the process continues until the breaker is reached.

*Figure 6-6*
*Example of centralized control (Courtesy of Alstom Grid)*

Once the faulted feeder section is isolated, the DMS switch order management (SOM) application is used to generated a suitable switching plan to restore service to as many customers as possible without creating any adverse electrical conditions (equipment overloads, low voltage violations, and so on) on the faulted feeder and any adjacent feeder to which load may be transferred.

A rules-based algorithm is scripted based on pre-engineered evaluation of each automated feeder. Someone, typically an operation support engineer, evaluates the feeder at peak loading conditions and documents a preferred restoration plan for a fault located on each feeder section. These plans are configured in the rules-based logic. When a fault occurs and a DA switch or breaker locks out, the rules-based logic is triggered. The rules include checks of loads, voltages, permits/tags, switch statuses, and so on. If all of these checks are successful, the logic proceeds to execute the pre-engineered restoration switching plan.

Regardless of whether the logic is rules-based or model-based, a FLISR algorithm must address each of the following issues in a structured, repeatable, and testable manner to satisfy a utility to the extent that it will allow fully automated restoration to occur:

- Safety
- Overloads
- Manual switching
- Load shedding/underfrequency (UF) relaying tripping
- System protection coordination
- Equipment/lines tagged out of service
- Cold load pickup
- Multiple contingency events (more than one fault)
- Lack of data/loss of communications

## Purpose of this Study

The purpose of this study was to consider each of the potential architectural approaches to DA with a focus on the unique challenges present in a severe impact storm. The goal was to identify key strengths and weaknesses of each approach, considering those challenges.

## Study Approach

The approach for this study was to consider the strengths and weaknesses of the DA architectural options presented in EPRI's Distribution Management System Planning Guide [8] and update this information considering the unique challenges present in a severe impact storm. Key among those unique challenges considered were:

- A high number of simultaneous outages affecting the same feeders or substations (multiple contingencies)
- A higher than normal probability of local area communications failures
- A higher than normal probability of wide area communications failures
- A higher than normal probability of foreign crews working on the system

## Key Findings

The key factors that impact whether or not a particular DA architecture is suitable in a severe impact storm situation were analyzed with respect to each of the identified challenges. Table 6-1 shows the results of this analysis.

*Table 6–1*
*How different DA architectures manage severe impact storm situations*

| Architecture | Multiple Contingencies | Loss of Local Comm. | Loss of Wide Area Comm. | Foreign Crews on System |
|---|---|---|---|---|
| **Stand-Alone Distributed Intelligence** | Unable to operate beyond pre-configured first contingency operations. If system is in an abnormal condition, this may result in overloads and/or re-tripping of tie reclosers. | Local communication is not required for operation of the restoration logic. | Wide area communication is not required for automated restoration switching, but is required to disable automatic operations. | Foreign crews must be made aware that DA switches may open or close automatically unless they are placed in manual mode and the appropriate clearances issued. |
| **Peer-to-Peer Distributed Intelligence** | This type of solution is able to continue to sectionalize, isolate faults and restore service beyond the first contingency without the need for central intelligence or DCC involvement. | Local communication between peer devices is essential to this approach. | Wide area communication is not required for automated restoration switching, but is required to disable automatic operations. | Foreign crews must be made aware that DA switches may open or close automatically unless they are placed in manual mode and the appropriate clearances issued. |
| **Substation-Based Decentralized Intelligence** | This type of solution is able to continue to sectionalize, isolate faults and restore service beyond the first contingency without the need for central intelligence or DCC involvement. | Local communication between peer devices is essential to this approach. | Wide area communication is not required for automated restoration switching, but is required to disable automatic operations. | Foreign crews must be made aware that DA switches may open or close automatically unless they are placed in manual mode and the appropriate clearances issued. |
| **Centralized Rules-Based Intelligence** | Unable to operate beyond pre-configured rules based operations. If system is in an abnormal condition, the rules will likely prevent any restoration switching from taking place. | Local communication between the substation and DA switches is essential to this approach. | Wide area communication is not required for automated restoration switching, but communication to the substation is required to disable automatic operations. | Foreign crews must be made aware that DA switches may open or close automatically unless they are placed in manual mode and the appropriate clearances issued. |

*Table 6-1 (continued)*
*How different DA architectures manage severe impact storm situations*

| Architecture | Multiple Contingencies | Loss of Local Comm. | Loss of Wide Area Comm. | Foreign Crews on System |
|---|---|---|---|---|
| **Centralized Model-Based Intelligence** | Unable to operate beyond pre-configured rules based operations. If system is in an abnormal condition, the rules will likely prevent any restoration switching from taking place. | Local communication is not required for this approach. | Wide area communication between the DCC and the DA switch locations is essential for both automated restoration However, automatic control may be disabled at the DCC. | Foreign crews must be made aware that DA switches may open or close automatically unless they are placed in manual mode and the appropriate clearances issued. |
| **Stand-Alone Distributed Intelligence** | This type of solution is able to continue to sectionalize, isolate faults, and restore service beyond the first contingency by analyzing the "as operated" configuration maintained at the DCC. | Local communication is not required for this approach. | Wide area communications between the DCC and the DA switch locations is essential for both automated restoration, however automatic control may be disabled at the DCC. | Foreign crews must be made aware that DA switches may open or close automatically unless they are placed in manual mode and the appropriate clearances issued. |
| **Peer-to-Peer Distributed Intelligence** | This type of solution is able to continue to sectionalize, isolate faults and restore service beyond the first contingency without the need for central intelligence or DCC involvement. | Local communication between peer devices is essential to this approach. | Wide area communication is not required for automated restoration switching, but is required to disable automatic operations. | Foreign crews must be made aware that DA switches may open or close automatically unless they are placed in manual mode and the appropriate clearances issued. |

## Key Outcomes

Tables 6-2 to 6-6 list strengths and weaknesses of the five architectures when considering the specific issues of a severe impact storm. Utilities can weigh these issues against similar but different analysis presented in EPRI's Distribution Management System Planning Guide [8] when considering the more general weather situations.

*Table 6–2*
*Stand-alone distributed control logic strengths and weaknesses*

| Strengths | Weaknesses |
|---|---|
| This approach does not depend on the availability of communications, information from other DA switches, or the availability of monitoring and control from a centralized DA master at the DCC. | If communications are not provided, this approach does not allow the utility to disable automation on a feeder, substation, regional or system-wide basis. |
| | This approach cannot operate beyond the first contingency. |
| | This approach cannot adapt protection settings to abnormal distribution or transmission configurations. |

*Table 6–3*
*Distributed control logic strengths and weaknesses*

| Strengths | Weaknesses |
|---|---|
| This approach can handle multiple contingencies that are common in severe impact events, restoring as many customers as possible with the remaining sources of power, until no alternatives exist. | Communications assisted protection schemes to enable more protective devices to "coordinate" are highly dependent on reliable communications. |
| With this approach, there is no need for communications to the control center to be functioning to perform restoration. | This approach requires peer-to-peer communications to be fully operational to pass information and direct switching activity. |

*Table 6–4*
*Decentralized control strengths and weaknesses*

| Strengths | Weaknesses |
|---|---|
| With this approach, the critical communication connection is between the substation and field devices, which may be simpler and more resilient than a wide area communications network. | If communications fails to the substation, the DA solution cannot be centrally controlled. |
| | Without integration to a centralized DMS/OMS server, this approach lacks information about as-operated states (manual or automated from another substation). |

*Table 6–5*
*Centralized rules-based control strengths and weaknesses*

| Strengths | Weaknesses |
|---|---|
| Makes switching decisions based on the as-operated condition down to the complexity of the simplified model employed. If the feeder is reconfigured for any reason, then the as-operated model is updated and the FLISR actions are based on this latest configuration. | The system relies on wide area communications for system operation. In some cases, communicating over a wide area may introduce considerable latency that can delay service restoration. The overall reliability of the wide area communication system may be lower than other alternatives, particularly in severe impact events. |
| Distribution system operators are fully aware of all switching actions and the current status of the feeder at all time. | Rules-based approaches do not include complete models enabling manual configuration changes to be reflected in the switch plan. |
| | Rules-based approaches do not include an on-line powerflow to enable ad hoc on-line studies of candidate restoration plans prior to execution. |

*Table 6–6*
*Centralized model-based control strengths and weaknesses*

| Strengths | Weaknesses |
|---|---|
| Makes switching decisions based on the as-operated condition, including due consideration of any temporary reconfiguration that has occurred (cuts, jumpers, manual switching, etc). If the feeder is reconfigured for any reason, then the as-operated model is updated and the FLISR actions are based on this latest configuration. | The system relies on wide area communications for system operation. In some cases, communicating over a wide area may introduce considerable latency that can delay service restoration. Furthermore, the overall reliability of the wide area communication system may be lower than other alternatives, particularly in severe impact events. |
| Distribution system operators are fully aware of all switching actions and the current status of the feeder at all time. Since all feeder reconfiguration actions originate in the control center, no switching will take place. | |
| All possible switching plans are analyzed and assessed using an on-line power flow program rather than simplifying assumptions. | |
| The model-driven FLISR solution identifies SCADA switching actions and also identifies possible switching actions on manual switches that narrow the de-energized area. This assists field crews in responding to the incident. | |
| The DMS solution is able to use all available sources to pinpoint the specific fault location within the damaged section. Available information sources include the OMS, protective relay distance to fault information from protective relay intelligent electronic devices (IEDs), and predictive fault location results. | |

The primary challenge is to determine which of the architectures is better when considering performance during a major event. This is a difficult decision, particularly given that it is unlikely a utility can make its DA decisions based solely on these events. It is suggested that individual utilities pay close attention to functionality that is necessary. For instance, if the utility must have a system that can be disabled during severe impact storms, then it must deploy some sort of central intelligence (or at least central override of a peer-to-peer approach).

# Section 7: Enhancement of DA – Multiple Contingency Restoration

## Motivation for this Study

The majority of contemporary DA/FLISR (automated restoration) solutions are only able to restore service for the first contingency (fault). This is because most of the automated restoration solutions are pre-engineered with automated rules or logic that only goes this far. In adverse weather or minor storm situations, this is sufficient as the potential for multiple events affecting the same feeder or substation are relatively low.

When storms progress in severity, this likelihood of multiple faults affecting the same feeder or group of feeders increases dramatically. During that progression, there is a period during which additional logic to respond to the second or subsequent contingency may enable additional restoration of customers, which may be beneficial. Of course, if the storm continues to increase in severity, there is an upper limit where no amount of enhanced restoration makes a difference (essentially when all of the potential restoring feeders are impacted).

## Background

Typical DA/FLISR algorithms are configured to isolate a fault between two automated switches and then close an available automated tie switch to restore service. The majority of algorithms presently deployed are configured to respond to the first event (contingency) and will not continue to attempt further restoration if a second fault (contingency) occurs. Following is an example of a typical FLISR operation:

The FLISR application function automatically detects that a fault has occurred, locates the fault (between two medium voltage switches), issues control commands to open the switches that bound the damaged area to isolate the damaged section of the feeder, and then closes other switches (where possible) to restore service to healthy sections of the feeder. The current state-of-the-art allows all of these actions to be completed without manual intervention (fully-automatic control). These steps are detailed below in an example showing a set of interconnected overhead feeders. Note: the numbers shown on the diagrams represent individual phase load in amperes (common on SCADA displays).

## Fault Detection and Location

FLISR should only operate following a short circuit (fault) on the feeder itself or in the facilities that normally supply the feeder. FLISR should not operate when a feeder becomes de-energized due to manual switching activities or due to a system wide emergency that triggers underfrequency or undervoltage load shedding. To meet this requirement, one or more fault detectors are needed to trigger FLISR operation when fault-level currents are detected. Common practice is to either use a protective relay intelligent electronic device (IED) in the substation or a line recloser with self-contained protection facilities to determine that a fault occurred. In this example, Figure 7-1 shows the feeder scheme with normal status, and Figure 7-2 shows that recloser j locks out in response to the fault.

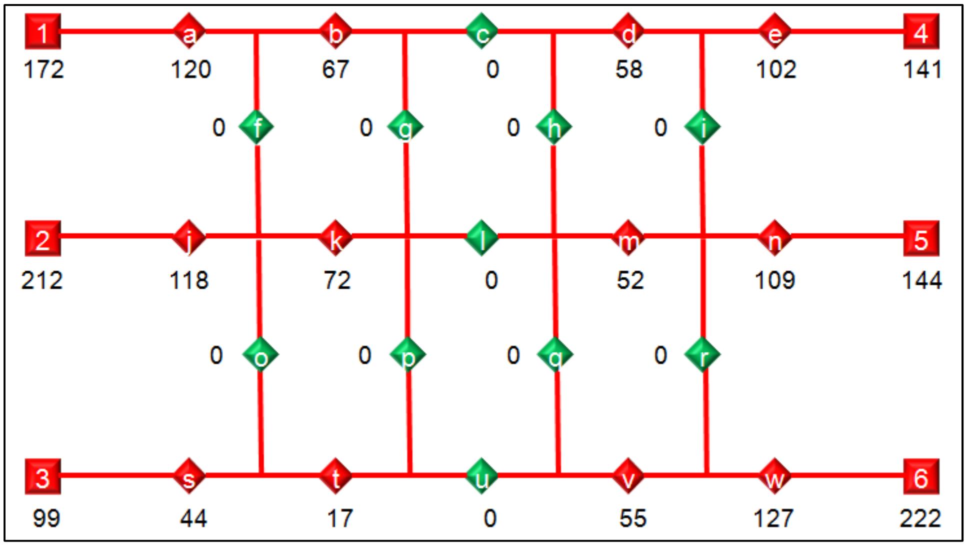


*Figure 7-1*
*Feeder automation scheme – normal status*

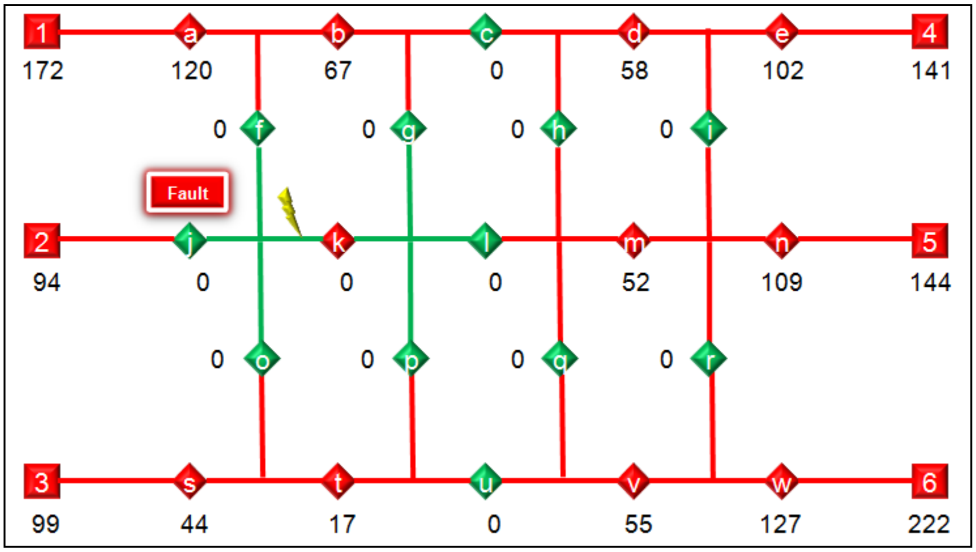


*Figure 7-2*
*Fault is detected and located*

### *Fault Isolation*

FLISR then issues control commands to open recloser k to completely isolate the damaged section of the feeder based on the fault location analysis described above (see Figure 7-3). It is common practice for FLISR to defer these control actions until the standard automatic reclosing sequence has been completed. This ensures that feeder reconfiguration by FLISR is only performed following a permanent fault (should not reconfigure the feeder if fault is a self-clearing "temporary" fault).

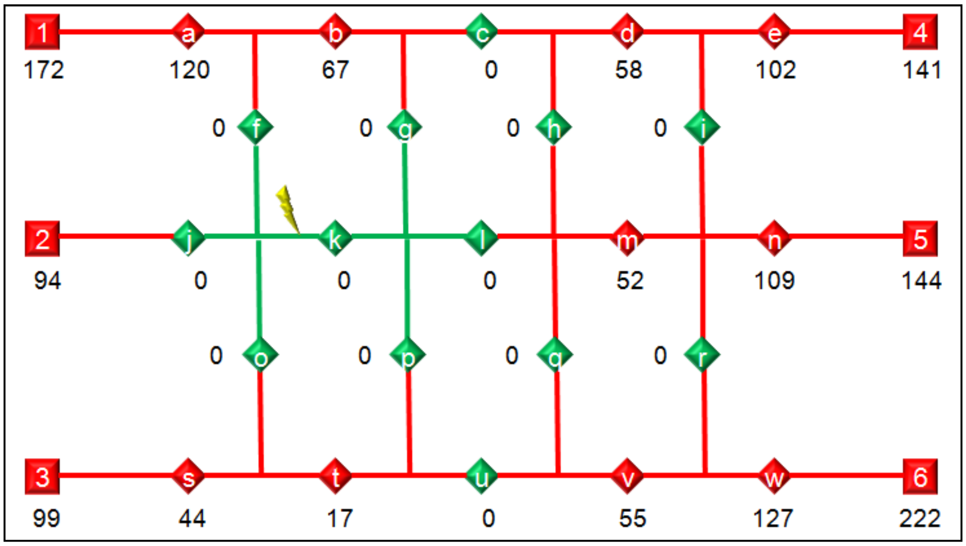


*Figure 7-3*
*Fault is isolated*

### Service Restoration

Once the damaged section of the feeder is isolated, FLISR attempts to restore service to as many healthy sections of the feeder as possible via the available sources. Available sources include the normal source of supply to the feeder, as well as any available backup sources that are connected to the faulted feeder via normally open, remotely controlled tie switches. Any feeder section that is upstream of the faulted feeder section (closer to the substation) can be restored from the original source with no further verification of available capacity. However, to restore feeder sections that are downstream of the faulted feeder section, the feeder must have at least one backup source with sufficient capacity to carry the additional load being transferred. If suitable backup sources do not exist, FLISR provides no additional benefit beyond what can be gained through regular line reclosers without supervisory control and FLISR software. FLISR compares the pre-fault load on each healthy feeder section and then compares that load with the spare capacity on backup sources. If sufficient capacity exists, then the tie switch is closed to restore service. If sufficient capacity does not exist, then the section in question remains de-energized until field crews arrive on the scene. In this case, tie recloser p is closed to restore the healthy portion of feeder 2 (see Figure 7-4).

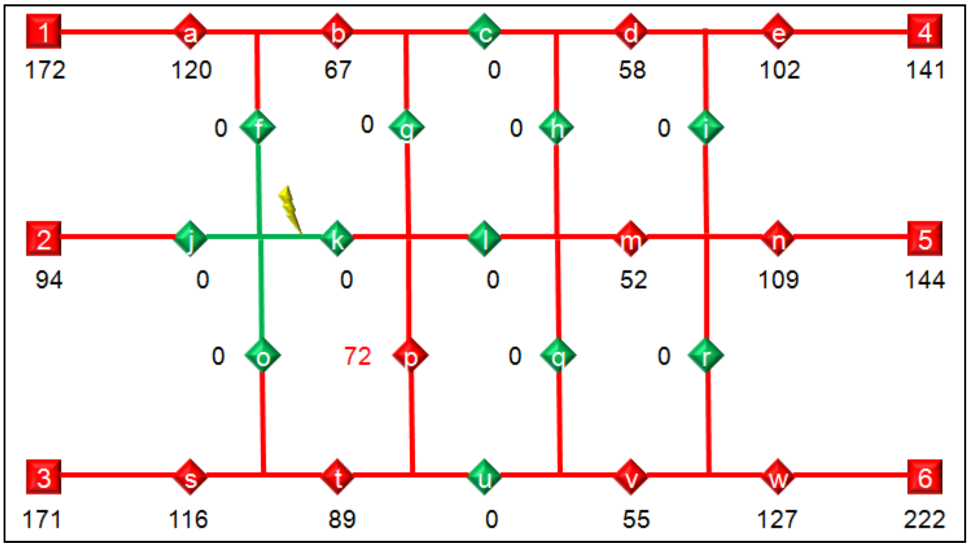


*Figure 7-4*
*Service is restored*

## Purpose of this Study

The purpose of this study is to investigate the benefits and challenges of multiple contingency automated restoration, when considering the unique challenges of a severe impact event, and then provide recommendations as to the benefits and costs of implementing this form of solution. Specific goals for this study include:

- Identifying and describing existing solutions to multiple contingency restoration
- Identifying and describing challenges to multiple contingency restoration

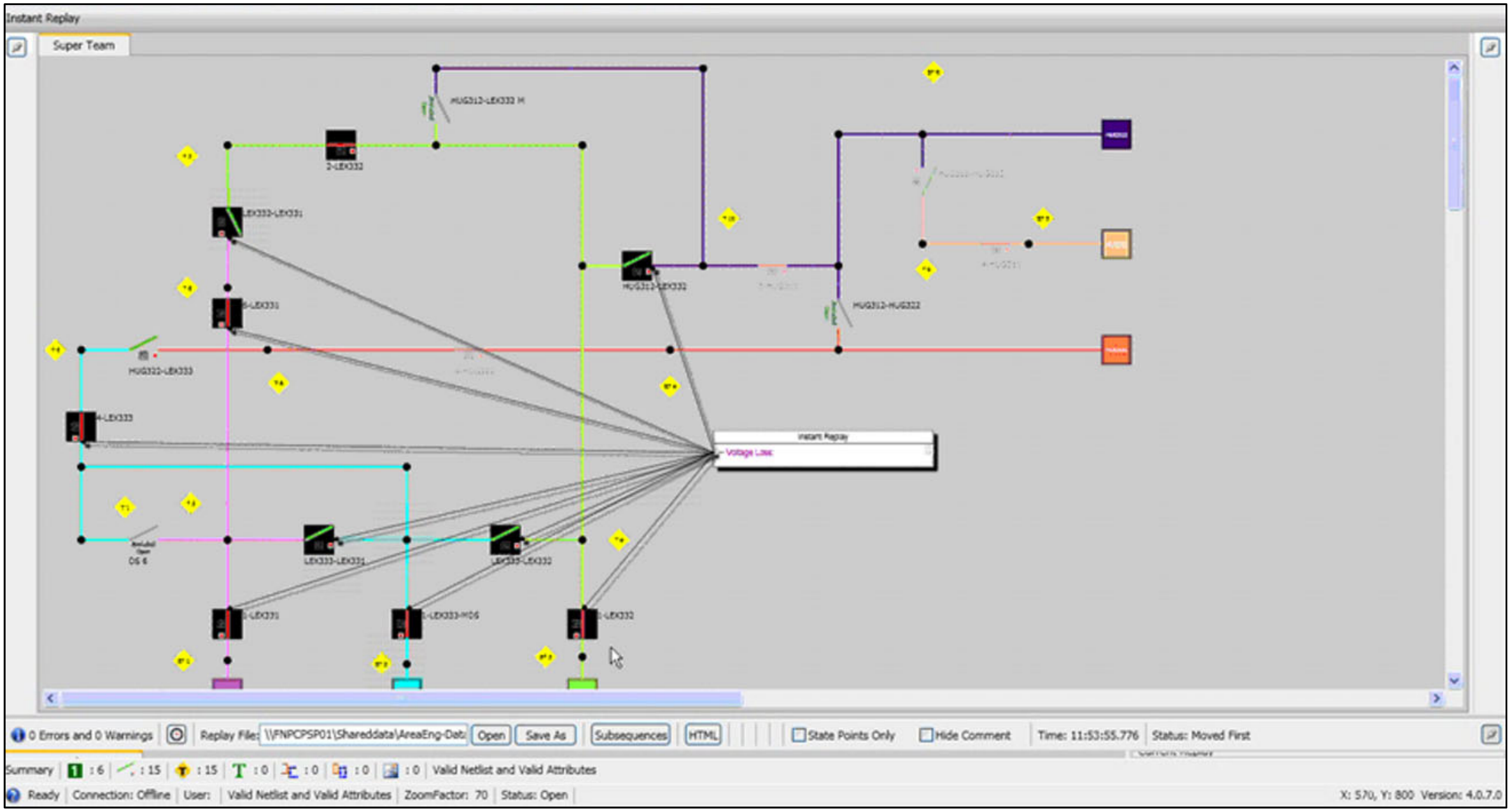
## Study Approach

Early in the investigation of the state of the industry, a few examples of fully implemented solutions for multiple contingency restoration were identified. These solutions were varied, but each solved the key issues related to this desired functionality. Given this availability, the approach for this study was to document specific case examples of this functionality that have been deployed by DGR-participating utilities, and then document the key functional requirements of a multiple contingency solution for restoration.

## Key Findings

Investigation of available solutions to address multiple contingency operations revealed two commercially available approaches: 1) centralized model-based and 2) distributed. Of the participating DGR utilities, two utilities have deployed centralized model-based solutions that include multiple contingency restoration, and one utility has deployed a distributed logic solution providing this capability.

During the 2014 DGR Summit, a second utility demonstrated another commercially available solution from S&C Electric. Its IntelliTeam SG solution extends the capability to perform automated restoration in a distributed intelligence fashion by enabling the linkage of many existing teams into a larger mesh of many interconnected feeders. This extends the ability to continue to perform automated restoration beyond a first contingency event. During the summit, the utility replayed a captured event in which a substation feeding three 35-kV feeders locked out. Within 90 seconds, multiple switches were opened to sectionalize the de-energized feeders, and all three feeders were fully restored by interconnected ties to three other 35-kV feeders supplied by a different substation. Figure 7-5 is a screen shot from a video replay of this event.



0 Errors and 0 Warnings | Replay File: \\FNPCPSP01\Shareddata\AreaEng-Dat | ☐ State Points Only | ☐ Hide Comment | Time: 11:53:55.776 | Status: Moved First

Summary | :6 | :15 | :15 | T :0 | :0 | :0 | :0 | Valid Netlist and Valid Attributes

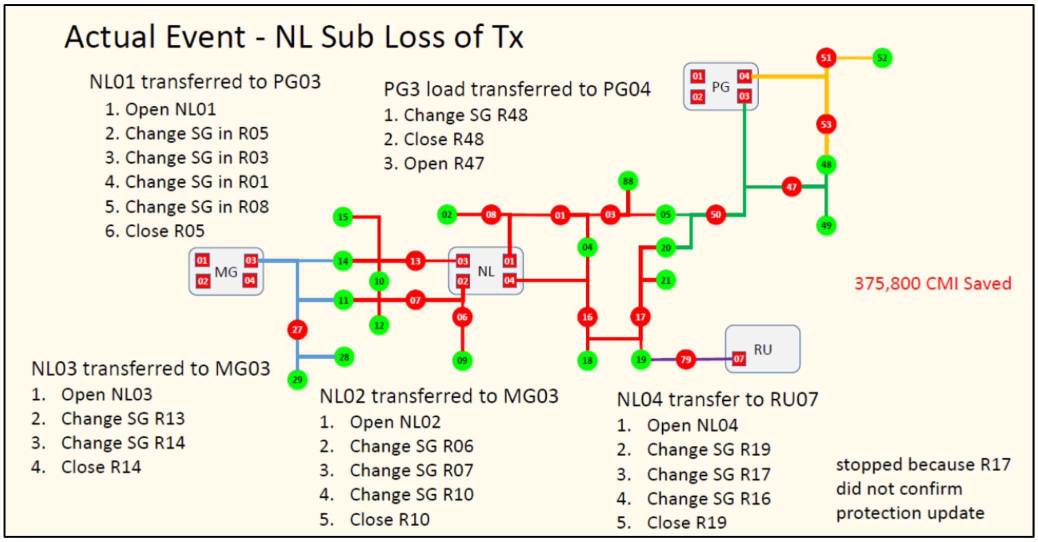
Ready | Connection: Offline | User: | Valid Netlist and Valid Attributes | ZoomFactor: 70 | Status: Open | X: 570, Y: 800 Version: 4.0.7.0

*Figure 7-5*
*Utility replay of multiple contingency restoration*

At EPRI's 2015 Smart Distribution and Power Quality Conference, a third utility presented the results of its newly deployed pilot DA solution, which employs a central model-based solution provided by Alstom Grid, with innovative automated restoration code specified by the utility. This new automation solution has a number of innovative features including:

- If there is a loss of communications to a DA switch, automated restoration does not fail. In this case, the algorithm simply combines feeder sections on either side of the non-responsive switch.
- Single-phase fault isolation and restoration are enabled by this logic.
- Volt/VAR/CVR is fully integrated into the DA automated restoration logic, which ensures that American National Standards Institute (ANSI) B voltage limits can be met before performing restoration switching.

The utility demonstrated an actual event in which a substation supplying four feeders was fully restored by four other feeders supplied by three different substations in a complex multiple contingency restoration effort (see Figure 7-6). Included in this automated response was a domino transfer reducing the load on one of the restoring feeders, enabling it to pick up enough load to enable full restoration.



Actual Event - NL Sub Loss of Tx

NL01 transferred to PG03
1. Open NL01
2. Change SG in R05
3. Change SG in R03
4. Change SG in R01
5. Change SG in R08
6. Close R05

PG3 load transferred to PG04
1. Change SG R48
2. Close R48
3. Open R47

NL03 transferred to MG03
1. Open NL03
2. Change SG R13
3. Change SG R14
4. Close R14

NL02 transferred to MG03
1. Open NL02
2. Change SG R06
3. Change SG R07
4. Change SG R10
5. Close R10

NL04 transfer to RU07
1. Open NL04
2. Change SG R19
3. Change SG R17
4. Change SG R16
5. Close R19

375,800 CMI Saved

stopped because R17 did not confirm protection update

*Figure 7-6*
*Utility example of multiple contingency restoration*

## Key Outcomes

Even with the distinct approaches used by the above-mentioned utilities, the general high-level functional requirements for this functionality are consistent (see below). These requirements are identified and described in detail for those utilities seeking to innovate, specify, or deploy multiple contingency restoration solutions.

**Requirement 1. Adaptive Logic** – The algorithm must adapt to any combination of one or more faults without reliance on a fixed set of rules or conditions. Instead, the algorithm should analyze the as-operated situation and automatically develop a sequence of switching steps to isolate the fault(s) and restore the maximum number of customers.

**Requirement 2. Automatic Control** – The algorithm should automatically execute the developed restoration switch plan, ensuring at each step that commanded switching operations have succeeded in the field before proceeding to the next step in the plan.

**Requirement 3. Protection Settings** – The algorithm should incorporate the ability to switch to alternate protection settings or alternate sectionalizer settings, as necessary, to maintain coordination after restoration switching has occurred.

**Requirement 4. Loss of Communications** – The algorithm should adapt to any loss of communications or failure to operate by an individual switch, rerouting the switch plan to continue to restore service without involving the non-responsive switch. If there is no alternative, the solution should cease automatic operation and log the problem.

**Requirement 5. Detailed Logging and Reporting** – While not waiting for centralized intervention to proceed, the solution should create a detailed log including the intended switch plan, every step of the restoration activity, monitored loads and voltages, and any alarms or failures. Status changes should be displayed on the SCADA interface for the DCC operators as soon as possible.

**Requirement 6. Voltage Limits** – The algorithm should maintain at least ANSI B voltages to all restoring and restored feeders.

**Requirement 7. Load Limits** – The algorithm should ensure that no emergency loading limits are exceeded on restoring or restored feeders.

**Requirement 8. Protection Coordination** – The algorithm should ensure that restoration switching does not create scenarios where fault currents on the feeder mains are too low to be visible within a zone of protection.

# Section 8: Enhancement of DA – Single-Phase Automation

## Motivation for this Study

Up until the recent past, most utilities deploying DA utilized switching devices that operated on a ganged three-phase basis. This means that all fault isolation and restoration switching took place as a three-phase system. This is counter to consistent utility experience that most (some estimates put it at 70%) distribution faults only affect a single phase. Thus, opportunities to further isolate the fault (on a per-phase basis) and maximize the number of customers restored are missed. In recent years, this has led to the development of the single-phase operating automated recloser, sectionalizer, or pulse closer.

Although these individual-phase operating devices have existed for a number of years, most utilities that deploy them do so in a "single-phase trip, three-phase lockout" mode. This means that they allow single-phase operation only for the automated trip, reclose, trip, or reclose sequence. Once the programmed reclose sequence hits the lockout step, this mode forces all three phases to open and lock out. This approach has the benefit of minimizing the impact of transient or temporary single-phase faults (which are a significant percentage of faults), but does not improve reliability for permanent single-phase faults. In fact, the single-phase trip, three-phase lockout mode only improves the number of momentary outages, and does nothing to improve the number of sustained outages over the reliability provided by a three-phase, gang-operated switch.

To take full advantage of the investment in individual phase operating DA switches, utilities can explore migrating the switches to single-phase trip, single-phase lockout mode, and adapting their FLISR algorithms to take full advantage of the sustained outage improvement afforded by single-phase fault isolation and service restoration switching.

## Background/Relevant Survey Information

The 2013 survey of DGR participants showed a sizable portion of utilities are deploying single-phase operating devices as part of their DA program (see Figure 8-1).

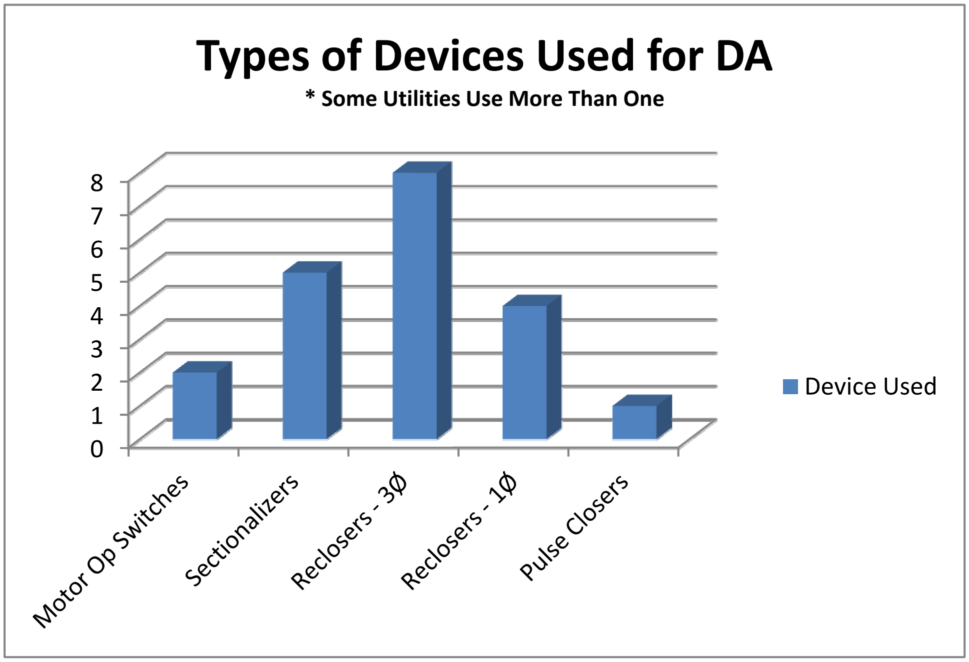


*Figure 8-1*
*Survey results: Types of devices deployed for DA*

Because the vast majority of distribution customers are supplied with single-phase service, deployment of single-phase trip and lockout devices on the mains can offer significant additional reliability benefits for almost the same cost of deployment. With the advent of automated single-phase trip and lockout devices, a number of utilities have adopted schemes that take advantage of one of two of the key rules of thumb of reliability engineers: Approximately 70% of faults on the overhead system are due to phase-to-ground contact. Various studies and anecdotal evidence also indicate that approximately 80% of overhead faults are temporary, meaning that they will restore successfully following one or more reclose cycles.

## Purpose of this Study

The purpose of this study was to explore and expose the opportunities and challenges surrounding the deployment of single-phase operating DA/FLISR on the distribution system.

## Study Approach

Theoretical knowledge, reliability statistics, and real-world experience were used to demonstrate the pros and cons of this evolutionary next step in DA/FLISR.

The following theoretical idealized example of a feeder with single-phase automation is presented for consideration. In this example, the feeders is broken into three sections starting from the left with a substation breaker, with single-phase operating reclosers as the mainline sectionalizing device, and normally open three-phase reclosers at ties. The phases should be interpreted as Aφ on top, Bφ in the middle, and Cφ at the bottom (see Figure 8-2).

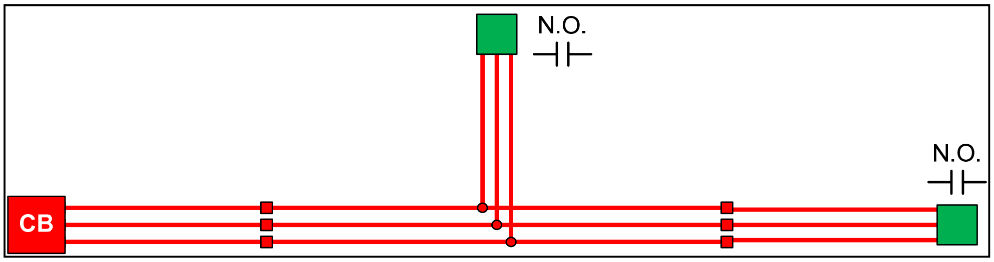


*Figure 8-2*
*Example of single-phase automation – initial condition*

When a fault occurs on Aφ, the Aφ recloser goes through its trip cycle. Customers upstream of the recloser, as well as those on Bφ and Cφ, are not affected. If the fault is permanent (which is typically only the case 30% of the time on OH circuits), the Aφ recloser goes to lock out (see Figure 8-3).

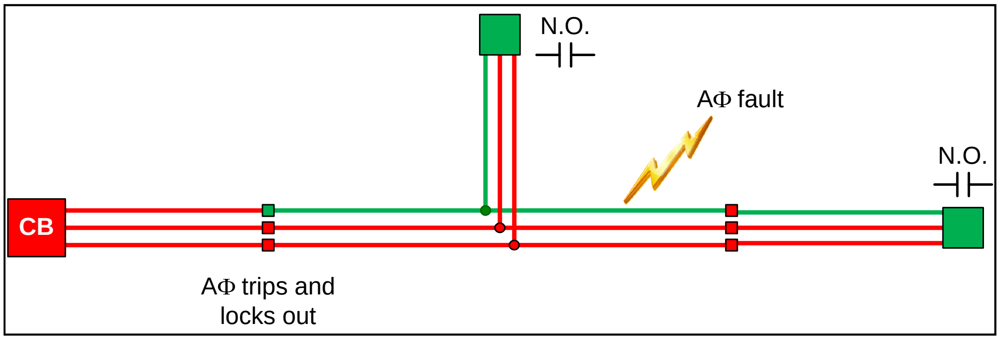


*Figure 8-3*
*Example of single-phase automation – fault occurs and recloser locks out*

The downstream recloser opens to sectionalize all three phases and isolate the fault (see Figure 8-4). This decision-making logic may take place locally, using just the information available to the recloser, or it may be directed centrally using information available to the central control logic. In either case, the important decision points are that the recloser experienced a sustained loss of potential on one or more phases and that it did not experience any fault current. All three phases are tripped to avoid the potential of having different phases fed from different directions on the same section. It is correct to note that customers on Bφ and Cφ downstream of the second recloser are subjected to a momentary interruption by this control logic, but is also correct to note that they would have experienced a longer outage if the first recloser had locked out all three phases.

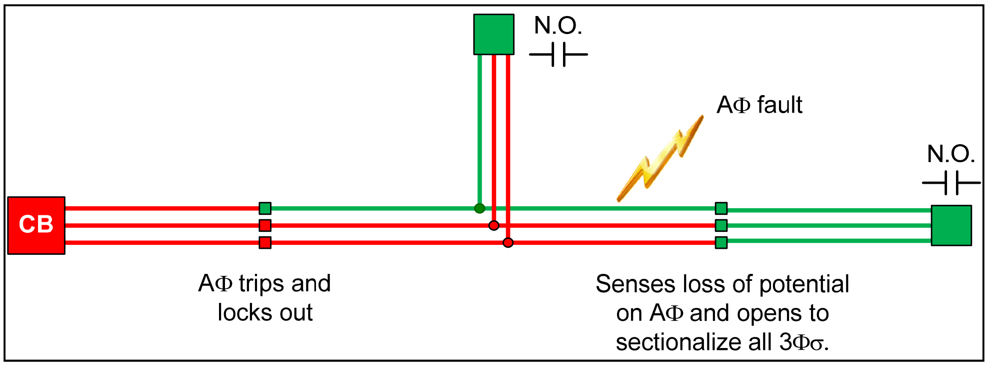


*Figure 8-4*
*Example of single-phase automation – fault isolated*

Once the fault has been isolated between the first and second recloser, control logic directs the closing of the 3φ tie switch, restoring all customers downstream of the second recloser (see Figure 8-5). At the end of this operation, only one ninth of the feeder experiences a sustained outage. A similar event with three-phase switching would have resulted in one third of the feeder experiencing a sustained outage.

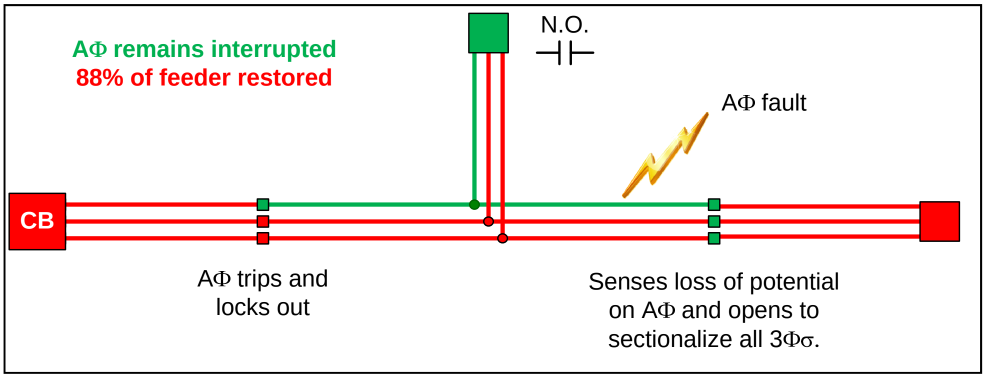
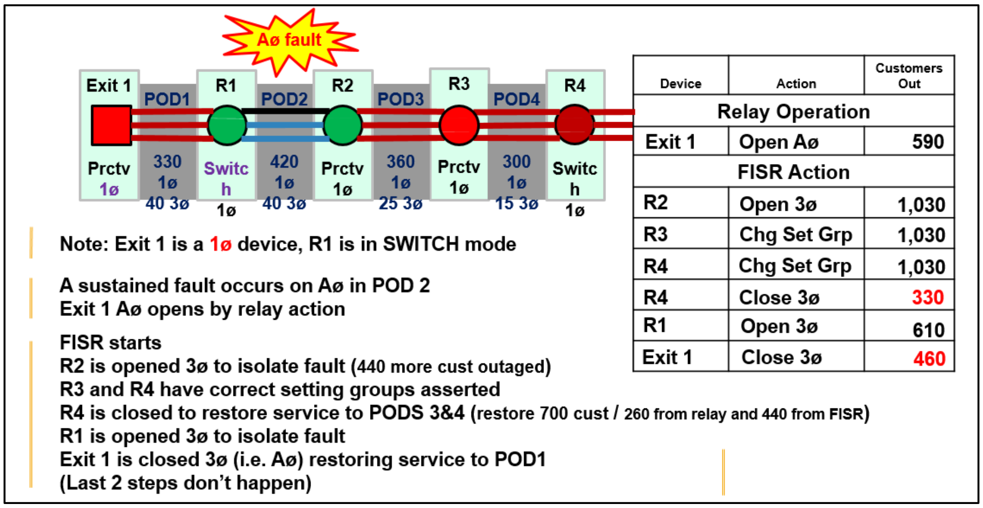


*Figure 8-5*
*Example of single-phase automation – restoration*

As a specific example, utilizing the latest generation of individual phase trip/lockout reclosers, one utility conceived of, and had their vendor perfect, a centralized DA algorithm that takes full advantages of the benefits of single-phase operation (minimizing fault impact and maximizing restoration capabilities) while minimizing safety concerns (does not allow automation to create interleafed situations where a three-phase line section is served from both directions – one phase from the left, and two phases form the right) and minimizing solution complexity (does not perform individual phase restoration switching). As shown in Figure 8-6, the system automatically compares alternative solutions and performs the restoration switching that maximizes customers restored, while meeting predefined restrictions on single-phase switching.



**Note: Exit 1 is a 1ø device, R1 is in SWITCH mode**

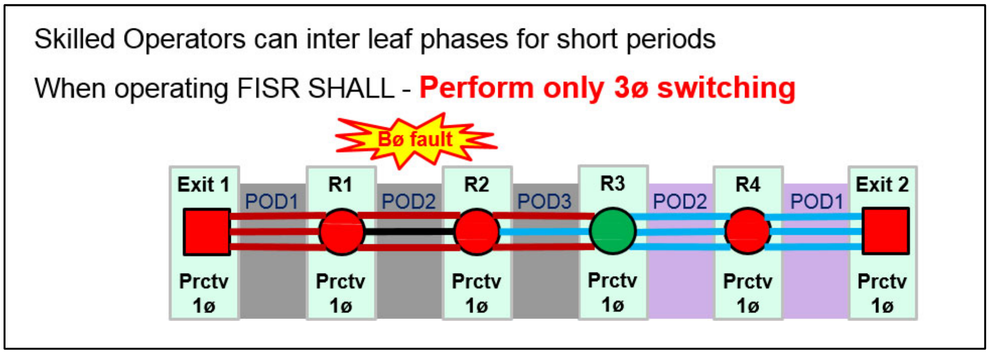
**A sustained fault occurs on Aø in POD 2**
**Exit 1 Aø opens by relay action**

**FISR starts**
**R2 is opened 3ø to isolate fault** (440 more cust outaged)
**R3 and R4 have correct setting groups asserted**
**R4 is closed to restore service to PODS 3&4** (restore 700 cust / 260 from relay and 440 from FISR)
**R1 is opened 3ø to isolate fault**
**Exit 1 is closed 3ø (i.e. Aø) restoring service to POD1**
**(Last 2 steps don't happen)**

| Device | Action | Customers Out |
|---|---|---|
| **Relay Operation** | | |
| Exit 1 | Open Aø | 590 |
| **FISR Action** | | |
| R2 | Open 3ø | 1,030 |
| R3 | Chg Set Grp | 1,030 |
| R4 | Chg Set Grp | 1,030 |
| R4 | Close 3ø | 330 |
| R1 | Open 3ø | 610 |
| Exit 1 | Close 3ø | 460 |

*Figure 8-6*
*DA FISR single-phase operation example*

The algorithm only directs three-phase sectionalizing and restoration, preventing automation from creating "interleafed" situations. This means that it will not create situations in which phases on the same feeder section are being supplied by different feeders (as shown in the example in Figure 8-7). It may be permissible for skilled operators to create these situations for short periods of time, given their knowledge of the system and field conditions, to maximize restoration, but this is deemed too complicated for the automation to manage.


Skilled Operators can inter leaf phases for short periods

When operating FISR SHALL - **Perform only 3ø switching**

*Figure 8-7*
*Inter leaf is not allowed by FDIR logic.*

Recognizing the value of single-phase protection and FISR, the utility decided to use single-phase reclosers as the substation feeder device, in the place of a three-phase operating breaker or recloser (see Figure 8-8). This provides the benefit of enabling single-phase fault isolation and restoration in the first feeder section out of the substation. An additional benefit was that this substation device was essentially the same recloser and controller as feeder level DA reclosers, saving on training, SCADA mapping templates, and reducing errors. To further standardize equipment, the same recloser/controller, with all of the inherent three-phase current and two-x-three-phase voltage sensing capabilities, is deployed, even where over-current protection functions are not utilized.

*Figure 8-8*
*Individual-phase operation substation recloser*

## Key Findings

A few utilities have developed and deployed innovative new FLISR algorithms that take advantage of single-phase automated switching. The deployments are quite different, but they follow some basic rules:

- Operational and restoration practices involving single-phase switching must adhere to normal operating practices.
- No “mixed phases” (for example, phases flowing in different directions on the same section)
- Adhered to existing customer tariffs, allowing the utility to single phase 3φ customers
- It is permissible to allow the automation to cause intentional momentary outages on unaffected phase(s) to serve the greater purpose of turning sustained outages into momentary outages on affected phase(s).
- A solution to the issue of not being able to coordinate multiple series reclosers is to intentionally miscoordinate one or more of them, also known as “setting them as a sectionalizer.”
- Ground protection settings must be evaluated to ensure that temporary intentional phase imbalance caused by singe-phase operations do not inadvertently trip the breaker or reclosers.

Several issues/opportunities were addressed differently between utilities. Table 8-1 presents these issues, without recommendation, but with the alternatives defined and explained.

*Table 8–1*
*Alternatives for addressing issues of single-phase automated switching*

| Issue/Opportunity | Reasons To Do | Reasons Not To Do |
|---|---|---|
| **Using Single-Phase Reclosers at the Substation Feeder Head** | Provides benefits of single-phase automation on the first section out of the substation. | Substation must be configured to enable installation of single phase reclosers (for instance, this would not work in a switchgear station). As an alternative, at least one utility has deployed single-phase reclosers outside of the substation to provide the benefits of single-phase switching on the feeder. |
| **Performing Single-Phase Switch, Single-Phase Lockout, and Single-Phase Sectionalizing** | In some configurations/fault locations, performing single-phase lockout or sectionalizing enables the restoration of unaffected phases on the affected section (POD) automatically. | There is a concern that setting up this situation automatically is too complex for the automation, and that this level of additional restoration should be directed only by human operators. |

## Key Outcomes

A number of significant learnings were developed as a result of this study:

- The experience of several utilities shows that single-phase FLISR works, is predictable, meets protection and control restrictions, and does not cause customer complaints.
- Single-phase FLISR improves both momentary and sustained outages statistics (frequency and duration). In the ideal example examined in this section, it enabled restoration of 88% of customers after a single-phase-to-ground fault on the three-phase mains versus 67% restored with 3Ø switching. This estimate is consistent with actual field experience of utilities that have deployed singe-phase FLISR.
- Field and control center operational concerns can be addressed through adherence to existing work practices, and adherence to existing permit and tagging procedures.

Single-phase switching devices can be deployed for essentially the same cost as three-phase, gang-operated switching devices. The only incremental difference is the prices difference of the switch, and the need for individual-phase voltage sensors.

# Section 9: Extension of Outage Management System – Storm Settings

## Motivation for this Study

One of the key tools necessary for a successful storm response is a modern Outage Management System (OMS). The OMS performs many functions including maintaining the as-operated feeder model, predicting which protective devices have operated based on customer outage calls, managing crew assignments, tracking individual outage jobs through their entire life cycle, and managing the overall storm operations. OMSs have been designed with blue sky days, adverse weather, minor storms, and even major storms in mind, but the unique catastrophic characteristics of a severe impact storm may not have been considered. In the wake of the events that led to establishment of the DGR Project, many utilities have expanded their storm response drills to much higher levels of calls, system damage, and outages to fully test their OMS' ability to perform under newly perceived maximum threat levels. This is necessary and highly recommended.

One area that has not been fully explored is the many configurations and settings that manage the call processing and protective device prediction algorithms. These configurations are often established based on typical blue sky or minor storm levels, but there is evidence that they should be rethought based on the volumes of calls present in major or severe impact storms, and other evidence that the availability of AMI-generated outage notifications may also necessitate a fresh look at these settings.

## Background/Relevant Survey Results

The OMS performs many essential functions needed to assist distribution system dispatchers when customers are experiencing service interruptions. One of the key OMS functions is outage protective device prediction. The OMS applies individual customer outage telephone calls (or, more recently, *last gasp* messages from AMI meters) to its distribution system model to determine which calls/messages appear to be related to the same outage event. After the calls/messages have been grouped, the OMS uses the model to search upstream (closer to the substation) to determine which fault interrupting device operated for this event. This information is used to direct field crews to the approximate location of the root cause of the outage event. The OMS often includes facilities for dispatching first responders and field crews to the outage location for fault investigation, damage assessment, and repairs.

### OMS Model

The OMS normally includes a detailed, as-built electrical and connectivity model of the electric distribution system. The electrical model should include the entire distribution primary circuit, including main line portions of the circuit, feeder laterals, and underground loops that are tapped off the main trunk of the feeder. The distribution system model should accommodate three-phase portions of the feeder as well as single-phase and two-phase line segments and laterals. However, many utilities lack phasing information, and as a result, outage prediction must be accomplished without phasing information.

### Outage Prediction

The typical settings of an outage prediction engine include the following:

- Minutes after first call to perform initial outage prediction (for example, wait for receipt of enough before predicting an outage)
- Minutes after first call to close the outage prediction (for example, cease allowing any additional calls to be combined, but instead create a separate outage event)
- Number of individual calls to bump up to a transformer prediction (for example, how many customer premises below a transformer cause the analysis to predict a failed transformer instead of multiple individual customer outages)
- Number of calls behind different transformers to bump up to a protective device prediction (for example, how many transformers below a protective device with outage calls cause the analysis to predict a protective device operation instead of multiple individual transformer outages)

The outage prediction works best on the radial network. Normally mesh (aka secondary mesh) is not modeled in the OMS, or if it is modeled, outage prediction is not supported by many vendors. The leading vendors support outage prediction in a mesh network, but usually predicted location is an upstream common node. In absence of AMI and/or SCADA/DA devices, the OMS is not capable of predicting outage-clearing devices in a mesh network.

Given the much higher probability of multiple outage events on the system during severe impact events compared to normal storms, these basic outage prediction settings may not be optimal for severe impact storms. Other factors must also be taken into account when considering these settings, including communications congestion due to the call volumes experienced during severe impact storms, as well as overloads of the analysis engine and OMS servers during these events.

## Outage Engine

In most OMSs, trouble analysis rules control the trouble analysis engine (also referred as the prediction engine or outage engine). These rules determine how outages and events are handled and how calls are grouped. The analysis engine receives all device operations (either user initiated for manual devices or SCADA provided) that are factored into outage analysis. It also interfaces with external systems such as an AMI to request and receive outage analysis data.

Often multiple rules are grouped into rule sets. The rule sets are defined based on weather condition (for example, blue sky, minor storm, major storm).

The purpose of the set is to provide analysis rules specific to the situation. For instance, during normal operation, it may take three calls to predict a fuse, but during severe impact storm mode, it may take five calls to predict a fuse out, accounting for the higher probability of multiple fault events.

### *Trouble Calls*

#### Clues

Clues are a subset of calls that add value to the system by providing additional information to set the outage priority or outage prediction. Usually an application that takes OMS trouble calls or the utility's customer relationship management system prompts customers to provide additional information about the outage being reported.

The outage prediction is driven by clues provided by the caller. The OMS often determines the priority/severity of an outage based on these clues:

- All power out
- Partial outage
- Area outage
- Blinking
- Dim lights
- AMI last gasp
- Hazard condition
  - Wire down (pole to pole, pole to house, and so on)
  - Pole broken
  - Pole fire
  - Sparking
  - Explosion/loud noise
  - Leaking oil
  - Sagging wire
  - Manhole open/manhole fire

### Trouble Calls-Priority

Priority calls are calls that have a priority value set by the system (for example, critical customers, hazard calls). The priority value of a trouble call determines how the call is grouped. A call with multiple trouble codes has the highest priority.

### AMI Last Gasp

The AMI last gasp or outage notification is treated by most OMS vendor's outage engine as any regular trouble call. The AMI last gasp is still not being treated differently than customer-initiated trouble calls because:

- Even though AMI last gasp has become reliable, there still could be false positives
- OMS has been around before AMI became mainstream, and OMS vendors have not enhanced the OMS prediction engine to treat AMI last gasp differently. However most OMS vendors identify the trouble call source as AMI so the user (or system) can ping the meter upon restoration.

OMS identifies AMI as a source of the trouble call, which enables the OMS to display various symbols in the map viewer to identify trouble calls reported by AMI.

During a storm situation or feeder lock-out, the AMI can send a number of last gasps. Often the OMS is not integrated with the AMI head-end system directly but via a meter data management (MDM) system. The MDM provides grouping or filtering capability, or OMS vendors use holding tables to store the last gasp before grouping them.

## *Outage Prediction Rules*

The OMS outage engine or prediction engine analyzes the as-operated condition of the distribution network to infer (predict) the probable cause device for reported outages. In most OMSs, the outage engine predicts only those devices that are specified as an outage clearing device. The prediction rules are driven by configuring various threshold parameters.

The outage prediction parameters are driven normally by a configuration table in the OMS database. Most vendors permit at least two levels of outage prediction parameters – blue sky day, and storm mode. There are also various permutations of prediction rules that allow the vendor to configure the system for different weather conditions, such as winter storm, thunderstorm, major storm, and so on. In essence, it changes one or more outage prediction parameters. During the storm situation, the threshold parameters have higher values.

Each of the parameters listed and described below can potentially be adjusted and customized for different storm situations, including severe impact storms.

### Number of Calls before Re-prediction

The amount of time before trouble calls are assigned probable status is also defined by the system configuration. Eventually the number of customers reporting an outage exceeds a threshold number or percentage, and the prediction engine predicts that the common transformer is most likely malfunctioning. An incident is created on the transformer, and the individual incidents previously created for the service points are rolled into one. Any customer call records associated with the previous service point incidents are also rolled into the new incident. When the outage engine makes a prediction, it checks whether or not call count threshold parameters for the zone are exceeded, and determines whether the count of troubled downstream devices exceeds specified parameters.

Most OMSs allow the system administrator to specify this number based on feeder network type and area of responsibility (AoR).

### Percent Customers

If a prescribed minimum percentage of customers report a problem for a specific branch, then a protective device on that branch is predicted to have operated by inference. This condition is more useful when AMI is reporting last gasp, because there is more predictability about the outage notifications being received than customers calling.

### Deadband

If a trouble call is submitted within a certain number of minutes of the restoration time of an event in the same affected area, it is normally grouped with the restored events.

### Number of Service Outages before Reprediction

This parameter specifies the number of service outages that must be present on a branch before upstream grouping may occur. Under normal circumstances, multiple customer calls are required to infer a service transformer outage. However, for utilities serving rural areas where service transformers often have only one customer, a single customer outage can trigger the service transformer outage as well.

### Number of Device Outages before Reprediction

This parameter is the number of predicted device outages before an outage is regrouped (repredicted) on an upstream branch to the next protective device. Parameters used for below level/zone or above level/zone inferencing logic are different depending on what part of the distribution network is being analyzed. For example, lowest level network devices (fuses at a lateral) and service transformers downstream of the fuse may have different count parameters than prediction rules for devices above the lateral fuse.

### Count Devices

If the count of troubled downstream devices exceed a defined parameter, then the device is identified as a probable outage device.

### Transformer Count

If the count of troubled transformers exceeds a set parameter value, then the protective device upstream of all transformers is predicted.

### Group by Phase

If a protective device is a probable fault clearing device and phase operable, then trouble call grouping is applied by phase (for example, the system does not predict that all three phases are out, but rather determines the likely de-energized phase based on trouble calls).

### Group Outage Max Age

Trouble calls that come into the system that could be grouped to an already predicted outage may not group automatically if the difference between the call time and the predicated outage start is more than x.

### Event Distance for Device Outages

This rule specifies the event distance to use when grouping individual device outages. If two or more devices have predicted outages, then the system looks for a common upstream device that may have operated. The OMS may automatically predict that the next upstream device is an outage device. The OMS may allow the user to set a number without event distance, so the OMS always predicts the next upstream "outageable" device for all the candidate devices. Here, event distance is n. The combined count of "outageable" devices on all the paths from the candidate devices to the shared common upstream device must be less than or equal to n, excluding the shared common upstream device itself and the candidate devices.

### Street Intersection Grouping

Most leading OMSs can also group non-customers (or also referred to as fuzzy) calls. Often, a customer is listed in a utility's customer information system but the OMS cannot find a record of that customer in the OMS database. (For various reasons, there could be a mismatch between customers in the CIS and OMS). In such a scenario, customer service representatives prompt customers to provide the nearest street intersection.

Similarly, a passerby, police officer, or fire department personnel may call to report an outage or hazard condition and provide the street intersection. The OMS can either associate the outage reported on a street intersection to the nearest device or to an on-going outage. If customers in a particular area are not found in the OMS database, then the OMS can also allow the user to interactively group all trouble calls into a single outage and dispatch the crew.

### Trouble Analysis Rules-Mesh Networking Grouping

Because mesh networks do not have any flow direction, radial upstream and downstream prediction rules do not apply. The mesh network prediction may utilize the following criteria:

- Distance – Merge outages on two mesh nodes if there are a specified number of branches between them.
- Calls Before Upgrade – This defines the number of calls required on a mesh device before a service outage is upgraded to a device outage.

### Proximity

One of the key concepts for grouping is event distance, or the measure of how far apart outages can occur before grouping them into a single outage. The combined count of protective devices between the candidate device and the common upstream device must be less than or equal to the event distance for grouping to occur. The candidate device is the originating device that is experiencing an outage. There can be more than one candidate device.

For example, Event Distance = Path A + Path B

- Path A = the number of protective devices between the first outage device and the common upstream device.
- Path B = the number of protective devices between the second outage device and the common upstream device.

### Nested Outages

The OMS also keeps track of nested outages. Some of the vendors use terminology called frozen outage, in which a single service outage is frozen after x number of minutes. Even if another outage is reported upstream, the frozen outage is not merged with the upstream outage. This enables users to keep track of downstream outages and dispatch crew to the location after the upstream outage is restored.

### Storm Mode Outage Prediction

OMSs also provide call processing for environments with large call volume. During a storm situation, functionality changes the way calls are handled. Normally, when a call is received, the OMS immediately processes the call by adding it to an existing incident or creating a new single premise incident.

During a storm situation, the prediction engine also looks for an upstream incident. If it does not find one, the call is held for a configurable amount of time. When the prediction engine processes a call, it determines whether the call can be added to an existing incident or if it must create a new incident. At this time, the prediction engine considers all calls (processed and unprocessed). For example, assume that several customers on the same transformer call to report no power. When the prediction engine processes the first call, it considers all other unprocessed calls and adds those calls associated with the same outage into the incident. This means that several calls are processed and added to a single incident rather than creating incidents on multiple service points before rolling them up to the transformer.

The 2013 survey asked whether utilities deploy different settings/configurations during storms. The results of that survey are shown in Figure 9-1.

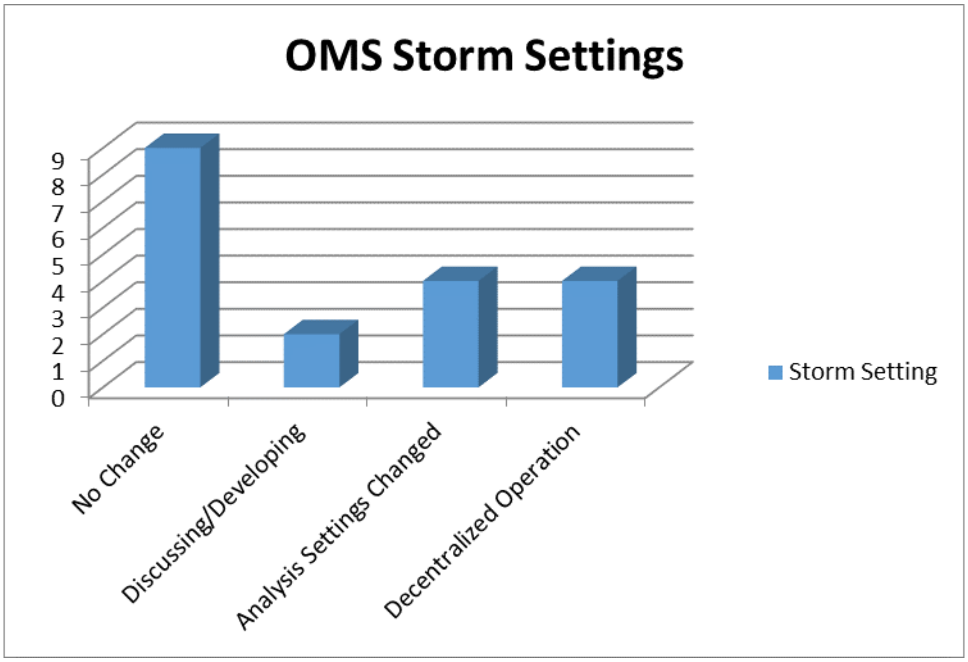


*Figure 9-1*
*Survey results for OMS storm settings*

Some notable comments to this question included:

- One utility reported that “As part of coastal storm plan, we put the OMS into storm mode (relax ETRS and modify call analysis parameters).”
- Another utility reported that it “experimented with changing OMS settings and concluded it was best to leave them the same as normal conditions.”
- Another utility reported that it employs, “storm mode settings which slow down the prediction engine.”

This survey also inquired whether utilities have experienced a severe impact storm with its OMS, and if so what was learned/changed as a result of the experience. The results are presented in Figure 9-2.

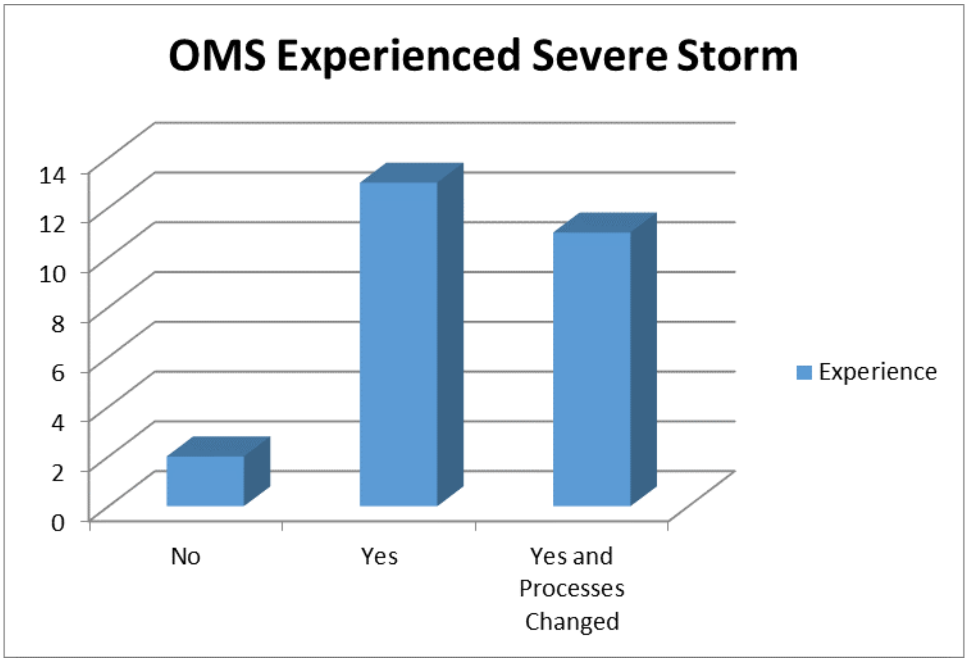


*Figure 9-2*
*Survey results for OMS has experienced a severe storm*

Some notable comments to this question include:

- One utility reported that "Customer call percentages are much higher because customers are now able to use other technologies (internet and smart phones) to report outages."
- Another utility reported that based on storm experience, the company "modified the program that transfers outage calls between the Customer Information System and OMS and the throughput was much improved during Superstorm Sandy."
- One utility reported that its "OMS client front end is web based. During one storm we found that the web server was slowing down. During this big storm they enabled the test server to provide additional capacity. This has become a standard practice to maximize throughput during storms."
- Another utility reported that "Recent severe events indicate the need for OMS systems to be able to handle much larger events than originally projected. Increased server size and call processing capabilities will be necessary." They also report that, "We failover the OMS system periodically to exercise the failover functionality. This is performed once or twice a year, and not just a test on the "test server" but a real operation of the production system."

## Purpose of this Study

The purpose of this study was to explain and expose the opportunity to modify OMS settings from normal operations to alternate settings, and determine if they add any value from a storm analysis perspective. Benefits might include faster analysis and prediction of trouble, more accurate prediction of trouble, and better handling of nested outages.

## Study Approach

This study analyzed the impacts of typical severe impact storm conditions on the variables typically configured into an OMS. These conditions include:

- Higher than normal number of nested outages.
- Longer than normal duration outages with complex restoration.
- Longer than normal duration situations with temporary repairs and partial restoration.
- Foreign crews present on the system.
- Longer time lag between restoration and as-operated model updates in OMS.
- Higher likelihood of model errors as the storm progresses into multiple days.
- Potential for additional storms to erupt in the days following the initial storm.

## Key Findings

While some utilities modify OMS analysis settings during storms, the practice of doing this, and the settings that are employed, are very inconsistent. The data demonstrating whether or not this is worth the effort and additional complexity does not exist, although there is anecdotal evidence of improved accuracy. An example of typical normal and storm mode settings is shown in Table 9-2, although there is some evidence/speculation that a third level of settings may be applicable for a severe impact storm.

*Table 9–1*
*OMS analysis settings in normal mode and storm mode*

| **Outage Prediction Rules – Normal and Storm Mode Examples** | | | |
|---|---|---|---|
| **Tuning Parameter** | **Normal** | **Storm Mode** | **Description** |
| Analysis Cycle | 1 | 5 | How often the outage engine runs to analyze outages in minutes. |
| Customer Calls | 2 | 5 | The number of customer calls (or AMI last gasps) before service outages are grouped and system predicts service transformer. |
| Deadband | 300 | 600 | Trouble calls submitted within x minutes of the restoration time of an event in the same affected area that are automatically grouped into the restored event. |
| Group By Phase | Fuse | Fuse | Only fuses have phase-sensitive grouping applied to them. |
| Group Fuzzy (non-customer calls) | 1 | 3 | Fuzzy calls that are in a specific geographic area are grouped together into a single event. |
| Outage Maximum Age | 10000 | 30000 | Trouble calls are no longer automatically grouped into the probable outage if the difference between the call time and the probable outage start time is greater than x number of seconds. The trouble call generates a new prediction. |
| Number of Calls before reprediction | 2 | 5 | |
| Number of predicted outages before regrouping | 2 | 4 | The number of predicted service or outages before regrouping takes place. |
| Move Up Isolated Outage | | 1 | In the course of normal grouping activity (as dictated by the configuration of the four rules above), promotes a device outages that occur on laterals with only one device. |
| Downgrade Device Outage to Service Outage | 2 | 5 | When a predicted device outage is manually re-predicted to downstream, and if the number of calls is less than x, then calls are treated as service outages. |
| Manual Grouping | No | Yes | Whether manual grouping of outages on different feeders is allowed. |

*Table 9-1 (continued)*
*OMS analysis settings in normal mode and storm mode*

| Outage Prediction Rules – Normal and Storm Mode Examples | | | |
|---|---|---|---|
| **Tuning Parameter** | **Normal** | **Storm Mode** | **Description** |
| Count Device | 2 | 4 | The count of downstream devices threshold. If the count exceeds this parameter, the device is eligible for an inferred outage. |
| Count Transformers | 2 | 5 | Lowest device in the network is inferred when the downstream service transformer exceeds this parameter. |
| Customer Freeze Time | 5 | 20 | The number of minutes the engine waits before freezing (locking a predicted customer outage). |
| Device Freeze Time | 5 | 20 | The number of minutes the engine waits before freezing (locking a predicted device outage). |

The impact of AMI last gasp outage alarms on OMS analysis is an opportunity ripe for an innovative solution. Because OMS analysis fully predates AMI last gasp outage and restoration notification, the entire OMS analysis process must be re-engineered to take full advantage of these capabilities. Also, because AMI was deployed with significant focus on the meter-reading application, there remain sizeable improvement opportunities for both the outage and restoration notification processes.

## Key Outcomes

This study identified the opportunity to set the OMS in one or more stages of alternate configurations/settings to account for the unique situations when progressing from blue sky to minor storm, major storm, and severe impact storm. The storm settings proposed in Table 9-1 attempt to address the list of conditions typically present in a severe impact storm, including:

- Higher than normal number of nested outages.
- Longer than normal duration outages with complex restoration.
- Longer than normal duration situations with temporary repairs and partial restoration.
- Foreign crews present on the system.
- Longer time lag between restoration and as-operated model updates in the OMS.
- Higher likelihood of model errors as the storm progresses into multiple days.
- Potential for additional storms to erupt in the days following the initial storm.

To continue to study the impacts of these alternate OMS settings, EPRI's distribution program will propose additional base program research to collect actual OMS outage analysis performance using various combinations of OMS analysis parameters, both with and without the availability of AMI last gasp information. The goal of this research will be to identify which, if any, analysis parameter settings leads to more accurate OMS outage predictions.

# Section 10: Enhancement of Adaptive Protection Shots of Reclosing

## Motivation for this Study

Sometimes the simple fixes make a big impact on reliability, particularly when considering the differences between blue sky days and storm days. One major issue that impacts reliability is the phenomenon of temporary faults, which can be successfully restored with one or more reclosing cycles. Determining the proper number of reclosing cycles is a balancing act between multiple important issues: reliability, safety and equipment life. The protection engineer must balance the desire of the reliability engineer to reclose multiple times to maximize the potential for a successful restoration, with the concerns of the asset management engineer to minimize repeated through faults to breakers and conductors caused by reclosing, with the concerns of everyone about minimizing the amount of time that a dangerous fault is present on the system. Most utilities choose to reclose an OH feeder between two and four times.

Recognizing that lightning and wind are the root causes of many temporary faults, some utilities have studied the success rates of reclosing in different weather conditions and found that reclosing is more successful in windy conditions. This has led to several different adaptive relaying approaches that should be studied to determine if there are opportunities for the industry as a whole to perform better from a reliability perspective while addressing critical safety and asset management issues.

### Background and Relevant Survey Information

Faults on the electric distribution system are divided into three categories based on their cause and their ability to clear. These types are defined below:

- **Transient Faults** – Lightning, lines slapping, and wind-induced tree contact are the most common causes for transient faults. The overvoltage from the lightning may cause a flashover of insulators, while wind may cause incidental tree contact or lines to slap into each other. The arc from these faults may not extinguish until the line is tripped, allowing for de-ionization of the fault path, after which it can be successfully reclosed if no permanent damage has resulted. As a rule of thumb, 80% of all overhead faults are transient and reclose successfully on the first shot.

- **Temporary Faults** – Wildlife and fallen or broken tree limbs are common causes of temporary faults, which persist longer than transient faults. These faults can often be burned clear by one or more additional reclosing shots. As a rule of thumb, 10-15% of all overhead faults are temporary and reclose successfully on the second or third shot.
- **Permanent Faults** – Downed conductors, trees fallen into the lines, or cable failures are causes of permanent faults. Additional reclosing does not clear the fault and only results in additional stress on distribution equipment due to repeated through-faults. If, after a few attempts, this trip-reclose sequence fails to clear the fault, the fault is determined to be permanent, and the breaker or recloser is allowed to trip and lockout, causing a sustained interruption that must be cleared by a line crew.

Reclosing is commonly set to occur two to four times before the device (breaker or recloser) locks out. Figure 10-1 shows a breaker set for three recloses. Once the fault occurs, the device trips on its instantaneous setting and recloses. If the fault persists, the recloser trips again on its instantaneous settings and recloses a second time. If the fault continues to persist, the recloser trips again on a delayed setting and recloses a third time. If the fault still persists, the recloser trips on a delayed settings and then locks out.

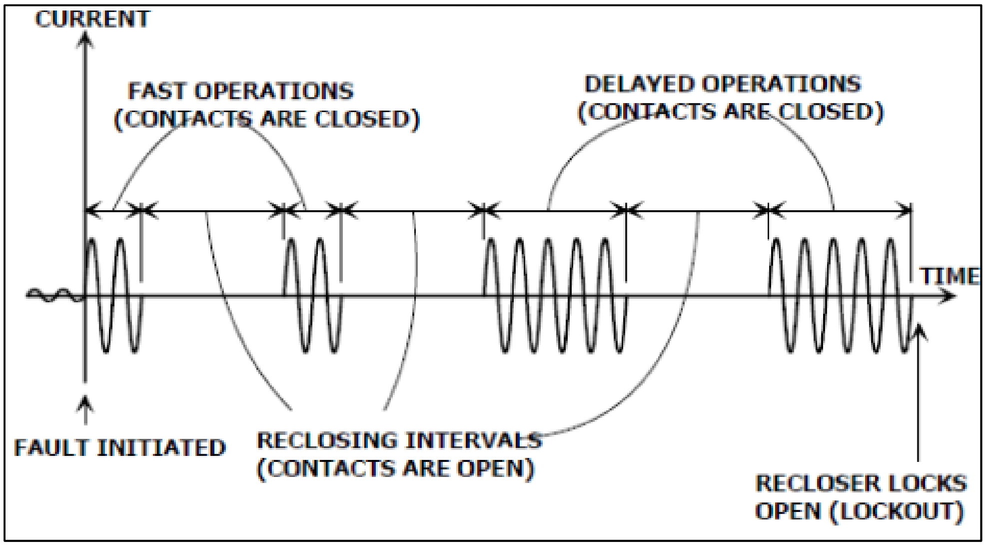


*Figure 10-1*
*Diagram of trip-reclose sequence*

As part of the industry scan on this topic, two studies of distribution system reclosing success rates were discovered. Their results are consistent and summarized in Figures 10-2 and 10-3.

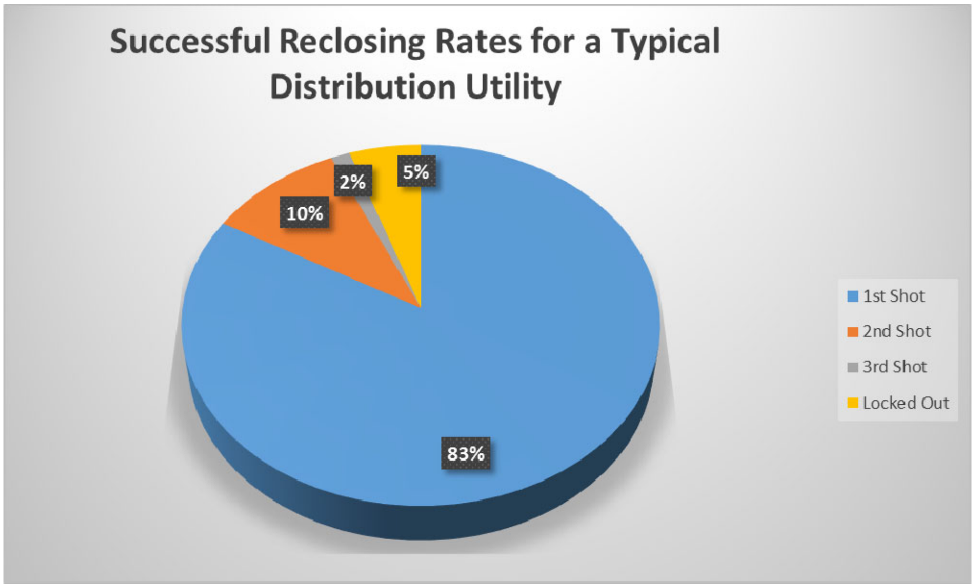


*Figure 10-2*
*Source: ABB Auto-Reclosing Pamphlet RK 85-201 E, 1979*

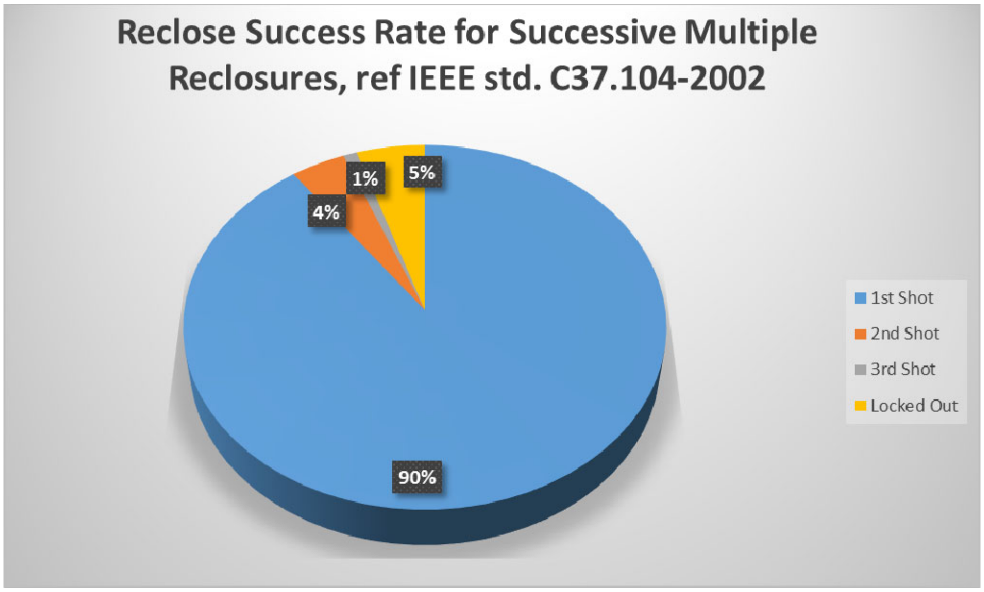


*Figure 10-3*
*Source: IEEE Guide for Automatic Reclosing of Line Circuit Breaker for AC Distribution, July 2012*

As part of the DGR Task 4 project, EPRI conducted a survey of reclosing practices among participating utilities, to determine the typical reclosing settings. Ten responses were received, indicating the variety of reclosing shot settings utilized and whether the utilities implement any adaptive reclosing settings for storm situations. The results are presented in Figure 10-4.

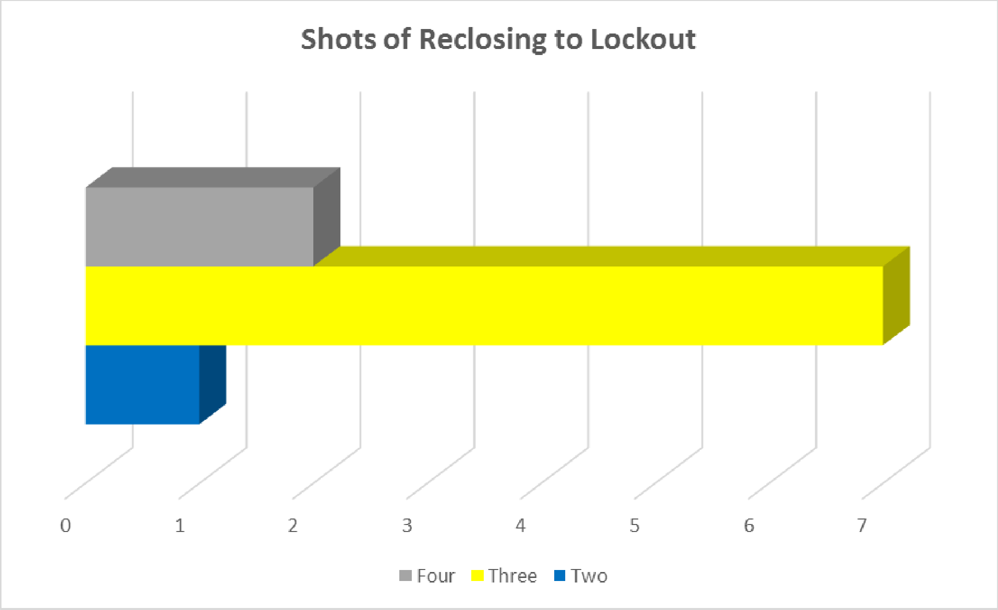
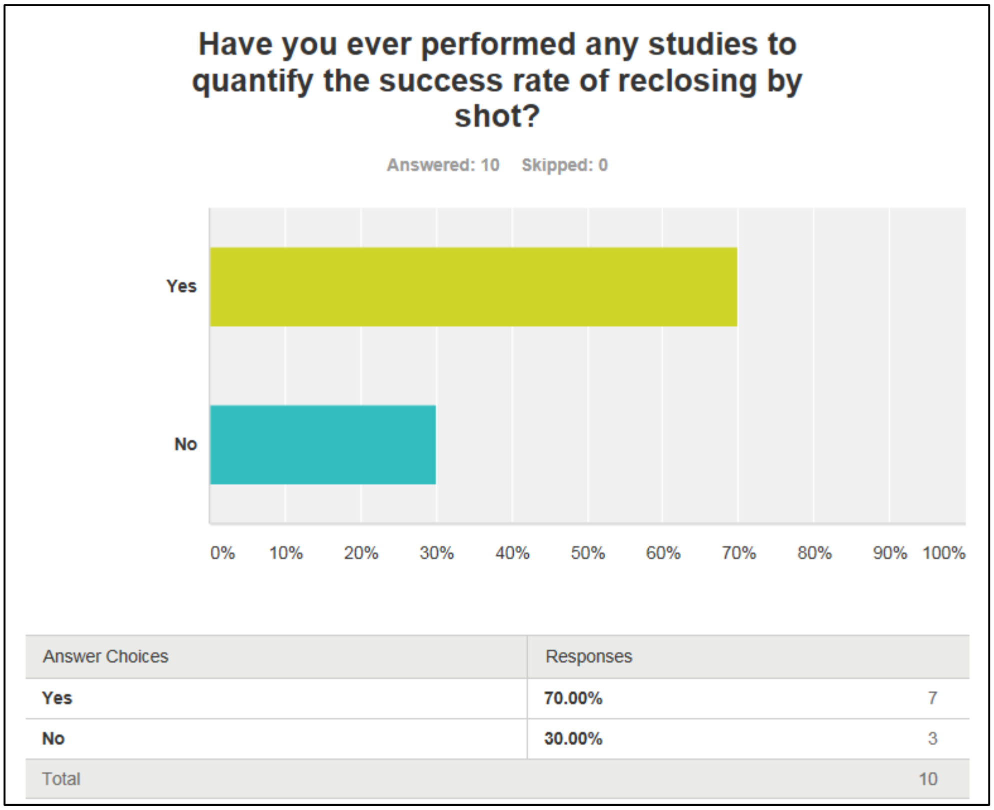


*Figure 10-4*
*Survey results: Shots of reclosing to lockout*

During the industry scan, it was discovered that a few utilities adaptively modify their reclosing practices based on weather conditions. Specifically, at least one utility adaptively changes from two shots of reclosing during blue sky days to three shots of reclosing when it switches the OMS into storm mode. The purpose of this adaptive protection scheme is to take advantage of perceived increases in success of the third reclosing shot during windy conditions, while lessening the impact of less successful third reclosing shots during blue sky conditions. Based on this discovery, the participating DGR Task 4 utilities were asked if they have performed any similar studies on their reclosing success rates (see Figure 10-5).



Have you ever performed any studies to quantify the success rate of reclosing by shot?

Answered: 10 Skipped: 0

| Answer Choices | Responses | |
|---|---|---|
| **Yes** | **70.00%** | 7 |
| **No** | **30.00%** | 3 |
| Total | | 10 |

*Figure 10-5*
*Survey results for success rate study*

One utility performed an analysis of one year's worth of detailed information regarding reclosing success rates and reported that, "for data from 3/1/2014 - 2/28/2015 for 10,167 events (where an event means that a reclosing sequence was initiated), 69.5% of faults cleared on the first reclose, 20.9% of faults cleared on the second reclose, 1.7% of faults cleared on the third reclose, and 7.9% of the faults did not clear due to breaker lock out. The above data is consistent with an analysis that was performed in late 1990s, mid 2000s and 2010." The data is summarized in Figure 10-6.

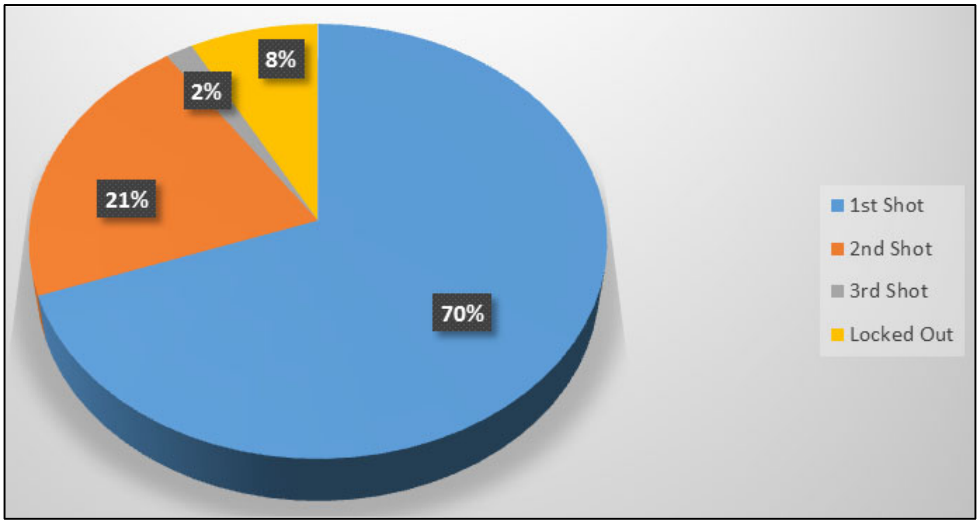


*Figure 10-6*
*Reclosing success at one utility*

One utility reported that reclosing success "Varies widely...but reclosing is less successful where short reclosing intervals are used."

Another utility reported that "We have [conducted studies], and if reclosing is successful it is roughly even at 50% success rate between the 1st and 2nd shots."

A third utility reported that they have "not [performed] a rigorous study, but informally the anecdotal evidence suggests minimal success in preventing recloser lock-outs with more than one reclose attempt."

A fourth utility reported that "Reclosing saves between approximately 40% and 60% of outages. The difference in range depends on weather for days being studied."

Another utility reported that "80% faults clear on first reclose, while 20% go to lock out."

## Purpose of this Study

The purpose of this study is to expose and investigate the issue of adaptive protection related to reclosing shots, and provide a clear description of opportunities and challenges related to this potential improvement.

## Study Approach

The approach for this study was to uncover utility data that enabled correlation between weather conditions and reclosing success rates. Utilities with reclosing success rate data were polled to determine if that data could be broken up by weather conditions to further study the impact of wind speed (sustained and top gust), and lightning conditions on the success of the second, third or fourth reclosing shot.

If this data pointed to limited success of the third reclose, a recommendation to only perform two recloses (one fast and one slow) may be offered. If the data pointed to success of the third reclose on a significant number of faults, a recommendation to stay with three recloses may be offered. If the data pointed to limited success of the third reclose on blue sky days, but significant success on weather days (with the definition of a weather day to be determined), then a recommendation to deploy adaptive protection may be offered.

## Key Findings

While there is significant anecdotal evidence that adaptive reclosing may improve performance during storm conditions (wind and lightning), this research determined that there is not sufficient published or available data to prove the concept conclusively.

## Key Outcomes

What is needed is more data to prove this concept. EPRI's Distribution Program plans to work with member utilities within the base research program (P180F) to begin the process of collecting data and determining the success rate for reclosing on each shot during blue sky and storm conditions. If the data correlates the hypothesis, a strategy to reclose just as much as necessary on blue sky days, while adding more shots during storms (as led to by the data), would be developed and published.

# Section 11: Enhancement of Adaptive Protection Fuse Saving

## Motivation for this Study

Having just discussed the benefits of reclosing on the successful restoration of transient and temporary faults, one must consider that most faults occur beyond tap or lateral fuses that cannot perform the reclosing function. They are designed to simply melt in the presence of fault current beyond a very short time duration, without the ability to reclose and restore temporary or transient faults. Clever protection engineers of the past conceived of the ability to intentionally "miscoordinate" an upstream circuit breaker or recloser with downstream fuses on the first shot of reclosing, enabling the upstream circuit breaker or recloser to attempt to clear the approximately 80% of faults that successfully reclose on the first shot. Since this action "saves the fuse," it became known as "fuse saving" and the alternative became known as "fuse sacrifice."

This study was an initiative to address the wide variances between utility application of fuse saving versus fuse sacrifice, and the potential of deploying fuse saving adaptively with modern IED relays and recloser controllers.

## Background/Relevant Survey Results

Typical protection coordination is designed and configured so that the protective device immediately upstream of the fault operates before any protective device further upstream. This is achieved by coordination of the time current curves (TCC) as shown in Figure 11-1. This process is designed to ensure that the minimum number of customers are disconnected by the action of a protective device.

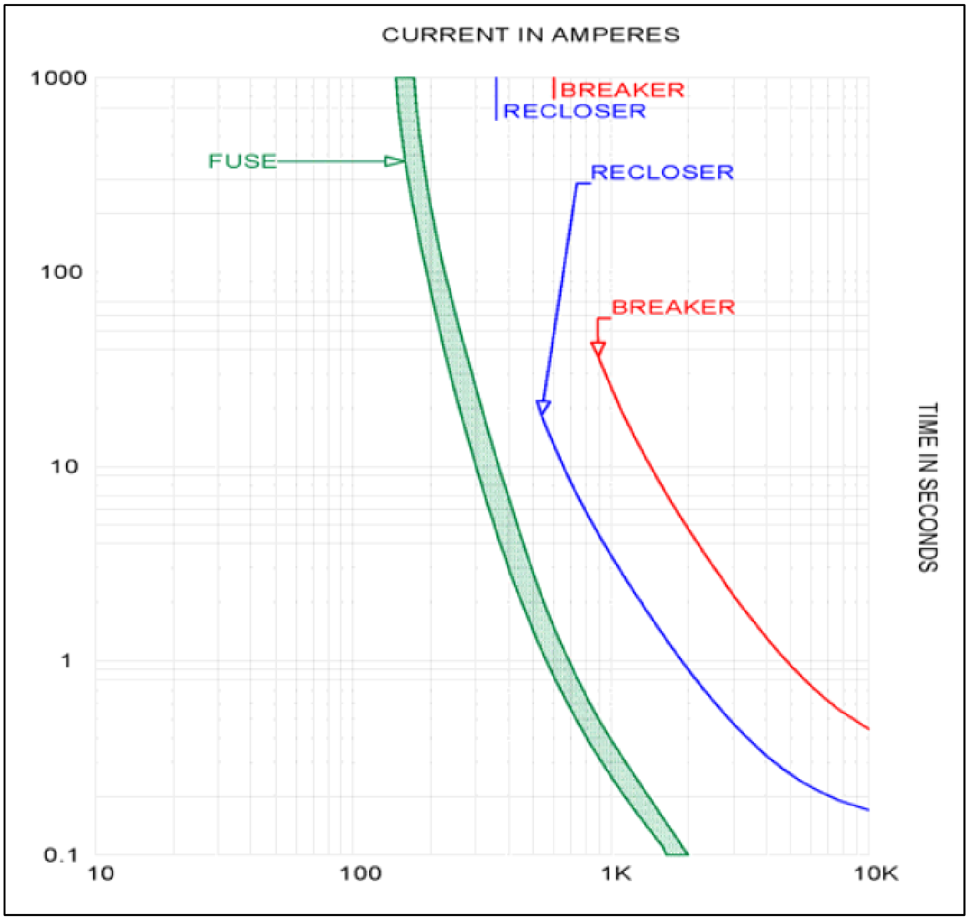


*Figure 11-1*
*Typical TCC coordination of fuse, recloser and circuit breaker achieving full coordination*

As described, fuse saving refers to the practice of setting substation breakers, substation reclosers, or line reclosers with a low-set instantaneous trip setting that intentionally operates before downstream fuses in an attempt to clear temporary faults (see Figure 11-2). In this case, there is no coordination of the instantaneous overcurrent element with the downstream fuses. The breaker is tripped before the fuse protecting the faulted section begins to melt. If this first reclosing attempt fails, the low-set instantaneous element is disabled and a high-set instantaneous element, as well as a time-overcurrent element that both coordinate with the downstream protective devices, are used. The advantage of fuse saving is that in case of a transient fault, the fuse does not melt (that is, the fuse does not require a replacement and results in a momentary interruption of the load during the dead interval of the reclosing sequence). This can be important, especially in cases in which the fuse is at a remote location, and under difficult weather conditions, when it will take a long time for the crew to get to the location and replace the fuse. A fuse saving scheme prevents longer outages due to a blown fuse caused by a temporary fault, but may cause more temporary outages to more customers because everyone on the feeder is disconnected instead of just allowing interruption of the customers downstream of the fuse.

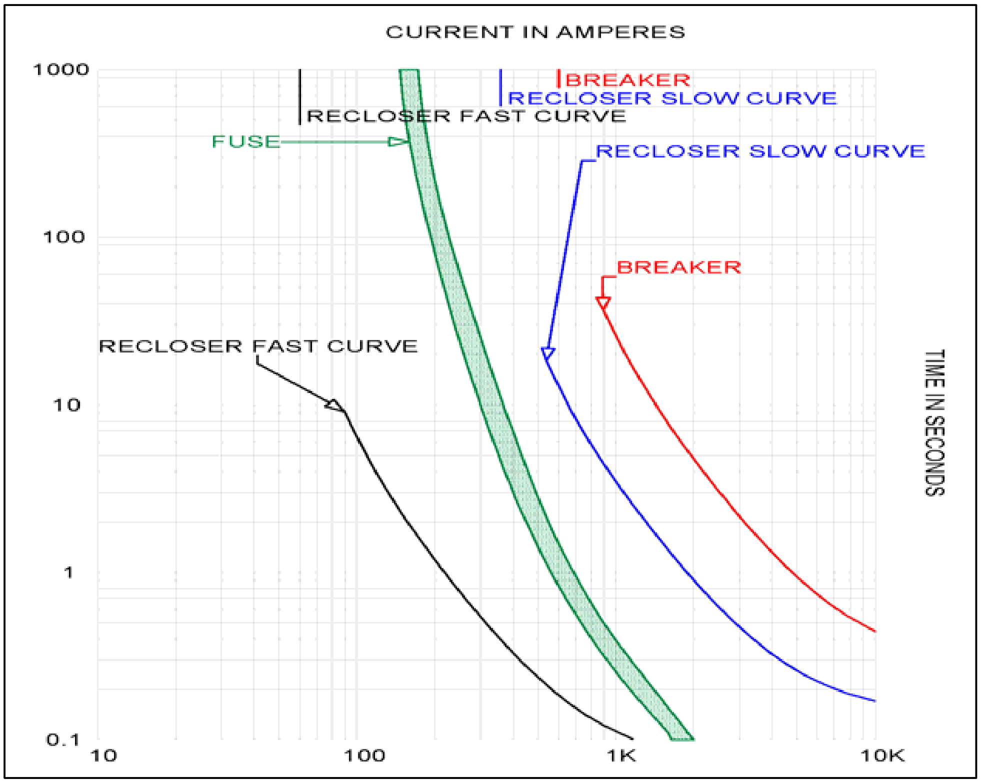


*Figure 11-2*
*Coordination showing fuse saving*

Fuse sacrifice (sometimes also referred to as "fuse clearing" or "fuse blowing") is the opposite approach in which the circuit breaker or recloser is set to fully coordinate with downstream fuses, and faults beyond fuses are always cleared by the fuse blowing. No attempt is made to clear transient faults with the upstream recloser/breaker. The advantage of fuse sacrifice is that only those specific customers downstream of the fuse are affected, and most of the customers on the feeder never see their power interrupted. The disadvantage is that the fuse needs to be replaced for all faults, even temporary ones, and the customers fed through this fuse are without power until the linemen can drive out to replace the fuse. If the fault is temporary, all customers, including those downstream of the fuse, might have been restored after a brief interruption when the recloser opened, if a fuse saving scheme had been used instead of a fuse blowing scheme.

Figure 11-3 provides an additional example comparing fuse saving with fuse sacrifice on a system coordinating a breaker with downstream distribution fuses.

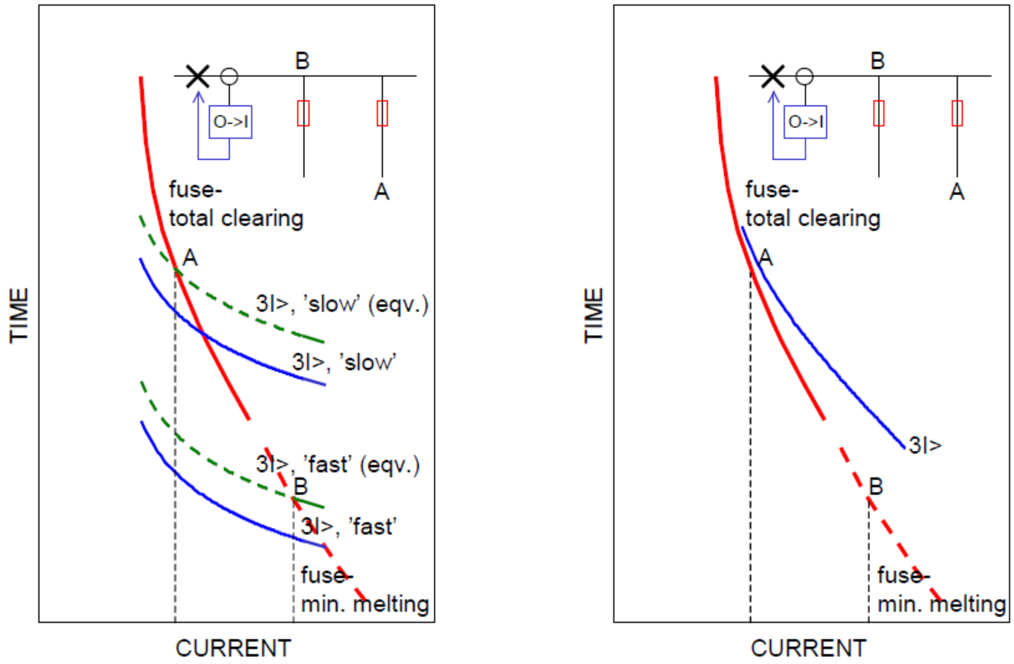
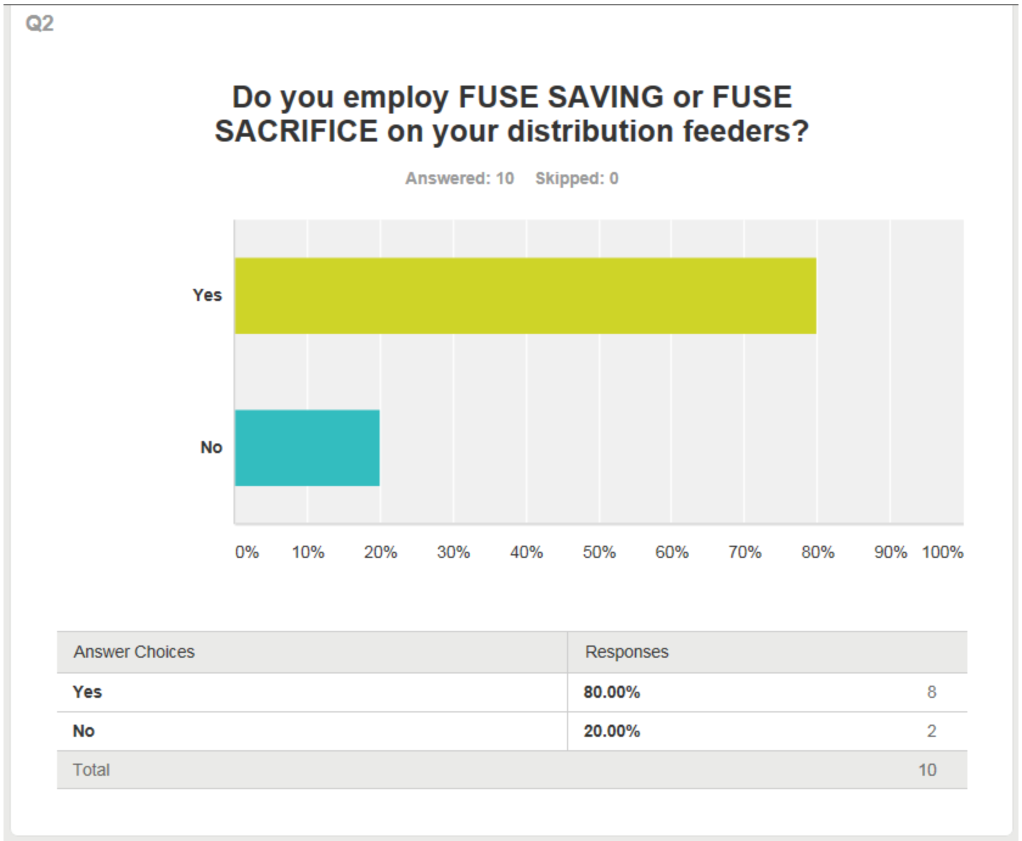


*Figure 11-3*
*Fuse saving (left) versus fuse clearing (right)*

As part of Task 4 of the DGR project, EPRI conducted a survey to better understand the spread of deployments of fuse saving by participating utilities. The results are presented in Figure 11-4.



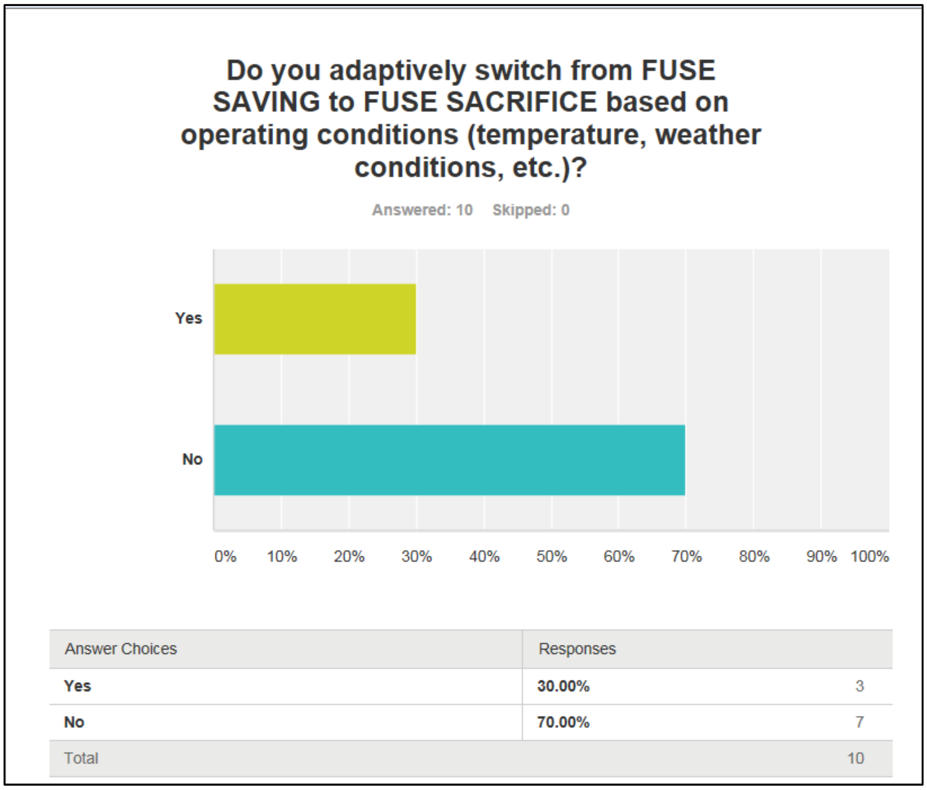
**Do you employ FUSE SAVING or FUSE SACRIFICE on your distribution feeders?**

Answered: 10 Skipped: 0

| Answer Choices | Responses | |
|---|---|---|
| **Yes** | **80.00%** | 8 |
| **No** | **20.00%** | 2 |
| Total | | 10 |

*Figure 11-4*
*Survey results: Fuse saving (Yes) versus fuse sacrifice (No)*

During the initial investigation of this topic, it was discovered that several utilities adaptively deploy fuse saving during adverse weather or storm situations (see Figure 11-5). The prevailing logic is that because there are more transient faults (lightning and wind induced) during storms, the success rates of fuse saving will be much higher. Additionally, customers are likely to be more forgiving of momentary outages during storms. As a result, adaptively using fuse saving during storms and fuse sacrifice during blue sky conditions provides a best of both worlds situation.



**Do you adaptively switch from FUSE SAVING to FUSE SACRIFICE based on operating conditions (temperature, weather conditions, etc.)?**

Answered: 10 Skipped: 0

| Answer Choices | Responses | |
|---|---|---|
| **Yes** | **30.00%** | 3 |
| **No** | **70.00%** | 7 |
| Total | | 10 |

*Figure 11-5*
*Survey results: Adaptive protection (Yes)*

The following detailed responses accompanied the survey:

One utility reported that “Fuse sacrifice is standard....Weather stations (automatic) or SCADA (dispatcher directed) is used to enable fuse saving during specific operating conditions.” More specifically, the company has developed what it calls “adaptive fuse saving” using local weather conditions monitored by weather stations installed at the distribution substation to drive automation that regulates whether fuse saving settings are in force.

Another utility reported that “We are currently in the midst of reprogramming our reclosers to better coordinate with the fuses offering some level of fuse sacrifice. This is not intended to change during blue sky vs stormy days.”

A third utility reported that “Yes all DA devices have fast trip enabled based on the following criteria:

- Wind speed: Summer: greater than 20 mph sustained, 35 mph gusts
- Winter: greater than 25 mph sustained, greater than 35 mph gusts
- Lightning projection: 5000 strokes when gust are expected to exceed 35 mph or a storm with predicted high lightning volume.”

Another utility reported that "During predicted weather events we activate 'lightning mode' on many of our reclosers which activates a quick trip mode which is faster than the first downstream fuse." More specifically, this function is enabled when weather related events are expected. To project the reliability impact, the company determines the customers impacted if lightning mode (quick trip) for the recloser was not in place. For instance, the company calculates the average numbers of customers beyond all fuses above 30K due to the fact that these smaller fuses would typically beat the fast trip of the recloser. The average number of customers was 60 customers, and the company assumes the event duration of 60 minutes. These assumptions yield 3600 customer minutes saved for each successful recloser operation in lightning mode.

Another utility provided an example of fuse saving with an electronic recloser and 65K and 100K fuses (see Figure 11-6). The company reported that "the smallest line fuse we use is a 40K. The next smaller size down we stock is a 20K and it doesn't coordinate well with transformer fusing."

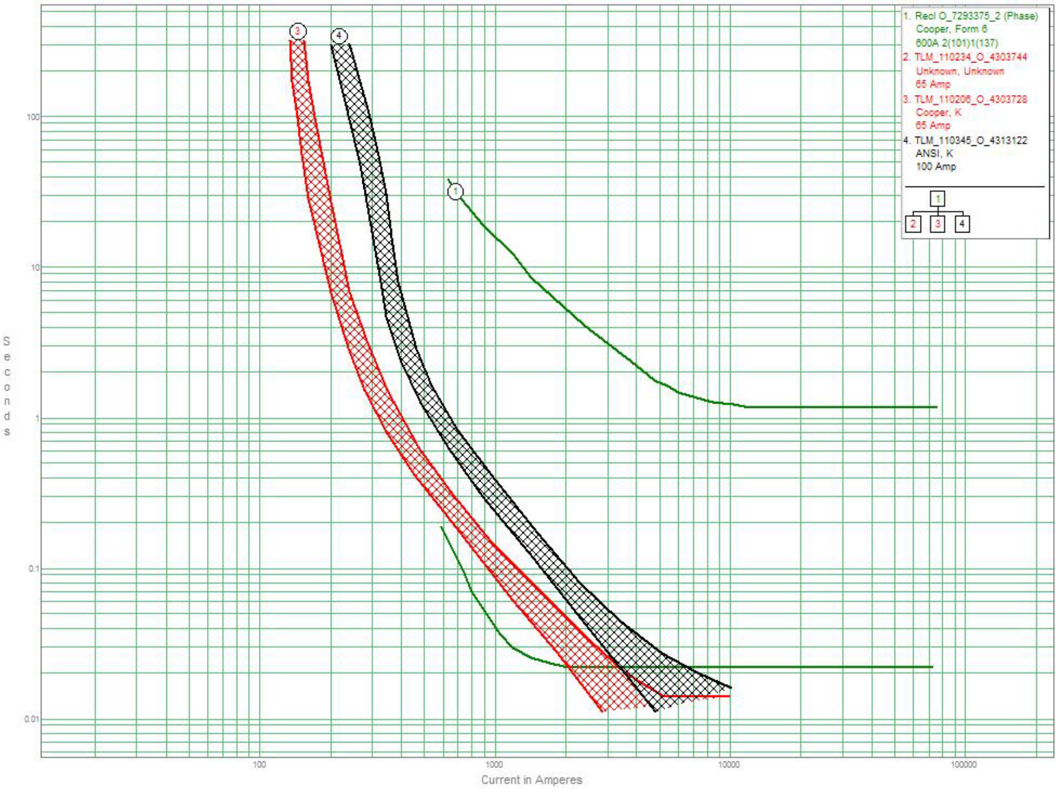


*Figure 11-6*
*Example of fuse saving coordination*

## Purpose of this Study

The purpose of this study is to expose and investigate the issue of adaptive protection related to fuse saving versus fuse sacrifice, and provide a clear description of opportunities and challenges related to this potential improvement.

## Study Approach

The approach for this study was to explore the challenges and opportunities related to the application of fuse saving on the distribution system, in particular as they apply to the conditions of a severe impact storm. Once these issues have been fully explored, the study explored demonstrated and potential methods for applying fuse saving in an adaptive fashion based on weather conditions. Adaptive protection solutions that have been deployed were discussed, and a general recommendation related to their application was provided.

## Key Findings

A detailed study of the challenges and opportunities presented by the application of fuse saving has resulted in a number of findings that are presented below.

### *Coordination Limits of Fault Current*

If the available fault current at the substation is too high, coordination with the downstream fuse may not be possible, thus fuse saving should not be applied. The fuse melting point and feeder breaker clearing must be compared for the expected fault current level at the fuse location to determine if a fuse saving scheme can be implemented. If the fuse melting time is less than the sum of the protection and breaker operating times for the calculated short circuit value at the fuse location, the fuse saving scheme should not be applied. As demonstrated in the circuit diagram and associated TCC curve in Figure 11-7, the fuse melts before low-set instantaneous overcurrent can operate for a current of 9000 amperes at the fuse location. In this example, fuse saving should not be applied, because it results in the fuse blowing, or perhaps worse, the circuit breaker and the fuse both operating.

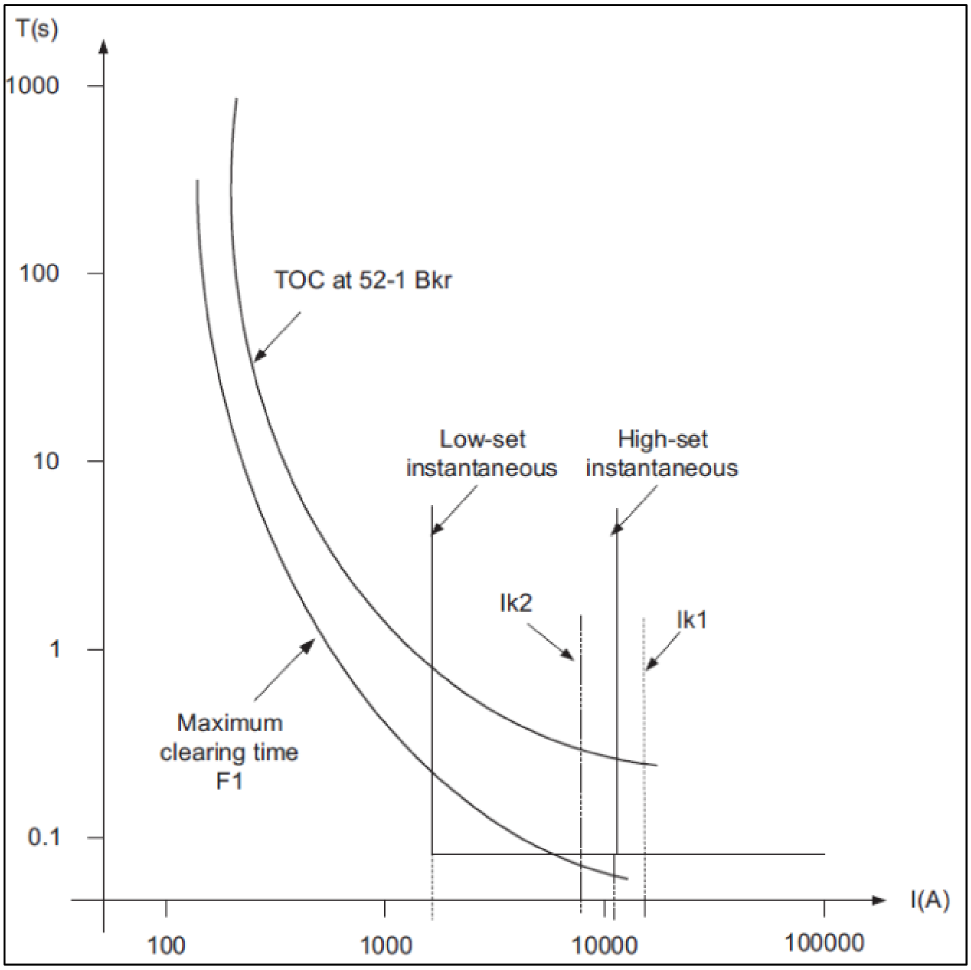


*Figure 11-7*
*Example where fuse saving cannot be applied*

If a fuse with a different TCC curve is applied to this system, the application of fuse saving becomes possible (see Figure 11-8). This demonstrates that the application of fuse saving is not a one size fits all solution, and that some amount of specific analysis is required for each utility to best understand when and where it should be applied. These challenges have led some utilities to abandon the practice of fuse saving and instead migrate to a fuse sacrifice philosophy.

## Single-Phase Fuse Operation versus Three-Phase Breaker Tripping

Recalling the rule of thumb that 70% of faults on the OH system involve only one phase and ground, and understanding that circuit breakers and many reclosers trip on a ganged three-phase basis, it should be well understood that the difference between the number of customers supplied by the fuse and the number of customers supplied by the circuit breaker are not only different because of the amount of the feeder they protect, but the customers affected by the blowing of a single-phase fuse are only approximately one-third of that number if the fault only affects a single phase. Re-examining Figure 11-7, assuming that 1000 customers are supplied by the circuit breaker and 150 of them are supplied by the fuse F1, a single-phase fault at F1 may only impact 50 customers. Thus, by implementing fuse saving, a momentary outage to 1000 customers is accepted to avoid a sustained outage for 50 customers.

### *Customer Satisfaction/Reliability Statistic Impacts of Fuse Saving*

It is well known that fuse saving results in sustained outage reduction for some customers, while increasing momentary outages to a larger set of customers. Thus, SAIFI and SAIDI are improved, while momentary average interruption frequency index (MAIFI) degrades. When the fuse sacrifice is employed, the tradeoff is reversed – reduced momentary activity comes at the expense of more frequent sustained outages. Utilities should carefully consider their customer base, and the inherent sensitivity of their customers to momentary outages in comparison to the benefits of sustained outage reduction when determining when and if to deploy fuse saving.

### *Issues Particular to Severe Impact Storms*

Unlike normal adverse weather or storm events, during a severe impact storm, customer concerns shift from the annoyance of momentary outages to the strong desire to avoid a sustained event. An outage that might normally take two hours to restore might take multiple days given the huge numbers of events affecting the utility. The utility and their customers share a keen interest in automatically clearing and restoring as many transient or temporary faults as possible, reducing the overall volume and duration of restoration efforts. Even if fuse saving is never employed during normal operations, for these reasons utilities may want to explore deploying it on an adaptive basis for severe weather events.

### *Innovative Approaches to Fuse Saving*

The industry scan revealed several innovative approaches to fuse saving that are described in the sections below.

#### Adaptive Fuse Saving

Several utilities have deployed fuse saving only during adverse weather or storm situations in an attempt to have the best of both worlds when balancing the reduction of sustained events versus increases in momentary events. Part of that logic includes the expectation that during blue sky days, crews are available to rapidly respond to small sustained outages, minimizing the duration of those events. These adaptive strategies have been deployed centrally by some utilities, while other utilities have deployed their strategy in a distributed fashion. Two examples are presented to compare this alternative.

One utility implemented SCADA control of fuse saving so that when its OMS switches into storm mode, a command is issued from the SCADA to enable fuse saving (where possible). In this manner, the company operates in a fuse sacrifice mode during blue sky conditions and fuse saving when in official storm mode.

Another utility has developed and deployed a distributed approach to adaptive protection. Essentially when a combination of wind and lightning measurements from substation-deployed weather stations exceed X mph and X strikes, fuse saving is implemented for that station only. Fuse saving remains in force for 60 minutes after these levels are reached. If the wind worsens and exceeds X mph, fuse saving is turned off with the assumption that winds above that level will result in fewer temporary (more permanent) faults.

### *Intelligent Fuse Saving*

S&C Electric proposed a new fuse-saving philosophy that it called "intelligent fuse-saving" [9]. This approach was developed with the goals of extending the range of coordination, eliminating unnecessary momentary outages, and minimizing interference with downline devices. A custom time-current characteristic (TCC) curve was developed to optimize coordination with downstream fuses. This customized TCC curve allowed fuse saving to be applied in troublesome high fault current situations. Their solution involved three innovations:

- **Develop optimized fuse-saving TCC curve.** A unique fuse-saving TCC curve is developed specifically for each of the downline fuse sizes and types that are commonly used on distribution systems, such as Type T, K, QR, KSR, coordinating speed, and others. This custom TCC curve is placed just below the fuse's minimum-melting curve, with appropriate allowances for such items as the control response and mechanical interrupting time with tolerances, fuse pre-loading, ambient temperature, and fault current asymmetry.
- **Partial range fuse-saving curve.** Ideally, a "fast" fuse-saving trip should only occur when the fault can actually be cleared before the downline fuse begins to melt. If the fuse cannot be saved, fast tripping should be skipped and timing should occur using a delayed curve that allows the fuse to operate before the recloser trips. This technique garners all the benefits of successful fuse-saving without the nuisance trips resulting from miscoordination at higher fault currents.
- **Single-phase tripping for fuse-saving.** The concept of a separate fuse-saving operating sequence can be taken one step farther by implementing single-phase tripping for the fuse-saving trips. Even in locations where single-phase tripping is not acceptable for any extended duration, it may be allowable to have just the first trip occur on the faulted phase in an attempt to clear a temporary fault in fuse-saving situations. If the fault current is higher than the maximum fuse-saving possibility, the first trip would occur on the delayed

curve, and this could be specified to be a three-phase trip. The advantage of a single-phase trip is a further reduction of the MAIFI index by approximately two-thirds because customers served by the non-faulted phase will not experience a momentary outage.

## Key Outcomes

An analysis of the available information related to fuse saving versus fuse blowing can be easily summarized in a list of advantages and disadvantages, which are presented in Table 11-1.

*Table 11–1*
Advantages and disadvantages of fuse saving

| Advantages of Fuse Saving | Disadvantages of Fuse Saving |
|---|---|
| In case of a temporary fault, the breaker or recloser trips, protecting the fuse so that it does not require replacement. This results in a momentary interruption of the load during the dead interval of the reclosing sequence.<br>This is important in cases where the fuse is at a remote location and under difficult meteorological conditions, when it will take a long time for the crew to get to the location and replace the fuse. | All the customers supplied from the feeder are affected by the interruption during the reclosing cycle. The power quality events in this case are a voltage sag caused by the short circuit, followed by a short interruption during the reclosing dead time.<br>The decision to apply fuse saving should be made based on the sensitivity of the load connected to the feeder to voltage sags or voltage interruptions. |

# Section 12: Enhancement of Sensing – Line/Pole Down

## Motivation for this Study

One of the significant advancements in the era of modern grid technology is the proliferation of sensors on the distribution system. Sensors are embedded in DA devices to measure voltage and current to drive automated restoration algorithms. They are co-installed with capacitor banks and voltage regulators to drive optimal voltage and VAR control strategies. In recent years, with the proliferation of distribution level communications networks (for example, AMI mesh networks), sensors have been installed more deeply into the distribution system for various applications. Sensors for the electric distribution system have primarily focused on measuring current and voltage, and calculated parameters based on these measured quantities.

Analogous to the substation and transmission environment, a set of additional measurements may yield value in the areas of asset management, damage assessment, and safety. Inspiration for this new breed of electric distribution sensors is partially derived from the extensive EPRI research in recent years on sensors in the transmission and substation programs. Measurements such as temperature, vibration, partial discharge and others, coupled with existing precise and accurate measurements of voltage and current, can yield solutions that provide an entirely new set of benefits.

The DGR project has performed research into the application of other forms of sensing aimed at supporting improvements in distribution resiliency. This research generated significant interest in determining the state of key pole assets and OH conductor installations, based on criteria such as distance from the service center, type of OH construction, and installation location of the pole. One specific area of concern is the deployment of spacer cable, which is a type of OH construction involving covered, but not insulated, conductors. This type of construction is more immune to incidental tree contact, preventing some faults and outages. The risk is that if the conductor falls to the ground, its cover may partially insulate the flow of fault current and result in live conductors on the ground, which is a potential public and utility worker safety issue. Participating utilities are seeking ways to detect whether this type of construction has fallen or if the pole has been knocked down.

## Background

In the area of enhancing functionality, the project team has explored using pole down/wire down sensors (also called position sensors), originally developed for transmission applications, on critical wires and poles (see Figure 12-1). The sensors detect when their angle has been changed. Often during storms, poles break due to trees falling onto spans supported by the pole. A need was identified for the reliable detection of broken poles in order to quickly enable damaged pole location to speed up damage assessment and restoration times. Deployed strategically on poles and lines, these sensors can report whether a pole is leaning or the pole is down. One key opportunity for deployment of wire down sensors is on spacer cable (Hendrix wire) where covered conductor is deployed to prevent incidental tree contact from causing an outage. A potential adverse side effect of this design is an increase in the potential of high impedance faults, due to the conductor cover increasing the fault impedance. Ideally this condition could be quickly detected by a wire down sensor.

This background section presents information contained in the EPRI report *Innovative Distribution Sensors* [10].

Figure 12-1
Prototype conductor sensor on distribution automation installation

## Purpose of this Study

The purpose of this study is to test and prove the concept that a position sensor installed on a conductor or a pole can be used to remotely determine whether a pole has been knocked over (or is leaning) and whether a conductor has fallen (to the ground or otherwise). Existing sensors developed by EPRI's Transmission/ Substation group have been used for this proof of concept. As this has proven valuable, work has proceeded to develop a cost and functionality optimized solution for distribution applications.

## Study Approach

A survey that was performed during 2013 indicated significant interest in determining the state of key pole assets and overhead conductor installations, based on criteria such as distance from the service center, type of overhead construction, and installation location of the pole. One specific area of concern is the deployment of spacer cable, which is a type of overhead construction involving covered, but not insulated, conductors. The benefit of this type of construction is that it is more immune to incidental tree contact, preventing some number of faults and outages. The risk is that if the conductor falls to the ground, its cover may insulate the flow of fault current and result in live conductors being on the ground, which is a significant public and utility worker safety issue. Utilities are exploring ways to detect if this type of construction has fallen and are also interested in determining when wires and poles are down. Outdoor testing of EPRI developed accelerometer sensors was conducted as part of this project to test each of these applications. The testing was performed at the EPRI Lenox laboratory using the full-scale distribution test yard.

### *Sensor*

EPRI Transmission and Substation programs have developed a sensor suite of wireless radio frequency (RF) sensors. These existing sensors were utilized in this proof-of-concept testing. The sensing transducer is a three-axis on-chip MEMS accelerometer. The output response ($X_{out}$, $Y_{out}$, and $Z_{out}$) is determined by the accelerometer's package orientation to gravity (g) as shown in Figure12-2. The sensors were powered for the proof-of-concept testing using high density lithium polymer batteries that have a greater than 10-year life expectancy. The sensor communicates to a base station located nearby using a low power radio frequency wireless communication in the 2.4 GHz open band with a range greater than 1-km line of site.

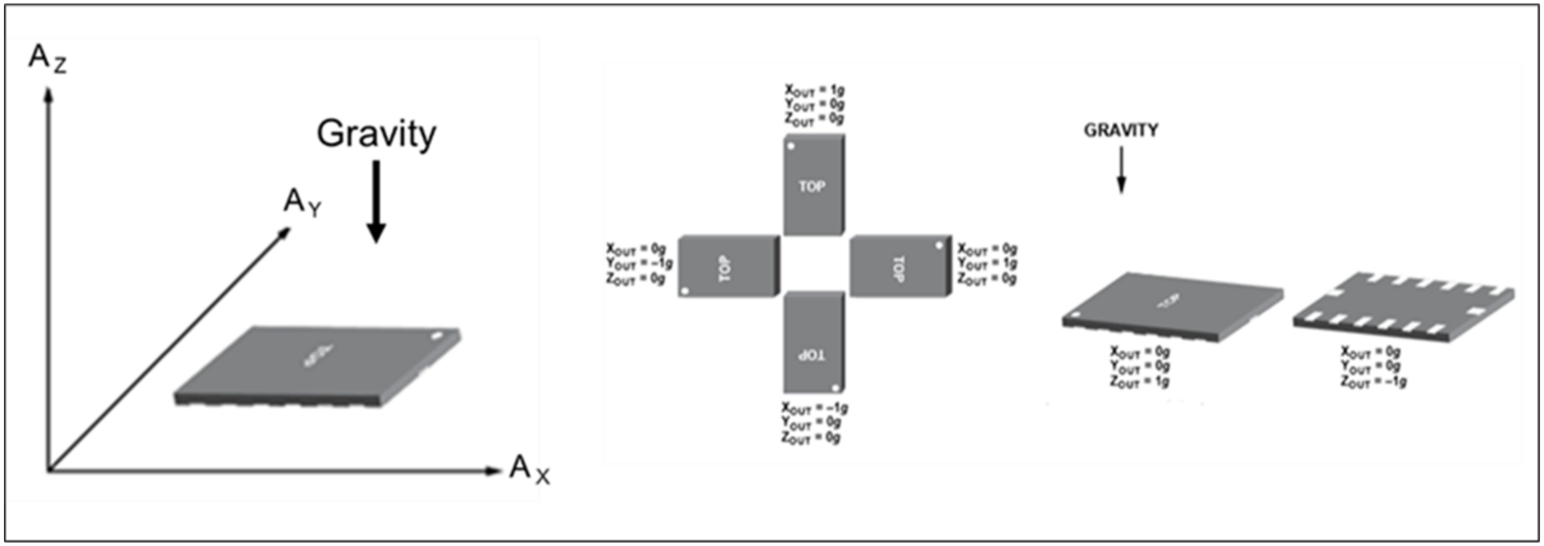


*Figure 12-2*
*Illustration of the sensing transducer's output response (Source: Analog Devices)*

### *Spacer Cable Construction Testing*

During storms or other adverse weather conditions, conductors sometimes fall. In most cases, this causes a protective device to trip, de-energizing the line. In some cases, particularly with construction involving covered conductors such as those used with spacer cable, a high impedance path to ground is formed.

Insufficient fault current is generated to trip a protective device. This situation is a significant safety concern to both the public and to utility line workers. The goal of this testing is to determine the feasibility of using a spacer cable sensor that would provide an indication of a downed spacer cable and determine if the line is still energized (eventually).

The EPRI accelerometer sensor was used to monitor spacer cable testing at the Lenox laboratory. The line was not energized during this testing. A simulated tree was dropped on the line during the testing. The accelerometer sensor was attached to the spacer as shown in Figure 12-3. The goal of this testing was to demonstrate that the onboard accelerometer can be used to detect movement of the spacer cable and to detect a downed or low hanging set of cables.

*Figure 12-3*
*Spacer cable testing at Lenox laboratory. Note the sensor is attached to spacer during this full-scale test.*

The position of the spacer cable system before and after the test is shown in Figure 12-4. Figure 12-5 shows the results of the testing performed using the accelerometer sensor. This was immediately detected by the sensor that was attached to the spacer mid-span and can be seen by the changes in the acceleration in all three axes.

*Figure 12-4*
*Position of spacer cable before and after test*

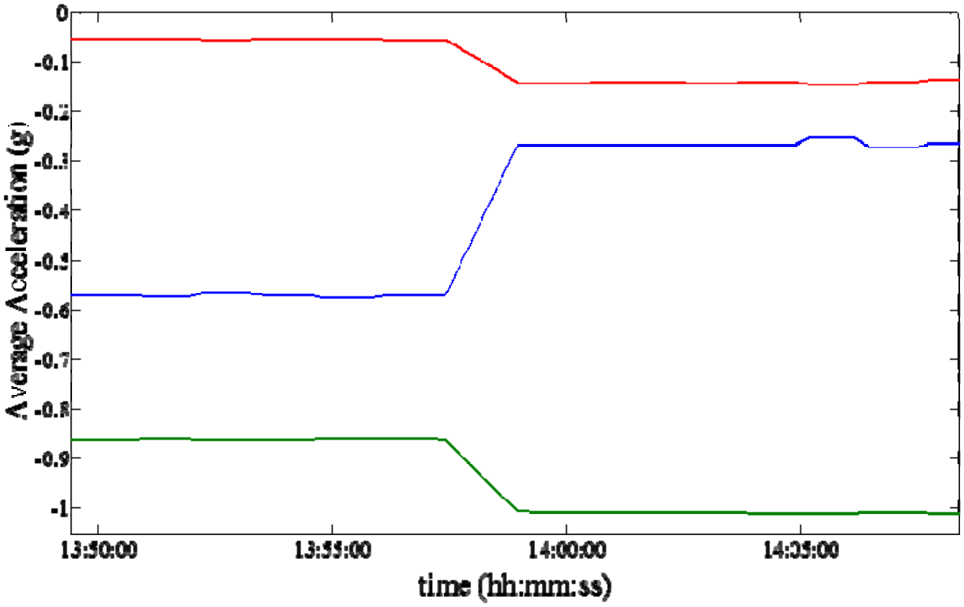


*Figure 12-5*
*The X-Axis, Y-Axis, and Z-Axis average acceleration for the spacer cable test.*

### *Standard Construction Testing*

During testing of the breakaway connectors that was performed as part of this project, the EPRI accelerometer sensors were used for the detection of a downed or leaning pole (see Figure 12-6) and for the detection of downed wire. The use of this type of sensor would be valuable to aid in damage assessment by quickly determining how many broken or leaning poles are on a system and also the location of any downed wires.

*Figure 12-6*
*Example of a prototype sensor installed on a pole*

The position of the accelerometer sensor that was placed on a conductor before and after a test is shown in Figure 12-7.

*Figure 12-7*
*Position of the conductor sensor before and after the test*

The conductor sensor was immediately able to detect that the conductor had fell, and this can be seen by the changes in the gravitational pull on the sensor in all three axes as shown in Figure 12-8.

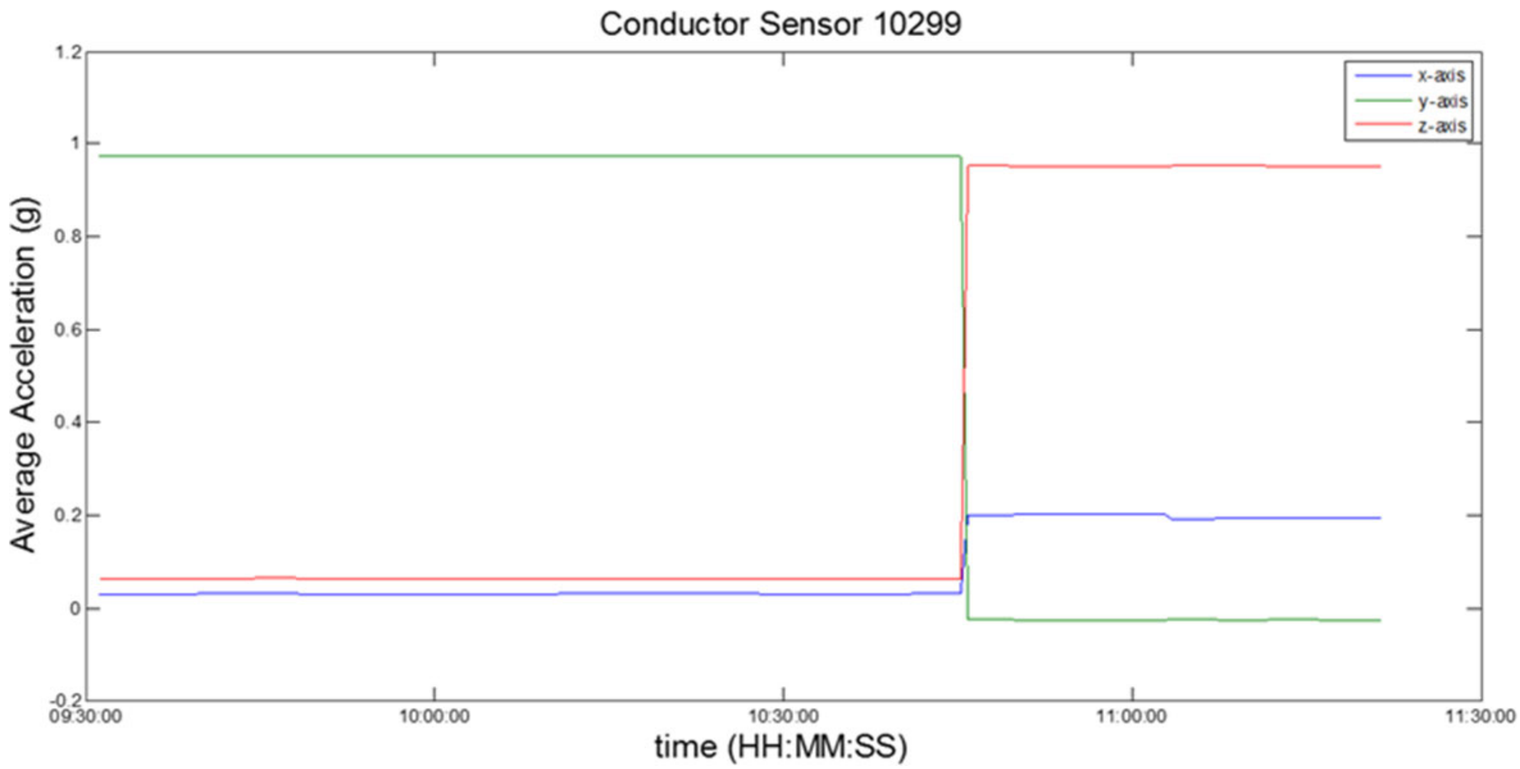
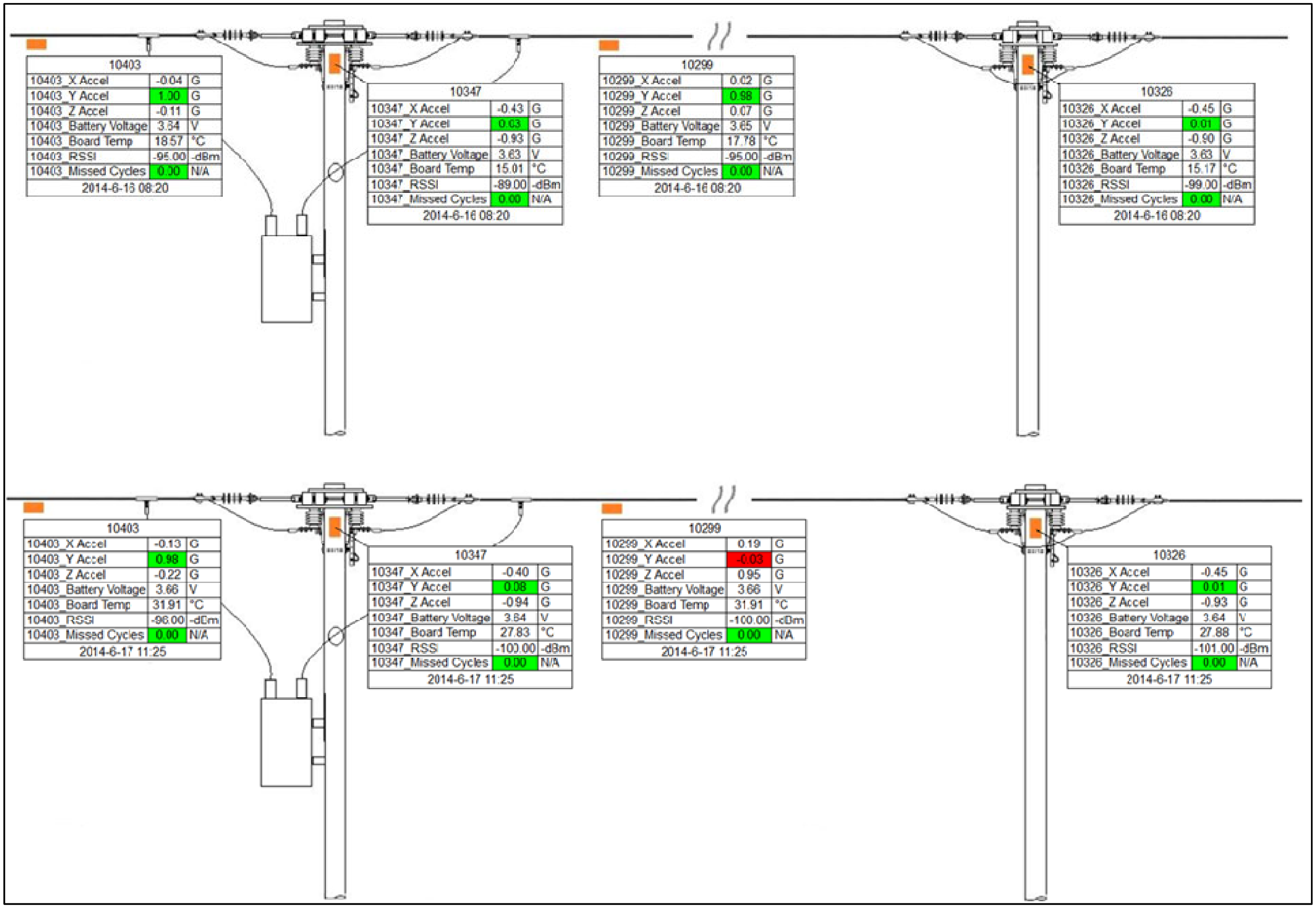


*Figure 12-8*
*The X-Axis, Y-Axis, and Z-Axis average acceleration for the conductor accelerometer sensor 10299*

For this test, the data collected was transmitted from the base station in Lenox through a cellular modem to servers located at EPRI Charlotte. The testing can be viewed in a graphical web interface in real time. Figure 12-9 shows a screenshot of the web interface before and after the testing occurred. For the particular orientation of each sensor, a change in the y-axis acceleration signaled that the wire had dropped down. The threshold was set for the y-axis to alarm, and this alarming can be seen in the web interface when that particular box changes from green before the test to red after the test.



| 10403 | | |
|---|---|---|
| 10403_X Accel | -0.04 | G |
| 10403_Y Accel | 1.00 | G |
| 10403_Z Accel | -0.11 | G |
| 10403_Battery Voltage | 3.64 | V |
| 10403_Board Temp | 18.57 | °C |
| 10403_RSSI | -95.00 | -dBm |
| 10403_Missed Cycles | 0.00 | N/A |
| 2014-6-16 08:20 | | |

| 10347 | | |
|---|---|---|
| 10347_X Accel | -0.43 | G |
| 10347_Y Accel | 0.03 | G |
| 10347_Z Accel | -0.93 | G |
| 10347_Battery Voltage | 3.63 | V |
| 10347_Board Temp | 15.01 | °C |
| 10347_RSSI | -89.00 | -dBm |
| 10347_Missed Cycles | 0.00 | N/A |
| 2014-6-16 08:20 | | |

| 10299 | | |
|---|---|---|
| 10299_X Accel | 0.02 | G |
| 10299_Y Accel | 0.98 | G |
| 10299_Z Accel | 0.07 | G |
| 10299_Battery Voltage | 3.65 | V |
| 10299_Board Temp | 17.78 | °C |
| 10299_RSSI | -95.00 | -dBm |
| 10299_Missed Cycles | 0.00 | N/A |
| 2014-6-16 08:20 | | |

| 10326 | | |
|---|---|---|
| 10326_X Accel | -0.45 | G |
| 10326_Y Accel | 0.01 | G |
| 10326_Z Accel | -0.90 | G |
| 10326_Battery Voltage | 3.63 | V |
| 10326_Board Temp | 15.17 | °C |
| 10326_RSSI | -99.00 | -dBm |
| 10326_Missed Cycles | 0.00 | N/A |
| 2014-6-16 08:20 | | |

| 10403 | | |
|---|---|---|
| 10403_X Accel | -0.13 | G |
| 10403_Y Accel | 0.98 | G |
| 10403_Z Accel | -0.22 | G |
| 10403_Battery Voltage | 3.66 | V |
| 10403_Board Temp | 31.91 | °C |
| 10403_RSSI | -96.00 | -dBm |
| 10403_Missed Cycles | 0.00 | N/A |
| 2014-6-17 11:25 | | |

| 10347 | | |
|---|---|---|
| 10347_X Accel | -0.40 | G |
| 10347_Y Accel | 0.08 | G |
| 10347_Z Accel | -0.94 | G |
| 10347_Battery Voltage | 3.64 | V |
| 10347_Board Temp | 27.83 | °C |
| 10347_RSSI | -100.00 | -dBm |
| 10347_Missed Cycles | 0.00 | N/A |
| 2014-6-17 11:25 | | |

| 10299 | | |
|---|---|---|
| 10299_X Accel | 0.19 | G |
| 10299_Y Accel | -0.03 | G |
| 10299_Z Accel | 0.95 | G |
| 10299_Battery Voltage | 3.66 | V |
| 10299_Board Temp | 31.91 | °C |
| 10299_RSSI | -100.00 | -dBm |
| 10299_Missed Cycles | 0.00 | N/A |
| 2014-6-17 11:25 | | |

| 10326 | | |
|---|---|---|
| 10326_X Accel | -0.45 | G |
| 10326_Y Accel | 0.01 | G |
| 10326_Z Accel | -0.93 | G |
| 10326_Battery Voltage | 3.64 | V |
| 10326_Board Temp | 27.88 | °C |
| 10326_RSSI | -101.00 | -dBm |
| 10326_Missed Cycles | 0.00 | N/A |
| 2014-6-17 11:25 | | |

*Figure 12-9*
*Web Interface for viewing of data in real time. The screenshot on top shows before the testing occurred and the screenshot below shows directly after the test.*

## Key Outcomes

Early identification of poles/wires down could improve the damage assessment process and enhance safety. EPRI will continue to work towards developing a cost-optimized sensor within the base Distribution Program.

A proposed conceptual design of this sensor is shown in Figure 12-10.

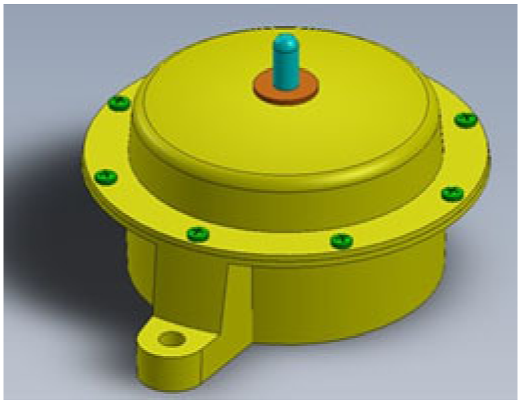


*Figure 12-10*
*Proposed conceptual design of pole/line down sensor*

The EPRI base program research will continue along several paths:

- Additional testing at the outdoor laboratory at Lenox, Massachusetts. The sensors will be installed on a full-scale system specifically to examine the downed and low hanging conductor application.
- Technology demonstrators at several utilities are planned for the pole and conductor downed concept.
- Specific sensor requirements will be developed to match the sensor's physical design, installation features, communications capabilities, and cost structure with the desired applications.

The application of accelerometers as an electric distribution utility sensor opens the possibility of deploying other types of measurement devices and points the way towards additional future research along these paths.

# Section 13: Enhancement of Sensing – Overhead Faulted Circuit Indicators

## Motivation for this Study

Locating specific fault locations on overhead (OH) systems is not always as simple as one might think, particularly during severe impact storms. Consider the difficulty involved in patrolling a circuit through wooded areas, in the dark and rain, with roads blocked, trees down, and flooding situations looking for broken cross-arms, fallen conductors or broken poles. The difficulties are complicated by a lack of information about where to even begin. The OMS analysis results simply indicate which protective devices are believed to have operated, which may be a recloser or fuse protecting a half mile of obscured OH feeder.

Due to the obvious difficulty inherent with locating faults on underground (UG) systems, there is widespread deployment of faulted circuit indicators (FCIs) to assist with narrowing down the search to the individual URD cable. The same widespread deployment has not occurred on OH lines, as the need for OH FCIs was not as great, development lagged, and costs were higher. In recent years, these factors have improved, and new developments have resulted in FCIs that can communicate remotely over D-SCADA or AMI networks. Utilities have begun piloting deployments of OH FCIs for a number of specific applications, and it makes sense to study them with an eye on severe impact storms.

## Background

Faulted circuit indicators (FCI) are small current sensors that provide local and/or remote indication that the circuit has experienced a current level that should be interpreted as evidence of a downstream fault. Faulted circuit indicators have been used for many years, particularly on underground systems, to aid in the location of faulted MV sections of feeders, enabling line crews, and later automation systems, to isolate the fault and restore unaffected customers as fast as possible. Figure 13-1 illustrates sample underground FCIs. In underground applications, a utility usually places a fault indicator at cable terminations along each primary cable. The indicators upstream of the fault have a fault indication, and the indicators downstream of the fault remain in the normal position. As a result, the utility can easily identify the faulted section of cable without undergoing a time-consuming re-fuse and sectionalize process.

*Figure 13-1*
*Typical Underground Faulted Circuit Indicators [11]*

A classic example of the use of underground FCIs is shown in Figure 13-2. Here an underground residential distribution (URD) loop is fed from two sources, which could be underground switchgear or separate fused supplies from overhead circuits. These sources supply a series of pad-mounted transformers with FCIs installed as indicated in Figure 13-2. Following a phase-ground fault on one of the cables, indicated by the lightning symbol, one of the fuses blows due to over current.

At the same time, the FCIs between the source and the fault have operated, as indicated by their red color. A field crew, or control center operator, seeing this situation, can correctly infer that the faulted cable lies between the last operated FCI and the first non-operated FCI, and can proceed to isolate the cable, test to ensure it has faulted, and then close the normal open point on the URD loop, restoring all customers to service. Once the cable has been isolated and customers restored, field crews begin work to further test the cable to determine the precise location of the fault, and make physical repairs to the cable so that the system can be restored to its normal operating configuration.

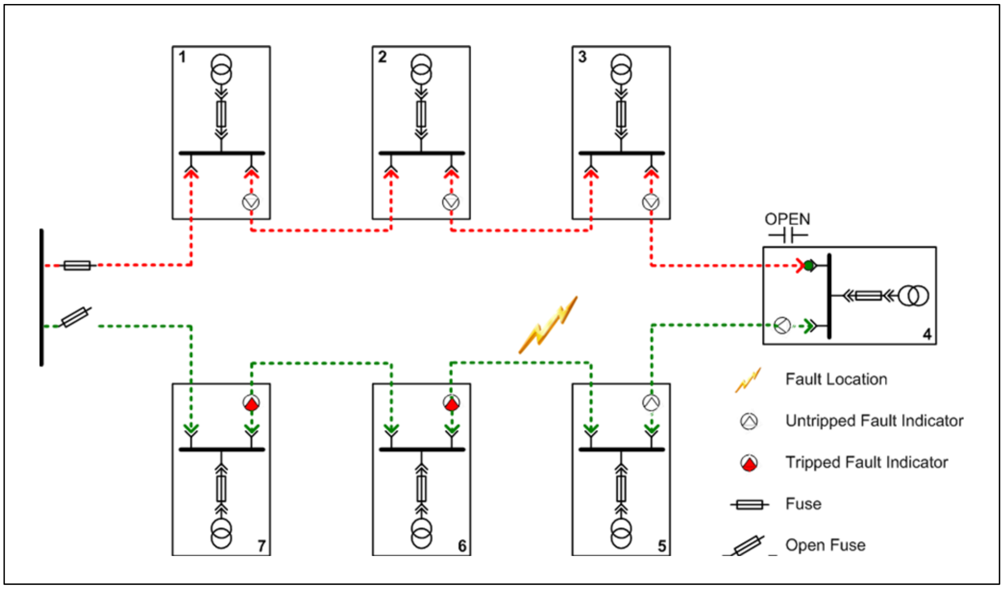


*Figure 13-2*
*Example of underground FCI operation*

When a fault occurs on an overhead system, the visually easy-to-see displays on overhead fault indicators help line crew identify the faulted section of line. Figure 13-3 illustrates overhead FCIs. Overhead applications include un-fused taps, long feeders with midline reclosers or sectionalizers, overhead-to-underground transitions, substation exit riser poles, river or road crossings, rear lot-line or alley distribution feeders, and feeders that experience recurring faults.

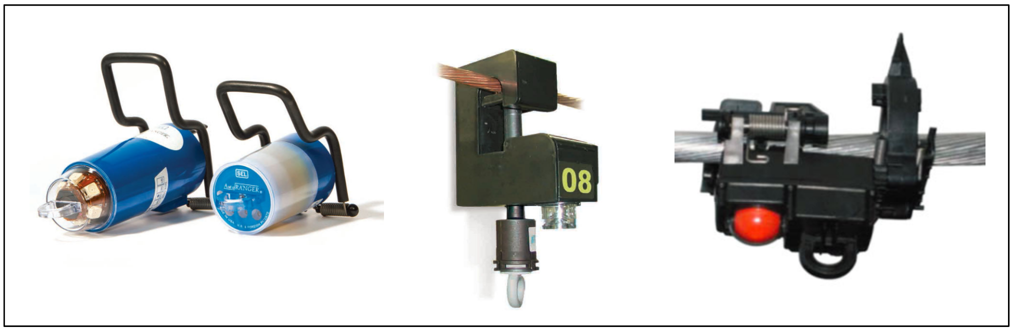


*Figure 13-3*
*Examples of North American overhead FCIs (SEL, Fischer Pierce, Eaton) [11,12,13]*

Overhead fault indicators have been used sparingly, but in recent years, with the advent of remotely communicating FCIs, their deployment has increased significantly. One of the beneficial locations for FCIs is at road crossings in areas where the overhead distribution lines are run through the back yards or rear alleys of residential communities (see Figure 13-4). These locations are often difficult to patrol by truck or foot, because in many cases mature trees, fences, and dogs have been added to the neighborhood since the homes and original distribution facilities were built. The addition of strategically placed FCIs can save significant time on restoration.

*Figure 13-4*
*Overhead application of FCIs - Rear lot street crossings*

Another common application of OH FCIs is at OH switch locations, because these are also the locations were fault isolation switching will take place (see Figure 13-5). FCI targets from these locations can be used to identify which switches can be opened to quickly isolate the fault to one section of the feeder, and which available tie switches can be closed to restore service to the unaffected sections.

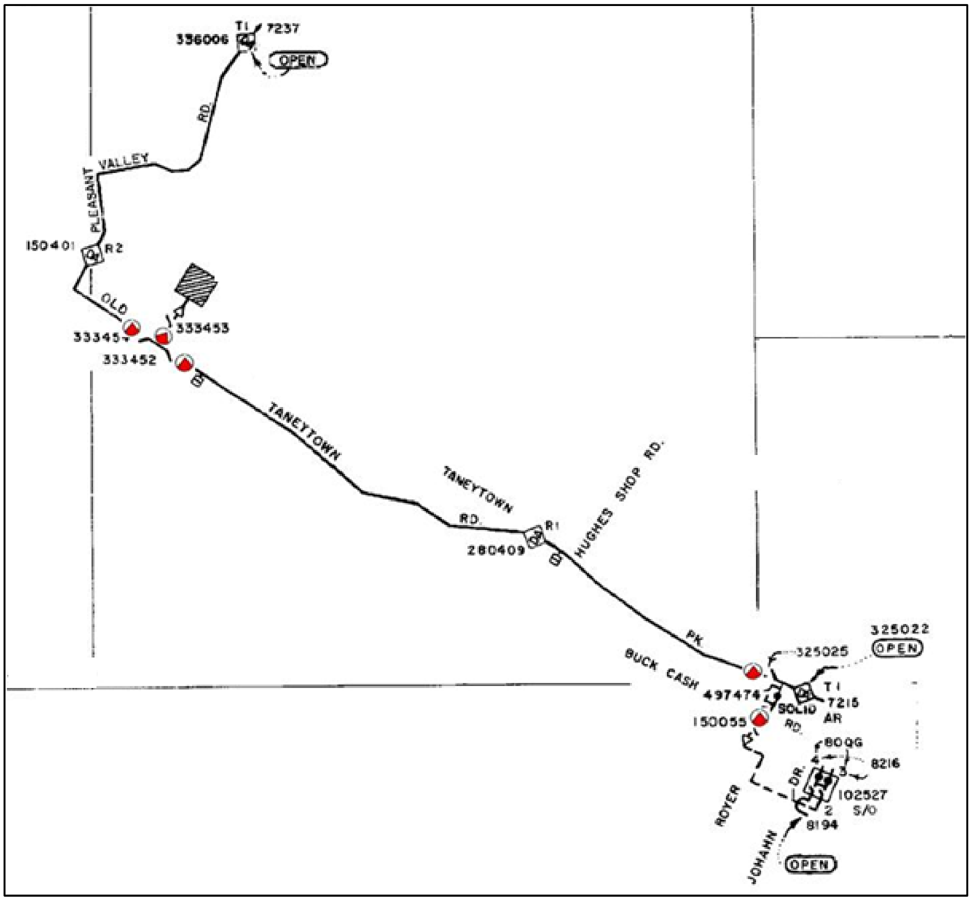


*Figure 13-4*
*Example of OH FCI application – disconnect switch locations*

## Purpose of this Study

The purpose of this study is to identify and investigate the issues related to the expanded use of OH FCIs to enhance the process of fault location, fault isolation, and service restoration during severe impact storms.

## Study Approach

This study investigated the key functional requirements for OH FCIs, documented the most beneficial implementation applications, and provided guidance with regard to a methodology of determining cost-effective locations for the implementation of FCIs.

## Key Findings

FCIs are a tool that specifically reduces the time necessary to find the fault, effect available restoration switching, and make repairs. While many utilities have deployed FCIs on the OH system as part of normal reliability improvement projects, more rigorous methods have been demonstrated to specifically calculate the reduction in customer minutes of interruption per investment in FCI deployment.

Recent technological improvements have resulted in a number of commercially available communicating FCIs, which can provide remote alarms via the D-SCADA or OMS to the DCC operator. These communicating FCIs further reduce patrol time by eliminating the need for field operations personnel to travel to the FCI location and physically observe the local indication.

For example, Baltimore Gas & Electric demonstrated a statistical method of determining the optimal number and location for FCIs by focusing on improvements to CAIDI, as well as documenting a methodology for cost-benefit analysis of FCI deployment. "Based on historical reliability indices, number of faults, causes of faults and number of protective devices in the zone, analysis was done to obtain the probabilities of fault occurrence in each zone. Normally, historical data for the location of each fault is not readily available, and even if it were available, it would not provide enough information for this type of analysis. But that would not be the case anymore. For any desired number of FCIs, analysis was done using the Monte Carlo analysis and random mutation hill climbing approach to calculate the expected average outage time, predict CAIDI and perform the cost-benefit analysis and discounted cash-flow analysis" [14].

As a general approach, utilities can evaluate the benefits of FCIs by making the assumption that fault locations can be identified more rapidly using FCIs than without FCIs. The amount and value of improvement depends on several factors, including:

- The types of challenges faced in the field (rear lot, heavy tree cover, long sections, weather, darkness), which can dramatically extend the patrol time for faults in a particular location.
- The use of communicating FCIs versus locally indicating FCIs (specifically reducing the amount of labor required to physically visit the FCI locations)
- Whether reduction in patrol times can translate directly into reduced costs (specifically during storms when foreign crews or employee overtime is costing marginal dollars over fixed labor expenses)

## Key Outcomes

The wide scale application of FCIs on OH systems can directly lead to reduced patrol times, reduced labor costs, and ultimately reduced total duration of restoration efforts. The EPRI Distribution base program will take up the task of developing a value driven application guide for OH faulted circuit indicators.

# Section 14: Enhancement of AMI – Outage Detection

## Motivation for this Study

The American Recovery and Reinvestment Act (ARRA) Federal stimulus program of the last several years provided funding for dozens of utility projects under the umbrella name of smart grid, many of which involved the implementation of smart electric meters that provide a number of new capabilities beyond simply remote access to meter data. These solutions are referred to as AMI, implying inclusion of not only the smart meter, but also the telecommunications infrastructure to provide two-way communications to each device, and the information technology infrastructure to collect and manage the vast amounts of data provided. Along with huge improvements and cost reductions to the metering/billing function of the electric distribution utility, these AMI deployments support a host of line functions, including supporting load planning by providing accurate power consumptions data from every meter, supporting efficiency improvements by providing accurate voltage data from every meter, and improving turn on/turn off processes by enabling remote connect/disconnect. Utilities are exploiting these capabilities across the globe, as deployment of these devices explodes.

## Background/Relevant Survey Results

As AMI solutions became more widely deployed, utilities began to explore their value to reliability and resiliency. Resiliency was likely not even mentioned in the business cases for these investments, but as usual, bright utility engineers were able to create value from new technologies in ways that were never original envisioned. Utilities participating in the EPRI DGR project reported in the Task 4 survey that they have used AMI meters for a number of advanced grid operations and storm management functions (see Figure 14-1).

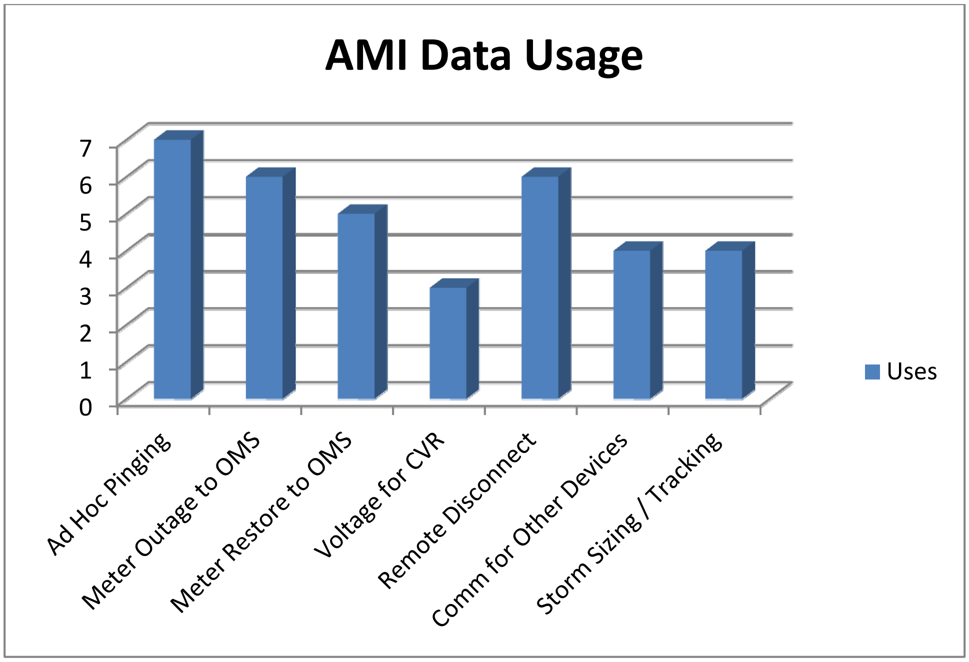


*Figure 14-1*
*Survey results: Use of AMI for operations/storm restoration (Note: CR = conservation voltage reduction)*

AMI is a highly communications-intensive solution, and the utilities participating in the DGR project have deployed AMI using several different technologies. Figure 14-2 shows that a majority have deployed mesh radio frequency (RF) solutions, while a sizable number have also deployed tower-based RF solutions.

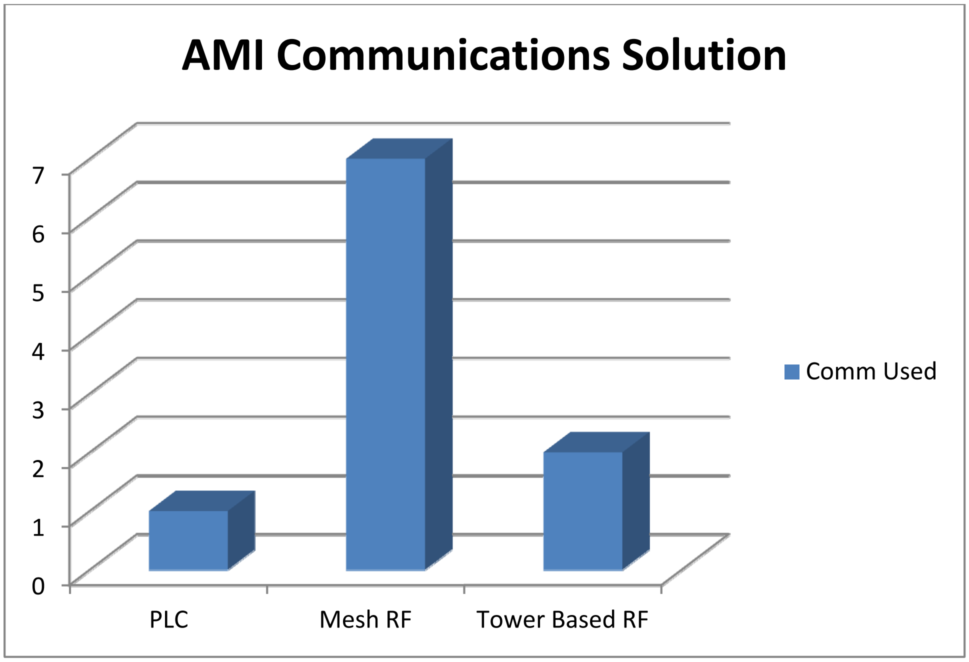


*Figure 14-2*
*Survey results: AMI communications solutions*

One utility reported that with its L&G mesh AMI network, "Single call outage restoration has been helpful. The AMI doesn't get much additional use during storms." The company also reported that it hasn't "used Outage Reporting function because we've found that the last gasp feature of the meters has been inconsistent and shown false positive outage reports."

Another utility reported that it is "Using a tower based AMI network, and have experienced outage calls that don't make it in to the OMS due to congestions, but have found that over 80% make it in within 2 minutes of the outage." The company also reported that "Restoration works much better, getting 99% of restoration alarms. The timeframe is also within 2 minutes."

Another utility reported that with its Itron mesh network the "only problem is that we miss 'power downs.' In the Itron system, the meters send three power downs to adjacent meters. This is only sent if the adjacent meters are powered. Most of the power down messages comes from meters at the edge of the mesh which can communicate directly with a battery backed-up collector. We experience a similar issue with restoration notification."

General comments indicated that tower-based communications provides better support for meter outage and restoration alarms because it is far less likely that the meter communication path will be interrupted versus a mesh network in which the meter can be energized but no longer has a mesh path back to the collector.

Figure 14-3 shows the number of responding utilities with an AMI that experienced a severe storm.

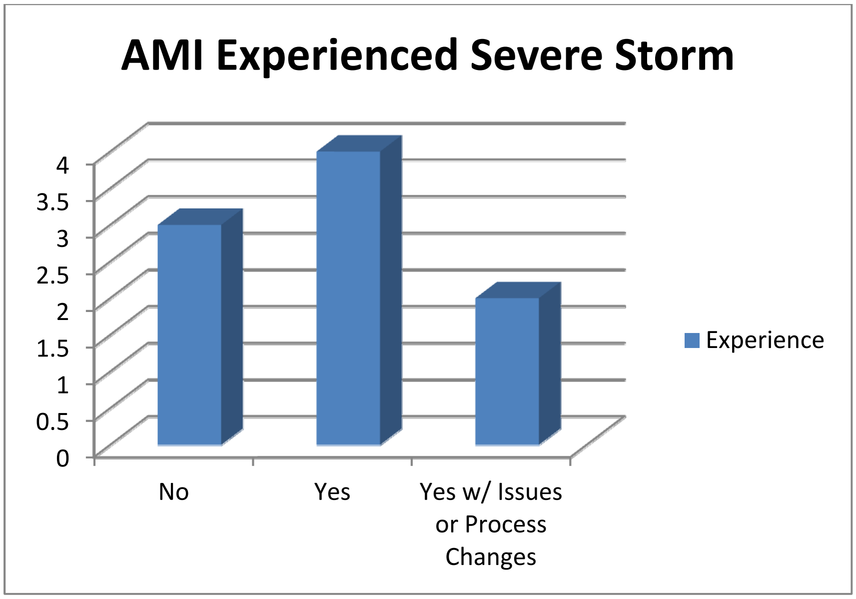


*Figure 14-3*
*Survey results: AMI experienced a severe storm*

### Purpose of this Study

The purpose of this study is to investigate and evaluate the key severe impact storm management capabilities related to outage detection provided by AMI deployments.

### Study Approach

Anecdotally, utilities have reported direct benefits of AMI deployments to storm operations. The most significant benefits reported were related specifically to the ability to use this solution to automatically and remotely determine whether a specific customer has experienced a power outage, and after repair and restoration work is complete, whether they have been restored. These capabilities address several problems that occur during every storm (small and large) and with every utility.

### Key Findings

This application relates to the need to determine exactly where the fault has occurred and which protective device has operated. Since the beginning of the industry, electric distribution systems have been largely unmonitored, relying on communications from customers to become aware that an outage has occurred. SCADA systems provided the ability to remotely monitor that a substation feeder breaker has locked out, and D-SCADA systems monitor many reclosers and sectionalizers. However, the myriad of unmonitored sectionalizers and reclosers, as well as fuses, isolate faults without significant remote monitoring. Up until the advent of AMI, when one of these devices operated, utilities were unaware of the outage until one or more customers placed a phone call to report the outage to the utility. Using manual analysis, and later OMSs, utilities compare the patterns of customer calls with the electric system configuration and apply logic to predict which protective device operated. Crews are then dispatched to the location of this protective device to begin searching for the fault to begin repairs.

AMI systems are able to send “last gasp” messages when they lose power to inform the utility OMS that they have lost power. This capability provides a number of benefits, including more accurate time for the beginning of the outage, and a complete record of every meter that has experienced a power outage. When this information is fed directly into the OMS, the result is more accurate outage diagnosis, which leads to fewer hours patrolling and troubleshooting in the field, and ultimately a more rapid and less expensive overall restoration effort.

Another situation that can be significantly improved by the utilization of AMI outage detection capabilities is when OH conductors are broken and no protective device operates. This may be the result of a high impedance fault resulting in insufficient fault current to operate a protective device, or it may be the result of a broken conductor that does not actually create a path to ground. AMI outage detection can provide the benefit of detecting a pattern of outages that begin downstream of a protective device indicating one of these conditions.

## Key Outcomes

While reliability and resilience will never justify the 10s or 100s of millions of dollars necessary to implement a utility-wide AMI deployment, when systems are justified and deployed they can provide significant benefit to the process of analyzing outages to determine which protective device has operated. Specifically, the following recommendations are made with respect to AMI outage detection:

- Utilities and OMS vendors should integrate the AMI meter data management systems with the OMS to direct AMI outage detection messages to the OMS call processing algorithm. This recommendation maximizes the accuracy of the OMS system’s protective device prediction algorithm.
- OMS vendors should develop an algorithm to identify and create a job type reflecting broken OH conductors or high impedance (HiZ) faults using AMI outage detection data. This recommendation enables utilities to identify and rapidly respond to wires down (broken conductors and HiZ faults) that do not result in a protective device operation.

OMS vendors should develop animated graphic displays to show the overall progression of storm related outages using AMI outage detection records. This recommendation enables utilities to view and project the progress of storms through the service territory in real time, enabling crews and other assets to be deployed most efficiently.

# Section 15: Enhancement of AMI – Restoration/Nested Outage Detection

## Motivation for this Study

The Federal stimulus program of the last several years provided funding for dozens of utility projects under the umbrella name of smart grid, many of which involved the implementation of smart electric meters, which provide a number of new capabilities beyond simply remote access to meter data. Referred to as advanced metering infrastructure (AMI), these solutions imply inclusion of not only the smart meter, but also the telecommunications infrastructure to provide two-way communications to each device, and the information technology infrastructure to collect and manage the vast amounts of data provided. Along with significant improvements and cost reductions to the metering/billing function of the electric distribution utility, these AMI deployments support a host of line functions, including:

- Supporting load planning by providing accurate power consumptions data from every meter
- Supporting efficiency improvements by providing accurate voltage data from every meter
- Improving turn on/turn off processes by enabling remote connect/disconnect

Utilities across the globe are exploiting these capabilities.

## Background

During storms, particularly during severe impact storms, the number of outages is so great that typically one fault occurs within another fault. This is called a nested outage and may cause some customers to remain out of service after a repair has been made. The opposite problem occurs when the OMS diagnoses one event as multiple smaller events. In this case, after repairs have been completed, more customers than expected are restored, and outage jobs remain in the OMS that are actually restored.

One of the key challenges to the use of AMI data for resiliency relates to the architecture of the communications network. Most AMI deployments use either tower-based communications in which each AMI meter communicates directly with a communications tower (one to many), or an RF mesh-based communications solution, in which meters form an ad hoc mesh and communicate in that fashion to one or more communication master stations. EPRI's DGR Task 4 survey revealed the distribution of communications solutions among the project funders (see Figure 15-1).

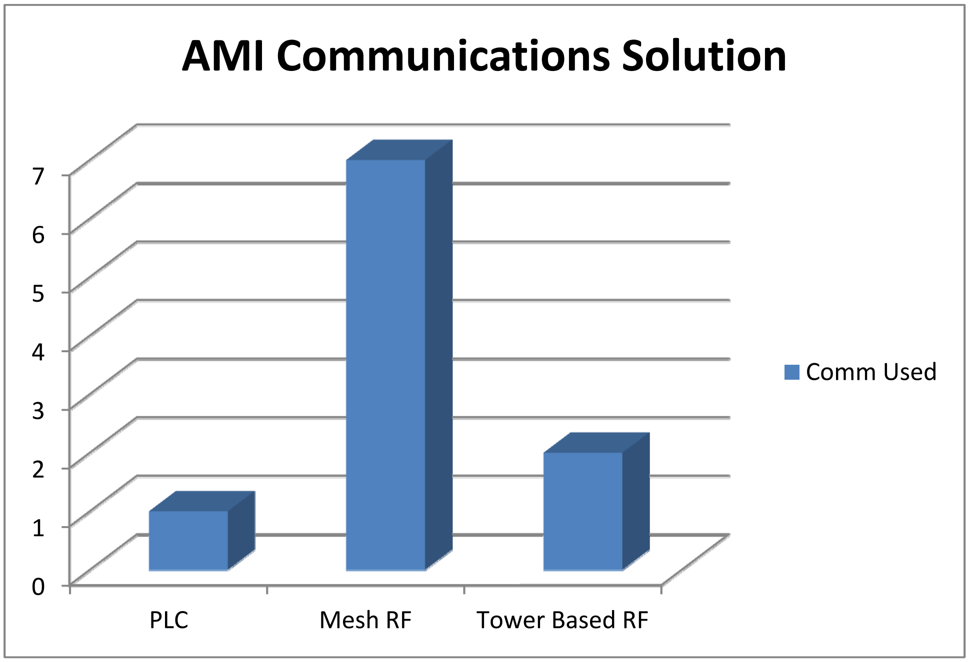


*Figure 15-1*
*AMI Communications Solutions (Note: PLC = power line communications)*

Experiences of member utilities indicate some challenges when using mesh RF systems for outage and restoration detection. Specifically, when portions of the mesh are disrupted by outages, it may be impossible to communicate with meters beyond that outage, even though they are supplied from another direction and actually in service.

This could disrupt their ability to confirm restoration. One utility commented that "Tower based communications provides better support for meter outage and restoration alarms because it is far less likely that the meter communication path will be interrupted verses as mesh network where the meter can be energized but no longer have a mesh path back to the collector."

Another utility described a similar experience, saying "Using a tower based AMI network, experienced outage calls that don't make it in to the OMS due to the congestions, but have found that over 80% make it in within two minutes of the outage. Restoration works much better. Get 99% of restoration alarms. The timeframe is also within two minutes."

It is well understood that AMI communications solutions decisions are made for a number of reasons (for example, cost, terrain, existing facilities) that have nothing to do with resiliency, and that this issue will not drive changes to the architecture. Nevertheless, it is important to understand this challenge and adapt OMS restoration confirmation solutions to account for this uncertainty.

One utility reported publicly that during Superstorm Sandy, the company avoided 6000 truck rolls by using AMI meters to ping meters, which saved over $1 million in restoration expenses [15].

Another utility reported that its PowerON OMS has implemented the use of active pinging of its mesh-networked customer meters to confirm restored customer power and to improve outage duration details. The company reports that this capability is available. However, some issues must be improved before the company plans to enable it for full-time use:

- Mesh network/meter connectivity is not fast enough for real-time results.
- Mesh reformation is slow.
- Mesh is resilient but reliability for real-time data is poor.
- Meter reconnection after an outage is lengthy (more than 15 minutes).
- Mass pinging is not achievable; limits to the system seem to be approximately a maximum of 50 requests.

When these issues are corrected, the expected benefits of meter pinging information along with additional down/up information are:

- Improved outage data quality (precise outage durations)
- Improved outage customer count information
- Future benefit to improve the real-time information to the field and DMS for the overall restoration process

Another utility reported that between December 22, 2014, and the end of May 2014, the company avoided 2488 truck rolls using meter ping functionality (see Table 15-1).

*Table 15–1*
*One utility avoided truck rolls using meter ping functionality*

| Location | 2014 | 2015 | Total Truck Rolls Avoided |
|---|---|---|---|
| District A | 9 | 254 | 263 |
| District B | 54 | 1612 | 1666 |
| District C | 49 | 510 | 559 |
|  | 112 | 2376 | 2488 |

## Purpose of this Study

The purpose of this study is to investigate and evaluate the key severe impact storm management capabilities related to restoration detection provided by AMI deployments.

## Study Approach

Anecdotally, utilities have reported direct benefits of AMI deployments to storm operations. The most significant benefits reported were related specifically to the ability to use this solution to automatically and remotely determine whether a specific customer has been restored from a power outage. This capability addresses several problems that occur during every storm (small and large) and with every utility.

## Key Findings

One of the particularly difficult activities associated with severe impact storms is the large number of overlapping and nested outages and abnormal switching conditions. As the days progress, accurately determining which customers are restored following a repair becomes increasingly difficult. This problem occurs during normal storm situations, but is orders of magnitude more difficult during major and severe impact storm restorations that may last days or weeks.

AMI provides the ability to actively interrogate individual meters or groups of meters to determine whether they are energized. This functionality requires some key capabilities including:

- Maintenance of AMI communications
- Low to moderate latency of AMI communications (seconds to minutes)
- High bandwidth of AMI communications (to enable multiple parallel requests)

## Key Outcomes

As exciting as the capability of detecting meter level outages is for the utility operator, the prospect of being able to verify restoration may provide more tangible benefits in severe impact storms. The experiences of the member utilities when discussing the progression of severe impact storm restoration is that during the last one to three days of the restoration effort, a significant amount of time is spent sending crews and line vehicles to locations that have already been restored. This is not only a waste of resources, but it also delays restoration of those customers who are still out of service.

Common practice is for utilities to utilize IVR systems or employees to call subsets of restored customers to verify restoration. This is a time consuming, yet far from accurate process, given the number of customers who are not home when the call arrives. Utilities used to infer restoration status by the presence of answering machines, but with modern voice mail, this inference is no longer valid.

Fortunately, modern AMI systems' ability to provide restoration verification (aka the meter ping), enables utilities to obtain a complete, accurate picture of which customers are restored, and which are still out of service.

- Utilities and OMS vendors should integrate the AMI restoration verification capability with the OMS to automatically periodically ping customers associated with active outages to ensure that all active outages are real and not already restored by ongoing restoration efforts. This recommendation eliminates phantom jobs, reducing truck rolls, saving dollars, and shortening the overall restoration effort.
- Utilities and OMS vendors should integrate the AMI restoration verification capability with the OMS to automatically verify restoration status, and create new nested outage records if restoration is incomplete. This recommendation identifies nested outages and ensures that these customers are not missed in the restoration effort.

# Section 16: Options Assessed in this Task That Enhance Resiliency

## Introduction

The options that are summarized in this section vary from significant capital investments in DA switch infrastructure hardening to modifications to OMS settings that can be accomplished for essentially no investment. Modern grid technology can assume many forms, and the options that have proven to be fruitful follow that pattern. The options extend existing functionality or provide enhanced functionality in ways that either addresses hardening or recovery as shown in Table 16-1.

*Table 16–1*
*Organization of Modern Grid Technology options*

| | Hardening | Recovery |
|---|---|---|
| **Extended Functionality** | • DA Pole Hardening<br>• Adaptive Shots of Reclosing<br>• Adaptive Fuse Saving | • Multiple Contingency FLISR<br>• OH Faulted Circuit Indicators<br>• AMI Integration with OMS |
| **Enhanced Functionality** | | • Battery Disconnect Switch<br>• Single Phase Automation<br>• OMS Storm Settings<br>• Pole/Line Down Sensors |

The options discussed in this task are different from many of the options discussed in other tasks because their potential for implementation depends greatly on decisions the utility has already made with respect to DA, automated restoration, protection and control technology, the OMS, and its AMI. In many cases, deploying these options only makes sense if prerequisite decisions have already been made.  For instance, the benefits of using AMI for restoration support are not nearly significant enough to justify AMI. Rather, if AMI has been justified for others reasons, this can be a beneficial capability.

## Summary of Option Costs and Benefits

Table 16-2 provides an overview of the main options that have surfaced out of research into modern grid technology. The table shows the options, representative costs, the benefits associated with the option in terms of the projected reduction in damage to assets for having applied the option, and projected benefits of applying the options to overall storm performance expressed in terms of projected reductions in duration, frequency, and storm cost. This section of the report describes the contents of Table 16-2 in detail.

In this section, the first option (in the first row in Table 16-2) is briefly described, including a description of the particular option, and discussion of any practical application issues and risks. Then, for this first option, the contents of each of the columns associated with that option are discussed, including:

- How the estimated costs of the option were derived *(Costs)*
- How the option-specific benefits were derived *(Option-Specific Benefit)*
- How the estimated projected benefits to storm duration were derived *(Duration)*
  - Overall storm duration
  - Storm CAIDI
- How the estimated projected benefits to storm frequency were derived *(Frequency)*
  - Storm SAIFI
  - Trouble cases/mile
  - Broken poles/mile
- How the projected reduction in storm costs were estimated *(Costs)*
- Other anticipated benefits to applying the option *(Other)*

This section then describes the second option, including any practical application issues and risks. However, this description describes how benefits and costs were derived only if the method differed from that of the first option.

The section concludes with a comparison of the various options.

*Table 16–2*
*Estimated costs and benefits for Modern Grid Technology options*

| **Costs** | | **Estimated Projected Benefits** | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Options** | **Costs** | **Option-Specific Benefit** | **Duration** | **Frequency** | **Costs** | **Other** | **Options** | **Costs** | **Option-Specific Benefit** |
| | | | **Overall Storm Duration** | **Storm CAIDI** | **Storm SAIFI** | **Trouble Cases/ Mile** | | | |
| **Battery Disconnect Switch** | $200 per DA Switch | Increase availability of DA and success of DA auto-restoration | Reduce probability of batteries failing during extended outages | No impact | No impact | No impact | No impact | Reduce post storm expense associated with replacing failed batteries | Eliminate need to disconnect DA batteries during extended outages (a practice of at least one utility) |
| **DA Pole Hardening** | Utility-specific costs | Increase size of DA poles or change to concrete to protect high cost infrastructure | No impact | No impact | No impact | No impact | Marginal impact, but not enough poles involved to project benefits | Reduce post storm expense associated with replacing damaged DA switches | NA |
| **Deploy Multiple-Contingency Auto Restoration** | Utility-specific costs | Increase number of customers restored automatically during storms and reduce overall storm restoration duration | Yes, but estimate of magnitude not possible | No impact | Yes, but estimate of magnitude not possible | No impact | No impact | No impact | NA |

*Table 16-2 (continued)*
*Estimated costs and benefits for Modern Grid Technology options*

| Costs | | Estimated Projected Benefits | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Options** | **Costs** | **Option-Specific Benefit** | **Duration** | **Frequency** | **Costs** | **Other** | **Options** | **Costs** | **Option-Specific Benefit** |
| | | | **Overall Storm Duration** | **Storm CAIDI** | **Storm SAIFI** | **Trouble Cases/ Mile** | | | |
| **Deploy Single-Phase Automation** | Utility-specific costs | Increase number of customers restored automatically during storms and reduce overall storm restoration duration | Yes, but estimate of magnitude not possible | No impact | Yes, but estimate of magnitude not possible | No impact | No impact | No impact | NA |
| **OMS Storm Settings** | One-time study and implementation | Increase accuracy of OMS outage prediction engine | Yes, but estimate of magnitude not possible | Yes, but estimate of magnitude not possible | No impact | No impact | No impact | No impact | NA |
| **Adaptive Protection – Shots of Reclosing** | Depends on existing utility infrastructure | Automatically restore temporary faults associated with wind or wildlife | Yes, but estimate of magnitude not possible | No impact | Yes, but estimate of magnitude not possible | No impact | No impact | No impact | NA |

*Table 16-2 (continued)*
*Estimated costs and benefits for Modern Grid Technology options*

| **Costs** | | **Estimated Projected Benefits** | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Options** | **Costs** | **Option-Specific Benefit** | **Duration** | **Frequency** | **Costs** | **Other** | **Options** | **Costs** | **Option-Specific Benefit** |
| | | | **Overall Storm Duration** | **Storm CAIDI** | **Storm SAIFI** | **Trouble Cases/ Mile** | | | |
| **Adaptive Protection – Fuse Saving** | Depends on existing utility infrastructure | Automatically restore temporary faults associated with lightning and wind | Yes, but estimate of magnitude not possible | No impact | Yes, but estimate of magnitude not possible | No impact | No impact | No impact | NA |
| **Line/Pole Down Sensors** | Currently $75 in quantities of 100k | Improve damage assessment process with actual data from pole and wire down sensors | Yes, but estimate of magnitude not possible | Yes, but estimate of magnitude not possible | No impact | No impact | No impact | Reduce damage assessment costs | NA |
| **OH Faulted Circuit Interrupters** | Approximately $3000 per pole with communications | Improve outage restoration time by pinpointing location of OH faults | Yes, but estimate of magnitude not possible | Yes, but estimate of magnitude not possible | No impact | No impact | No impact | Reduce patrolling costs | NA |

*Table 16-2 (continued)*
*Estimated costs and benefits for Modern Grid Technology options*

| Costs | | Estimated Projected Benefits | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Options** | **Costs** | **Option-Specific Benefit** | **Duration** | **Frequency** | **Costs** | **Other** | **Options** | **Costs** | **Option-Specific Benefit** |
| | | | **Overall Storm Duration** | **Storm CAIDI** | **Storm SAIFI** | **Trouble Cases/ Mile** | | | |
| **Nested Outage/ Restoration Detection integrated with OMS** | Utility-specific costs | Utilize AMI network integrated with OMS to automatically confirm restoration, nested outages, and clear already restored events. | Yes, but estimate of magnitude may vary. Utilities have reported significant anecdotal value | No impact | No impact | No impact | No impact | Reduce cost of sending crews to outages that have already been restored | Reduce the duration of the last quartile of storm restoration by eliminating outages that have already been restored |

The modern grid technology options are described in the following sections.

## Discussion of Battery Disconnect Switch Option

**Option Description** – This option involves the retrofit of existing DA switch controllers with a newly developed battery disconnect switch to disconnect the battery after an extended outage, preventing the battery from being drained beyond recharging.

**Practical Application and Risks** – This option could be implemented at the next regularly scheduled battery replacement visit (every 3-5 years typically).

**Costs** – The cost of the battery disconnect switch is projected to be in the $500 per unit range. Installation would require an additional 30 minutes per battery replacement visit.

**Option-Specific Benefit** – This option aims to extend the capabilities of DA by reducing the probability that DA switch installations fail to operate during extended outages due to backup power supply failures.

**Overall Storm Duration** – There are multiple documented cases where utilities have faced the mass failure of large numbers of DA switch batteries following extended outages due to the deep discharge of batteries so they will no longer hold a charge. These occurrences have not led to extended outage durations, but have extended the post-restoration cleanup process, and added to the overall cost of the storm restoration.

**Storm CAIDI** – No impact.

**Storm SAIFI** – No impact.

**Trouble Cases/Mile** – No impact.

**Broken Poles/Mile** – No impact.

**Costs** – There are a number of cases where utilities have been forced to replace a large number (or even all) of their DA switch batteries as a result of an extended outage that so deeply discharged the batteries that they were unable to hold a charge. This option fully prevents that from occurring, avoiding any additional storm costs associated with battery replacement.

**Other** – Some utilities, in an effort to avoid such a group failure of batteries, deploy field crews to DA switch controllers and physically disconnect the batteries to prevent them from being deeply discharged. If the battery disconnect switch were deployed, theses field crews could better be used as damage assessors or loop restoration crews.

## Discussion of DA Pole Hardening Options

**Option Description** – This option involves changing construction standards for OH DA switch poles to make the installations more robust to reduce the possibility of damage during severe impact storms. These changes may be as simple as moving up to the next pole size, or more complex including the installation of shield wires or migration to concrete poles.

**Practical Application and Risks** – This option could be implemented as simply a change of construction standards, an incremental retrofit program, or a dedicated short-term retrofit program.

**Costs** – The cost of this improvement varies significantly depending on the type of construction standard change specified by the individual utility and the aggressiveness in which the change is planned to be implemented.

**Option-Specific Benefit** – This option aims to protect DA switch poles from storm damage. The logic here is that DA poles have up to $50,000 of long lead time equipment installed on them, and they requires additional protection.

**Overall Storm Duration** – No impact.

**Storm CAIDI** – No impact.

**Storm SAIFI** – No impact.

**Trouble Cases/Mile** – No impact.

**Broken Poles/Mile** – While this option could significantly reduce the probability that a DA switch pole is broken during a severe impact storm, there are so few of these poles that this does not significantly change the overall storm rate of broken poles per mile.

**Costs** – This option protects some of the most expensive to replace poles on the distribution system.

**Other** – N/A

## Discussion of Multiple-Contingency Auto Restoration Option

**Option Description** – This option involves deploying enhanced decision making logic that enables the DA system to continue to perform fault isolation and service restoration functions beyond the first contingency.

**Practical Application and Risks** – This option could be implemented by deploying enhanced centralized automated restoration logic that adapts to changing conditions by continuing to restore as many customers as possible given real time system configuration and loads. It could also be deployed by upgrading distributed logic in an automated restoration architecture.

**Costs** – The cost of this improvement varies significantly depending on the architecture and vintage of DA/FLISR deployed.

**Option-Specific Benefit** – This option increases the number of customers restored automatically during storms. This has the impact of reducing overall storm restoration duration.

**Overall Storm Duration** – There is a positive impact on overall storm restoration duration, but it is not possible to develop a general estimate, as the impact depends greatly on the level and type of DA/FLISR already deployed.

**Storm CAIDI** – No impact.

**Trouble Cases/Mile** – No impact.

**Storm SAIFI** – There is a positive impact on SAIFI, but it is not possible to develop a general estimate, as the impact depends greatly on the level and type of DA/FLISR already deployed.

**Trouble Cases/Mile** – No impact.

**Broken Poles/Mile** – No impact.

**Costs** – No impact.

**Other** – N/A

### Discussion of Single-Phase Automation Option

**Option Description** – This option involves deploying single-phase fault trip and lockout devices that enable enhanced automated logic to isolate faults and restore service on an individual phase basis.

**Practical Application and Risks** – Implementation of this option requires the upgrade/replacement of DA switches (mainline only, tie switches not necessary) with single-phase operating devices. Additionally, new FLISR logic must be deployed to manage fault isolation and service restoration switching on a per-phase basis.

**Costs** – The cost of this improvement varies significantly depending on the architecture and vintage of DA/FLISR deployed.

**Option-Specific Benefit** – This option increases the number of customers restored automatically during storms. This has the impact of reducing overall storm duration.

**Overall Storm Duration** – There is a positive impact on overall storm restoration duration, but it is not possible to develop a general estimate, as the impact depends greatly on the level and type of DA/FLISR already deployed.

**Storm CAIDI** – No impact.

**Storm SAIFI** – There is a positive impact on storm SAIFI, but it is not possible to develop a general estimate, as the impact depends greatly on the level and type of DA/FLISR already deployed.

**Trouble Cases/Mile** – No impact.

**Broken Poles/Mile** – No impact.

**Costs** – No impact.

**Other** – N/A

### Discussion of OMS Storm Settings Option

**Option Description** – This option involves developing and implementing new OMS outage analysis parameter settings to improve the accuracy of predicted protective devices during the unique circumstances likely during severe impact storms.

**Practical Application and Risks** – This option could be implemented by studying the impacts of OMS outage analysis settings and developing and implementing those settings in the test systems and later in the production systems.

**Costs** – The cost of this improvement involves the labor cost associated with conducting the study and deploying and testing the new settings.

**Option-Specific Benefit** – This option increases accuracy of OMS outage prediction engine, reducing field time associated with patrolling.

**Overall Storm Duration** – There is a positive impact on overall storm duration, but it is not possible to develop a general estimate.

#### *Storm CAIDI*

**Storm CAIDI** – There is a positive impact on CAIDI, but it is not possible to develop a general estimate.

**Storm SAIFI** – No impact.

**Trouble Cases/Mile** – No impact.

**Broken Poles/Mile** – No impact.

**Costs** – No impact.

**Other** – N/A

## Discussion of Adaptive Protection – Shots of Reclosing Option

**Option Description** – This option involves studying the benefits of adaptive shots of reclosing, and implementing the results of that study in a protection and control scheme that adapts the level of reclosing shots in a geographic area expected to experience storm conditions (for example wind and lightning).

**Practical Application and Risks** – The implementation of this option is greatly simplified by the availability of Intelligent Electronic Device (IED) relays where adaptive settings can be implemented in logic. The overall control of these adaptive protection functions could be guided by local weather stations, SCADA-directed by centralized weather monitoring, or OMS-directed based on regional storm status settings. Without IEDs, this option requires additional hardwired logic and additional control and status points added to the substation SCADA RTU.

**Costs** – The cost of this improvement varies significantly dependent on the penetration of IED relays deployed.

**Option-Specific Benefit** – This option automatically restores temporary faults associated with wind or wildlife, reducing the number of feeder and recloser lockouts, and as a result reduces the number of outage jobs that must be dispatched during the storm.

**Overall Storm Duration** – There is a positive impact on overall storm restoration duration, but it is not possible to develop a general estimate.

**Storm CAIDI** – No impact.

**Storm SAIFI** – There is a positive impact on storm SAIFI, but it is not possible to develop a general estimate.

**Trouble Cases/Mile** – No impact.

**Broken Poles/Mile** – No impact.

**Costs** – No impact.

**Other** – N/A

## Discussion of Adaptive Protection – Fuse Saving Option

**Option Description** – This option involves studying the benefits of implementing adaptive fuse saving in a protection and control scheme that adapts the overcurrent protection in a geographic area expected to experience storm conditions (for example, wind and lightning).

**Practical Application and Risks** – The implementation of this option is greatly simplified by the availability of Intelligent Electronic Device (IED) relays where adaptive settings can be implemented in logic. The overall control of these adaptive protection functions could be guided by local weather stations, SCADA-directed by centralized weather monitoring, or OMS-directed based on regional storm status settings. Without IEDs, this option requires additional hardwired logic and additional control and status points added to the substation SCADA RTU.

**Costs** – The cost of this improvement varies significantly dependent on the penetration of IED relays deployed.

**Option-Specific Benefit** – This option automatically restores temporary faults associated with wind or lightning beyond downstream fuses, reducing the number of blown fuses, and as a result reduces the number of outage jobs that must be dispatched during the storm.

**Overall Storm Duration** – There is a positive impact on overall storm restoration duration, but it is not possible to develop a general estimate.

**Storm CAIDI** – No impact.

**Storm SAIFI** – There is a positive impact on storm SAIFI, but it is not possible to develop a general estimate.

**Trouble Cases/Mile** – No impact.

**Broken Poles/Mile** – No impact.

**Costs** – No impact.

**Other** – N/A

### Discussion of Line/Pole Down Sensors Option

**Option Description** – This option involves deploying pole and wire down sensors in various applications to remotely alarm when OH conductors have fallen or when poles have been damaged or broken.

**Practical Application and Risks** – Wire down sensors may be installed on spacer cable as an integrated feature of the spacer.

**Costs** – This device is being designed and developed; projected costs are yet to be determined.

**Option-Specific Benefit** – This option reduces the risk of spacer cable falling on the ground and not generating enough fault current to trip a protective device, enabling wider application of this resiliency option. Pole down sensors may be installed on poles in remote areas, providing more direct specific information on pole damage and speeding up the damage assessment process.

**Overall Storm Duration** – There is a positive impact on overall storm restoration duration, but it is not possible to develop a general estimate.

**Storm CAIDI** – There is a positive impact on storm CAIDI, but it is not possible to develop a general estimate.

**Storm SAIFI** – No impact.

**Trouble Cases/Mile** – No impact.

**Broken Poles/Mile** – No impact.

**Costs** – There is a positive impact on the cost of damage assessment, but it is not possible to develop a general estimate.

**Other** – N/A

### Discussion of OH Faulted Circuit Indicator Option

**Option Description** – This option involves deploying OH faulted circuit indicators (FCIs) to address various operating scenarios (rear lot construction, alley distribution, remote rural installations).

**Practical Application and Risks** – OH FCIs may be installed as either remotely communicating or non-remotely communicating installations on OH conductors.

**Costs** – An order of magnitude cost estimate for a set of 3three remotely communicating OH FCIs and the necessary communications remote units is $3000. This cost may vary significantly depending on the particular OH FCI and particular communications technology deployed.

**Option-Specific Benefit** – This option provides either remote real-time or field data on the location of OH faults. Eliminating the need to patrol fenced back yards, narrow alleys and remote forested areas on foot, these devices allow field crews to patrol from their trucks, narrowing down the faulted section to the distance between two successive OH FCIs. This improves outage duration, as well as crew safety.

**Overall Storm Duration** – There is a positive impact on overall storm restoration duration, but it is not possible to develop a general estimate.

**Storm CAIDI** – There is a positive impact on storm CAIDI, but it is not possible to develop a general estimate.

**Storm SAIFI** – No impact.

**Trouble Cases/Mile** – No impact.

**Broken Poles/Mile** – No impact.

**Costs** – There is a positive impact on the cost of patrolling individual outages, but it is not possible to develop a general estimate.

**Other** – N/A

### Discussion of Nested Outage/Restoration Detection Option

**Option Description** – This option involves utilizing an AMI network integrated with an OMS to automatically confirm restoration and nested outages, and clear already restored events.

**Practical Application and Risks** – This application can only be deployed if a fully implemented AMI solution is already in service, with capabilities of reporting restoration status and/or pinging to confirm energization with low latency (less than 5 minutes) and throughput capable of supporting the volume of messaging associated with a severe impact storm.

**Costs** – The costs of this option involve the integration of the Meter Data Management System (MDMS) and the Outage Management System (OMS), assuming the base capabilities already exist in the AMI.

**Option-Specific Benefit** – This option enables the storm center to verify the full restoration of outages after field crews report restoration has taken place, identifying nested outages or incorrect customer connection data. This option also, importantly, enables storm center personnel to pre-check the continued presence of outages prior to dispatching field crews. This is particularly important during severe impact storms, as utilities are typically left with large volumes of small (house service, transformer level) outage jobs, many of which are the result of inaccurate models/OMS analysis and have already been restored by other field restoration activities.

Utilities can individually estimate the magnitude of this benefit by studying their historical averages of trouble jobs found OK at the end of extended storms.

**Overall Storm Duration** – There is a positive impact on overall storm restoration duration, but it is not possible to develop a general estimate.

**Storm CAIDI** – No impact.

**Storm SAIFI** – No impact.

**Trouble Cases/Mile** – No impact.

**Broken Poles/Mile** – No impact.

**Costs** – This option may significantly reduce the costs associated with sending crews to outages that have already been restored, as well as reducing the overall duration of the storm restoration, enabling the early release of foreign crews and central storm organizations.

**Other** – N/A

# Section 17: Conclusions and Recommendations

This research project has deeply studied a variety of modern grid technology opportunities, many of which while unable to prevent poles or lines from falling, are critical to efficiently managing the restoration effort. Many of these issues are relatively new in the history of the electric distribution industry, so the level of experience using these solutions during severe impact storms is limited. This research has identified, investigated, surveyed participants, explored options, exposed case studies, and in some cases identified innovate new solutions associated with the use of modern grid technologies to positively impact efforts to manage the restoration of severe impact events.

As summarized in the previous chapter, the costs associated with these improvements may be definable (as with the downed pole sensor or battery disconnect switch) or they may be highly utility dependent (as with implementation of fuse saving or use of AMI for outage restoration confirmation). The expected benefits of these improvements are not yet well supported by field experience. Although logic and judgement point to their significant value, their specific benefits cannot be accurately quantified at this time.

The most clearly supported recommendations are listed in Table 162, and supported by the discussions in section 16. Additionally, throughout this research, opportunities for additional future work have been identified and are summarized in Table 17-1.

*Table 17–1*
*Summary of recommendations for future modern grid technology work*

| Research Area | Future Research | Details | Program Area |
|---|---|---|---|
| Backup Power Supply | Prototype and Test Battery Disconnect Switch | Develop cost effective solution and evaluate its performance and potential benefits | P180H.023 |
| Backup Power Supply | Test Battery Cooling Technology | Determine if battery cooling can have a positive impact on battery life | P180H.023 |
| Protecting Critical Infrastructure | Perfect Break-Away Designs | Address the technical challenges of breakaway pins and sacrificial spans to develop deployable solutions which can be field tested | P180D |
| OMS Storm Settings | Develop recommended storm settings | Study alternative settings and gather field experience to justify their value | P180F.013 |
| Shots of Reclosing | Develop recommended adaptive settings | Study alternative settings and gather field experience to justify their value | P180F.013 |
| Fuse Saving | Develop recommended adaptive settings | Study alternative settings and gather field experience to justify their value | P180F.013 |
| Line/Pole Down Sensors | Prototype and Test Pole and Line Down Sensors | Develop cost effective solution and evaluate its performance and potential benefits | P180H.022 |
| OH Fault Indication | Develop application guide | Study alternatives and produce a data drive deployment guide | P180F.012 |
| AMI Restoration | Develop application guide | Study alternatives and produce a data driven deployment guide for integration of restoration detection into OMS/DMS | P180F.012 |

# Section 18: References

1. *Distribution Grid Resiliency: Overhead Structures*. EPRI, Palo Alto, CA: 2015. 3002006780.
2. *Distribution Grid Resiliency: Vegetation Management*. EPRI, Palo Alto, CA: 2015. 3002006781.
3. *Distribution Grid Resiliency: Undergrounding*. EPRI, Palo Alto, CA: 2015. 3002006782.
4. *Distribution Grid Resiliency: Storm Response Practices*. EPRI, Palo Alto, CA: 2015. 3002006784.
5. *Distribution Grid Resiliency: Prioritization of Options*. EPRI, Palo Alto, CA: 2015. 3002006668.
6. The GridWise Alliance, "Improving Electric Grid Reliability and Resilience: Lessons Learnd from Superstorm Sandy and Other Extreme Events; Workshop Summary and Key Recommendations," June 2013, http://energy.gov/sites/prod/files/2015/03/f20/GridWise%20Improving%20Electric%20Grid%20Reliability%20and%20Resilience%20Report%20June%202013.pdf.
7. *Integrated Technology for Distribution Systems Applications: Power Supplies in Switch and Recloser Controllers*. EPRI, Palo Alto, CA: 2014. 3002003251, http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002003251.
8. *Distribution Management System Planning Guide: How to Run a Distribution Automation Program*. EPRI, Palo Alto, CA: 2013. 3002001292, http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002001292.
9. McCarthy, Chris, et al. "A New Fuse-Saving Philosophy," 2008 DistribuTech Conference Proceedings, 2008, http://www.sandc.com/edocs_pdfs/edoc_048976.pdf.
10. *Innovative Distribution Sensors*. EPRI, Palo Alto, CA: 2014. 3002001299, http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002001299.
11. SEL website, https://www.selinc.com/SEL_Catalogs/
12. Fisher Pierce Overhead and Underground Faulted Circuit Indicators," http://www.powerconsultants.com.au/pdffiles/FisherPierce/Fault%20circuit%20Indicators.pdf.

13. Cooper Power Systems, “Outage Advisor; Fault Detection and Location Solution,” 2011, http://crystalriverranch.org/wp-content/uploads/2013/04/CooperFaultDetection.pdf.

14. Paul J. Frey, Aleksandar Vukojevic and Michael S. Smith, “BG&E Makes a Smart Grid Case; Placement of fault circuit indicators is optimized by using internally developed methodology,” Dec 1, 2012, Baltimore Gas and Electric, *T&D World Magazine*, http://tdworld.com/distribution/bge-makes-smart-grid-case.

15. Lacy, Stephen, “Resiliency: How Superstorm Sandy Changed America’s Grid,” Greentech Media Inc., 2014, https://www.greentechmedia.com/articles/featured/resiliency-how-superstorm-sandy-changed-americas-grid.

# Appendix A: List of Acronyms

| | |
|---|---|
| AMI | advanced metering infrastructure |
| ANSI | American National Standards Institute |
| AoR | area of responsibility |
| ASU | automatic sectionalizing unit |
| CAIDI | customer average interruption duration index |
| CVR | conservation voltage reduction |
| DA | distribution automation |
| DCC | distribution control center |
| DGR | distribution grid resiliency |
| DMS | distribution management system |
| EPRI | Electric Power Research Institute |
| ETR | estimated time of restoration |
| FCI | faulted circuit indicator |
| FDIR | fault detection, isolation and recovery |
| FISR | fault isolation and service restoration |
| FLISR | fault location, isolation, and system restoration |
| GIS | Geographic Information Systems |
| GPS | global positioning system |
| IED | intelligent electronic device |
| IVR | interactive voice response |

| | |
|---|---|
| MAIFI | momentary average interruption frequency index |
| MDM | meter data management |
| NERC | North American Electric Reliability Corporation |
| OH | overhead |
| OMS | outage management system |
| PLC | power line communications |
| R&D | research and development |
| RF | radio frequency |
| RTU | remote terminal unit |
| SAIDI | system average interruption duration index |
| SAIFI | system average interruption frequency index |
| SCADA | supervisory control and data acquisition |
| SOM | switch order management |
| TCC | time-current characteristic |
| TEC | thermoelectric cooler |
| UF | underfrequency |
| UG | underground |
| URD | underground residential distribution |
| VAR | voltage ampere reactive |
| VRLA | valve regulated lead acid (battery) |

**Export Control Restrictions**
Access to and use of EPRI Intellectual Property is granted with the specific understanding and requirement that responsibility for ensuring full compliance with all applicable U.S. and foreign export laws and regulations is being undertaken by you and your company. This includes an obligation to ensure that any individual receiving access hereunder who is not a U.S. citizen or permanent U.S. resident is permitted access under applicable U.S. and foreign export laws and regulations. In the event you are uncertain whether you or your company may lawfully obtain access to this EPRI Intellectual Property, you acknowledge that it is your obligation to consult with your company's legal counsel to determine whether this access is lawful. Although EPRI may make available on a case-by-case basis an informal assessment of the applicable U.S. export classification for specific EPRI Intellectual Property, you and your company acknowledge that this assessment is solely for informational purposes and not for reliance purposes. You and your company acknowledge that it is still the obligation of you and your company to make your own assessment of the applicable U.S. export classification and ensure compliance accordingly. You and your company understand and acknowledge your obligations to make a prompt report to EPRI and the appropriate authorities regarding any access to or use of EPRI Intellectual Property hereunder that may be in violation of applicable U.S. or foreign export laws or regulations.

**The Electric Power Research Institute Inc.,** (EPRI, www.epri.com) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, affordability, health, safety and the environment. EPRI also provides technology, policy and economic analyses to drive long-range research and development planning, and supports research in emerging technologies. EPRI's members represent approximately 90 percent of the electricity generated and delivered in the United States, and international participation extends to more than 30 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass.

Together...Shaping the Future of Electricity

***Program:***
Distribution Systems

© 2015 Electric Power Research Institute (EPRI), Inc. All rights reserved. Electric Power Research Institute, EPRI, and TOGETHER...SHAPING THE FUTURE OF ELECTRICITY are registered service marks of the Electric Power Research Institute, Inc.

3002006783

**Electric Power Research Institute**
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com