U.S. DEPARTMENT OF
ENERGY

Electricity Delivery
& Energy Reliability

American Recovery and
Reinvestment Act of 2009

Fault Location, Isolation, and Service Restoration Technologies Reduce Outage Impact and Duration

Smart Grid Investment
Grant Program

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RECOVERY ACT SMART GRID PROGRAMS

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Executive Summary

Under the American Recovery and Reinvestment Act of 2009 (Recovery Act), the U.S. Department of Energy (DOE) and the electricity industry have jointly invested over $7.9 billion in 99 cost-shared Smart Grid Investment Grant projects to modernize the electric grid, strengthen cybersecurity, improve interoperability, and collect an unprecedented level of data on smart grid and customer operations.

Improving grid reliability is a major goal of the electric power industry and can reduce economic losses, lost productivity, and customer inconvenience from power disruptions. For several utilities, Smart Grid Investment Grant (SGIG) funding accelerated the application of fault location, isolation, and service restoration (FLISR) technologies and systems that help accomplish fewer and shorter outages.

The report draws from the experiences of 5 utilities conducting 7 SGIG projects (involving 10 total operating companies):

- **CenterPoint Energy**, headquartered in Houston, Texas
- **Duke Energy**, headquartered in Charlotte, North Carolina
- **NSTAR Electric Company**, headquartered in Boston, Massachusetts
- **Pepco Holdings, Inc.,** headquartered in Washington, DC, has three SGIG projects led by two of its utilities:
    - **Atlantic City Electric** (1) and **Pepco** (1 in Maryland and 1 in Washington, D.C.)
- **Southern Company**, headquartered in Atlanta, Georgia, has one SGIG project that involves four utilities:
    - **Alabama Power**, **Georgia Power**, **Gulf Power**, and **Mississippi Power**

FLISR technologies and systems involve automated feeder switches and reclosers, line monitors, communication networks, distribution management systems (DMS), outage management systems (OMS), supervisory control and data acquisition (SCADA) systems, grid analytics, models, and data processing tools. These technologies work in tandem to automate power restoration, reducing both the impact and length of power interruptions.

FLISR applications can reduce the number of customers impacted by a fault by automatically isolating the trouble area and restoring service to remaining customers by transferring them to adjacent circuits. In addition, the fault isolation feature of the technology can help crews locate the trouble spots more quickly, resulting in shorter outage durations for the customers impacted by the faulted section. The reduced number of customers interrupted (CI) and the associated customer minutes of interruptions (CMI) are the primary measured benefits of the technology.

Major Findings

Five projects provided quantitative metrics for 266 FLISR operations they collectively implemented between April 2013 and March 2014. Collective estimated impacts in that time period include:

- Reduced number of customers interrupted: About **270,000 fewer customers suffered interruptions** (of >5 minutes) compared to estimated outcomes without FLISR.
- Reduced outage impact: Customers experienced about **38 million fewer minutes of interruption** compared to estimated outcomes without FLISR.

On average during this time period, **FLISR reduced the number of customers interrupted (CI) by up to 45%, and reduced the customer minutes of interruption (CMI) by up to 51% for an outage event**. FLISR implementation involves greater automation and integration than traditional technologies and systems—making resources, time, and corporate commitment key elements of success. Automated devices typically need more frequent firmware and software upgrades than traditional utility equipment. Standard templates from vendors typically require customization to meet each utility's unique distribution system configurations and integrate effectively with existing SCADA systems, OMS, and DMS.

FLISR operations also bring changes in grid operations that require increased training and expertise for field technicians, engineers, and grid operators, particularly in database management, data analytics, and information systems. Cross-functional teams of technical experts in these areas better enable effective implementation. Field staff typically required the most training to learn new equipment capabilities and gain confidence in their proper operation.

An essential component for successful FLISR operations is the communications network for remote monitoring and control of technologies and systems. FLISR communication networks require increased resilience because they must operate under conditions where the grid itself is damaged or not functioning properly. The two-way communications network must have sufficient coverage and capacity to interface and interoperate with a wide variety of technologies and systems, including various field devices and DMS, OMS, and SCADA systems.

Utilities saw the most benefit from FLISR investments that modernized poorly performing or highly vulnerable substations and feeder groups, or those that serve customers that suffer significant economic or public health and safety losses during power outages. Table 1 provides a summary of the key results, lessons learned, and future plans from the featured projects.

Table 1. Summary of Key Results	
Outage Causes for FLISR Events	i. **Issues with trees and vegetation caused the most outages** (25%) for the 266 FLISR events the projects reported. Equipment failures (18%) and accidents (9%) were also significant factors.
FLISR Effectiveness for Reducing the Number of Customers Interrupted and Customer Minutes of Interruption	ii. FLISR operations **reduced the number of customers interrupted** for partial-feeder outages (by about 55%) and full-feeder interruptions (by about 37%). iii. FLISR also **reduced the number of customer minutes of interruption** for partial-feeder outages (by about 50%) and full-feeder outages (by about 51%). iv. FLISR operations were **more successful in reducing the number of customers interrupted for automated switching operations** (reduced by about 55%) than for manually validated operations (reduced by about 35%). v. FLISR was also **more successful in reducing the number of customer minutes of interruption for automated switching operations** (reduced by about 53%) than for manually validated operations (reduced by about 47%).
Lessons Learned for Communication Networks from FLISR Technology Implementation	vi. The utilities found that **communication networks require greater resilience than power delivery systems because they must be able to control automated switches under conditions where the grid system is damaged** or not functioning properly due to downed lines, faults, or other grid disturbances. vii. Utilities with **legacy communication networks should conduct evaluations and implement upgrades** before deploying FLISR technologies and systems.

All of the utilities plan to continue investing in FLISR capabilities to add new features and expand coverage to new substations and feeders.

1. Introduction

Fault location, isolation, and service restoration (FLISR) technologies are one of the distribution automation (DA) tools SGIG projects are deploying to provide operators greater visibility into disturbances and automatically reroute power to reduce the number of affected customers from downed power lines, faults, or other disturbances. In addition to fewer and shorter outages for customers, FLISR technologies help utilities improve their standard reliability metrics, such as the System Average Interruption Frequency Index (SAIFI) or System Average Interruption Duration Index (SAIDI). In many states, improvements in these metrics are tied to utility financial incentives, often through performance standards or performance-based rates. This section provides an overview of how FLISR technologies improve reliability.

1.1 What is FLISR?

Fault location, isolation, and service restoration (FLISR) includes automatic sectionalizing and restoration, and automatic circuit reconfiguration. These applications accomplish DA operations by coordinating operation of field devices, software, and dedicated communication networks to automatically determine the location of a fault, and rapidly reconfigure the flow of electricity so that some or all of the customers can avoid experiencing outages. Because FLISR operations rely on rerouting power, they typically require feeder configurations that contain multiple paths to single or multiple other substations. This creates redundancies in power supply for customers located downstream or upstream of a downed power line, fault, or other grid disturbance.

1.2 How Does FLISR Result in Fewer and Shorter Outages?

Figure 1 presents simplified examples (A-D) to show how FLISR operations typically work. In Figure 1-A, the FLISR system locates the fault, typically using line sensors that monitor the flow of electricity and measures the magnitudes of fault currents, and communicates conditions to other devices and grid operators.

Once located, FLISR opens switches on both sides of the fault: one immediately upstream and closer to the source of power supply (Figure 1-B), and one downstream and further away (Figure 1-C). The fault is now successfully isolated from the rest of the feeder.

With the faulted portion of the feeder isolated, FLISR next closes the normally-open tie switches to neighboring feeder(s). This re-energizes un-faulted portion(s) of the feeder and restores services to all customers served by these un-faulted feeder sections from another substation/feeder (Figure 1-D). The fault isolation feature of the technology can help crews locate the trouble spots more quickly, resulting in shorter outage durations for the customers impacted by the faulted section.

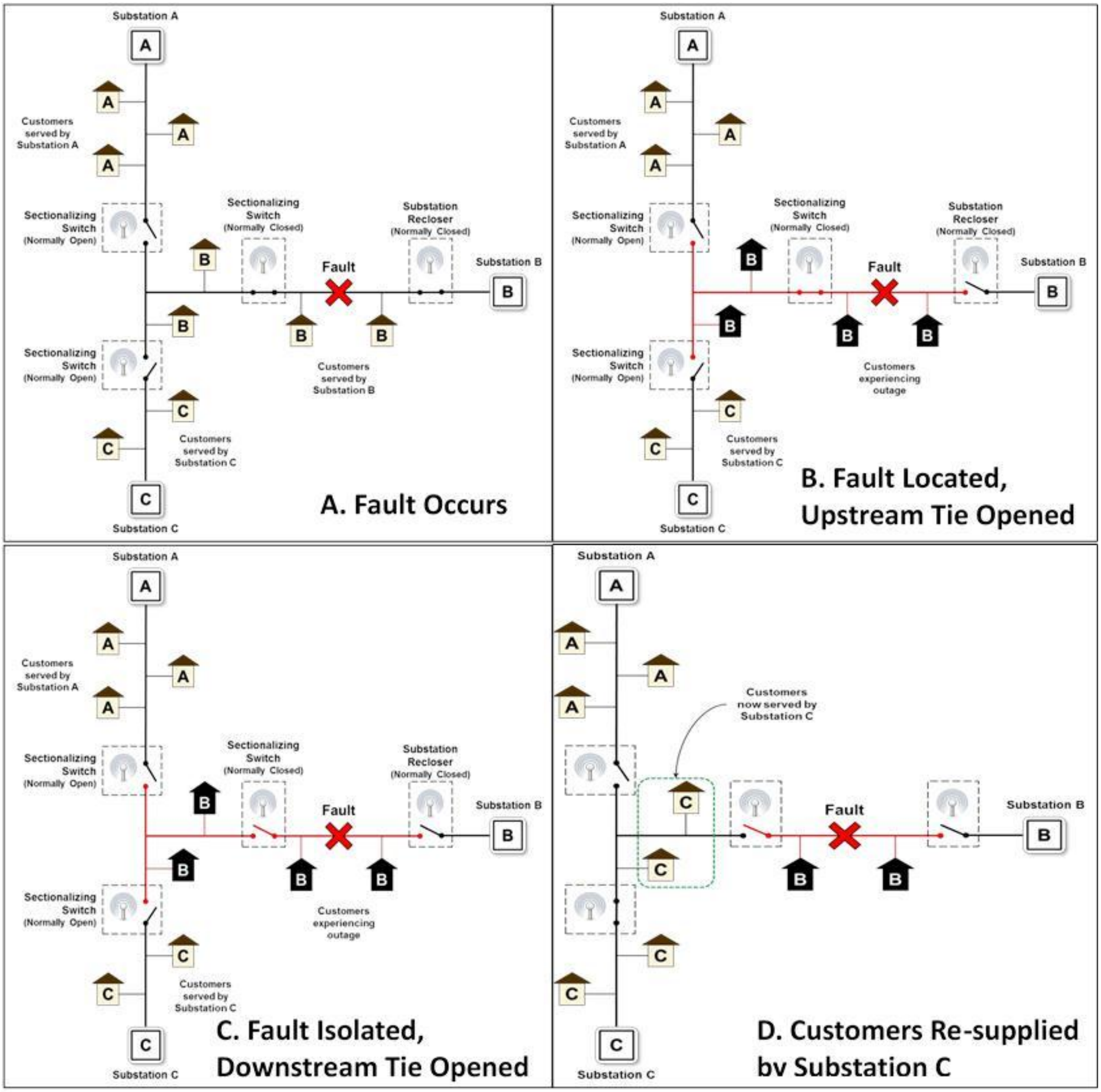

Figure 1. Schematics Illustrating FLISR Operations.

FLISR systems can operate autonomously through a distributed or central control system (e.g., DMS), or can be set up to require manual validation by control room operators. Implementing autonomous, fully automated FLISR systems typically requires extensive validation and calibration processes to ensure effective and reliable operations. Automated FLISR actions typically take less than one minute, while manually validated FLISR actions can take five minutes or more.

Two standard reliability metrics are typically used to evaluate FLISR operations: 1) the number of customers interrupted (CI), and 2) the number of customer minutes of interruption (CMI). Both of these metrics are components of the equations that are used to calculate SAIFI and SAIDI. CI is a measure of the number of customers interrupted by an outage. CMI is a measure of the duration of interruptions experienced by customers. The avoided CI and CMI can be used to measure the benefits of FLISR operations. It is important to note that FLISR does not avoid outages but works to minimize their impacts on customers when they do occur.

2. Overview of the Featured SGIG Projects

This report features 5 utilities conducting 7 SGIG projects (involving 10 total operating companies) with measured impacts and benefits from FLISR operations:

- **CenterPoint Energy**, headquartered in Houston, Texas
- **Duke Energy**, headquartered in Charlotte, North Carolina
- **NSTAR Electric Company**, headquartered in Boston, Massachusetts
- **Pepco Holdings, Inc. (PHI),** headquartered in Washington, DC, has three SGIG projects led by two of its utilities:
    - **Atlantic City Electric** (1) and **Pepco** (1 in Maryland and 1 in Washington, D.C.)
- **Southern Company**, headquartered in Atlanta, Georgia, has one SGIG project that involves four utilities:
    - **Alabama Power**, **Georgia Power**, **Gulf Power**, and **Mississippi Power**

The three PHI utilities each implemented their own SGIG project and used similar technologies and approaches for FLISR operations. The four Southern Company utilities implemented subprojects under Southern Company's SGIG project. All four use similar technologies and approaches for FLISR operations.

Table 2 shows the main features of the FLISR activities operated by the utilities and their projects. The projects call their FLISR activities by different names, use different types of field devices, apply manually-validated or fully-automated modes of operation, and accomplish operations with distributed servers or a centralized distribution management system (DMS).

Table 2. Overview of FLISR Project Activities.

Features	CenterPoint	Duke	NSTAR	PHI	Southern
Name of FLISR System	Self-Healing Grid	Self-Healing Teams	Auto Restoration Loops	Automatic Sectionalizing & Restoration (ASR)	Self-Healing Networks
Field Devices Involved	Intelligent Grid Switching Devices (IGSDs) act as switching devices and monitoring equipment	Electronic reclosers, circuit breakers, and line sensors	Telemetry communications, line sensors, and "smart" switches	Substation breakers, field switches, reclosers, and "smart" relays	Automated switches/ reclosers, and fault indicators
Mode of FLISR Operation	Manual validation required	Fully automated	Transitioned to full automation during the project	Fully automated	Fully automated
Location of FLISR Operations	Dedicated server; to be transitioned to DMS	Dedicated self-healing application	DMS	Dedicated server in the substation	Dedicated server or DMS

2.1 CenterPoint Energy

CenterPoint Energy is an electric transmission and distribution company serving approximately 121 Retail Electric Providers (REPs) in Texas. CenterPoint's REPs serve more than 2 million customers located on the Texas Gulf Coast, including the Houston metropolitan area. The utility operates more than 3,750 line miles of electric transmission, 50 transmission substations, 1,500 electric distribution feeders, and 240 distribution substations. CenterPoint's summer peak demand exceeds 16 gigawatts. Figure 2 shows a service territory map.

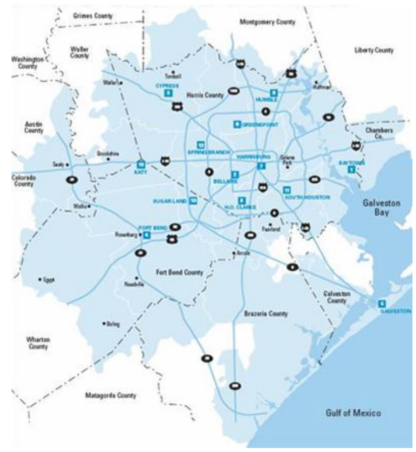

Figure 2. CenterPoint Service Territory Map.

CenterPoint's SGIG project has a total budget of about $639 million, including DOE funding of $200 million under the Recovery Act. The project includes deployment of a variety of technologies and systems, including:

- 2.2 million smart meters along with associated communication networks and systems for meter data management
- DA upgrades on about 180 feeders located in the central Houston and ship-channel areas—where much of the critical chemical, petrochemical, and oil refining infrastructure in the region are located—as well as in reliability-challenged areas across the northern portion of the service territory
- More than 560 automated feeder switches; monitoring equipment to measure loads and voltages at the device and communicate information on line loadings, voltage levels, and fault data
- Advanced Distribution Management System (ADMS) for controlling system operations

FLISR Operations: The key technologies for CenterPoint's FLISR operation are the intelligent grid switching devices (IGSD). The IGSDs comprise a comprehensive package of technologies installed on distribution feeders that perform a number of integrated grid functions. The switches, for example, use enclosures similar to line reclosers to provide reliable switching operations across thousands of operations without maintenance. IGSDs also includes monitoring equipment to measure load and voltage accurately and enable power quality analysis at the device. The system uses data storage and communications control packages that perform analytics and securely communicate rapidly with processors at both the substation and at the utility's central computing location.

CenterPoint's ADMS manages FLISR operations beginning March 2015. ADMS replaces CenterPoint's legacy DMS, outage management system (OMS), and distribution supervisory control and data acquisition (SCADA) systems and allows the utility to use real-time smart meter and IGSD data to better plan, engineer, and operate the grid. ADMS also integrates with the company's geographic information systems (GIS), customer information systems (CIS), transmission management system, and many other back-office applications. ADMS capabilities include near-real time distribution load flow data capture and a platform for controlling FLISR operations. Figure 3 shows CenterPoint's distribution management system in 1993 and in 2014, illustrating how new technologies have made system operations increasingly digital.

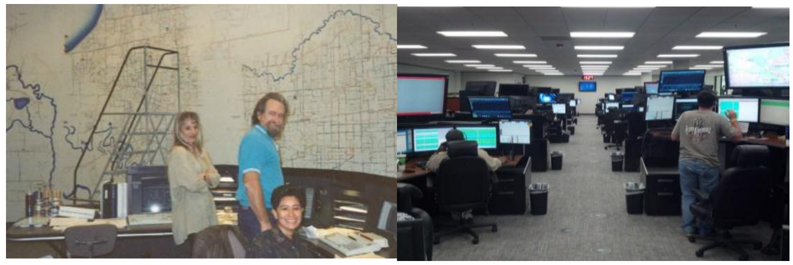

Figure 3. CenterPoint DMS – 1993 and 2014.

2.2 Duke Energy

Duke serves more than 7 million customers in six states: Indiana, Florida, Kentucky, North Carolina, Ohio and South Carolina. Duke operates more than 30,000 line-miles of transmission, 260,000 line-miles of distribution, 530 transmission substations, 1,250 distribution substations, and owns almost 50 gigawatts of electric generation capacity. Duke is currently implementing a 10-year plan to deploy smart grid technologies and systems across its footprint of regulated utility companies. Figure 4 shows a service territory map.

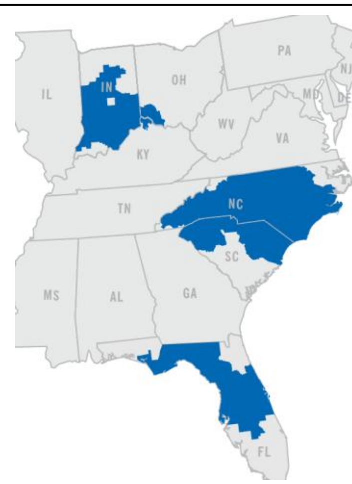

Figure 4. Duke Service Territory Map.

Duke's multi-faceted SGIG project has a total budget of almost $556 million, including DOE funding of $200 million under the Recovery Act. The project includes deployment of a variety of technologies and systems:

- More than 1 million smart meters in North and South Carolina and Ohio, communication networks, and systems for meter data management
- DA devices such as remote fault indicators, automated feeder switches, equipment condition monitors, and automated capacitors

- Distribution management systems and SCADA upgrades
- Customer systems such as in-home displays, web portals, and time-based rate programs
- Residential and commercial electric vehicle charging stations in North and South Carolina and Indiana

Figure 5 shows the electronic reclosers, control units, and line monitors deployed by Duke.

Figure 5. Electronic Reclosers, Control Units, and Line Sensors Installed by Duke.

FLISR Operations: Duke installed "Self-Healing Teams" of field devices for FLISR operations. The teams of devices include centrally located control software, and field installed electronic reclosers and switches that use digital-cell or radio communications. The device teams connect electronic reclosers and circuit breakers from two or three neighboring feeders and enable them to operate together in an integrated manner. These devices measure and digitally communicate information regarding distribution line loadings, voltage levels, and fault data to a central application that remotely locates and isolates faulted distribution line sections and automatically restores service to non-faulted line sections.

Duke used the following criteria to select the most advantageous feeders to implement Self-Healing Teams: feeder outage histories, availability of communications installations, and the number and type of customers on the feeder. Line sensors are placed at strategic locations along the feeder lines to help identify long-lasting faults and outages and enhance the utility's response for accelerating restoration of services. Data from the line sensors are communicated to the utility's control room.

2.3 NSTAR Electric Company

NSTAR serves about 1.1 million customers in Massachusetts, including Boston, and operates about 700 line-miles of transmission, almost 8,000 line-miles of distribution, about 1,950 feeders, and 220 distribution substations. It has a summer peak demand exceeding 4,500 megawatts. Figure 6 shows a service territory map.

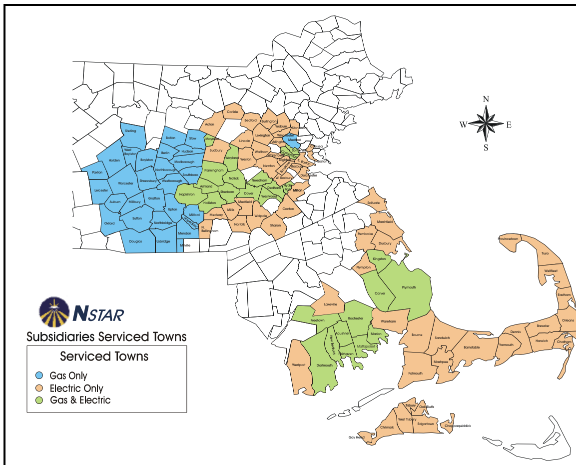

Figure 6. NSTAR Service Territory Map.

NSTAR's SGIG project has a total budget of about $20 million, including about $10 million in DOE funds under the Recovery Act. The project includes deployment of DA equipment for about 400 feeders, about 360 automated feeder switches, about 100 automated capacitors, and equipment condition monitors. These devices, which include auto-sectionalizing units, operate in NSTAR's auto restoration loop system, which accomplishes FLISR operations. Figure 7 shows reclosers and controls deployed by NSTAR for FLISR operations.

Figure 7. Recloser and Controls Deployed by NSTAR.

FLISR Operations: NSTAR deployed about 166 auto restoration loops and conducted FLISR operations in three modes. Mode 1 is a supervisory mode, where switching schemes and restoration sequences are determined and controlled by operators. This is NSTAR's legacy mode of operations prior to SGIG. Mode 2 is an operational acknowledgement mode where restoration sequences are determined based on computer simulations. However, operators must validate the sequence manually before switching commands are executed. Mode 3 is an auto-restoration mode where execution of restoration sequences is fully automated and does not require manual validations.

The automated switches are remotely monitored and controlled using two-way radios, which help the dispatchers to quickly switch around main line circuit problems, and restore as many customers as possible, usually in less than five minutes. All 166 auto restoration loops were tested using Mode 2 and transitioned to Mode 3 operations in 2013.

2.4 Pepco Holdings, Inc. (PHI)

PHI serves approximately 2 million customers through three utilities in Delaware, Maryland, New Jersey, and Washington, D.C. PHI implemented three SGIG projects for Pepco-DC, Pepco-MD, and Atlantic City Electric (ACE). Figure 8 shows a map of PHI's service territories.

Pepco-DC's SGIG project has a total budget of almost $93 million, including almost $45 million in DOE funding under the Recovery Act. This project includes deployments of advanced metering infrastructure (AMI), DA, and direct load control (DLC). Pepco-MD's SGIG project has a total budget of more than $213 million including almost $105 million in DOE funding under the Recovery Act. This project also includes deployments of AMI, DA, and DLC. Finally, PHI-ACE's SGIG project has a total budget of almost $38 million, including almost $19 million of DOE funds under the Recovery Act. This project includes deployments of DA and DLC.

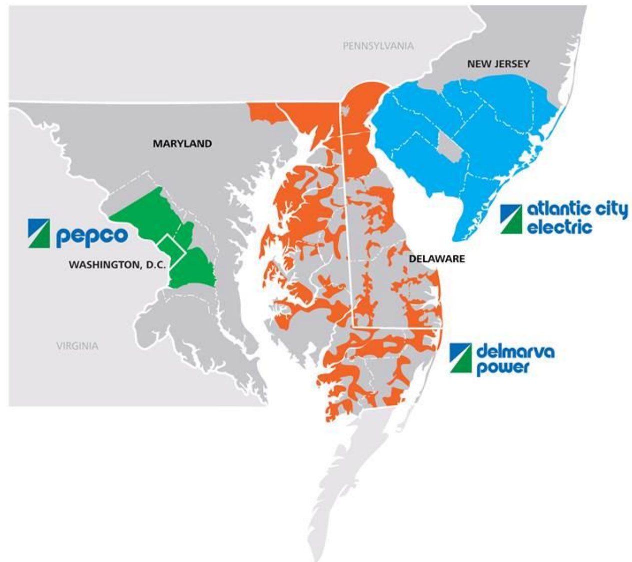

Figure 8. PHI Service Territories Map.

FLISR Operations: All three of PHI's SGIG projects deployed comparable technologies and systems for the DA portions of their projects. Project deployments associated with FLISR included automated feeder reclosers and switches, associated controllers, smart relays, electronic substation relays, distributed remote terminal units in substations, and automated sectionalizing restoration systems for FLISR operations. Table 3 provides a breakdown of equipment installed across the three projects.

Table 3. Breakdown of PHI's Device Deployment for FLISR Operations

Devices	PHI-DC	PHI-MD	PHI-ACE	Totals
Automated Feeder Reclosers &Switches	42	103	164	**301**
Recloser & Switch Controllers	64	205	164	**433**
Smart Relay Upgrades	306	466	55	**827**
Substation DRTUs	6	23	8	**37**
Number of Feeders	**19**	**67**	**27**	**113**
Number of Substations Involved	**9**	**23**	**8**	**40**

PHI's goal for automated sectionalizing and restoration (ASR)—PHI's name for FLISR—involved targeting worst-performing feeders and those experiencing multiple yearly lockouts, which make up about 10%-15% of its systems. The 113 feeders that received SGIG equipment make up about 6% of PHI's Pepco and ACE systems. PHI's ASR schemes segment feeders into two, three, or four sections using closed remote-controlled switches or automatic circuit reclosers in the field. For any fault in one section, ASR first opens closed switches to isolate the faulted section, and then restores the non-faulted sections by reclosing feeder breakers and/or closing open tie switches to other feeders. Figure 9 shows a screen shot of PHI's ASR operations.

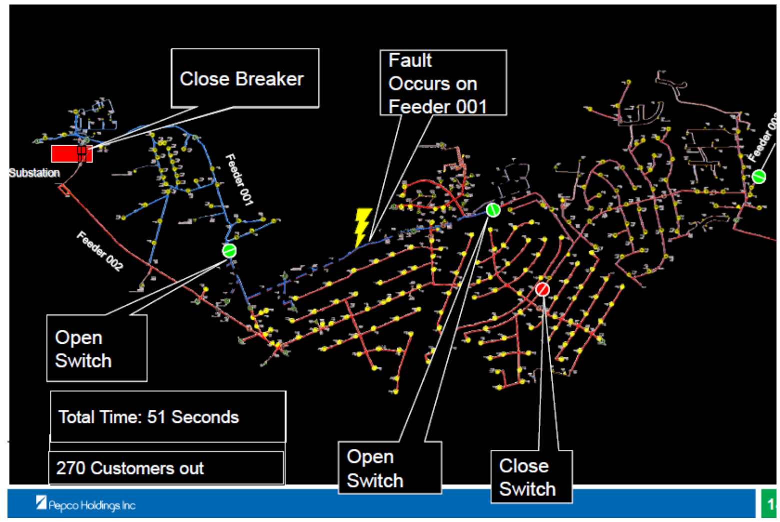

Figure 9. Screen Shot of PHI Demonstration of ASR Operations.

Generally ASR operates in less than a minute. ASR programs run on hardened computers in substations, and communicate with substation breakers, and automated field reclosers and switches. The automated circuit recloser and switch controllers gather field intelligence and device status, and send the information through packet radio networks. When breakers or reclosers open, the ASR program automatically reviews the field intelligence and sends commands to restore as many customers as possible. If necessary, the program communicates with other substations to use their feeders to restore load, based on pre-fault loads to ensure that switching won't cause overloads.

2.5 Southern Company

Southern serves more than 4.4 million customers across four operating companies: Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. Southern operates about 27,000 line-miles of transmission, 143,000 line-miles of distribution, more than 4,700 feeders, and more than 3,300 distribution substations. It owns about 42 gigawatts of electric generation capacity. Figure 10 shows a map of Southern's four operating utilities.

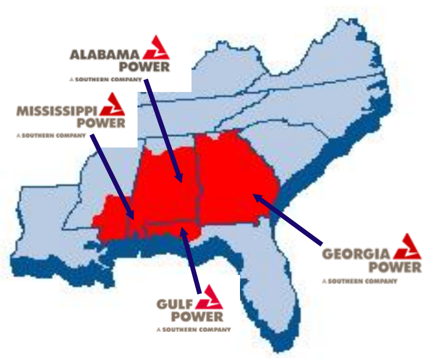

Figure 10. Southern Service Territories Map.

Southern's SGIG project has a total budget of more than $330 million, including more than $164 million of DOE funds under the Recovery Act. The project includes deployment of automated feeder switches, automated capacitors and voltage regulators, and equipment condition monitors for more than 320 feeders. It also includes smart relays and upgrades for SCADA communication networks at more than 350 substations, and distribution management systems for monitoring grid conditions and conducting FLISR operations.

FLISR Operations: DA technologies and systems involve smart grid applications such as automated controls for voltage and reactive power management and automated feeder switching for self-healing grids. Southern's integrated distribution management system (IDMS) monitors data streams from a variety of systems including meter data management, outage management, and the DA communications infrastructure, which connects to automated switchers, reclosers, and line monitors—the devices used for accomplishing FLISR operations. Figure 11 shows a typical DMS workstation used by Southern.

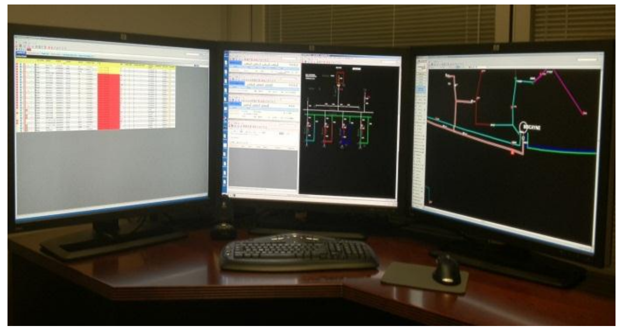

Figure 11. Typical DMS Workstation Deployed by Southern's Operating Utilities.

Each of the operating companies carries out its own DA projects. For example, Georgia Power operates 100 self-healing network schemes involving more than 250 feeders serving more than 360,000 customers. Summer peak demand for these customers exceeds 2.6 gigawatts. More than 840 smart feeder relays were installed at Georgia Power under SGIG.

Alabama Power's smart healing networks involve 440 feeders serving more than 198,000 customers. Alabama Power operates about 75 self-healing networks in centralized mode and about 365 feeders using non-centralized self-healing networks. Figure 12 shows an operational dashboard for Alabama Power's DMS.

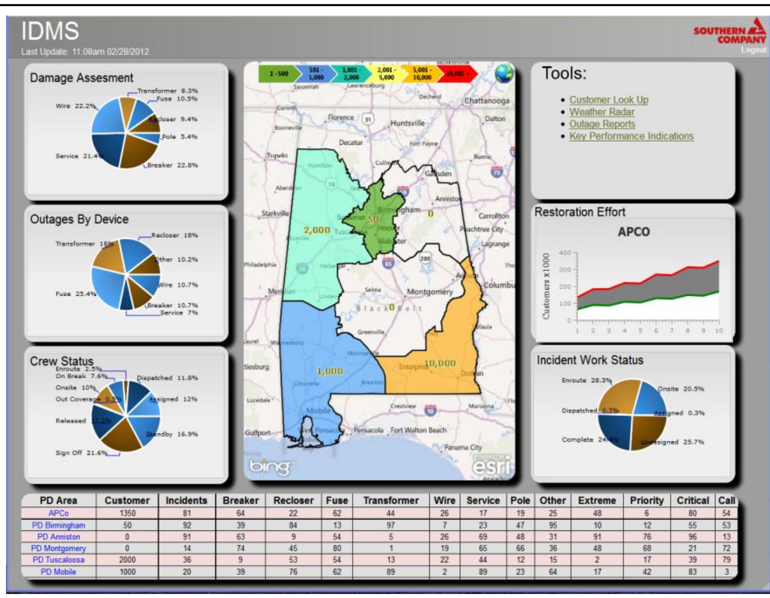

Figure 12. Alabama Power's DMS Operational Dashboard.

Gulf Power operates a total of 550 automated reclosers. Gulf Power operates 14 self-healing network schemes with 36 reclosers on 28 feeders. Gulf Power deployed two different types of schemes. For critical loads, Gulf installed a high-speed automatic source-transfer scheme. This scheme requires two smart controllers that communicate peer-to-peer using fiber optic communications systems. For area loads, Gulf Power installed an automatic network reconfiguration scheme which requires three smart controllers that communicate peer-to-peer using four to six radio transceivers. In addition, Gulf installed 16 additional fault-indicators on critical structures to help identify and locate issues on hard-to-patrol lines.

Mississippi Power installed 11 self-healing network schemes involving 33 feeders and 98 reclosers. The utility is currently adding three additional schemes involving 18 feeders and more than 34 reclosers.

3. Analysis Results

The 5 utilities with 7 SGIG projects (involving 10 operating companies) use different names, technologies, and systems for FLISR operations. However, the utilities applied similar capabilities for FLISR operations between 2011 and 2014. Between April 2013 and March 2014, the utilities collectively implemented 266 FLISR operating events that resulted in:

- Reduced number of customers interrupted: About **270,000 fewer customers suffered interruptions** (of >5 minutes) compared to estimated outcomes without FLISR.
- Reduced outage impact: Customers experienced about **38 million fewer customer minutes of interruption** compared to estimated outcomes without FLISR.

Five of the utilities provided detailed data for each outage event in that one-year time frame. On average during this time period, FLISR reduced the number of customers interrupted (CI) by up to 45% and reduced the customer minutes of interruption (CMI) by up to 51% for an outage event. The estimated reductions in CI and CMI are generally consistent with utility expectations of system performance.

3.1 Causes of Outages and FLISR Results

FLISR operations responded to outages from a variety of causes. Figure 13 shows a breakdown of outage causes based on feeder level data for the 266 FLISR events. **Trees and vegetation caused the most outages**; **equipment failures, accidents, and wind, weather, and lightning strikes were other significant factors**.

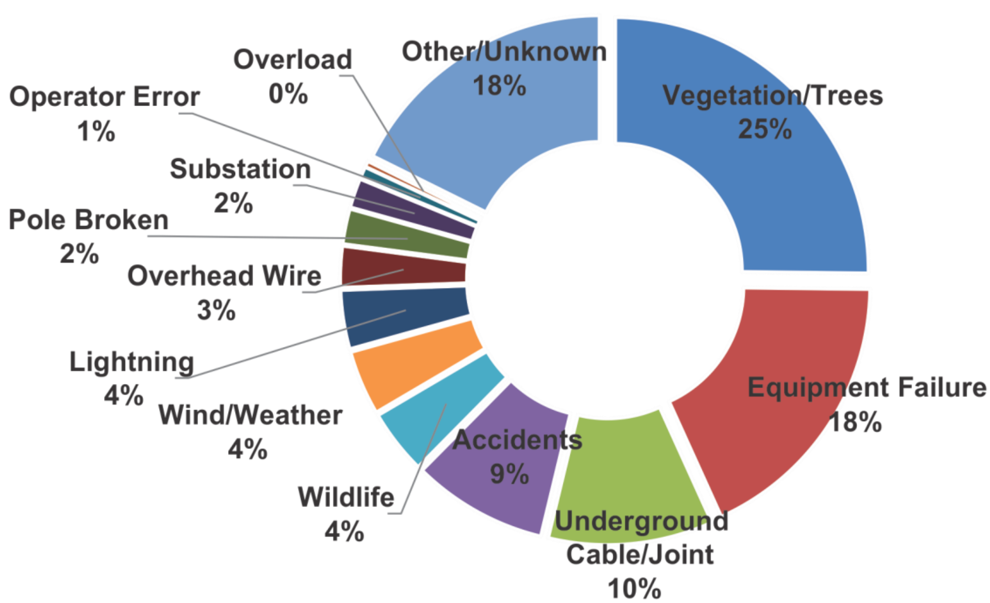

Figure 13. Breakdown of Outage Causes for 266 FLISR Events.

Figure 14 shows the effects of FLISR operations on the number of customers interrupted (in thousands) for each of the causes shown in Figure 13.

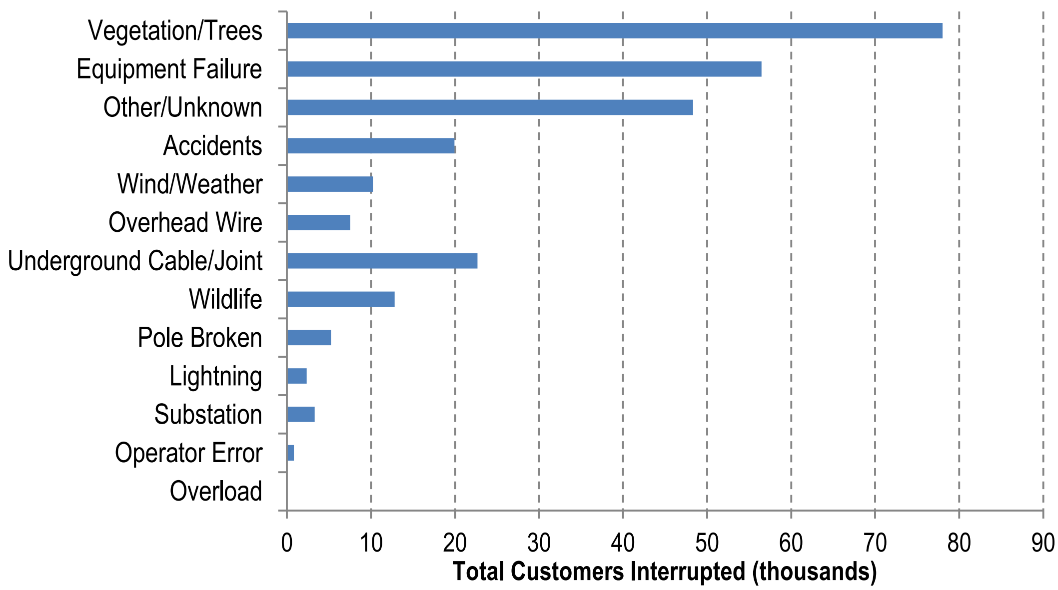

Figure 14. Total Reduction of Number of Customers Interrupted by Cause.

Figure 15 shows the effects of FLISR operations on the customer minutes of interruption (in millions of minutes)—which gives insight into the length of outages—for each of the causes shown in Figure 13.

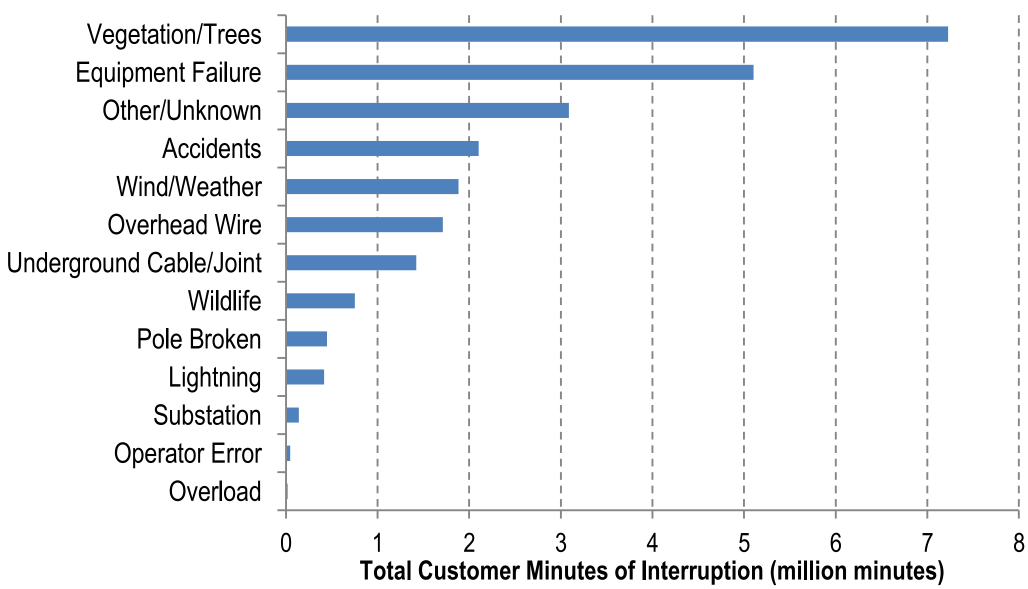

Figure 15. Total Reduction of Customer Minutes of Interruption, by Cause.

FLISR operations can be applied to: (1) full-feeder outages where the fault is upstream of a sectionalizing switch (and thus interrupts service to all customers on a feeder), or (2) partial-feeder outages where the fault is downstream of a sectionalizing switch (and thus interrupts service to a portion of customers on a feeder). Figure 16 provides results for FLISR operations for both full-feeder and partial-feeder outages and shows substantial reductions in the number of customers interrupted and customer minutes of interruption for both types of outages. Table 4 and Table 5 provide supporting data.

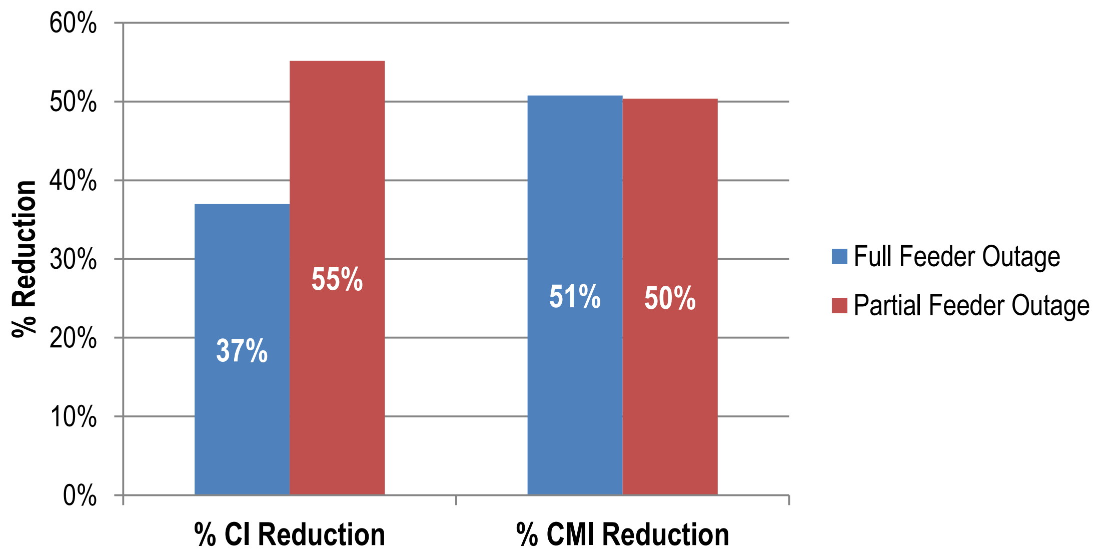

Figure 16. FLISR Effects on the Number of Customers Interrupted and Customer Minutes of Interruption by Type of Outage.

Table 4. Effects of FLISR Operations on Customers Interrupted by Type of Outage

Type of Outage	Total Estimated CMI without SGIG technologies	Total Actual CMI with SGIG technologies	% Reduction as a result of SGIG technologies
Full Feeder Outage	255,424	160,972	37%
Partial Feeder Outage	206,763	92,726	55%

Table 5. Effects of FLISR Operations on Customer Minutes Interrupted by Type of Outage

Type of Outage	Total Estimated CI without SGIG technologies	Total Actual CI with SGIG technologies	% Reduction as a result of SGIG technologies
Full Feeder Outage	18,301,994	9,016,784	51%
Partial Feeder Outage	17,470,615	8,676,751	50%

3.2 FLISR Results by Type of Operating Scheme

The effectiveness of FLISR operations varies by the type of operating scheme employed by the utility. Figure 17 shows the number of customers interrupted and the customer minutes of interruption by type of FLISR operating scheme: (1) remotely controlled with manual validations, or (2) fully automated control and validation. Table 6 and Table 7 provide that data behind the percent reductions shown in Figure 17.

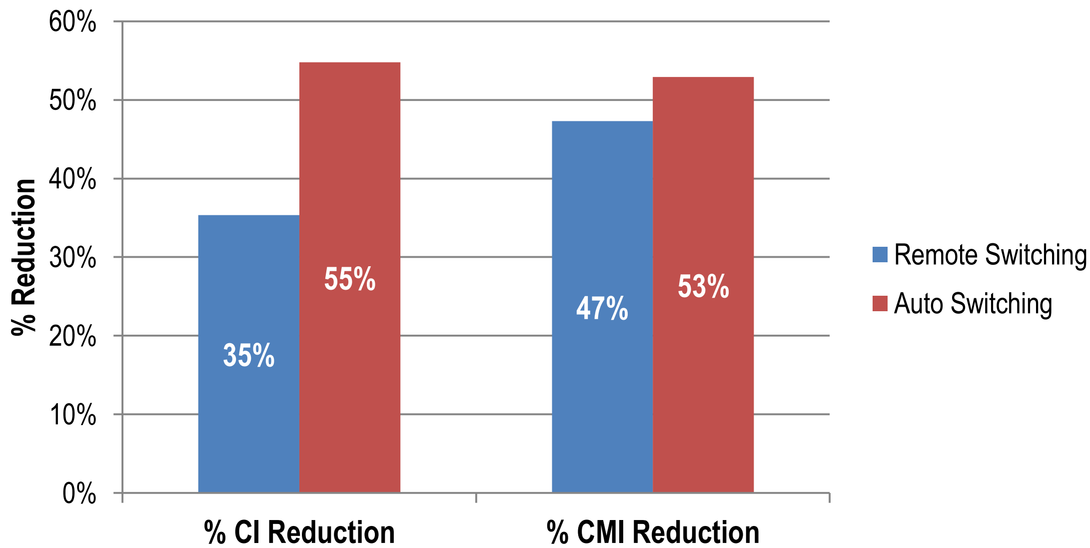

Figure 17. FLISR Effects on the Number of Customers Interrupted and Customer Minutes of Interruption by Type of Operating Scheme.

Table 6. FLISR Systems' Impact on Customer Minutes of Interruption by Type of Switching

Type of Switching	Total Estimated CMI without SGIG technologies	Total Actual CMI with SGIG technologies	% Reduction as a result of SGIG technologies
Operator-Initiated	15,037,440	7,926,425	47%
Fully Automated	20,735,169	9,767,110	53%

Table 7. FLISR Systems' Impact on Customers Interrupted by Type of Switching

Type of Switching	Total Estimated CI without SGIG technologies	Total Actual CI with SGIG technologies	% Reduction as a result of SGIG technologies
Operator-Initiated	230,388	148,917	35%
Fully Automated	231,799	104,781	55%

Remote switching operations that are manually validated by control room operators typically suffer from time lags that do not occur with fully automated switching. The electric power industry defines sustained outages as service interruptions that last five minutes or longer; as a result, manually validated FLISR operations typically have less impact on CI than automated FLISR operations.

4. Lessons Learned and Future Plans

The technologies and systems for successful FLISR operations have different features and operating characteristics than traditional electric distribution assets. Communication networks and software for control and system management often require more frequent maintenance and are subject to more frequent upgrades. These features require utilities to evaluate existing business processes and practices; increase training for grid operators, engineers, and technicians; and implement new procedures for cybersecurity protections. The utilities faced a number of challenges in these areas and shared learned lessons about how to overcome them.

4.1 Lessons Learned – Communication Networks

One of the key lessons learned involves the communications infrastructure that is critical to achieving benefits from FLISR operations. **The utilities found that communication networks require greater resilience than power delivery systems because they must be able to control automated switches under conditions where the grid system is damaged or not functioning** properly due to downed lines, faults, or other grid disturbances.

Utilities considering investments in FLISR would benefit from comprehensive evaluations for communications requirements from the start of project planning. For example, NSTAR learned that less-than-robust radio communications can interfere with distribution automation operations. NSTAR's communications network for DA was in place when automated switches, reclosers, and line monitors for FLISR operations were being installed; in several instances, the network lacked radio coverage to accomplish required tasks. Figure 18 shows a schematic of FLISR communications architecture deployed by NSTAR. **Utilities with legacy communication networks should conduct evaluations and implement upgrades before deploying FLISR technologies and systems**.

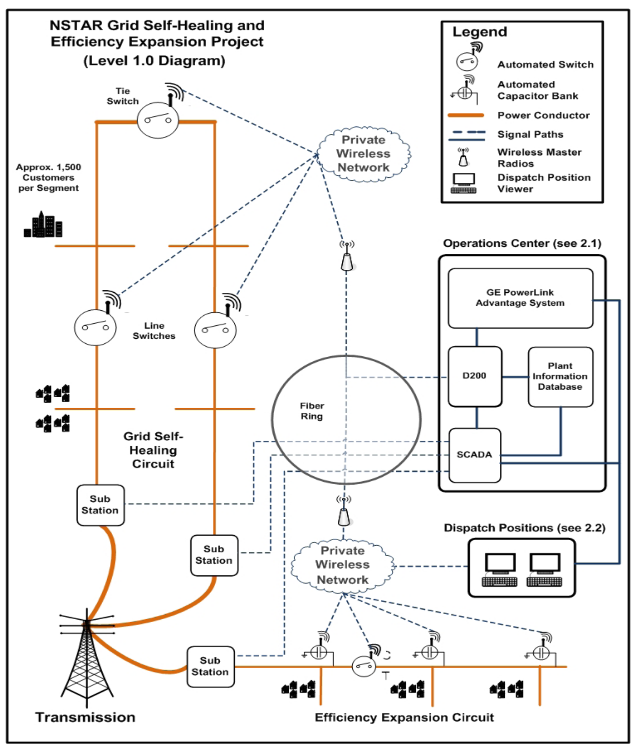

Figure 18. Schematic of Communications Architecture at NSTAR.

4.2 Lessons Learned – Deployment of New Devices and Systems

Several of the utilities learned that successful deployments of FLISR technologies and systems require additional steps and considerations that do not necessarily follow traditional utility asset management practices. Conducting simulation modeling and system and equipment testing proved essential in reducing deployment errors because testing validated interoperability and network connections. This demonstrated continued need to develop simulation models and tools. Figure 19 shows a recloser testing facility at CenterPoint.

Figure 19. Testing Facility for Reclosers at CenterPoint.

Georgia Power developed a DNP simulator that was independent of either SCADA or the FLISR systems. The simulator eliminated the need for field trials. The DNP simulator was used for operator training as well as scenario testing of the vendors' SCADA and FLISR software.

Because automated devices often require more frequent firmware and software upgrades—as well as customized refinements to meet the unique needs of various distribution system configurations—**more frequent field tests and evaluations were often required**. To address this, PHI is moving towards remote "over-the-air" upgrade capabilities to reduce the amount of time needed to implement changes in the field when new software versions become available. Figure 20 shows examples of these automated field devices, deployed by Southern's operating companies, which may require more frequent firmware and software upgrades and testing.

Figure 20. Automated Line Reclosers, Sectionalizing Switches, and Line Sensors Deployed by Southern.

4.3 Lessons Learned – Business Practices and Training

New continuing maintenance processes and practices were essential for SGIG utilities. For example, battery failures are among the most common maintenance issues; addressing this often requires adding redundant power sources and implementing proactive battery replacement programs. Equipment condition monitoring devices can be deployed for remote evaluations.

Vendors typically play a critical role in implementation, and several of the utilities found they needed hands-on interactions to customize product and service offerings to meet utility- and feeder-specific needs. For example, Southern found that standard vendor templates were not always optimal for the varying system configurations in its services territories. Southern required 20 feeder templates for its systems rather than the 2 or 3 initially offered by vendors.

CenterPoint found **working closely with vendors throughout the entire process for quality assurance and commissioning resulted in fewer miscommunications and oversights**, and ultimately enabled faster field device interoperability. New procedures for change management and vendor-related communication protocols are helpful for ensuring deployment success.

Education and training programs for headquarters and field staff about the requirements of the new devices and systems are essential. The utilities found implementation of FLISR systems resulted in significant process changes that require greater expertise in information systems, database management, and grid analytics. Use of cross-functional teams helped several of the utilities to find multi-disciplinary solutions. Technical teams of software and hardware engineers, data analysts, and business process specialists were typically required for success. Several utilities found field staff required the most time and attention to learn new equipment capabilities and gain confidence in its proper operations.

4.4 Future Plans

Several of the utilities are moving forward with refining FLISR operations and expanding their application to include new features and cover more substations and feeders.

CenterPoint plans to expand the capabilities of its IGSD systems from requiring manual validations, to fully automating FLISR operations. More experience is required to ensure that field devices and central distribution management systems operate properly and meet company requirements for accuracy and reliability. Full automation will be tested on a limited number of substations and feeders before larger-scale deployments are implemented.

Duke plans to complete its 10-year strategy for grid modernization and expand deployments of self-healing teams to additional substations and feeders with focus on areas in Indiana, Kentucky, Florida, and the Carolinas.

NSTAR plans to continue deploying automated feeder switching and related equipment on additional feeders where cost-effective.

PHI plans to continue its automatic sectionalizing and restoration deployments with the goal of reaching 10%-15% of their systems, including expansion into areas covered by Delmarva Power. Existing deployments primarily target individual feeders based on reliability performance; where cost-effective, plans would include expanding coverage to other feeders in the vicinity of existing ASR schemes.

Southern plans on moving forward with the integration of its distribution management and outage management systems, and create single user interfaces for grid operators. Plans also include expanding coverage of self-healing networks within its operating utilities to further reduce service interruptions for customers. By the end of the second quarter of 2015, Georgia Power plans to have all of its automated normal open points controlled by a centralized FLISR system.

5. Where to Find Additional Information

To learn more about national efforts to modernize the electric grid, visit the Office of Electricity Delivery and Energy Reliability's **website** and **www.smartgrid.gov**. DOE has published several reports that contain findings on topics similar to those addressed in the projects featured in this report. Web links are provided in Table 8.

Table 8. Web Links to Related DOE Reports	
SGIG Program, Progress, and Results	i. Progress Report II, October 2013 ii. Progress Report I, October 2012 iii. SGIG Case Studies
SGIG Analysis Reports	iv. Application of Automated Controls for Voltage and Reactive Power Management – Initial Results, December, 2012 v. Reliability Improvements from Application of Distribution Automation Technologies – Initial Results, December, 2012
Recent Publications	vi. Smart Meter Investments Yield Positive Results in Maine, February 2014 vii. Smart Meter Investments Benefit Rural Customers in Three Southern States, March 2014 viii. Control Center and Data Management Improvements Modernize Bulk Power Operations in Georgia, August 2014 ix. Using Smart Grid Technologies to Modernize Distribution Infrastructure in New York, August 2014 x. Automated Demand Response Benefits California Utilities and Commercial & Industrial Customers, September 2014 xi. New Forecasting Tool Enhances Wind Energy Integration in Idaho and Oregon, September 2014 xii. Automated Demand Response Benefits California Utilities and Commercial & Industrial Customers, September 2014 xiii. Integrated Smart Grid Provides Wide Range of Benefits in Ohio and the Carolinas, September 2014 xiv. Municipal Utilities' Investment in Smart Grid Technologies Improves Services and Lowers Costs, October 2014 xv. Smart Grid Investments Improve Grid Reliability, Resilience, and Storm Response xvi. Evaluating Electric Vehicle Charging Impacts and Customer Charging Behaviors - Experiences from Six Smart Grid Investment Grant Projects