U.S. DEPARTMENT OF ENERGY

Electricity Delivery & Energy Reliability

American Recovery and Reinvestment Act of 2009

Reliability Improvements from the Application of Distribution Automation Technologies – Initial Results

Smart Grid Investment Grant Program

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RECOVERY ACT SMART GRID PROGRAMS

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Executive Summary

The U.S. Department of Energy (DOE), Office of Electricity Delivery and Energy Reliability (OE), is implementing the Smart Grid Investment Grant (SGIG) program under the American Recovery and Reinvestment Act of 2009. The SGIG program involves 99 projects that are deploying smart grid technologies, tools, and techniques for electric transmission, distribution, advanced metering, and customer systems.[1]

Of the 99 SGIG projects, 48 are seeking to improve electric distribution system reliability. In general, these projects seek to achieve one or more of the following distribution reliability objectives: (1) reducing the frequency of both momentary and sustained outages, (2) reducing the duration of outages, and (3) reducing the operations and maintenance costs associated with outage management.

Achieving these demand-side objectives result in the following benefits:

- Higher levels of productivity and financial performance for businesses and greater convenience, savings from less food spoilage, and avoidance of medical and safety problems for consumers
- Enhanced system flexibility to meet resiliency needs and accommodate all generation and demand-side resources
- Lower costs of electricity and more opportunities to keep rates affordable

This report presents information about these projects on the types of devices and systems being deployed, deployment progress as of June 30, 2012, expected benefits, and initial results. The report discusses the new capabilities being implemented including enhanced outage detection, automated feeder switching, and remote diagnosis and notification of the condition of distribution equipment. Of the 48 SGIG electric distribution reliability projects, 42 are implementing automated feeder switching making it the most prevalent approach in the SGIG program for achieving distribution reliability objectives.

Analysis of Initial Results

Most of the distribution reliability projects are in the early stages of implementation and have not finished deploying, testing, and integrating field devices and systems. However, four

[1] For further information, see the *Smart Grid Investment Grant Program Progress Report*, July 2012, which can be found at www.smartgrid.gov.

projects reported initial results to DOE-OE based on operational experiences through March 31, 2012. They are called "initial results" because the four projects are still optimizing their systems and they represent only about 10% of the 42 SGIG distribution reliability projects that are deploying automated feeder switching. Additional data received over the next two years will be needed to obtain a better understanding of the impacts.

Table ES-1 provides a summary of the initial results from the four projects, and covers a total of 1,250 distribution feeders. The table shows the changes in the major reliability indices due primarily to automated feeder switching and is based on a range of results that were measured during summer and winter periods from April 1, 2011 to March 31, 2012.[2]

The reliability indices shown in the table are the ones commonly used by the electric power industry to estimate changes in reliability.[3] The changes were calculated from baselines that the projects estimated using at least three years of historical data. Negative changes indicate the reliability indices are improving while positive changes indicate the reliability indices are getting worse. The results show a range of observed reliability changes from automated feeder switching, with SAIFI and MAIFI showing improvements in all cases, and SAIDI and CAIDI showing mixed results.

Reliability Indices	Description	Range of Percent Changes
SAIFI	System Average Interruption Frequency Index (outages)	-11% to -49%
MAIFI	Momentary Average Interruption Frequency Index (interruptions)	-13% to -35%
SAIDI	System Average Interruption Duration Index (minutes)	+4% to -56%
CAIDI	Customer Average Interruption Duration Index (minutes)	+29% to -15%

Table ES-1. Changes in Reliability Indices from Automated Feeder Switching

Observations

Additional information will be collected and analyzed across more projects, feeders, and time periods to develop a more comprehensive understanding of the changes in reliability. Observations from the initial results include:

[2] Projects used the IEEE Guide for Electric Power Distribution Reliability Indices – Standard 1366TM-2003 and excluded major events.

[3] Appendix A provides definitions and the formula for calculating the reliability indices and Appendix B provides benchmark information for these indices.

- Projects with automated feeder switching were able to reduce the frequency of outages, the number of customers affected by both sustained outages and momentary interruptions, and the total amount of time that customers were without power (as measured by customer minutes interrupted). In general, these changes were in line with the expectations of the projects.
- Projects are generally applying automated feeder switching to their worst performing feeders. The results show that the greatest percentage improvements in reliability from automated feeder switching occur when applied on the worst performing feeders.
- In most cases, the projects were not yet using the full set of automated capabilities. For example, many projects also plan to use distribution management systems for accomplishing automated feeder switching, and none of the four reporting projects had this feature fully operational yet. This underscores the need for further data and analysis as many of the projects plan to use this feature in the future.
- Several of the projects had more prior experience with automated feeder switching than others. The projects report a substantial learning curve for grid operators, equipment installers, and field crews in figuring out the full set of capabilities and how to use them to their best advantage. The projects with more experience reported having more confidence in the grid impacts and reliability improvements they observed.
- Projects pursued both centralized and distributed forms of control systems for automated feeder switching, depending on their circumstances and objectives. The relative merits of these two approaches, and the circumstances when they best apply, are important considerations.
- The initial results raise questions about the usefulness of CAIDI as an index for measuring the effects of automated feeder switching on the duration of customer interruptions. This is because automated feeder switching generally reduces the number of customers experiencing sustained outages (reducing the denominator of the index), relative to the duration of the sustained outages (expressed in the numerator.)

Next Steps

As discussed, the focus of this report is on the impacts of automated feeder switching. Future reports will analyze automated feeder switching in greater detail and with more data. In addition, the impacts of other distribution reliability capabilities will also be analyzed including fault and outage detection and notification, and equipment health monitoring. Improvements in operations and maintenance costs from distribution reliability upgrades will also be assessed. DOE-OE will continue to work with the projects and other industry stakeholders to assess these smart grid applications and their effects on the reliability indices.

While all of the 48 SGIG distribution reliability projects will ultimately have important information and findings to share, DOE-OE will focus its analysis on the ones that are most able to provide quantitative data and results. In the next year, many more of the projects will be measuring changes in distribution reliability, including the four included in this report. DOE-OE plans to conduct follow-up analysis presenting additional results from SGIG distribution reliability projects in the future. In the meantime, updates on deployment progress and case studies highlighting project examples are posted regularly on www.smartgrid.gov.

1. Introduction

The U.S. Department of Energy (DOE), Office of Electricity Delivery and Energy Reliability (OE), is implementing the Smart Grid Investment Grant (SGIG) program under the American Recovery and Reinvestment Act of 2009. The SGIG program involves 99 projects that are deploying smart grid technologies, tools, and techniques for electric transmission, distribution, advanced metering, and customer systems. DOE-OE recently published the *Smart Grid Investment Grant Program Progress Report* (July 2012) to provide information about the deployment status of SGIG technologies and systems, examples of some of the key lessons learned, and initial accomplishments.[4]

DOE-OE is analyzing the impacts, costs, and benefits of the SGIG projects and is presenting the results through a series of impact analysis reports. These reports cover a variety of topics, including:

- Peak demand and electricity consumption reductions from advanced metering infrastructure, customer systems, and time-based rate programs
- Operational improvements from advanced metering infrastructure
- Reliability improvements from automating distribution systems
- Efficiency improvements from advanced volt/volt-ampere reactive (VAR) controls in distribution systems
- Efficiency and reliability improvements from applications of synchrophasor technologies in electric transmission systems

1.1 Purpose and Scope

This impact analysis report presents information on the 48 SGIG projects seeking to improve electric distribution system reliability, specifically the types of devices being deployed, systems being implemented, deployment progress, expected benefits, and initial results. In general, the SGIG electric reliability projects seek to achieve one or more of the following distribution reliability objectives: (1) reducing the frequency and customers affected by both momentary and sustained outages, (2) reducing the duration of outages, and (3) reducing the operations and maintenance costs associated with outage management. In achieving these objectives, the projects are applying a variety of new capabilities including enhanced fault and outage detection and notification, automated feeder switching, and remote diagnosis and notification of the condition of distribution equipment.

[4] DOE-OE, *Smart Grid Investment Grant Program Progress Report*, July 2012, www.smartgrid.gov.

Most of the 48 SGIG distribution reliability projects are in early stages of implementation and have not finished deploying, testing, and integrating the smart grid devices and systems. The data in this report represent the first time the projects have reported impacts. Four of the projects, representing 1,250 feeders, have reported to DOE-OE about initial results based on operational experiences through March 31, 2012. The four projects upgraded 870, 185, 120, and 75 feeders, respectively. The initial results presented in this report include feeders that have automated feeder switching installed and operational, but the equipment has not yet been fully integrated with distribution management systems.

Grid impact information is reported to DOE-OE by the projects as averages over six-month periods and is compared with pre-established baselines. Baselines were calculated by each project using three or more years of historical data and covering time periods before distribution automation devices and systems were implemented.

1.2 Background on Electric Distribution Reliability

The reliability of electric distribution systems is critically important for both utilities and customers. Electric reliability affects public health and safety, economic growth and development, and societal well-being. Many utilities estimate the value of electric services to consumers to assess the benefits of investments to improve reliability.[5]

Most power outages are caused by weather-related damage to overhead power lines. High winds, ice, and snow can cause trees to touch power lines, and sometimes can cause lines and poles to break. Animal contact, vehicle accidents, equipment failure, and human error also contribute to power outages.

Power outages in electric distribution systems are documented and classified by the number of customers affected and the length of time that power is out. The Institute of Electrical and Electronic Engineers (IEEE) specifies three types of outages:

- **Major Events** are those that exceed the reasonable design and/or operational limits of the electric power system and affect a large percentage of the customers served by the utility.[6]

[5] Lawrence Berkeley National Laboratory, "Estimated Value of Service Reliability for Electric Utility Customers in the United States" LBNL-2132E, June 2009.

[6] The recently published IEEE Standard 1366™ – 2012 contains the preferred approach for determining major events. However, this standard was not available at the time the analysis presented in this report was conducted.

- **Sustained Interruptions** include outages not classified as momentary events and that last for more than five minutes.
- **Momentary Interruptions** involve the brief loss of power to one or more customers caused by opening and closing of interruption devices.

Reliability indices are commonly used to assess outages and evaluate the performance of electric systems. For the SGIG program, DOE-OE requested that the projects use the definitions and calculation methods listed in the IEEE Guide for Electric Power Distribution Reliability Indices – IEEE Standard 1366™-2003.[7] These are the standard indices used by the electric power industry and provide a uniform methodology for data collection and analysis. Major event days are excluded from the indices to better reveal trends in daily operations.

The indices used for the analysis include:

- System Average Interruption Frequency Index (SAIFI)
- Momentary Average Interruption Frequency Index (MAIFI)
- System Average Interruption Duration Index (SAIDI)
- Customer Average Interruption Duration Index (CAIDI)

1.3 Organization of this Report

Section 2 of this report provides information on the types of devices and systems being deployed by the SGIG electric distribution reliability projects and their expected benefits. Section 3 provides information on the status of deployment including details about the specific reliability objectives the projects are trying to achieve. Section 4 provides a summary of the DOE-OE analysis of the four distribution reliability projects that reported initial results. Section 5 discusses next steps for DOE-OE analysis of the SGIG electric distribution reliability projects.

Four appendices provide supplementary information. Appendix A provides information on the definitions of the reliability indices. Appendix B provides benchmark data on the reliability indices from the IEEE Distribution Reliability Working Group. Appendix C provides analysis details of the results for the four projects. Appendix D provides a table of the 48 SGIG electric distribution reliability projects, summaries of deployment progress, and certain of the planned implementation activities. Appendix E provides an overview of automated feeder switching operations.

[7] Going forward, IEEE 1366™ – 2012 will be used.

2. Overview of Systems, Devices, and Expected Benefits

This section provides an overview of the devices and systems that the SGIG distribution reliability projects are deploying, as well as the benefits these devices and systems are expected to provide, including:

- Communication networks,
- Information and control systems,
- Field devices, and
- Expected benefits.

To implement automated distribution capabilities properly, it is necessary to integrate communications networks, control systems, and field devices. In addition, testing and evaluation is required to determine whether the equipment is performing as designed. Training of grid operators and field crews is also required to ensure safe and efficient use of the technologies.

For example, smart relays, automated feeder switches, and distribution management systems can be coordinated to implement fault location, isolation, and service restoration (FLISR) operations. It is thus important to understand how the devices and systems work together, in addition to understand how they work on their own, as utilities typically pursue approaches that involve varying degrees of coordination.

2.1 Communications Networks

Communications networks for distribution systems make it possible to acquire data from sensors, process the data, and send control signals to operate equipment. The application of communications networks for these purposes enhances the capabilities of grid operators to manage power flows and address reliability issues.

Most utilities use multi-layered systems to communicate between information and control systems and field devices. In many cases, two-layer communications networks are used. Typically, the first layer of the network connects substations and distribution management systems at headquarter locations and consists of high-speed, fiber optic or microwave communications systems. Some utilities use existing supervisory control and data acquisition (SCADA) communications systems for this layer. The second layer of the network typically connects substations with field devices and uses wireless networks or power line carrier communications.

2.2 Information and Control Systems

Equipment Automation Approaches

Automated feeder switching is accomplished through automatic isolation and reconfiguration of segments of distribution feeders using sensors, controls, switches, and communications systems. Automated feeder switches can open or close in response to a fault condition identified locally or to a control signal sent from another location. When combined with communications and controls, the operation of multiple switches can be coordinated to clear faulted portions of feeders and reroute power to and from portions that have not experienced faults. These coordinated actions are called fault location, isolation, and service restoration.

FLISR actions can reduce the number of customers who experience sustained outages and the average duration of outages. The performance of FLISR systems depends on several factors, including (1) the topology of the feeders (i.e., radial, looped, and networked), (2) loading conditions, (3) the number of feeder segments affected, and (4) the control approaches implemented. Appendix E provides examples of feeder switching operations.

In general, there are two main types of automation approaches: centralized and decentralized. Centralized switching involves distribution management systems or SCADA to coordinate automated equipment operations among multiple feeders. Decentralized switching (also sometimes called distributed or autonomous switching) uses local control packages to operate automated equipment on specific feeders according to pre-established switching logics. Many projects are using a combination of centralized and decentralized approaches.

The amount of time it takes to accomplish FLISR actions depends on the sequence of events, field devices, and the extent of latency in the communications systems. Centralized systems take more factors into account when determining switching strategies and take longer to perform FLISR, but they include more switching options if there are loading issues or other complications. Decentralized systems typically switch between a few predetermined feeders and are able to perform FLISR more quickly.

The different feeder switching devices, systems, and approaches depend on the project's objectives, legacy equipment and systems, long-term grid modernization goals, and investment timetables. Projects that seek to address a small group of feeders that are highly vulnerable to outages may favor a distributed approach, while projects that seek to improve reliability for large portions of their service territories may choose a centralized approach. Other aspects of distribution system modernization, such as voltage controls, reactive power management, and asset management also affect investment decisions in feeder switching approaches.

Automated Control Packages

Some utilities are retrofitting existing distribution switches with automated control packages, or installing new switches equipped with these controls. The control packages include computers, user interfaces, and communications systems that enable equipment to be programmed and controlled remotely. Two examples are shown in Figure 1.

Figure 1. Examples of Automated Control Packages

These devices use voltage and current sensors to detect faults. The controllers open and close the switches independently, or in combination with other switches, depending on the programmed logic and system conditions. This capability is essential to balancing feeder loads during FLISR operations without damaging equipment.

Control packages can also be operated remotely by operators or distribution management systems. Depending on the specific needs, control packages can have more complex algorithms that can respond to changing system conditions or operational objectives. For example, with severe storms approaching, switches can be programmed not to reclose based on the expectation that most faults could not be cleared with reclosing. This capability can avoid problems that arise from unnecessary reclosing and from fault currents on portions of the system that would ultimately go out of service because of storm damage.

Distribution Management Systems

Distribution management systems (DMS) integrate different sources of data from sensors, monitors, and other field devices to assess conditions and control the grid. They act as visualization and decision support systems to assist grid operators with monitoring and controlling distribution systems, components, and power flows. DMS are typically used to monitor the system for feeder and equipment conditions that may contribute to faults and outages, identify faults, and determine optimal switching schemes to restore power to the greatest amount of load or number of customers.

A DMS continuously updates dynamic models of the distribution system in near real time so grid operators can better understand distribution system conditions at all times. Changes in system loads, outages, and maintenance issues are presented to operators through dashboards and visualization tools. DMS can also be used as simulators for training grid operators and as tools to analyze restoration responses to various types of outage scenarios. DMS can also be used to automate or support voltage and volt-ampere reactive (VAR) controls, as well as other activities that increase the efficiency of distribution operations and maintenance.

Outage Management Systems

Outage management systems (OMS), as shown in Figure 2, are information management and visualization tools that analyze outage reports to determine the scope of outages and the likely location of problems. An OMS compiles information on the times and locations of customer calls, smart meter outage notifications, and fault data from substations and monitoring devices on feeder lines. Typically, OMS incorporate geographic information systems that are linked to computers used by repair crews so they can get to precise outage locations more quickly and often with a better idea of the problem they will need to solve. In the past, most OMS operated with information limited to customer calls and general information about substation outages and breaker positions. By filtering and analyzing outage information from multiple sources, modern OMS can provide grid operators and repair crews with more specific and actionable information to manage outages and restorations more precisely and cost-effectively, resulting in improved operations.

Figure 2. Example of a Visual Display from an Outage Management System

Utilities also use OMS to communicate outage information to customers, including the likely causes and estimated restoration times. An OMS may be integrated with DMS to provide additional inputs for visualization and decision support that can be beneficial, particularly when addressing large outages and major events.

2.3 Field Devices

Field devices comprise a suite of technologies that are installed along feeder lines and in substations and are used to manage power flows on the grid. Field device operations can be coordinated with information and control systems to achieve electric distribution reliability objectives.

Fault Detection and Automated Feeder Switches

Smart relays and fault analysis applications incorporated with DMS provide greater accuracy in locating and identifying faults and their causes. Remote fault indicators notify grid operators and field crews when faults occur and voltage and current levels are outside normal operating boundaries. Smart relays collect electrical information about faults and use more sophisticated algorithms to help grid operators with diagnostic analysis of the locations and causes of faults.

These devices and systems typically use higher-resolution sensors that are better able to detect fault signatures and identify and address momentary interruptions. Through analysis of fault detection data, utilities can implement corrective actions (e.g., automated feeder switching or vegetation management) and reduce the likelihood of sustained outages. Recent advances in sensor and relay technologies have also improved the detection of high-impedance faults. These faults occur when energized power lines come in contact with foreign objects (e.g., tree limbs), but the contact produces a low fault current. Currents from these types of faults are difficult to detect with conventional relays.

Fault indicators, such as the examples shown in Figure 3, are sensors that detect electric signatures associated with faults, such as high currents or low/no voltages. Fault indicators can have visual displays installed with them to assist field crews and communications networks that are integrated with SCADA or DMS. By monitoring faults and their pre-cursors, utilities can identify problems with equipment or tree contacts with power lines, and initiate corrective actions to prevent sustained outages.

Automated feeder switches open and close in response to control commands from autonomous control packages, DMS, or grid operator commands. Switches can be configured to isolate faults and reconfigure faulted segments of the distribution feeder to restore power. Switches are also configured to open and close at predetermined sequences and intervals when

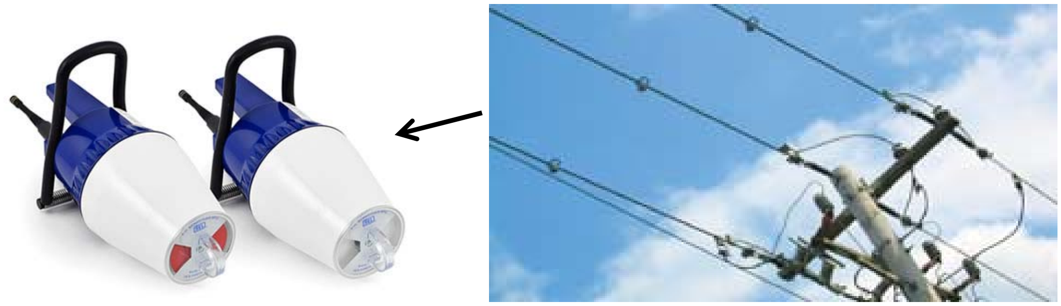

Figure 3. Example Remote Fault Indicator

fault current is detected. This action, known as reclosing, is used to interrupt power flow to a feeder that has been contacted by an obstruction and reenergize after the obstruction has cleared itself from the line. Reclosing reduces the likelihood of sustained outages when trees and other objects temporarily contact power lines during storms and high winds.

Equipment Health Sensors and Load Monitors

Equipment health sensors monitor conditions and measure parameters, such as power transformer insulation oil temperatures, that can reveal possibilities for premature failures. These devices can be configured to measure different parameters on many types of devices. Typically, these devices are applied on substation and other equipment whose failure would result in significant consequences for utilities and customers.

When coupled with data analysis tools, equipment health sensors can provide grid operators and maintenance crews with alerts and actionable information. Actions may include taking equipment offline, transferring load or repairing equipment. Figure 4 provides an overview of an equipment health sensor network for monitoring substation power transformers.

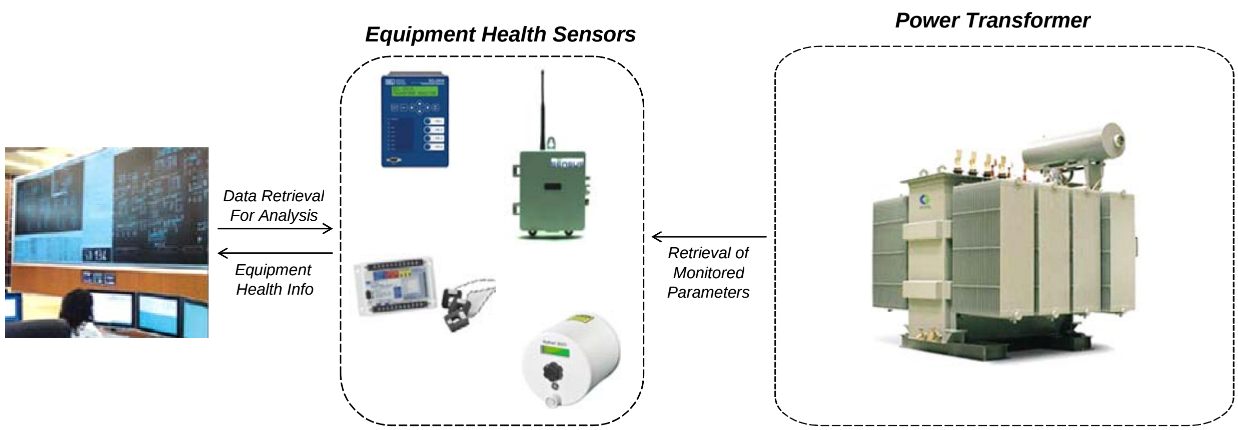

Figure 4. Illustration of an Equipment Health Sensor Network for Power Transformers

Figure 5 is an example of a feeder monitor that can measure load on distribution lines and equipment in near-real time. When data is communicated to grid operators, these measurements can be used to trigger alarms when loads reach potentially damaging levels. Load monitors need to be integrated with communications networks and analysis tools so that grid operators can effectively assess loading trends and take corrective switching actions, when necessary. These field devices are used in coordination with information and control systems to prevent outages from occurring due to equipment failure or overload conditions.

Figure 5. Example Feeder Monitor

Outage Detection Devices and Smart Meters

Until recently, most utilities only realized that customers had lost power when the customers called to report the outage. Not all customers report outages; those who do may do so at different times and few customers report when the power has come back on. Thus utilities have had incomplete information about outage locations, resulting in delayed and inefficient responses. New devices and systems make it possible for utilities to know when customers lose power and to pinpoint outage locations more precisely. This capability improves restoration times and shortens outage durations.

Smart meters are equipped with outage notification capabilities that allow the devices to transmit a “last gasp” alert when power to the meter is lost. The alert includes the meter number, which indicates its location, and a time stamp. Advanced metering infrastructure (AMI) head end systems (HES) process these alerts and can notify grid operators and repair crews which meters lost power and their locations. The HES is normally integrated with an OMS to process outage data from multiple sources and help operators to assess the scope of outages and determine their likely causes.

Smart meters can also transmit “power on” notifications to operators when power is restored. This information can be used to more effectively manage service restoration efforts and help ensure that no other outages have occurred before repair crews are demobilized. Some utilities use an AMI feature that allows them to “ping” meters in affected areas to assess outage boundaries and verify whether power has been restored to specific customers. These capabilities enable field crews to be deployed more efficiently, thus saving time and money.

2.4 Expected Benefits

There are two main types of benefits from deploying smart grid devices and systems to address distribution reliability challenges: reliability improvements and operational savings.

Improved Reliability

Both sustained outages and momentary interruptions have the potential to negatively affect public health and safety, economic activity, and societal well-being. Fewer interruptions for commercial and industrial customers often mean higher levels of output and productivity and lower levels of scrap and spoilage. This affects their financial performance and ability to compete. The benefits of fewer outages for residential customers range from greater convenience, to savings from less food spoilage, to avoidance of medical and safety problems.

Reducing the frequency of outages, as measured by SAIFI and MAIFI, is generally related to a combination of factors including undergrounding, storm hardening, infrastructure improvements, and the use of automated distribution systems. For example, diagnosis and notification of equipment conditions can prevent equipment failures while FLISR actions primarily involve reductions in the number of customers affected by sustained outages. This happens when automated feeder switching is installed on a feeder and the circuit is divided into sections, which can reduce the customers affected during an outage by rerouting power and protecting non-affected sections and the customers they serve.

Reducing outage duration, as measured by SAIDI, is generally related to the implementation of distribution automation and more efficient operating and restoration practices. Isolating, reclosing, or FLISR actions can reduce outage duration for customers on sections of feeders that are isolated from damages. Outage durations are reduced primarily for two reasons: automated switching eliminates the time required to dispatch field crews to manually actuate switches, and automated isolation of the portions of the feeder that are not damaged reduce the number of customers affected by sustained outages. In addition, the duration of outages can also be reduced by improving methods for locating and addressing faults.

Reducing the duration of outages, as measured by CAIDI, is generally related to the implementation of outage detection technologies and more efficient restoration practices for those customers experiencing sustained outages. Remote fault indicators and smart meters can be used to improve restoration times. Improved outage detection capabilities reduce the time to identify and locate outages. They also reduce the number of customers who experience a "nested outage" for prolonged periods after other customers have had power restored.

Table 1 provides a summary of the various smart grid applications for electric distribution reliability and their expected impacts on the frequency and duration of outages.

Operational Savings

Utilities spend significant resources locating and responding to outages. The use of AMI and smart meters, fault detection technologies, and automated controls can help improve the allocation of field resources to restore power. Cost reductions are derived from fewer truck rolls and labor resources to locate and troubleshoot outages. Costly rework can be avoided by

Smart Grid Applications	Primary Impacts on Outages
Fault detection and automated feeder switching	Reductions in the frequency and duration of outages and the number of affected customers
Diagnostic and equipment health sensors	Reductions in the frequency of outages and the number of affected customers
Outage detection and notification systems	Reductions in the duration of outages

Table 1. Applications and Impacts on Outages

using smart meter restoration notifications to ensure all customers have power restored before demobilizing field crews. It is expected that the level of savings from these actions will correlate with the size of the outage. The greatest savings will occur during restoration following major events that require many field crews and long work periods, often under extreme conditions.

Utilities frequently operate switches to support load balancing and to de-energize feeder segments for maintenance. Before automation, many of these activities required crews to travel to multiple sites and perform switching operations manually before maintenance operations began. When the maintenance work was completed, manual switching was again required to put feeders back into their original service configurations. Automated feeder switching can produce operational savings by eliminating manual switching and improving the productivity of field crews.

Traditionally, distribution equipment is maintained mostly by visual inspection, on-site testing, and repairs are made by field crews. Maintenance may also include replacement of parts or entire devices. Utilities normally maintain equipment on predetermined schedules based on manufacturer guidelines. Utilities are now beginning to use equipment health sensors and asset management systems to optimize maintenance schedules and lower costs. Referred to as condition-based maintenance, these processes employ equipment health sensors, communications networks, and advanced algorithms to determine (1) the condition of key assets, (2) operating trends and the likelihood of failure, and (3) when to notify operators and field crews that maintenance is required. Condition-based maintenance is intended to deploy resources more efficiently while maintaining acceptable reliability performance levels.

3. SGIG Distribution Reliability Projects and Deployment Progress

The 48 SGIG projects deploying various electric distribution technologies, tools, and techniques to improve reliability are listed in Table 2. Appendix D provides further information on these projects and the devices and systems they have deployed as of June 30, 2012.

Once these projects finish installing equipment and begin operations, they are expected to have enhanced capabilities for improving electric distribution reliability. However, most of the projects have not finished installing equipment, and many are currently focused on testing and preparing to begin operations in the near future.

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

Table 2. SGIG Projects Deploying Distribution Reliability Devices and Systems

Figure 6 provides a summary that shows the number of projects that are deploying various types of devices and systems to improve distribution reliability. As shown, there is a relatively high level of interest in automated feeder switches. Many of the projects are deploying automated switches on a small number of feeders to evaluate equipment performance before deciding to undertake large-scale investments in distribution automation projects. Several of the projects have already gone through this step and are installing automated switches on a large number of feeders. AMI outage detection capabilities and remote fault indicators are also being used in a majority of the projects.

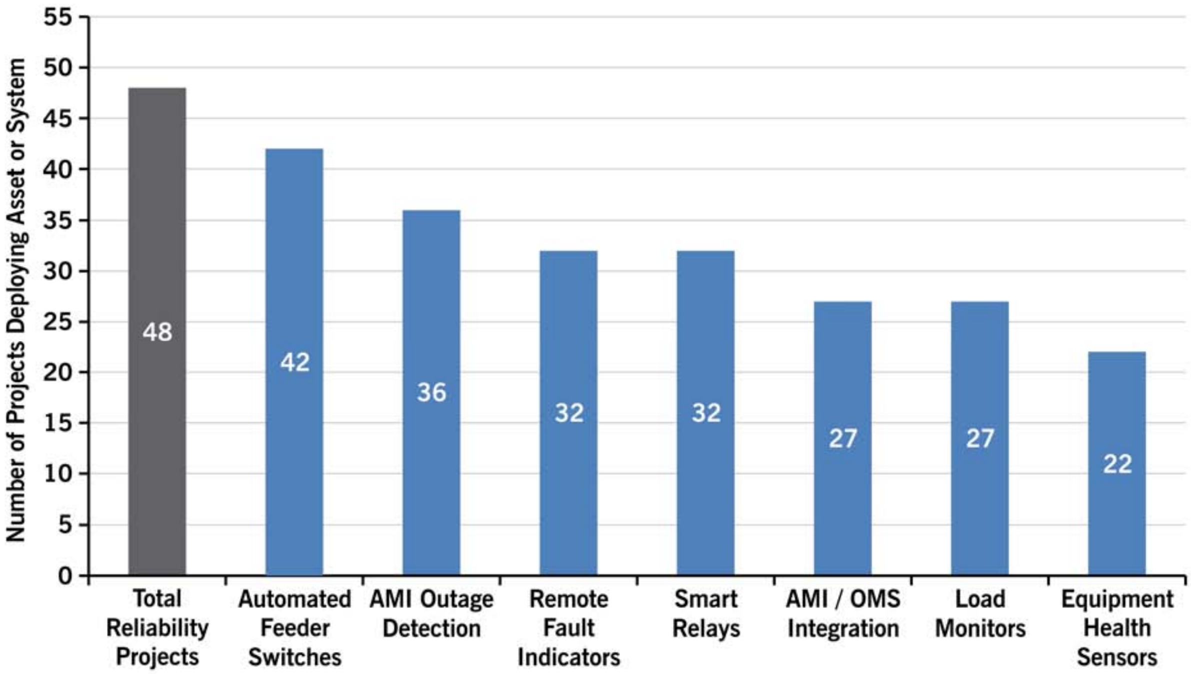

Figure 6. Number of SGIG Reliability Projects Deploying Certain Devices and Systems

Figure 7 provides a breakdown of the 42 projects that are deploying automated feeder switches to show the range in the number of feeders being upgraded. Utilities typically install one to three switches on a distribution feeder depending on the configuration, length, customers served, and the number of different routes (tie points) to alternate power sources. As shown, there are a number of projects deploying a small number of switches to test interoperability and functionality with communication networks and enterprise systems. These projects intend to resolve issues on specific feeders and generally affect a small number of customers. Other projects are installing large numbers of switches which affect reliability for specific regions, but generally not for entire systems.

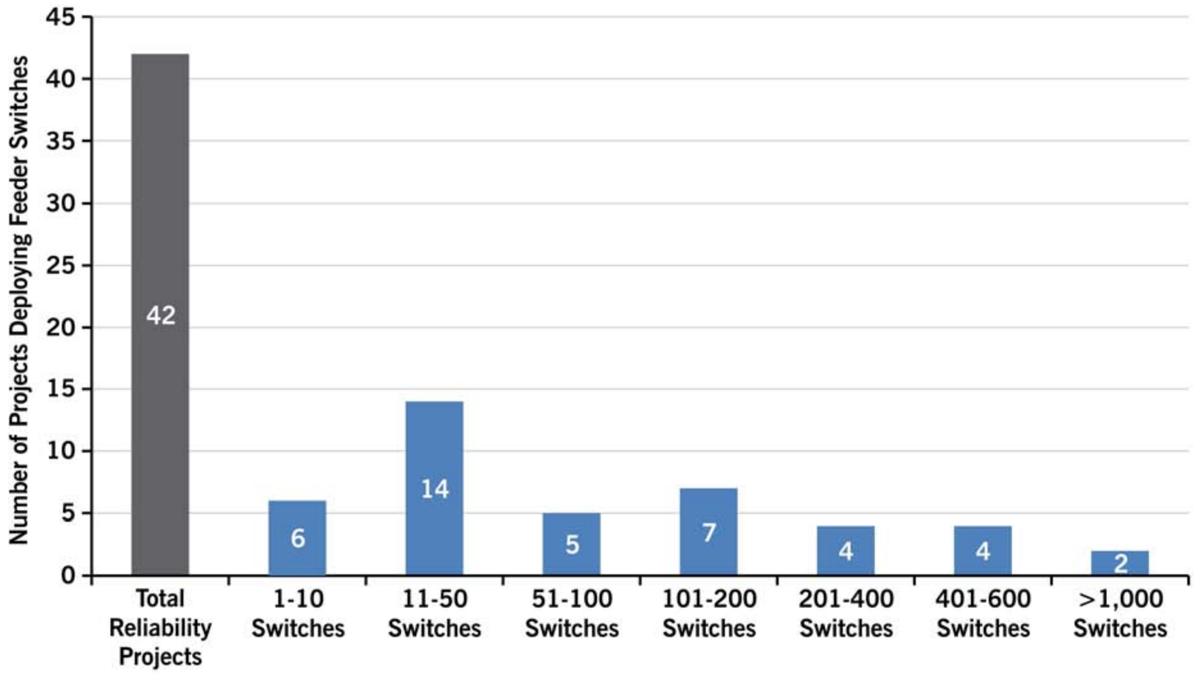

Figure 7. Number of Projects Deploying Automated Feeder Switches

3.1 Deployment Progress

Figure 8 provides an overview of the progress of projects that are deploying automated feeder switches as of June 30, 2012. The chart shows that about 32% of the projects have completed the installation of automated feeder switches and that about 30% have not gotten started yet, and the rest are somewhere in between. In total, about 50% of the automated feeder switches have been installed by the projects.

Appendix D provides project level details of the different devices and systems that are being deployed by the 48 projects. For example, it lists whether the projects plan to deploy certain types of equipment, whether or not they plan to integrate applications or systems, the devices and systems being deployed for diagnosis and notification of equipment conditions and detection of outages. Appendix D shows that the majority of the projects are deploying multiple types of devices and systems.

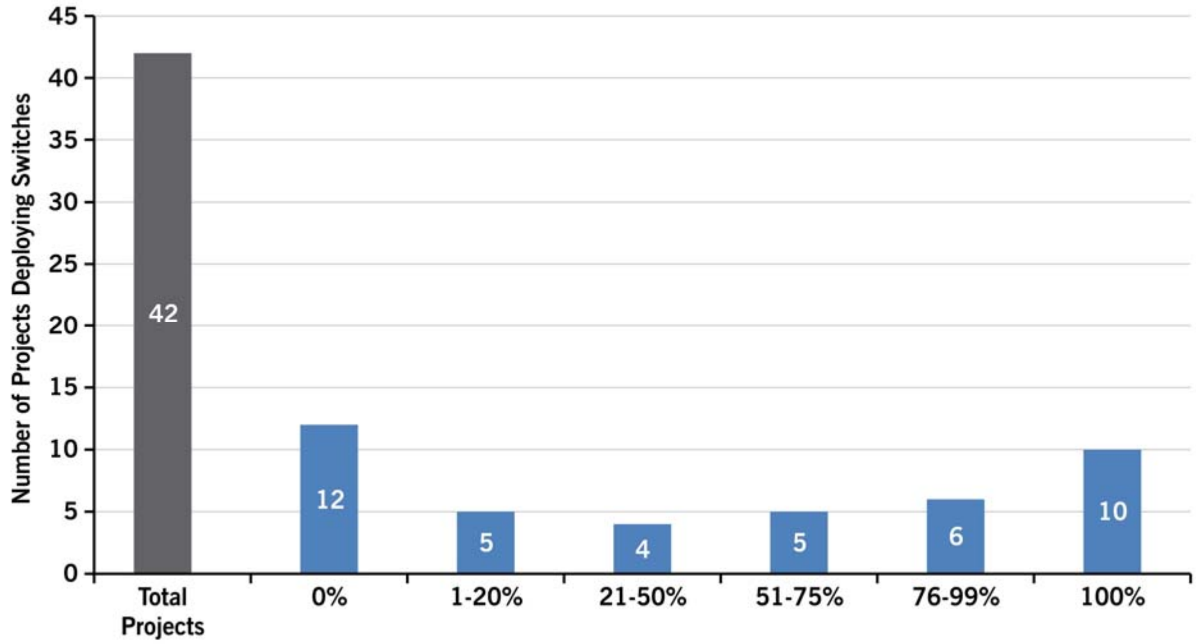

Figure 8. Progress with Deploying Automated Feeder Switches

3.2 Project Examples

The following examples provide more specific information to illustrate how electric distribution reliability objectives are being accomplished by SGIG projects.[8] The examples explain the distribution reliability objectives that the projects are pursuing and how the devices and systems are being applied to achieve them.

CenterPoint Energy Houston Electric, LLC (CEHE)

CEHE is a regulated transmission and distribution company serving over two million metered distribution-level customers in a 5,000-square-mile area along the Texas Gulf Coast, including the Houston metropolitan area. CEHE is pursuing two primary reliability objectives: (1) reducing the frequency of outages due to equipment failures and other factors and (2) restoring service more quickly to reduce outage duration. Equipment is being installed on radial overhead feeders with a density of approximately 151 customers per distribution mile. DMS and multi-layer communications systems consisting of fiber, Ethernet, microwave, and wireless mesh networks are being integrated with AMI to accomplish these objectives.

[8] Descriptions of these and other SGIG projects are available at: http://www.smartgrid.gov/recovery_act/deployment_status/project_specific_deployment

Monitoring equipment on substation power transformers will be used by CEHE to prevent equipment failures caused by thermal overloading. The DMS will analyze equipment health sensor data and provide operators and repair crews with information to respond to abnormal operating conditions.

Advanced metering infrastructure will be used by CEHE to transmit premise-level outage and restoration notifications to CEHE's OMS and DMS. These data will be used in conjunction with outage information from SCADA and customer calls to dispatch service crews to complete repair orders.

CEHE is automating feeders by replacing electromechanical relay panels with microprocessors, installing automated feeder switches, and retrofitting existing switches. These devices will be integrated with DMS, which compiles information from SCADA, other distribution equipment, and smart meters to support FLISR. Based on this information, the DMS will be able to remotely assess operating conditions on the distribution system, locate faults, and reroute power for service restoration. CEHE grid operators will operate switches remotely until DMS integration and automated FLISR are operational in 2014.

EPB

Located in Chattanooga, Tennessee, EPB serves approximately 172,000 customers, involving approximately 309 distribution feeders and 117 substations. EPB is pursuing two primary distribution reliability objectives: (1) reducing outage frequency and (2) restoring service more quickly to reduce outage duration. EPB is installing new automated feeder switches on its 46-kilovolt and 12-kilovolt overhead feeders. These feeders are a combination of radial and looped overhead feeders with a density of approximately 48 customers per distribution mile. The project expects to realize the equipment's full potential a year after all equipment is installed and integrated.

EPB has installed decentralized automated feeder switches and control packages with fault interrupting and reclosing capabilities to isolate faults and reroute power to the portions of feeders that are not damaged. The implementation of this fault locating, isolation, and service restoration (FLISR) capability will be completed in 2012. While the switches operate autonomously, operational and outage data are sent to the SCADA system and operators can also control the switches remotely. EPB is also implementing DMS this year.

The overall communications network for distribution automation utilizes a virtual local area network (VLAN) on EPB's fiber optic system. The fiber network also includes a separate VLAN that supports AMI. EPB has installed the majority of its smart meters and has implemented outage notification capabilities. EPB is using AMI to confirm that power is restored to customers before demobilizing restoration crews. AMI and an OMS are being integrated at the end of this year, and the project is using outage notification data for better decision support by grid operators and field crews.

Philadelphia Electric Company (PECO)

Headquartered in Philadelphia, Pennsylvania, PECO serves 1,600,000 customers, involving approximately 2,278 distribution feeders and 450 distribution substations. PECO is pursuing two primary reliability objectives: (1) reducing outage frequency and (2) restoring service more quickly to reduce outage duration. Automated loop scheme equipment is being installed mostly on radial overhead feeders with a customer density of approximately 73 customers per distribution mile. Some portions of PECO's underground system are also being addressed.

A DMS and fiber optic and wireless communications networks are being integrated with new and existing reclosers. Smart relays and load monitors are being installed at substations to detect disturbances and isolate faults. AMI outage detection is also being integrated with OMS to support restoration activities.

Automated feeder switches are operating in a decentralized manner to accomplish reclosing, but will be integrated with a DMS to accomplish FLISR. Reclosers isolate faults and attempt to clear the fault by reclosing after preconfigured intervals and over current settings. Reclosing actions are logged and communicated to the OMS so PECO can analyze the impact on outage duration and the number of customers affected.

4. Analysis of Initial Results

This section presents analysis of the four SGIG projects representing four feeder groups that reported initial results to DOE-OE and includes results that are aggregated over all four feeder groups and also analyzed at the project level. Observations based on the initial results are also presented. Appendix C provides more detailed analysis of the four feeder groups, which are labeled A through D to mask the identity of the projects because the data is considered confidential according to the terms and conditions of the grants.

The analysis results include changes in the reliability indices that were calculated based on differences between baseline forecasts and measured conditions from April 1, 2011 to March 31, 2012. The baselines were developed by the projects using historical reliability data for the feeders where equipment was installed and operational. The projects used IEEE standards for calculating baselines and excluded data from time periods that were considered to be outside of historical averages. The initial analysis focuses on the impacts from automated feeder switching and enhanced fault detection capabilities as this was the equipment that was installed and operational. Future analysis will address other smart grid capabilities for distribution reliability.

4.1 Aggregated Results

Grid operators used both decentralized and centralized distribution automation approaches to isolate faults and restore power to feeder segments that were not damaged. Some projects used both approaches within their system based on the feeder designs, customer densities, and outage histories. Smart meter notifications were used by one project to confirm power restorations and avoid nested outages, but were not used to coordinate automated feeder switches or to support grid operators.

Table 3 provides initial results of the impacts from the operation of the devices and systems for the four feeder groups. The table provides a range of results based on the number of feeder switches that were operational during the observation period. The ranges include low and high percent changes in the reliability indices from the corresponding baselines. The baseline values are also listed to provide reference points of the historical reliability levels. Only one project tracked MAIFI and reported results in this area.

The results show significant improvement in reducing sustained interruptions, momentary interruptions, and average system interruption duration as calculated by changes in SAIFI, MAIFI, and SAIDI respectively. (See Appendix A for definitions of these indices and equations showing how they are calculated.) The greatest improvements in these indices occur for the feeder groups with the worst baseline reliability levels.

Also shown in the table is an additional index used for assessing reliability impacts, Customer Minutes Interrupted (CMI), that measures the total number of customers and the minutes they were without power. As shown in Appendix A, CMI is one of the inputs used to calculate SAIDI.

Table 3 also shows that average customer interruption duration index (CAIDI) worsened in most cases, despite the fact that the extent of sustained outages was reduced by automated feeder switching. This is due largely to the terms of the equation that is used to calculate CAIDI. For example, as the number of customers experiencing sustained outages is reduced, the denominator of the CAIDI index also goes down relative to the value of the numerator, and thus the overall index increases. Reducing CAIDI requires reducing restoration times for those remaining without power after automated feeder switching operations have occurred. It is expected that enhanced fault detection and outage detection and notification capabilities will contribute to reductions in the duration of sustained outages for affected customers, and thus reduce CAIDI.

Reliability Indices	Units	Range of Improvement % Change (Low to High)	Range of Baselines (Low to High)
SAIFI	Average Number of Sustained Interruptions	- 13% to - 40%	0.8 to 1.07
MAIFI	Average Number of Momentary Interruptions	-28%	9.0
SAIDI	Average Number of System Outage Minutes	-2% to -43%	67 to 107
CAIDI	Average Number of Customer Outage Minutes	+28% to -2%	67 to 100
CMI	Total Number of Customer Minutes Interrupted (Millions)	+8% to -35%	44 to 20

Table 3. Summary of Changes in Distribution Reliability (April 2011–March 2012)

4.2 Feeder Group-Specific Results

Figure 9 shows the changes in reliability for the four feeder groups A, B, C, and D. Outage frequency (SAIFI) is given on the horizontal axis and customer outage duration (CAIDI) is shown on the vertical axis. Curves representative of system outage duration (SAIDI) are held constant to show the relationship between CAIDI, SAIFI, and CMI.

The figure depicts the reliability changes by the movement from the baseline (solid circles) to the measured results (open circles). As shown in the figure, reliability improvements occur from fewer and shorter outages, which on the chart are shown by changes to the left and/or down. The change in the size of the circles represents the change in the number customer minutes interrupted (CMI).

The figure shows that all of the projects are improving reliability by reducing the frequency and duration of sustained outages. This reduction is attributable to the operation of automated feeder switches to isolate faults and restore power resulting in a reduction in the number of customers experiencing sustained outages. Feeder group A attributed a portion of the improvements to the use of equipment health sensors to prevent overloading of power transformers which would have resulted in a significant outage on multiple feeders.

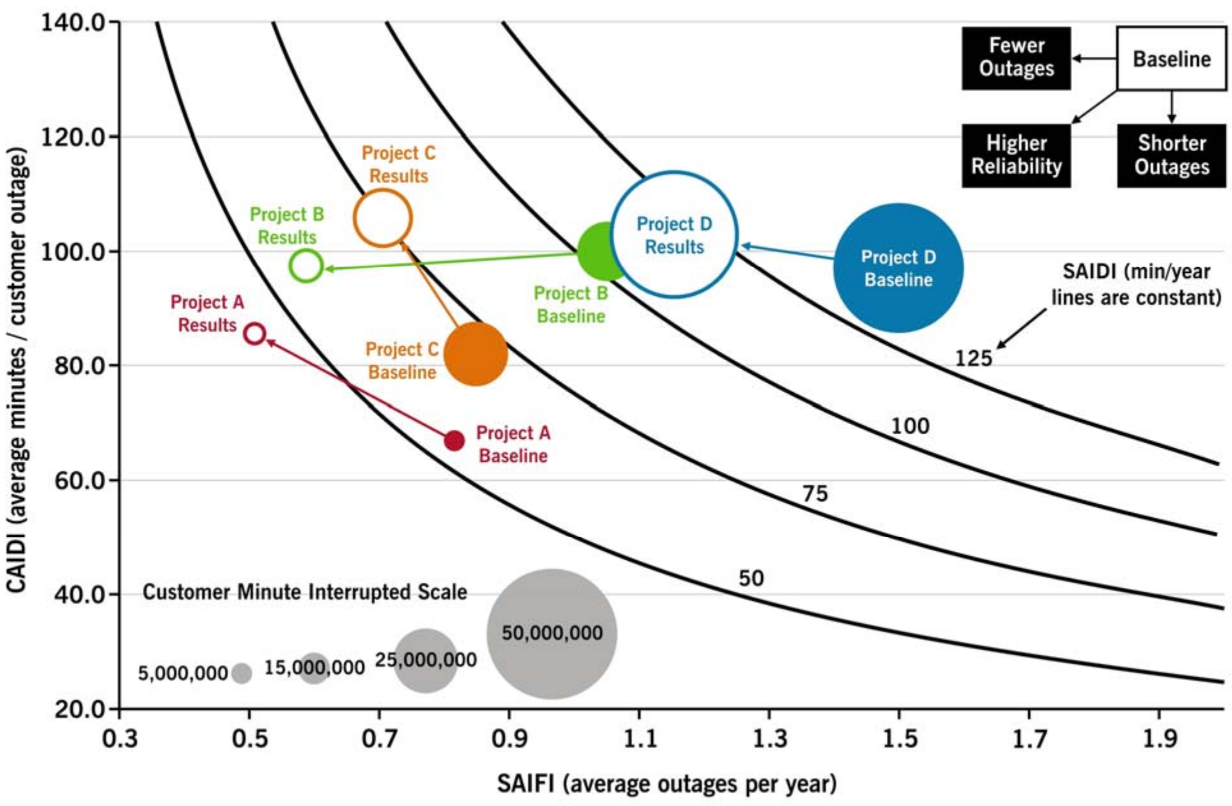

Figure 9. Project-Level Changes in Distribution Reliability (April 2011–March 2012)

Feeder groups A, C, and D show CAIDI getting worse while SAIDI is getting better. As discussed previously, reductions in CAIDI will be improved as the time to restore power to those remaining without power it is reduced.

Feeder group B, on the other hand, showed CAIDI improvements, but they did not attribute the improvements to the deployment of smart grid equipment but rather to the types of outages that occurred and the convenient location of the feeder and the ability of field crews to restore power relatively quickly. With the application of outage detection and notification systems, and corresponding improvements in service restoration practices, the duration of outages experienced by affected customers on all feeders and locations can decrease, and thus CAIDI can be expected to decrease.

In general, reliability improved overall because of reductions in SAIFI and SAIDI. The projects expect that improvements in outage frequency and CMI to continue as more switches are installed and grid operators gain experience developing automation schemes and developing actionable information from fault detection devices and equipment health sensors.

4.3 Summary of Observations

As discussed, most of the projects that have reported initial results are still installing equipment, integrating systems, and refining approaches to achieve their respective distribution reliability objectives. While impacts have been observed, many are the result of deployments and integration efforts that are not complete. Because the projects have different levels of experience with the various automation approaches, they have indicated that there is a significant learning period for grid operators and field crews to understand the new devices and systems and determine the best ways to use them to achieve desired results. In general, the companies with the most prior experience have been the ones most able to achieve better results.

The projects have been able to attribute reductions in the frequency and duration of outages to the installation and operation of fault detection and automated feeder switching equipment. In general, these projects report that they have relatively high confidence levels in the initial results and have confirmed information on specific outages and switching operations to support their preliminary findings.

One of the contributing factors to the observed reduction in the frequency of sustained outages is the process of repairing worn or damaged equipment as part of the overall installation process when deploying the SGIG equipment. These practices have contributed to the reliability improvements observed here but are not related to the operation of the new devices and systems.

There is a relatively high level of variation in the reported results. Some of this is due to the variations in devices and systems being installed and to variations in the levels of experience with operating automated distribution devices and systems. There is a learning period during which grid operators and field crews become acquainted with functions, capabilities, and strategies for operating automated feeder switches to achieve performance improvements and develop needed competencies. In addition, differences in baselines also contribute to the variability of results.

The initial results also indicate a need to monitor the impacts of automated feeder switching on CAIDI over time to assess its usefulness as a reliability index. This is because increases in CAIDI do not necessarily indicate that reliability is getting worse. In fact, because of automated feeder switching fewer customers are experiencing sustained outages, and therefore reliability is getting better. Improvements in CAIDI can be achieved with other approaches such as advancements in outage detection and notification and implementation of improvements in service restoration practices.

Most utilities do not track the frequency of momentary interruptions, and/or they do not have sufficient historical data to develop appropriate baselines. Projects may not have the data measurement systems in place, or they may not be required to provide this information to regulators. However, the deployment of smart devices and systems provide the projects with new and better ways to assess momentary interruptions. Some projects report that they plan to use these data to identify feeders that have high frequencies of momentary interruptions, and that they will follow up and do more inspections of these feeder segments, and will take corrective actions, such as vegetation management, to avoid momentary interruptions (and sustained outages) in the future.

5. Next Steps

As additional data on the impacts become available, DOE-OE will conduct further analysis of the results. Collaboration between DOE-OE and the SGIG distribution reliability projects is essential for ensuring that appropriate data are gathered and reported, and for understanding the analysis results. Collaboration includes reviews of results with the appropriate project teams to validate them and share what has been learned.

The analysis has focused so far on changes in reliability indices but will be expanded as more projects complete equipment deployment and begin to integrate the new devices and systems with distribution system operations. For example, DOE-OE plans to expand the analysis to understand the role of distribution reliability devices and systems in reducing restoration and operations and maintenance costs.

Depending on the availability and quality of quantitative data from the projects, potential areas for future analysis include: understanding the incremental impact of smart meters when working together with distribution automation systems, analyzing results over extended time periods to identify trends and changes as they relate to increased operational experience, tracking the operation of automated feeder switching equipment to better determine customers affected and outage duration impacts, and assessing the integration of DMS with existing and new devices and systems and the effects of refined restoration algorithms on reliability levels.

The SGIG projects—including the four discussed in this report—will continue to implement distribution reliability devices and systems and report activities and results. DOE-OE plans to present additional results and lessons learned from the SGIG distribution reliability projects in the future. In the meantime, updates on deployment progress and case studies highlighting project examples are posted regularly on www.smartgrid.gov.

Appendix A. Reliability Indices

Reliability Index	Equation Description	Equation
System Average Interruption Frequency Index (SAIFI)	The sum of the number of interrupted customers (N_i) for each power outage greater than five minutes during a given period, or customers interrupted (CI), divided by the total number of customers served (N_T). This metric is expressed in the average number of outages per year. Major events are excluded.	$SAIFI = \frac{\sum N_i}{N_T} = \frac{CI}{N_T}$
System Average Interruption Duration Index (SAIDI)	The sum of the restoration time for each sustained interruption (r_i) multiplied by the sum of the number of customers interrupted (N_i), or customer minutes interrupted (CMI), divided by the total number of customers served for the area (N_T). This metric is expressed in average minutes per year. Major events are excluded.	$SAIDI = \frac{\sum r_i N_i}{N_T} = \frac{CMI}{N_T}$
Customer Average Interruption Duration Index (CAIDI)	The sum of the restoration time for each sustained interruption (r_i) multiplied by the sum of the number of customers interrupted (N_i), or customer minutes interrupted (CMI), divided by the sum of the number of customers interrupted (N_i). This metric is commonly expressed in minutes per outage. Major events are excluded.	$CAIDI = \frac{\sum r_i N_i}{\sum N_i} = \frac{CMI}{\sum N_i}$
Momentary Average Interruption Frequency Index (MAIFI)	The sum of the number of momentary interruptions (IM_i) multiplied by the sum of the number of customers interrupted for each momentary interruption (N_{mi}) divided by the total number of customers served (N_T). This metric is expressed in momentary interruptions per year.	$MAIFI = \frac{\sum IM_i N_{mi}}{N_T}$

Appendix B. IEEE Reliability Benchmark Data

Since 2003, the IEEE Distribution Working Group has surveyed Canadian and U.S. electric utilities each year to develop benchmark data on distribution reliability. Benchmark data are provided by more than 100 utilities; cover all types, sizes, and regions; and are intended to provide information so that utilities can assess their performance relative to one another.

Figures B-1, B-2, and B-3 provide a six year summary of the different performance levels for SAIFI, SAIDI, and CAIDI and show the variability among utilities and over time. The benchmarks were calculated using the IEEE Guide for Electric Power Distribution Reliability Indices – IEEE Standard 1366™-2003. The lines on the charts represent the minimum values for the respective quartiles. Additional information on the survey and links to detailed results for each year is listed at http://grouper.ieee.org/groups/td/dist/sd/doc/ .

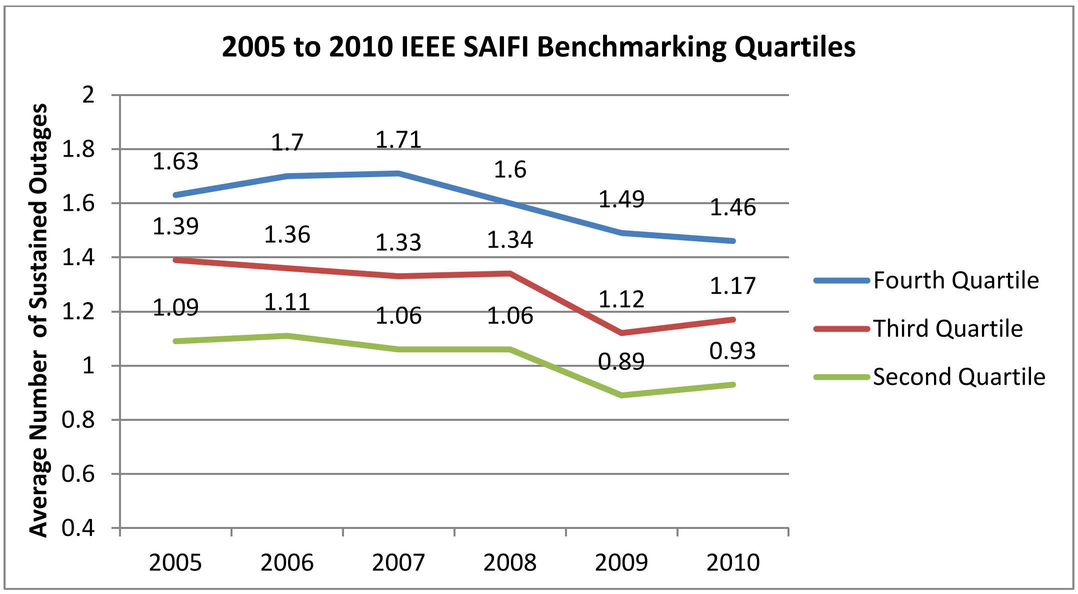

Figure B-1. Summary of IEEE Benchmark Data – SAIFI

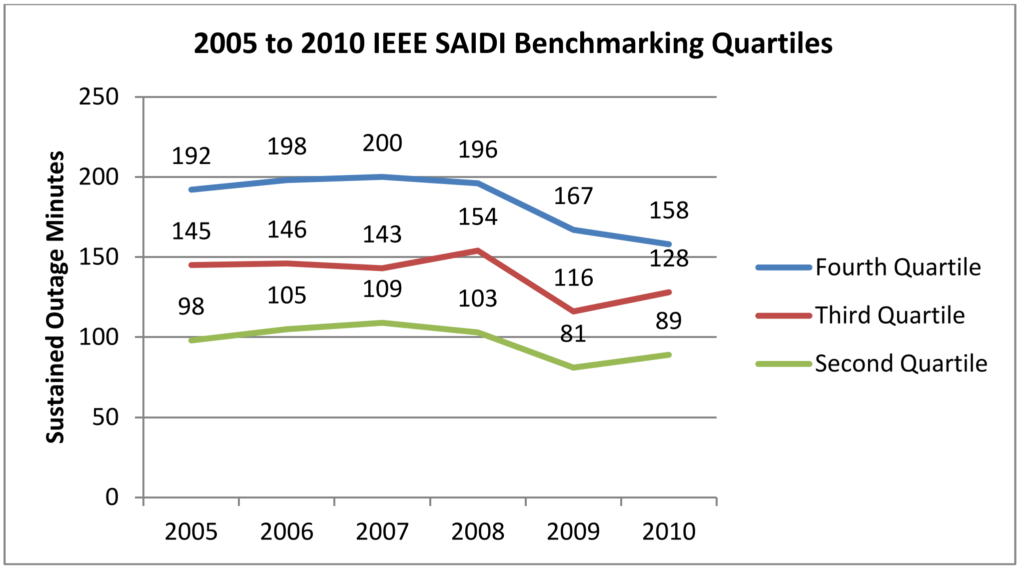

Figure B-2. Summary of IEEE Benchmark Data – SAIDI

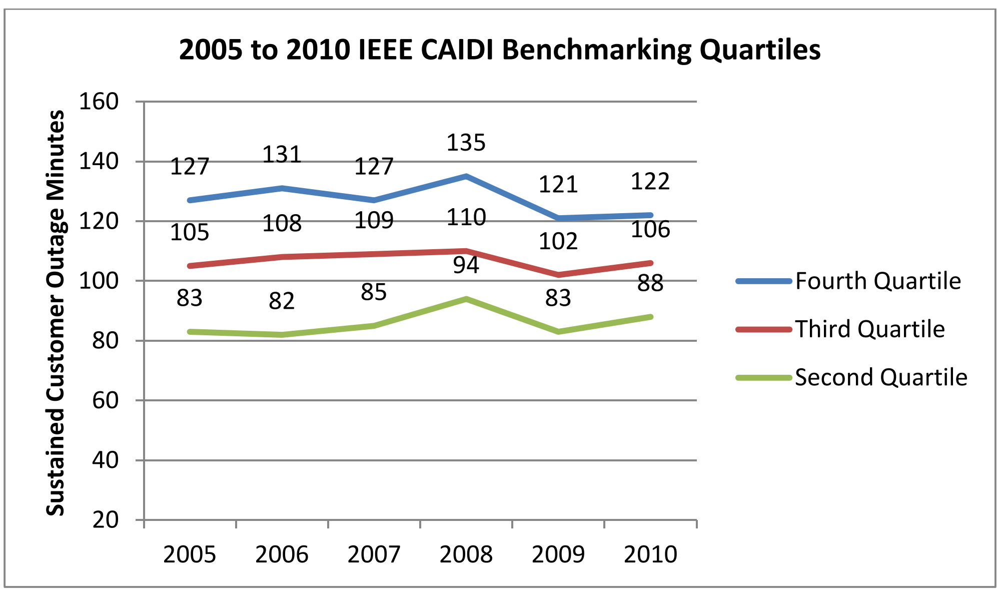

Figure B-3. Summary of IEEE Benchmark Data – CAIDI

These figures show that many U.S. utilities are monitoring changes in reliability levels using the IEEE calculations to determine reliability indices, and that they are developing benchmarks against which they can evaluate and compare their performance. The SGIG electric distribution reliability projects are using comparable approaches in developing baselines for the feeder groups analyzed in this report.

Appendix C. Supplementary Analysis Results

Tables C-1 through C-4 provide tabular results for each of the four feeder groups analyzed in Section 4 and are labeled A through D to mask the identity of the projects. Each feeder group comprises a set of feeders that have been upgraded by the projects. The four feeder groups correspond to the four projects. The feeder groups include both looped and radial feeder configurations.

Feeder Group A

Table C-1 provides initial results for Feeder Group A, which consists of 120 feeders. For this project, grid operators reported having prior experience deploying and operating automated feeder switching equipment and indicated that the initial results were in line with their expectations.

Grid operators attribute improvements in SAIFI and MAIFI to the operation of decentralized automated feeder switching and reclosing. The operators also indicate that some of the impacts on outage frequencies, including MAIFI, are related to the inspection and repair of worn feeders that occurred at the same time as the installation of the SGIG equipment.

The operators report that improvements in SAIDI and CMI are also primarily related to automated feeder switching. Fault detection capabilities, derived from smart relays and DMS, were used to support some of the restorations. The majority of the SAIDI and CMI impacts were said to be due to reductions in the number of customers affected by automated feeder switching and reclosing. AMI outage detection was not operational, but it is planned for implementation in the near future.

The operators indicated that increases in CAIDI were due to the CAIDI calculation method. The automated feeder switches reduced the number of customers affected by sustained outages.

Index	Units	April 2011–September 2011		October 2011–March 2012	
		Baseline	% Δ	Baseline	% Δ
SAIFI	Number of Interruptions	1.0	- 41%	0.6	- 31%
MAIFI	Number of Interruptions	12.6	- 35%	5.5	- 13%
SAIDI	Number of Minutes	72.3	-25%	37.0	-11%
CAIDI	Number of Minutes	70.4	+27%	63.3	+ 29%
CMI	Number of Customer Minutes (Millions)	8.5	-25%	6.9	-11%

Table C-1. Feeder Group A Results

Feeder Group B

Table C-2 provides initial results for Feeder Group B, which consists of approximately 95 overhead radial distribution feeders with tie points in the first reporting period, and 185 during the second. Grid operators for Feeder Group B reported having prior experience deploying and operating automation devices and systems and SCADA systems but indicated that the full capabilities of the equipment had not yet been implemented. The operators also noted that weather variability contributed to reliability improvements, in addition to automated feeder switching, when compared to the baselines.

The operators for Feeder Group B indicated that improvements in SAIFI were related to the operation of centralized remote feeder switching and distributed reclosing. Switching enabled operators to avoid sustained outages for portions of the feeder that were not damaged. Improvements in SAIDI and CMI were also said to be related to remote feeder switching and reclosing. The majority of the feeder switches were capable of remote operations, but additional integration and engineering work is required before FLISR is fully operational.

The operators reported an increase in CAIDI during the first reporting period and a decrease during the second. They said the decreases in CAIDI were the result of a feeder segment that happened to be relatively easy to repair.

Index	Units	April 2011–September 2011		October 2011–March 2012	
		Baseline	% Δ	Baseline	% Δ
SAIFI	Number of Interruptions	1.3	- 41%	0.8	- 49%
MAIFI	Number of Interruptions	--	--	--	--
SAIDI	Number of Minutes	133.2	- 35%	79.8	- 56%
CAIDI	Number of Minutes	99.6	+ 11%	100.0	- 15%
CMI	Number of Customer Minutes (Millions)	20.4	- 35%	22.6	- 56%

Table C-2. Feeder Group B Results

Feeder Group C

Table C-3 provides initial results for Feeder Group C, which consists of approximately 285 overhead distribution feeders with tie points in the first reporting period and 870 in the second. The grid operators reported having little prior experience deploying and operating remote feeder switches and fault location analysis tools and they said they do not believe they have realized the full potential of the devices and systems yet.

The operators reported that improvements in SAIFI were related to the operation of centralized remote feeder switching and reclosing. Distribution feeders were also inspected before the SGIG equipment was installed. Portions of the feeder that were out of specification or damaged were identified and repaired. Examples include vegetation management, fuse replacement, and cross arm replacement. The operators indicated that some devices were not fully operational during the first reporting period and that they were gaining experience with the equipment and fault location analysis tools, including DMS. They said that the lack of experience contributed to measured increases in the duration of customer outages.

The operators reported decreases in outage frequency and duration for the second period, which they attributed to feeder switching, relays, and better use of analysis tools. Switching enabled the operators to avoid sustained outages for portions of the feeder that were not damaged.

Index	Units	April 2011–September 2011		October 2011–March 2012	
		Baseline	% Δ	Baseline	% Δ
SAIFI	Number of Interruptions	1.1	- 20%	0.6	- 11%
MAIFI	Number of Interruptions	--	--	--	--
SAIDI	Number of Minutes	84.2	+ 4%	49.2	- 13%
CAIDI	Number of Minutes	80.0	+ 29%	84.1	- 2%
CMI	Number of Customer Minutes (Millions)	48.8	+ 8%	46.4	- 9%

Table C-3. Feeder Group C Results

Feeder Group D

Table C-4 provides initial results for Feeder Group D, which consists of approximately 75 overhead looped feeders.

Grid operators attributed reductions in the frequency of sustained outages to reclosing and remote breaker switching. Reductions in SAIDI and CMI were also attributed to reclosing and switching. The operators plan to implement feeder switching to reroute power from alternate sources using a DMS, but this functionality was not operational during the reporting periods. AMI outage detection capabilities were also not operational or integrated with the OMS during the reporting periods. Operators anticipate additional benefits when these functions and capabilities are fully operational.

Index	Units	April 2011–September 2011		October 2011–March 2012	
		Baseline	% Δ	Baseline	% Δ
SAIFI	Number of Interruptions	1.5	- 22%	1.5	- 24%
MAIFI	Number of Interruptions	--	--	--	--
SAIDI	Number of Minutes	139.7	- 14%	139.7	- 16%
CAIDI	Number of Minutes	97.0	+10%	97.0	+11%
CMI	Number of Customer-Minutes (Millions)	19.0	- 14%	19.2	- 16%

Table C-4. Feeder Group D Results

Appendix D. SGIG Electric Distribution Reliability Projects

X* Project installed/deployed
X Project will install/deploy
N/A Project will not install/deploy

Project	Automated Feeder Switches			Devices Deployed as of 6/30/2012				Applications Planned				
	Installed (#)	Expected (#)	Installed (%)	Equipment Health Sensors	Load Monitors	Remote Fault Indicators	Smart Relays	FLISR	AMI Outage Detection	AMI/OMS Integration	DMS	Other System Integration
Avista Utilities	258	258	100%	N/A	102	N/A	102	X	N/A	N/A	X	OMS/DMS
Burbank Water and Power	N/A	N/A	N/A	0	N/A	0	74	X	X*	X	X	MDMS/OMS/DMS/GIS/SCADA
CenterPoint Energy	204	584	35%	0	0	0	155	X	X*	X*	X	OMS/DMS/GIS
Central Lincoln People's Utility District	0	17	0%	7	0	0	0	X	X*	X	X	N/A
City of Anaheim, California	17	70	24%	N/A	0	14	N/A	X	X	X	N/A	N/A
City of Auburn, Indiana	0	13	0%	0	0	0	20	X	X*	X	X	AMI/SCADA/DA devices
City of Fort Collins Utilities	0	5	0%	N/A	0	0	N/A	X	X*	N/A	N/A	N/A
City of Glendale, California	4	18	22%	N/A	0	0	4	X	X*	X	N/A	OMS/DMS
City of Leesburg, Florida	0	12	0%	0	0	0	0	X	X	X	N/A	N/A
City of Naperville, Illinois	7	7	100%	N/A	0	0	12	X*	X*	N/A	N/A	SCADA/DA devices
City of Ruston, Louisiana	0	10	0%	N/A	N/A	0	N/A	X	X*	N/A	X	N/A
City of Tallahassee, Florida	0	75	0%	N/A	N/A	0	N/A	X	N/A	N/A	N/A	SCADA
City of Wadsworth, Ohio	0	24	0%	0	0	0	0	X	X*	N/A	X	N/A
Consolidated Edison Company of New York, Inc.	572	630	91%	11,170	274	381	61	X	N/A	N/A	X	OMS/DMS/SCADA
Cuming County Public Power District	0	9	0%	N/A	67	N/A	N/A	N/A	N/A	N/A	X	N/A

Project	Automated Feeder Switches			Devices Deployed as of 6/30/2012				Applications Planned				
	Installed (#)	Expected (#)	Installed (%)	Equipment Health Sensors	Load Monitors	Remote Fault Indicators	Smart Relays	FLISR	AMI Outage Detection	AMI/OMS Integration	DMS	Other System Integration
Denton County Electric Cooperative	2	2	100%	N/A	N/A	6	N/A	X	X	X	N/A	N/A
Detroit Edison Company	5	121	4%	2	N/A	N/A	31	X	X*	N/A	X	AMI/DMS/SCADA
Duke Energy	387	416	93%	N/A	49	219	251	X*	X	X	X	OMS/SCADA/GIS
El Paso Electric	13	13	100%	N/A	6	8	8	X*	N/A	N/A	X	OMS/DMS
EPB	1,124	1,300	86%	N/A	0	0	0	X	X*	X	X	MDMS/OMS/DMS
FirstEnergy Service Corporation	0	30	0%	N/A	0	N/A	0	X	N/A	N/A	N/A	N/A
Florida Power & Light Company	230	254	91%	2,452	108	159	863	X*	X	X	N/A	N/A
Golden Spread Electric Cooperative, Inc.	0	121	0%	0	N/A	N/A	N/A	X	X*	X	N/A	OMS/SCADA
Guam Power Authority	0	34	0%	0	N/A	0	0	X	X	X	X	N/A
Hawaiian Electric Company	29	29	100%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	X*	SCADA/DA devices
Indianapolis Power & Light Company	158	178	89%	0	N/A	0	435	N/A	X	N/A	X	N/A
Knoxville Utilities Board	N/A	N/A	N/A	N/A	N/A	0	N/A	N/A	X*	X	N/A	SCADA/DA devices
Minnesota Power	1	6	17%	0	1	N/A	N/A	X	X*	X	N/A	N/A
Northern Virginia Electric Cooperative	10	14	71%	33	N/A	N/A	19	N/A	N/A	N/A	N/A	N/A
NSTAR Electric Company	254	295	86%	N/A	254	254	N/A	X*	N/A	N/A	X	N/A
Oklahoma Gas & Electric	69	125	55%	N/A	N/A	N/A	8	X	X*	X	X	OMS/DMS/GIS
PECO	100	100	100%	N/A	N/A	0	209	X	X	X	X	N/A
Potomac Electric Power Company – Atlantic City Electric Company	146	146	100%	11	N/A	N/A	30	X	N/A	N/A	N/A	EMS

Project	Automated Feeder Switches			Devices Deployed as of 6/30/2012				Applications Planned				
	Installed (#)	Expected (#)	Installed (%)	Equipment Health Sensors	Load Monitors	Remote Fault Indicators	Smart Relays	FLISR	AMI Outage Detection	AMI/OMS Integration	DMS	Other System Integration
Potomac Electric Power Company – District of Columbia	38	51	75%	14	N/A	N/A	354	X	X*	X	N/A	EMS
Potomac Electric Power Company – Maryland	67	94	71%	8	N/A	65	306	X	X*	X	N/A	EMS
Powder River Energy Corporation	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	SCADA/DA devices
PPL Electric Utilities Corporation	213	213	100%	N/A	N/A	0	0	X	X	X	X	OMS/DMS
Progress Energy Service Company	218	440	50%	24	1,425	N/A	N/A	X	X	N/A	X	OMS/DMS/SCADA
Public Utility District No. 1 of Snohomish County	0	31	0%	N/A	11	11	281	X	N/A	N/A	X	DMS/GIS/SCADA
Rappahannock Electric Cooperative	N/A	N/A	N/A	N/A	23	N/A	N/A	N/A	X*	X*	N/A	N/A
Sacramento Municipal Utility District	2	153	1%	N/A	0	0	97	X	X*	N/A	N/A	N/A
South Mississippi Electric Power Association	N/A	N/A	N/A	5	28	0	39	N/A	X*	X	N/A	GIS/SCADA/AMI/CIS
Southern Company Services, Inc.	1,537	2,059	75%	109	N/A	62	739	X*	X*	X*	X	AMI/OMS/DMS
Southwest Transmission Cooperative, Inc.	12	12	100%	99	0	54	92	X	X*	N/A	N/A	N/A
Talquin Electric Cooperative	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	X*	X*	X	AMI/OMS/DMS
Town of Danvers, Massachusetts	4	45	9%	N/A	1	N/A	0	X	X*	X	X	MDMS/OMS/DMS/ SCADA
Vermont Transco, LLC	23	144	16%	7	23	13	151	N/A	X*	X*	X	N/A
Westar Energy, Inc.	31	31	100%	N/A	N/A	27	N/A	X	X*	X	N/A	N/A

Appendix E. Overview of Feeder Switching Operations

Automated feeder switches are becoming key components in electric distribution systems. These devices can be opened or closed in response to sensing a fault condition, or by receiving control signals from other locations. Figures E-1 and E-2 show how this can be accomplished.

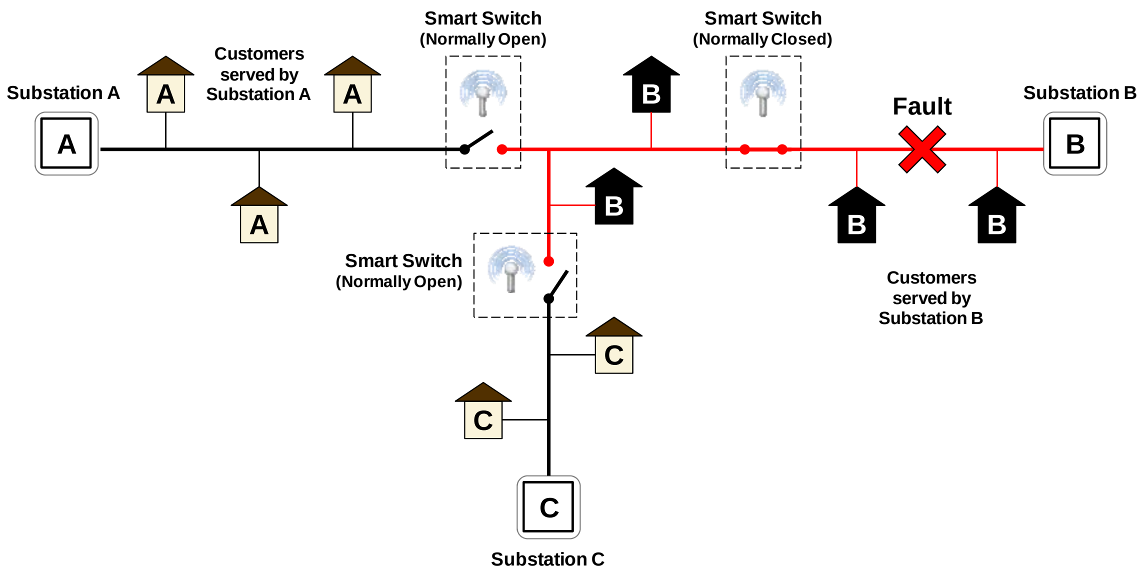

Figure E-1. Configuration of Feeder Before Switching

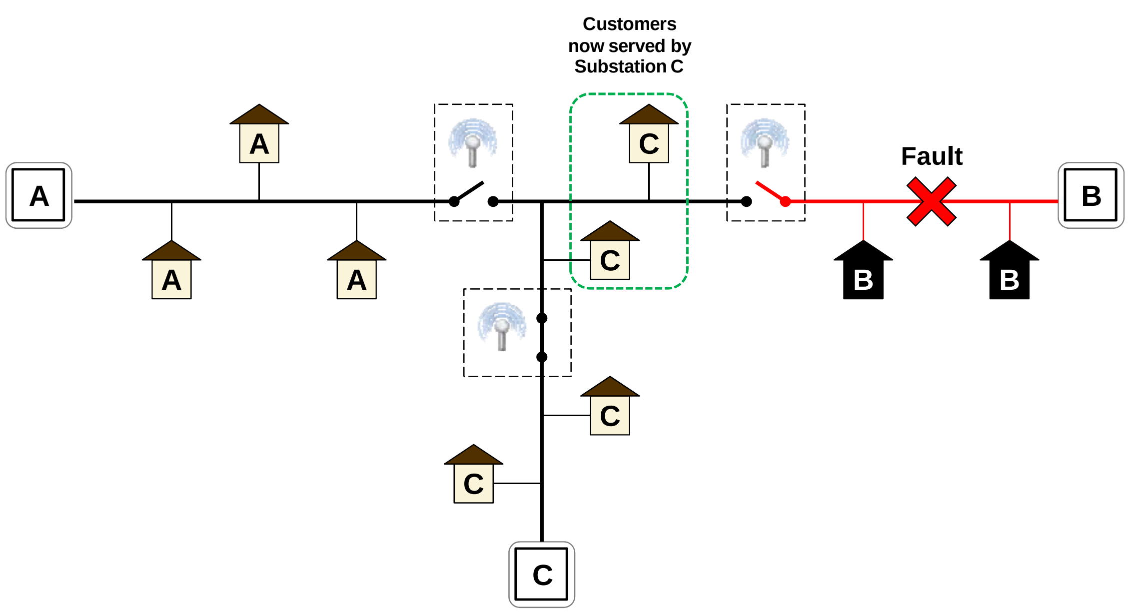

Figure E-2. Configuration of Feeder After Switching

In general, there are three major types of feeder configurations that are deployed by utilities: (1) radial feeders, (2) looped feeders, and (3) networked feeders. Utilities typically employ radial feeders for remote areas where population densities are relatively low. Looped and networked feeders are most suitable for more densely populated areas.

Radial Feeders

Radial feeders originate at substations, serve groups of customers, and are not connected to any other feeder. Power flows along radial feeders from substations to customers along a single path, which, when interrupted, results in loss of power to the customers served by those feeders. Radial feeders are typically connected to a single substation and cannot be fed from other sources.

Figure E-3 illustrates a typical switching sequence for radial feeders. In this example, the number of customers who experiences outages can be reduced by operating a switch on the feeder.

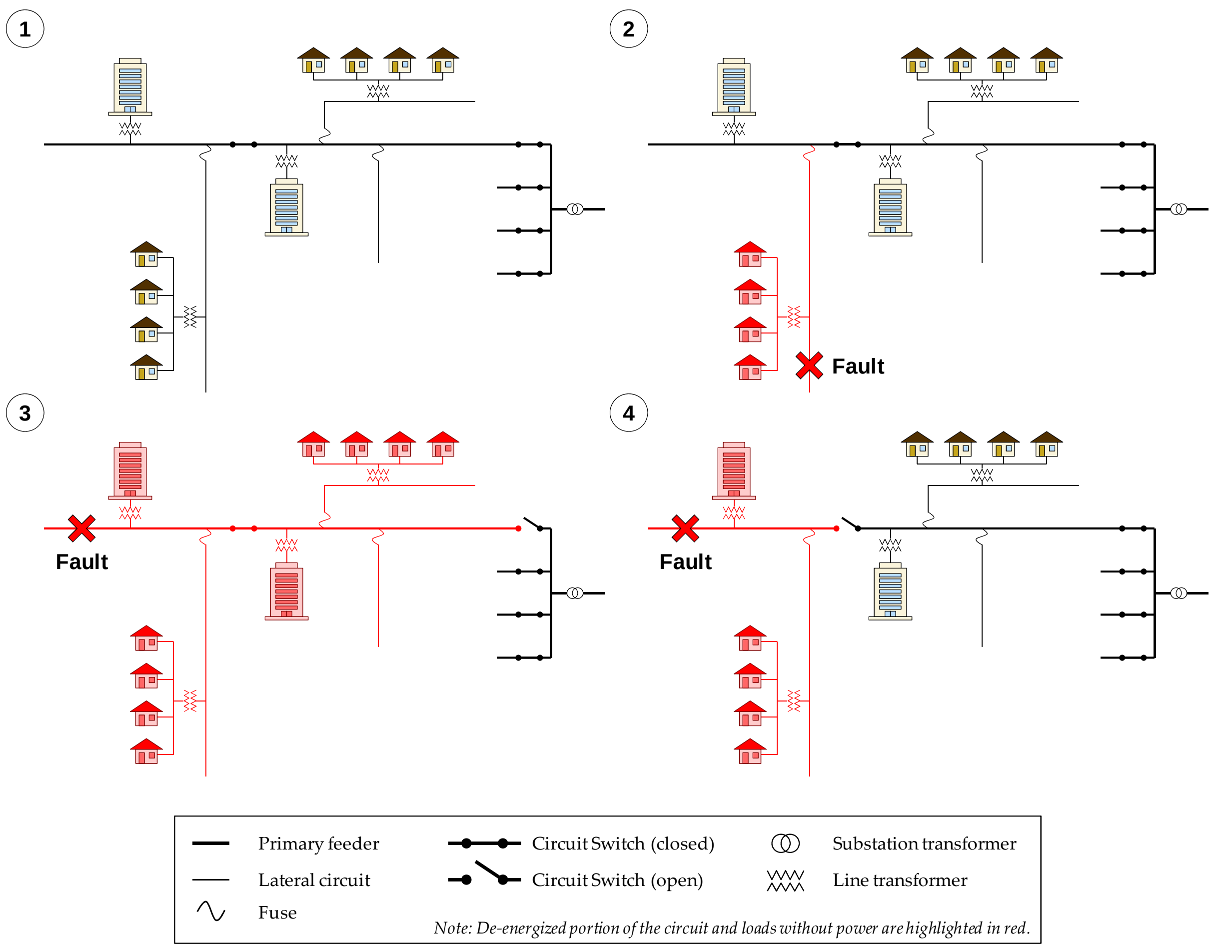

Figure E-3. Example of Switching Operations on Radial Feeders

Looped Feeders

Looped feeders involve at least two feeders interconnected through normally open tie points (i.e., under normal conditions, electricity does not flow through the tie point). Power can flow on looped feeders from alternate paths during outages. Figure E-4 illustrates switching operations on looped feeders and shows how utilities can reduce the impacts of faults by quickly isolating them.

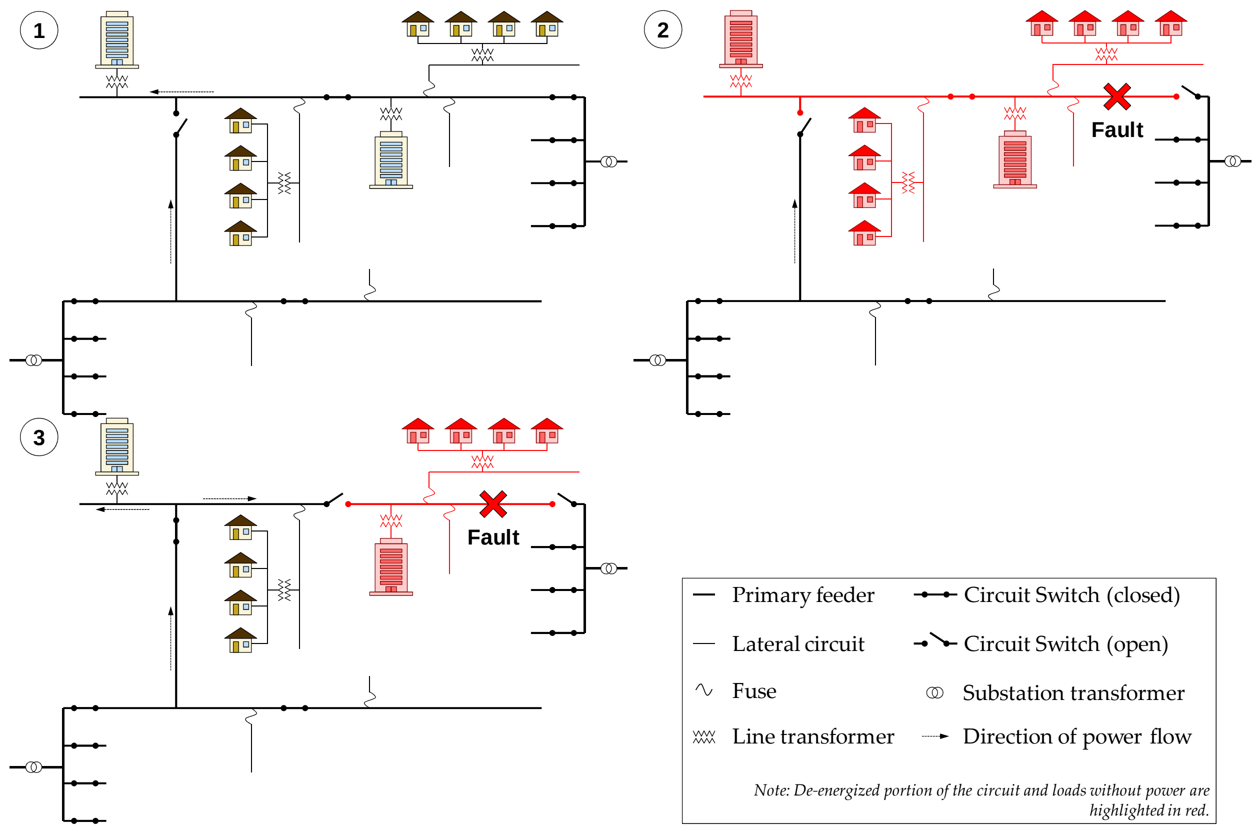

Figure E-4. Example of Switching Operations on Looped Feeders

Networked Feeders

Networked feeders involve multiple power flows from multiple sources to all of the customers that are served by the network. If a failure occurs in one of the lines, power can be rerouted instantly and automatically through other pathways. For example, if one source is interrupted due to a faulted segment, the customer is automatically transferred to another source. Figure E-5 illustrates switching operations on networked feeders to reduce the impacts of outages.

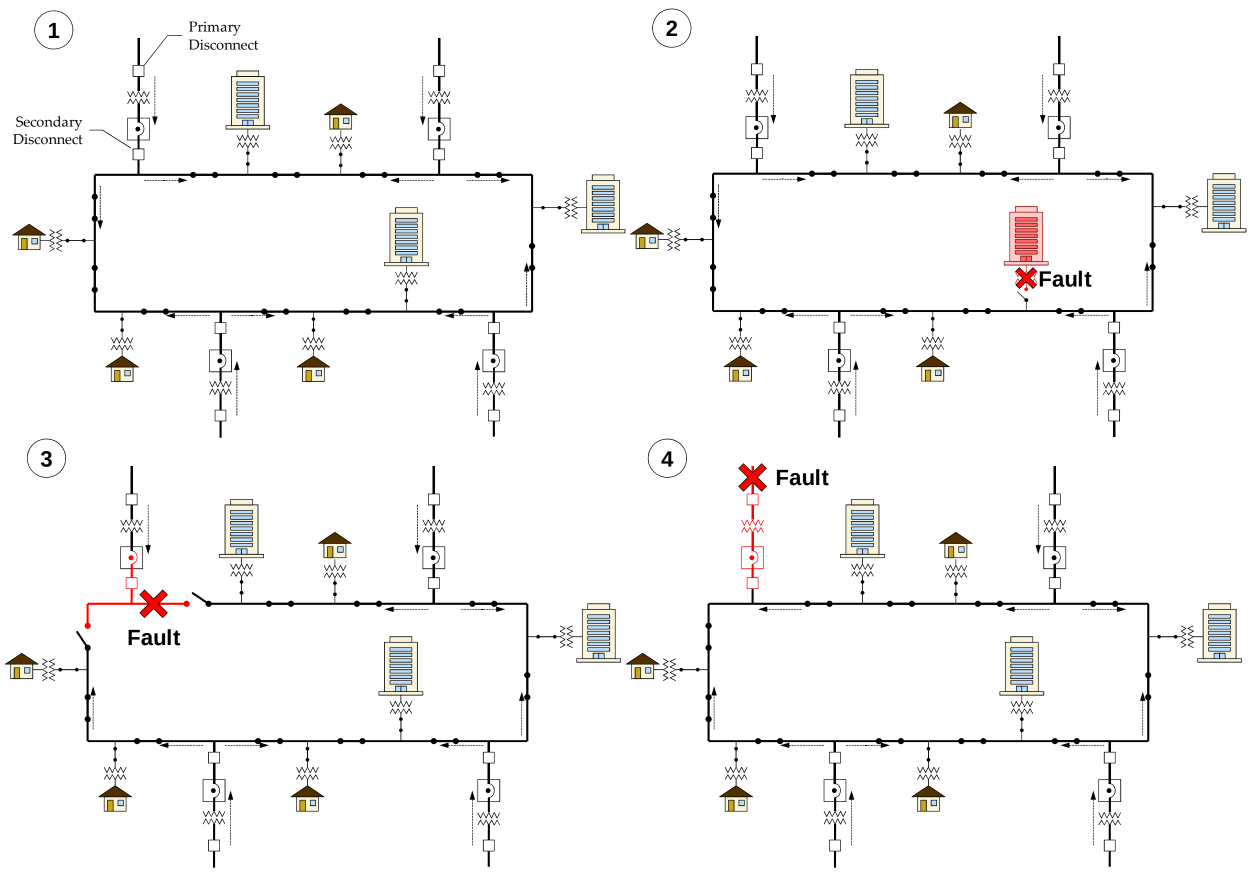

Figure E-5. Example of Switching Operations on Networked Feeders