Distribution Automation

RESULTS FROM THE SMART GRID INVESTMENT GRANT PROGRAM

September 2016

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U.S. DEPARTMENT OF ENERGY
Office of Electricity Delivery and Energy Reliability

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Executive Summary

Across the United States, more than 6 million miles of distribution lines and more than 200,000 distribution circuits provide the critical link between the bulk power grid and 160 million electricity customers.[1] Distribution automation (DA) uses digital sensors and switches with advanced control and communication technologies to automate feeder switching; voltage and equipment health monitoring; and outage, voltage, and reactive power management. Automation can improve the speed, cost, and accuracy of these key distribution functions to deliver reliability improvements and cost savings to customers.

Prior to ARRA, the widespread adoption of DA technology was hampered by a lack of data on performance, cost, and benefits in real-world applications. This report shares key results from the 62 SGIG projects implementing DA technologies and also documents lessons learned on technology installation and implementation strategies. With this report, the U.S. Department of Energy (DOE) aims to further accelerate grid modernization by helping decision makers better assess the benefits and costs of DA investments and learn from leading-edge utilities.

The Smart Grid Investment Grant (SGIG) Program

The American Recovery and Reinvestment Act (ARRA) of 2009 provided DOE with $3.4 billion to invest in 99 SGIG projects to modernize the electric grid, strengthen cybersecurity, improve interoperability, and collect smart grid impact data. Electricity industry recipients matched or exceeded this investment dollar-for-dollar.

Deployment of DA accounted for more than a quarter of the $7.9 billion total SGIG investment. SGIG utilities installed nearly 82,000 smart digital devices to upgrade 6,500 U.S. distribution circuits, including:

DA Asset	Total Installed
Remote Fault Indicators	13,423
Smart Relays	11,033
Automated Feeder Switches	9,107
Automated Capacitors	13,037
Automated Voltage Regulators	10,665
Transformer Monitors	20,263
Automated Feeder Monitors	4,447

Utilities also invested in the high-bandwidth, low-latency communications systems and information management and control systems that form the backbone of DA operations.

Major Findings

SGIG projects demonstrated that DA technologies and systems can achieve substantial grid impacts and benefits that met and often exceeded pre-project expectations, including:

- → **Improved fault location, isolation, and service restoration capabilities** that result in fewer and shorter outages, lower outage costs, reduced equipment failure, and fewer inconveniences for consumers.
- → **Improved distribution system resilience to extreme weather** events by automatically limiting the extent of major outages and improving operator ability to diagnose and repair damaged equipment.

[1] U.S. Energy Information Administration, "Electric power sales, revenue, and energy efficiency: Form EIA-861 detailed data files," Final 2014 data, October 21, 2015.

→ **More effective equipment monitoring and preventative maintenance** that reduces operating costs, enables more efficient use of capital assets, reduces the likelihood of equipment failures, and leads to fewer outages.

→ **More efficient use of repair crews and truck rolls** that reduces operating costs, enables faster service restoration, and lowers environmental emissions.

→ **Improved grid integration of selected distributed energy resources (DER)** such as thermal storage for commercial and municipal buildings.

Each SGIG DA utility installed a distinct set of DA assets, tested different capabilities, and deployed assets at a different scale—enabling each utility to test technology integration and explore costs and performance based on their individual objectives, systems, and experience levels. As a result, utility costs and performance were not directly comparable across all projects. Nonetheless, the SGIG projects produced important findings on DA technology performance and benefits in four key areas: reliability and outage management; voltage and reactive power management; equipment health monitoring, and integration of DER. This report also highlights select projects that exemplify the wide range of DA results and lessons learned.

Reliability and Outage Management

DA reduced the frequency, impact, duration, and cost of major storms and outage events, which significantly improved reliability indices for several utilities.

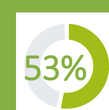
DA technologies provided advanced capabilities for operators to detect, locate, and diagnose faults. In particular, fault location, isolation, and service restoration (FLISR) technologies can automate power restoration in seconds by automatically isolating faults and switching some customers to adjacent feeders. FLISR can reduce the number of affected customers and customer minutes of interruption *by half* during a feeder outage for certain feeders. Fully automated switching and validation typically resulted in greater reliability improvements than operator-initiated remote switching with manual validation.

Precise fault location enabled operators to dispatch repair crews accurately and notify customers of outage status, which reduced outage length and repair costs, reduced the burden on customers to report outages, and increased customer satisfaction.

Per outage event, FLISR operations:[2]

Reduced number of customers interrupted by

Reduced customer minutes of interruption by



In 2013, 3 utilities reported System Average Interruption Frequency Index (**SAIFI) improvements of 17%-58%** from pre-deployment baselines

DA operations **avoided >197,000 truck rolls**[3] and **3.4 million vehicle miles traveled** from 2011 to 2015[4]

Savings reduced an estimated **2,350 metric tons of CO_2 equivalent**—the same amount produced to power 214 homes for a year[5]

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[2] Average per event for FLISR operations reported by five utilities over one year.
[3] Data from 16 reporting SGIG DA utilities from April 2011 to March 2015.
[4] Data from 18 reporting DA utilities from April 2011 to March 2015.
[5] Based on analysis of truck roll data from 18 SGIG DA utilities between April 2011 and March 2015, using U.S. Environmental Protection Agency, "Greenhouse Gas Equivalencies Calculator," last updated April 2014.

DA helped customers avoid outage costs and created operations and maintenance (O&M) efficiencies that led to savings for utilities.

For customers, DA operations during major storms saved one utility's customers on a 14-feeder segment $1.2 million in one year. For utilities, automating functions that previously required field crews to conduct on-site monitoring, maintenance, and repair reduced labor costs, truck rolls, vehicle-miles traveled, and replacement part costs.

FLISR and smart meters at the Electric Power Board of Chattanooga, TN helped operators **restore system-wide power about 17 hours earlier than without DA** after a July 2012 derecho. After another storm in February 2014, EPB was able to **restore power 36 hours faster and reduce affected customers from 70,000 down to 33,000**.

SGIG utilities in total **avoided $6.2 million in distribution operations costs** in about 1 year[6] and **avoided $1.46 million in switching costs** over 3 years[7]

Voltage and Reactive Power Management

Automated voltage regulation and power factor correction enabled utilities to reduce peak demands, more efficiently utilize existing assets, defer capital investments, and improve power quality for the growing digital economy.

Utilities used CVR to reduce feeder voltage levels, improve the efficiency of distribution systems, and reduce energy consumption, especially during peak demand periods.

Automated power factor correction provides grid operators with new capabilities for managing reactive power flows and boosting power quality. Several utilities improved power factors to near unity through integrated volt/volt-ampere reactive controls (IVVC), and one utility reduced reactive power requirements by about 10%-13% over one year.

Several utilities found that **CVR can result in energy savings of 2-4 percent on affected feeders**—a change that when applied system-wide could save hundreds of thousands of dollars in yearly energy costs and reduced environmental emissions

ConEdison **increased its 4kV substation capacity by 2.8 percent** under peak conditions using CVR, resulting in a net **savings of $15.7 million**.

O&M savings from CVR formed the largest portion by far of Duke Energy's 20-year smart grid business case, with a **net-present value of more than $155 million**

Southern Company realized about **$3.4 million in net present-value from deferred distribution capacity investments** by using automated capacitor banks to reduce reactive power loss.

[6] Data from Nine SGIG DA utilities that reported savings from April 2013 to September 2014.
[7] Data from eight SGIG DA utilities that reported savings from April 2011 to March 2014.

Equipment Health Monitoring

Installing sensors on key components (e.g., power lines and transformer banks) to measure equipment health parameters can provide real-time alerts for abnormal equipment conditions as well as analytics that help utility engineers plan preventative equipment maintenance, repair, and replacement.

These technologies and systems also equip grid operators with new capabilities to better dispatch repair crews based on diagnostics data.

Florida Power and Light prevented an outage for 15,000 customers and avoided $1 million in restoration costs by identifying and repairing a transformer before it failed

Several utilities automated monitoring to reduce physical inspections, enable proactive maintenance, and better diagnose equipment failures

Integration of Distributed Energy Resources (DER)

Grid integration of DERs requires advanced tools to monitor and dispatch DERs, and to address new power flow and control issues, such as low-voltage ride through, harmonic injection, voltage fluctuations, and reactive power management. Some SGIG utilities evaluated distributed energy resource management systems (DERMS) and integrated automated dispatch systems (IADS) on small DER installments. A small number also tested thermal energy storage for commercial and government buildings.

Burbank Water and Power in California used DER management systems to control ice storage systems that made ice overnight to power daytime air conditioning loads, which reduced the buildings' cooling requirements by about 5%

Key Lessons and Conclusions

Many DA utilities faced a learning curve that required new business practices, custom solutions, and extensive training and testing. Tackling new technical challenges revealed valuable lessons learned that can help other electric utilities embarking on DA projects:

- **Return on Investment for a Specific Technology or Function is Utility-Specific:** Cost-effectiveness depends on a number of factors, including project scale, the functionality of individual devices, the utility's learning curve, and the need for wholly new software and systems or the ability to retrofit. Larger scale projects saw the most significant results and could better leverage foundational investments in communications infrastructure and information systems integration.
- **DA Applications Produce Large Volumes of New Data for Processing and Analysis**: Installing thousands of smart monitoring devices gave operators unprecedented levels of data to process, store, analyze, error-check, and turn into actionable information. Operators recommended establishing policies for data storage, retention, access, and security from the start.
- **Standard Protocols for Data Interfaces Were Limited**: Ensuring uniform data standards among a wide range of technologies and systems was a challenge. Many utilities used standard protocols to build data interfaces among software applications.

- **Extensive Equipment Testing and Customization May Be Required**: Automated devices typically need more frequent firmware and software upgrades than traditional utility equipment, requiring more frequent field tests and evaluations. Standard templates from vendors also typically require customization to meet each utility's unique distribution system configurations. Many found that lab conditions for testing field device communications did not always accurately represent field conditions.
- **DA Requires Increased Workforce Training and Expertise**: DA brings changes in grid operations that require increased training and expertise for field technicians, engineers, and grid operators, particularly in database management, data analytics, information systems, and cybersecurity.
- **Communications Systems Need Comprehensive Planning for Multiple Smart Grid Functions**: Many utilities attempted to realize synergies in their communications strategies by leveraging new systems for DA, AMI, and other smart grid applications. This requires comprehensive evaluation of communications requirements from the start of project planning.
- **Systems Integration is a Critical Element of DA Deployment**: Multiple information management and control systems all need access to new data streams to effectively accomplish DA functions. Systems integration proved to be one the most significant challenges during DA implementation under SGIG, particularly for those utilities deploying DA equipment for the first time. Integration often required developing customized software for data processing, error checking, and coding.
- **Cybersecurity and Interoperability Are Integral to Smart Grid**: Cybersecurity was a cornerstone of the SGIG program from its onset. Sound cybersecurity policies, plans, and practices were integrated throughout each project lifecycle, including design, procurement, installation, commissioning, and ongoing maintenance and support.

Future Directions and Next Steps

With the SGIG projects complete, the vast majority of SGIG DA utilities are expanding their smaller-scale DA deployments in a phased approach to upgrade more feeders and substations, focusing on poor performers or those that serve critical business needs for reliability. Several also plan to extract more value from existing deployments by upgrading communications capacity, activating unused DA functions embedded in existing devices and management systems, and installing new devices and systems on already automated feeders and substations.

DOE continues to support grid modernization through research, development, demonstration, analysis, and technology transfer activities. While the SGIG program is now complete, grid modernization remains an important national priority. DOE through the Grid Modernization Initiative (GMI) recently released a Grid Modernization Multi-Year Program Plan (MYPP) that describes the challenges and opportunities for achieving a modern, secure, sustainable, and reliable grid and how DOE will help achieve this through programs and activities. The Grid Modernization Lab Consortium, a multi-year collaboration among 14 DOE National Laboratories and regional networks, will enable DOE in developing and implementing the activities in the MYPP. [8]

[8] DOE, Grid Modernization Initiative, *Grid Modernization Multi-Year Program Plan*, November 2015.

DA deployments highlighted several continuing challenges for grid modernization:

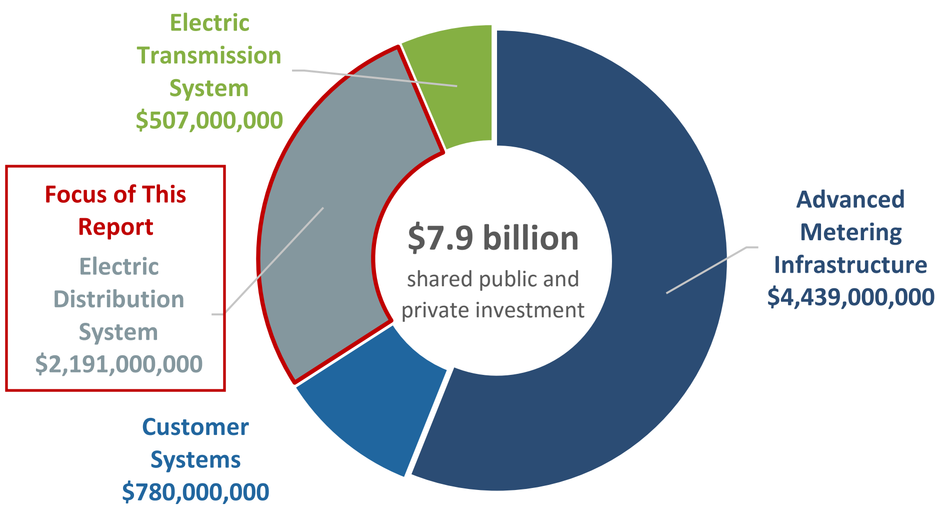
- Improved cybersecurity and interoperability standards, protocols, tools, and techniques for safe, rapid, and cost-effective DA implementation.
- Faster simulation methods and more robust control approaches to operate modern grid systems with large amounts of variable generation.
- High-resolution, low-cost sensors that report real-time conditions along feeders to enhance distribution system operator visibility beyond substation assets.
- Advanced DERMS for integrating distributed and demand-response resources in a coordinated and cost-effective way.
- Advanced grid devices and power electronics, such as solid-state distribution transformers, offer enhanced functionality and flexibility to increase total system efficiency and manage microgrids.
- Lower cost and safer energy storage systems for improved DER integration and distribution system management.

1 Distribution Automation Deployment in the Smart Grid Investment Grants

In 2009, the U.S. Department of Energy (DOE) launched the Smart Grid Investment Grant (SGIG) program—funded with $3.4 billion dollars from the American Recovery and Reinvestment Act (ARRA) of 2009—to jumpstart modernization of the nation's electricity system, strengthen cybersecurity, improve interoperability, and collect an unprecedented level of data on smart grid and customer operations. When matched with an additional $4.5 billion in industry investment, the 99 SGIG projects invested a total of $7.9 billion in new smart grid technology and equipment for transmission, distribution, metering, and customer systems (see Figure 1).

The large public and private investments made under ARRA have accelerated smart grid technology deployments, providing real-world data on technology costs and benefits along with valuable lessons learned and best practices. This report informs electric utilities, policymakers, and other key stakeholders of the qualitative and quantitative impacts, benefits, costs, and lessons learned from SGIG projects that implemented distribution automation (DA). Most SGIG projects began in 2009 and concluded in 2015, making this the final report on DA results from the SGIG program.

Figure 1. Breakdown of $7.9 Billion SGIG Investment



DA investments in the electric distribution system totaled about $2.19 billion—including Recovery Act funds from DOE and cost share from the utilities—accounting for 27 percent of the total SGIG investment. Of the 99 total SGIG recipients, 62 utilities installed and evaluated one or more DA technologies and systems, and reported key results to DOE. (Many of these 62 DA projects also installed new advanced metering infrastructure [AMI] or customer-based technologies and systems. Project results specific to those technologies are reported separately in *Advanced Metering Infrastructure and Customer Systems: Results from the SGIG Program*. Separate SGIG projects that tested transmission system technologies reported results in *Advancement of Synchrophasor Technology in Projects Funded by the American Recovery and Reinvestment Act of 2009*.)

SGIG project funds were used for several purposes: the purchase, testing, and installation of hardware and software; conducting training; implementing cybersecurity protections; systems integration activities; data collection and analysis; and other technical and administrative tasks needed for successful completion of project objectives.

Full descriptions and results of all projects can be found on SmartGrid.gov. This report highlights select projects that exemplify the wide range of results and lessons learned from the SGIG DA projects.

1.1 DA Technologies and Functions Deployed in SGIG

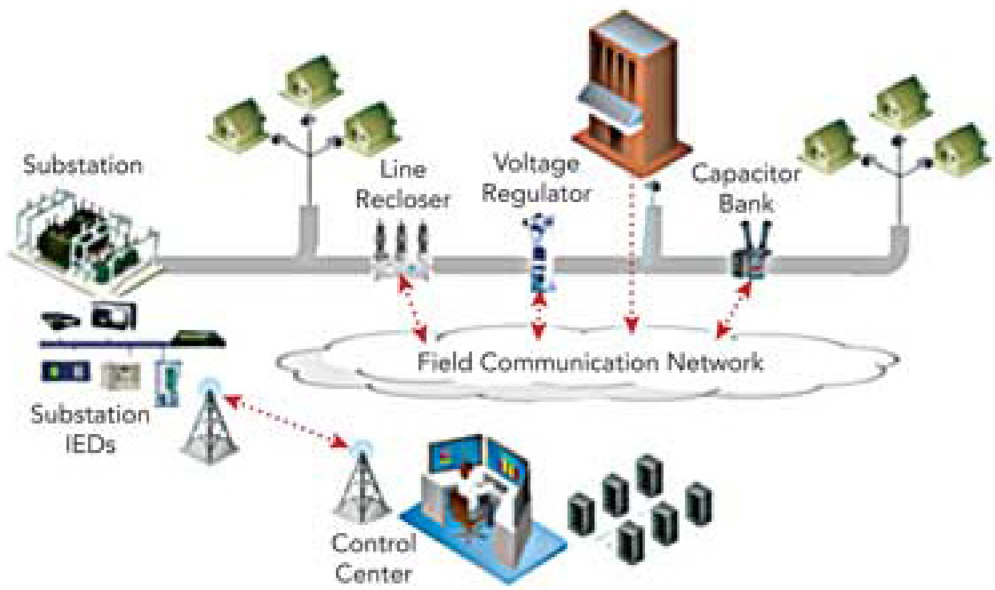
DA applies advanced control and communication technologies and integrates digital controls, switches, and sensors to improve or automate electricity delivery functions that were previously either not possible or were performed using electro-mechanical or manual processes. DA can improve the speed, cost, and accuracy of several key distribution system processes, including fault detection, feeder switching, and outage management; voltage monitoring and control; reactive power management; preventative equipment maintenance for critical substation and feeder line equipment; and grid integration of distributed energy resources (DER). Table 1 describes the four key DA applications and the specific smart grid functions that SGIG utilities tested during the projects.

Table 1. SGIG Smart Grid Applications and Functions under DA Projects

DA Application	Specific Smart Grid Functions
Reliability and Outage Management	• Remote fault location and diagnostics • Automated feeder switching • Outage status monitoring and notification • Optimized restoration dispatch
Voltage and Reactive Power Management	• Integrated voltage and volt–ampere reactive (VAR) controls (IVVC) • Automated voltage regulation • Conservation voltage reduction (CVR) • Real-time load balancing • Automated power factor corrections
Asset Health Management	• Real-time or near real-time equipment health monitoring
Distributed Energy Resources (DER) Integration	• Integrated and automated DER dispatching and management • Operation of customer-sited thermal energy storage systems

Achieving these functions required the deployment of advanced field devices, including remote fault indicators, smart relays, automated feeder switches, feeder and transformer monitors, automated capacitors, and automated voltage regulators. These devices can work autonomously or be monitored and controlled via communications networks linked to back-office information management and control systems (Figure 2[9]). Optimizing the control and performance of DA operations relies heavily on robust communication systems to transmit large volumes of data, and effective systems integration to analyze data and provide actionable information for grid operators.

Figure 2. Illustration of a Distribution Automation System



To implement DA, advanced field devices are typically equipped with radio, wireless, or cellular communication to transmit data to collection points and ultimately back to utility control centers using backhaul communications networks. At the control center, the data is typically integrated into the supervisory control and data acquisition (SCADA) system, distribution management system (DMS), and outage management system (OMS) for processing, analysis, and action, either automatically or by operators. Table 2 outlines the nearly 82,000 DA field devices installed under SGIG.

Table 2. DA Asset Deployments under SGIG Projects

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

[9] Robert Uluski, "Developing a Business Case for Distribution Automation," *Electric Light & Power*, June 10, 2013.

Investor-owned utilities, municipal and public power utilities, and electric cooperatives all conducted and reported on SGIG DA projects. Most of the projects focused on testing only select applications, and thus each project installed a different combination of assets and conducted systems integration in different ways. Table 3 shows which devices and systems support each DA applications.

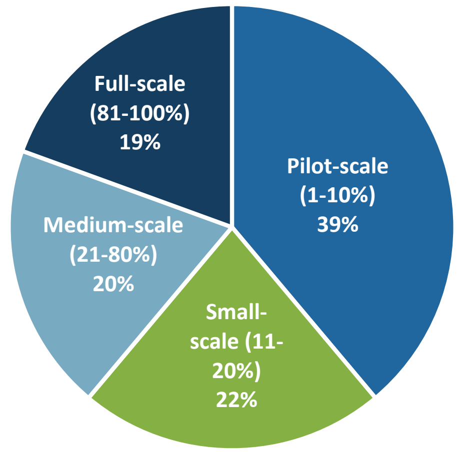
Table 3. Devices and Systems that Support DA Applications

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

The majority of SGIG DA utilities were primarily interested in integration tests, technology performance evaluation, and cost-benefit analysis before committing to expanded DA deployments. Each utility deployed DA assets at a different scale to achieve distinct evaluation objectives. For example, one project deployed just 2 transformer monitors, while another deployed more than 17,000 (or about 86 percent of total installed by all SGIG projects). About 61 percent of the reporting utilities implemented DA at either a small scale (covering less than 20 percent of feeders) or pilot scale (covering less than 10 percent of feeders).

Just under 20 percent of reporting utilities implemented system-wide deployment of DA assets (covering more than 80 percent of feeders). For the most part, these utilities had previous experience with DA technologies and systems. Figure 3 shows the percentage of SGIG DA utilities that deployed DA assets at each scale.

Figure 3. Extent of SGIG DA Asset Deployments by Percent of Utility System (36 Projects Reporting)



Distribution Automation Field Devices[10]

Remote Fault Indicators

Remote fault indicators are sensors that detect when voltage and current levels on feeders are outside normal operating boundaries. Operators can use this information to rapidly determine the location of a fault (such as an equipment failure or tree contacting a power line), or distinguish between a fault and temporary high loads, such as high motor starting current. Fault indicators can be equipped with visual displays to assist field crews, and connected to communications networks that are integrated with SCADA, OMS or DMS to provide greater accuracy in locating and identifying faults.

Smart Relays

Smart relays apply sophisticated software to accurately detect, isolate, and diagnose the cause of faults. They may be installed in utility substations for feeder protection or on devices in automated switching schemes. Device controls are activated according to equipment settings and algorithms. The relays also store and process data to send back to grid operators and back office systems for further analysis. Recent advances in sensor and relay technologies have improved the detection of high-impedance faults—difficult to detect with conventional relays—that occur when energized power lines contact a foreign object, but such contact only produces a low-fault current.

Automated Feeder Switches and Reclosers

Automated feeder switches open and close to isolate faults and reconfigure faulted segments of the distribution feeder to restore power to customers on line segments without a fault. They are typically configured to work with smart relays to operate in response to control commands from autonomous control packages, distribution management systems, or signals from grid operators.

Switches can also be configured to open and close at predetermined sequences and intervals when fault currents are detected. This action, known as reclosing, is used to interrupt power flow to a feeder that has been impacted 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.

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[10] For additional descriptions of devices, communications networks, and information management systems, see DOE, *Reliability Improvements from the Application of Distribution Automation Technologies – Initial Results*, November 2012.

Automated Capacitors

Utilities use capacitors to compensate for reactive power requirements caused by inductive loads from customer equipment, transformers, or overhead lines. Compensating for reactive power reduces the total amount of power that need to be provided by power plants, resulting in a flatter voltage profile along the feeder, and less energy wasted from electrical losses in the feeder. A distribution capacitor bank consists of a group of capacitors connected together. The capacity of the banks installed on distribution feeders depends on the number of capacitors, and typically ranges from 300 to 1,800 kilovolt-ampere reactive (kVAR). Capacitor banks are mounted on substation structures, distribution poles, or "pad-mounted" in enclosures.

Automated Voltage Regulators and Load Tap Changers

Voltage regulators are types of transformers that make small adjustments to voltage levels in response to changes in load. They are installed in substations (where they are called load tap changers) and along distribution feeders to regulate downstream voltage. Voltage regulators have multiple "raise" and "lower" positions and can automatically adjust according to feeder configurations, loads, and device settings. For example, as load on distribution feeders increases, the amount of voltage drop along those feeders also increases. A voltage regulator on the feeder detects when voltages are above or below target levels and then automatically adjust voltages to stay within the desired range.

Automated Feeder Monitors

Feeder monitors measure load on distribution lines and equipment and can trigger alarms when equipment or line loadings reach potentially damaging levels. Monitors deliver data in near-real time to back office systems and analysis tools so that grid operators can effectively assess loading trends and take corrective switching actions, such as taking equipment offline, transferring load, or repairing equipment 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.

Transformer Monitors

Transformer monitors are equipment health sensors for measuring parameters, such as power transformer insulation oil temperatures, that can reveal possibilities for abnormal operating conditions and premature failures. These devices can be configured to measure different parameters on many types of devices. Typically, these devices are applied on substation transformers and other equipment whose failure would result in significant reliability and cost impacts for utilities and customers.

Communications Networks

Many SGIG utilities expanded the communications networks for distribution systems to acquire large volumes of new data from sensors, process the data, and send control signals with low-latency to operate equipment. Communications networks allow utilities to connect devices to each other and to SCADA, DMS, and other information and control systems, which greatly expands the capabilities of grid operators to manage power flows and address reliability issues.

SGIG utilities leveraged a variety of wired and wireless communications technologies to support their smart grid application. Choosing the most suitable communication technologies and configurations required utilities to examine multiple requirements, considering all current and future smart technologies that may use the networks:

- Bandwidth
- Latency
- Cost
- Reliability and coverage
- Spectrum availability[11]
- Backup power needs
- Cybersecurity considerations

Most utilities use at least two-layer communication systems to communicate between field devices and information and control systems. Typically, the first layer of the network connects substations and distribution management systems at headquarter locations. Some utilities use existing SCADA communications systems for this layer. Many SGIG utilities chose high-speed, fiber optic or microwave communications systems, while some chose to contract third-party telecommunication vendors for their high speed cellular network.

The second layer of the network typically connects substations with field devices, where most SGIG utilities did not have a legacy system to leverage. Many SGIG utilities chose some form of wireless network for this layer, including radio frequency mesh or Wi-Fi.

Information Management and Control Systems

DMS, OMS, SCADA, and AMI can all play critical roles in automating distribution system functions. Their effective integration is often key to successful DA efforts. For example, OMS and DMS are typically used to integrate various sources of fault information—from line sensors, reclosers, AMI, and customer calls—and display this data on geographic information system (GIS) and SCADA screens for both control room operators and field crews. With low-latency communications networks, this information can be updated in near real time.

DA projects ideally include field device integration with the DMS, which is 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. DMS deployments can involve varying degrees of sophistication, from data collection and monitoring to highly complex, automated systems capable of independently managing the operation of the distribution system. Greater levels of sophistication and centralized controls are typically associated with producing greater levels of smart grid capabilities.

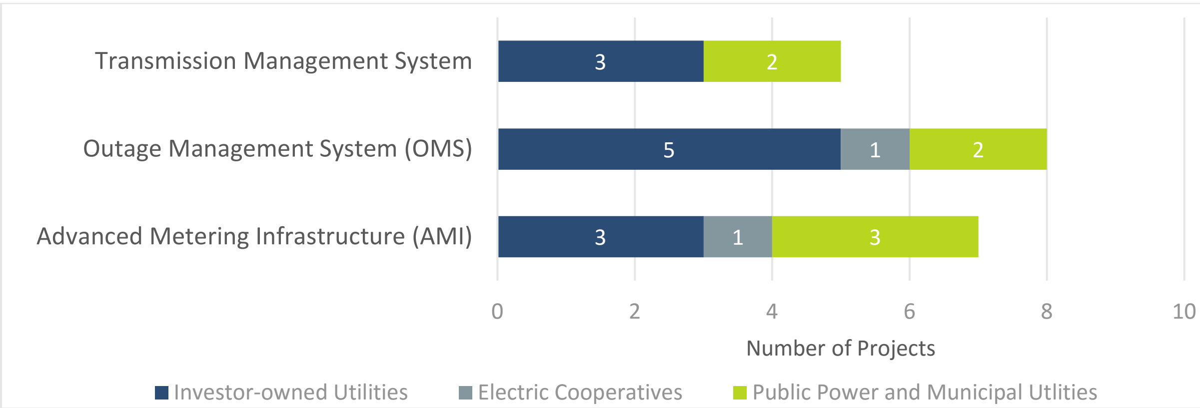
DMS integrate data from sensors, monitors, and other field devices to assess conditions and control the grid. They act as visualization and decision support systems to assist grid operators with monitoring and controlling distribution systems, components, and power flows. DMS can be used to automate or support voltage and volt-ampere reactive (VAR) controls, as well as other activities that increase the

[11] The Federal Communications Commission (FCC) manages and licenses the electromagnetic spectrum for the communications of commercial users and state, county, and local governments, including commercial and non-commercial fixed and mobile wireless services, broadcast television and radio, satellite, and other services. Frequency bands are reserved for different uses. There is a finite amount of spectrum and a growing demand for it. See FCC, "About the Spectrum Dashboard."

efficiency of distribution operations and maintenance. A DMS continuously updates 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 typically presented to operators through dashboards and visualization tools.

Fifteen of the SGIG DA utilities reported that they integrated their DMS with one or more additional information management or control systems (see Figure 4).

Figure 4. Number of SGIG DA Utilities that Integrated DMS with Other Types of Information Management and Control Systems (15 utilities reporting)



OMS are information management and visualization tools that analyze outage data and status of protective devices 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 monitoring and protective devices in substations and on feeder lines. Advanced OMS integrates smart meter data from AMI networks to improve detection of outage location and number of customer impacted. Currently, most OMS incorporate GIS to help repair crews get to outage locations more quickly, often with a better idea of the problem.[12] 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.

Figure 5. A Visual Display from an Outage Management System

[12] Typically, distribution system operators use information provided by the OMS to direct field crews to outage locations. Crews do not typically do this on their own unless they have mobile devices with links to the OMS. Several of the SGIG DA utilities found advantages from equipping field crews in this way and decentralizing aspects of service restoration activities.

1.2 Project Build and Impact Metrics

Each SGIG project collected and reported two types of metrics: 1) **build metrics**, including the number of installed devices, device functions, and their costs; and 2) **impact metrics** (e.g., fewer outages, reliability index improvements, reduced line losses, reduced electric demand) that assessed the effects of the new technologies and systems on grid operations and business practices. Appendix B includes a detailed review of the data collection and analysis process.

At the outset of the SGIG program, DOE collaborated with each of the project teams to develop a Metrics and Benefits Reporting Plan (MBRP) outlining how the utility would collect and report metrics over the course of the project. DOE analysis[13] of the DA projects involved the assessment of four key components (see Figure 6), along with lessons learned.

Figure 6. SGIG Analysis Process

- ***Assets*** (e.g., automated feeder switches)
- ***Functions*** (e.g., switches automatically open/close to reconfigure power flows)
- ***Impacts*** (e.g., fewer and shorter power outages)
- ***Benefits*** (e.g., lower economic losses from outages)

Because DA involves not only new technologies but also new business practices and procedures, DOE analysis also included assessment of lessons learned and best practices from the SGIG projects.

1.3 Key Data Limitations and Considerations

This report is designed to present a comprehensive review of DA technology impacts and benefits reported under the SGIG program. **Results on DA technology cost, performance, and savings were not directly comparable across *all* 62 DA projects for a number of reasons, including utility size and project scale, differences in the specific devices and functions deployed, pre-project technology maturity, and baseline data availability.** Several factors are important to consider when evaluating project data and results in this report:

- **SGIG DA utilities did not deploy every technology or function**, and therefore did not all report results for every data point. As a result, select charts and graphs are marked with notations such as "36 projects reported this data point." In some cases, the most significant benefits represent experiences from a small number of projects. While several DA utilities deployed more than one DA asset or tested more than one application, almost all of the DA assets were deployed by 30 or fewer utilities. Similarly, a large percentage of certain DA devices were deployed by only a

[13] The DOE analysis approach is further outlined in: Electric Power Research Institute (EPRI), *Guidebook for Cost/Benefit Analysis of Smart Grid Demonstration Projects*, Revision 1, December 2012.

handful of SGIG utilities. For example, 78 percent of SGIG remote fault indicators were deployed by just 3 utilities.

- **As expected, large-scale technology deployments produced the most significant and meaningful impacts and benefits. The DA projects had a wide range of scale,** and directly comparing technology results across all projects at different scales was not meaningful; instead, the report includes aggregated results where possible and individual project results as examples. Some results were reported by only a small subset of utilities.

- **The SGIG DA utilities had differing levels of experience and expertise with DA** technologies and systems. Utilities that had steeper learning curves yielded limited impact data during time periods when they were first installing and operating the new technologies.

- **Individual project case studies are highlighted in this report, including certain project costs and benefits, to present a range of examples on the DA technology cost-benefit ratio**. Though all projects reported DA implementation costs, [14] costs varied greatly among projects and average DA implementation costs were not reliable metrics for several reasons:

  - Utilities did not uniformly measure and report total equipment costs. In reporting the total cost per device, many utilities included several different non-hardware costs—including software and licensing fees, hardware installation labor, IT testing and requirements gathering, project management, software integration, and staff training. These costs can vary greatly based on the utility's prior DA experience and existing technology platforms.

  - Small-scale deployments are not able to achieve the same economy of scale as large-scale deployments, given the fixed cost of new system implementation.

  - Costs may vary based on different capabilities or functionalities of individual devices.

  - Some utilities deployed wholly new equipment, whereas others may have been able to retrofit existing devices to operate in an automated fashion.

  - DA hardware and software was largely purchased by 2010, making it likely that cost data is not indicative of current or future equipment costs.

- **Some utilities had trouble establishing reliable historical baselines from which to measure improved performance.** Accurately measuring the impact of DA technologies required consistent measurement of historical performance—before the technologies were implemented. Several utilities underestimated the time, effort, and engineering expertise required to accurately measure smart grid impacts and historical baselines. Some utilities had difficulty measuring year-to-year performance changes attributable to SGIG deployments versus those resulting from routine feeder maintenance, storm damages, and changing customer demographics.

[14] Information on how individual projects deployed funds and evaluated impacts can be found on the Project Information page at SmartGrid.gov.

2 Major Findings: Reliability and Outage Management

Improving grid reliability can reduce economic losses and customer inconveniences from sustained power interruptions, which are estimated to cost the economy almost $80 billion annually.[15] Table 4 summarizes select results from the 46 SGIG DA utilities that applied DA for reliability and outage management.

Table 4. Reliability and Outage Management Results from DA Investments

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

[15] Lawrence Berkeley National Laboratory, Cost of Power Interruptions to Electricity Consumers in the United States, LBNL-58164, (LBNL, 2006).

2.1 Remote Fault Location, Isolation, and Service Restoration using Automated Feeder Switching

DA technologies provided advanced capabilities for operators to detect, locate, and diagnose faults. Remote fault indicators, relays, and reclosers provide access to real-time data on key feeders, which when delivered to a fully functional DMS, can help operators accurately determine causes and locations of faults and the extent of outages when they occur.

In addition, utilities with AMI can configure smart meters to generate “last gasp” signals when they lose power. Control room operators can also “ping” smart meters to confirm power outages or restoration status. Integrating AMI data with DMS, OMS, and GIS can thus help operators pinpoint and visualize outages, and deploy repair crews to precise fault locations. Several DA utilities also implemented AMI as part of their SGIG projects.[16]

Many SGIG utilities deployed DA technologies for more than simple fault indication. Fault location, isolation, and service restoration (FLISR) technologies and systems involve automated feeder switches and reclosers, line monitors, communication networks, DMS, OMS, SCADA systems, grid analytics, models, and data processing tools. These technologies work in tandem to automate power restoration by automatically isolating faults and restoring service to remaining customers by transferring them to adjacent feeders via tie lines. This can reduce the number of customers impacted by a fault and the length of an interruption.

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.

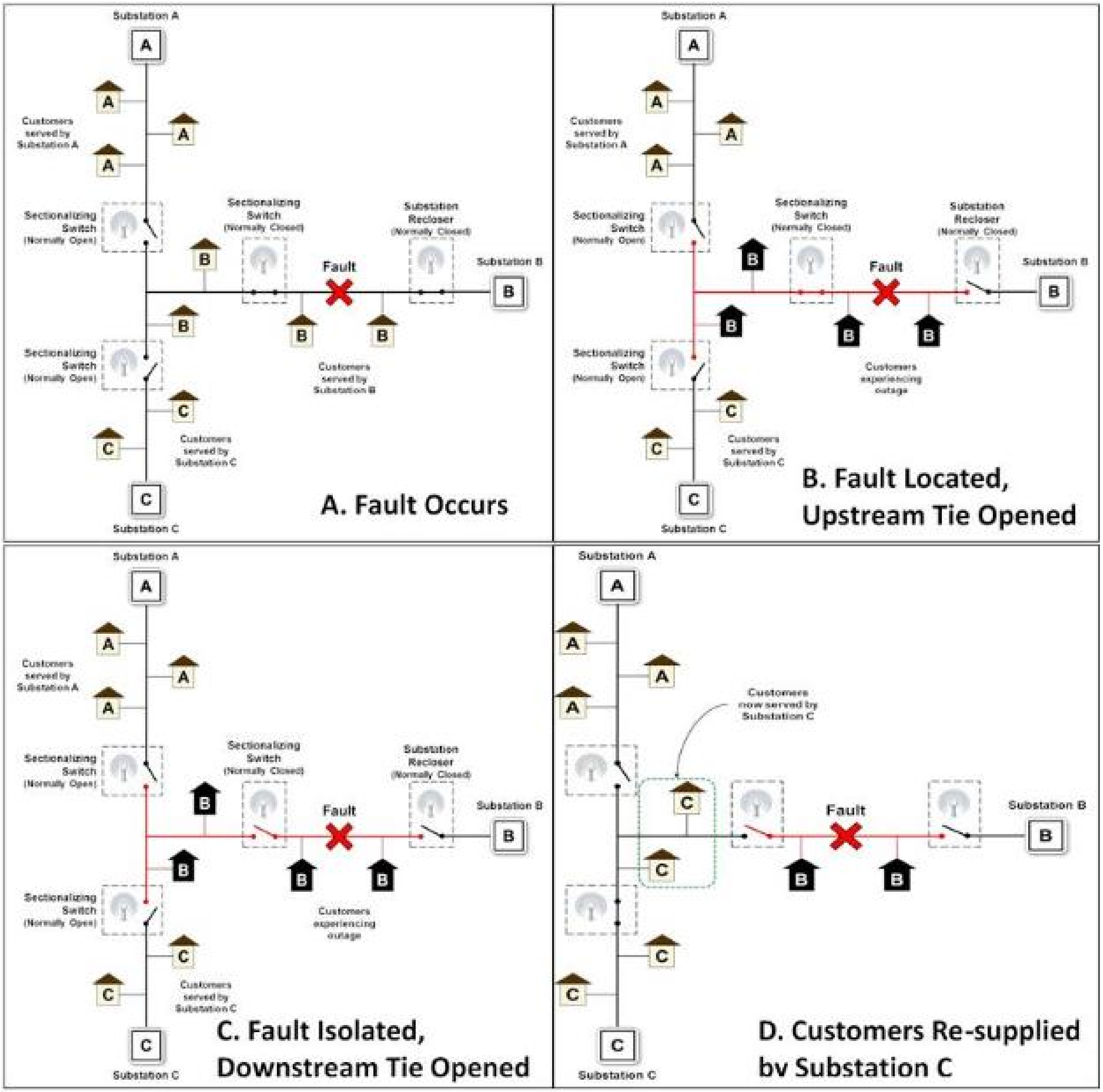
Figure 7 presents simplified examples (A-D) to show how FLISR operations typically work. In Figure 7-A, the FLISR system locates the fault, typically using line sensors that monitor the flow of electricity and measures the magnitudes of fault currents, and communicates conditions to other devices and 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 7-B), and one downstream and further away (Figure 7-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 portion(s) of the feeder without a fault and restores services to all customers served by these feeder sections from another substation/feeder (Figure 7-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.

[16] SGIG results from AMI applications are presented separately in: DOE, *Advanced Metering Infrastructure and Customer Systems: Results from the Smart Grid Investment Grant Program*, 2016.

Figure 7. Illustration of FLISR Operations



Several SGIG utilities implemented FLISR in distinct ways. For example, Pepco's Automatic Sectionalizing & Restoration (ASR) schemes segment feeders into two, three, or four sections using closed remote-controlled switches or automatic circuit reclosers in the field. Duke Energy also installed "Self-Healing Teams" of field devices, which connect electronic reclosers and circuit breakers from two or three neighboring feeders and enable them to operate together in an integrated manner. See the case studies for detailed descriptions of how each utility designed and operated their FLISR functions.

→ See **Case Study:** Pepco (page 50)

→ See **Case Study:** Duke Energy (page 40)

Table 5 also summarizes some of the key FLISR activities within the SGIG program.[17]

Table 5. Overview of Five SGIG FLISR Utility Activities

	CenterPoint Energy	Duke Energy	Eversource	Pepco	Southern Company
Name of FLISR System	Self-Healing Grid	Self-Healing Teams	Auto Restoration Loops	Automatic Sectionalizing & Restoration	Self-Healing Networks
Field Devices Involved	Intelligent Grid Switching Devices 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

Key Result: Measurable Improvements in Reliability

DA implementation resulted in significant improvements in reliability indices for several SGIG utilities. Most utilities use reliability indices developed by the Institute of Electrical and Electronic Engineers (IEEE) to track performance and evaluate improvement needs. Table 6 provides a summary of the four primary reliability indices used by the electric power industry.

Table 6. IEEE Reliability Indices [18]

Reliability Index	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 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.	$SAIDI = \frac{\sum r_i N_i}{N_T} = \frac{CMI}{N_T}$

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[17] For more information, see: DOE, *Fault Location, Isolation, and Service Restoration Technologies Reduce Outage Impact and Duration*, (DOE, November 2014).
[18] IEEE, *Guide for Electric Power Distribution Reliability Indices*, IEEE Standard 1366-2012, (IEEE, 2012).

Reliability Index	Description	Equation
Customer Average Interruption Duration Index (CAIDI)	The sum of the restoration time for each sustained interruption (r_i) multiplied by the number of customers interrupted (N_i), or 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 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.	$MAIFI = \frac{\sum IM_i N_{mi}}{N_T}$

The best way to evaluate the impact of DA technologies on system reliability is to compare reliability indices before and after deployment using a well-established pre-deployment baseline. Unfortunately, many SGIG utilities had trouble establishing accurate, reliable pre-deployment baselines from which to measure performance improvements. It is recognized that the process of developing a baseline is complex and time consuming for utilities. Simply comparing reliability indices from year to year—rather than against a baseline—cannot effectively measure the full impact of DA investments.[19]

Utilities that **did** compare results against pre-deployment baselines reported significant reliability improvements with DA. In 2013 alone, three utilities reported SAIFI improvements of 17 percent to 58 percent compared to pre-deployment baselines (see Figure 8). [20] SAIFI is the primary metric used to track the frequency of outages.

The impact of DA on reliability depends on the system design and its potential for improvement. Utilities that applied DA technologies to the worst feeders first saw a larger relative impact than utilities who applied DA to feeders with less room for improvement.

PPL Electric Utilities Corporation estimated a 58 percent decrease in the average number of interruptions experienced by customers in 2013, and a 55 percent drop in the average number of customer minutes interrupted. Based on these results, PPL estimates a 25 percent improvement in reliability over the subsequent five years through the continued deployment of DA.

Duke Energy also reported experiencing a 17 percent improvement in SAIFI 2013 from DA operations in Ohio, while the Northern Virginia Electric Cooperative (NOVEC) compared 2011-2013 data from 41 feeders with pre-deployment five-year benchmarks and showed improvements across all major reliability indices.

→ See **Case Study:** PPL Electric Utilities Corporation (page 48)

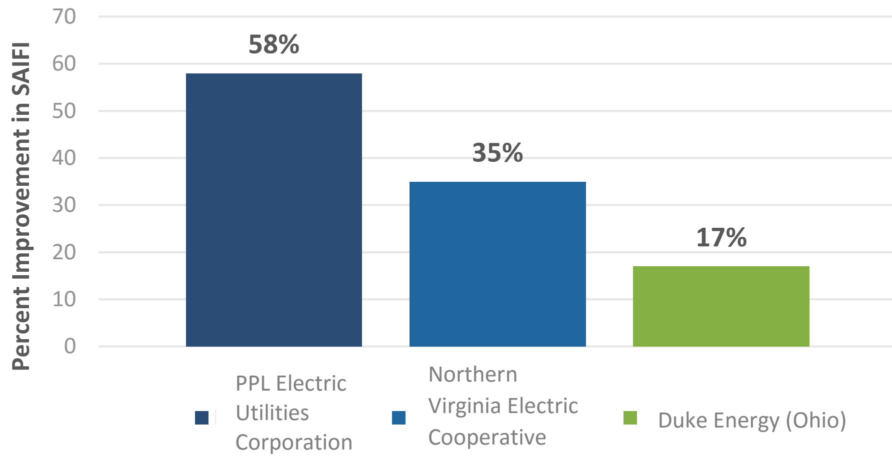
→ See **Case Study:** Northern Virginia Electric Cooperative (page 34)

→ See **Case Study**: Duke Energy (page 40)

[19] For example, Appendix D shows SAIFI, SAIDI, CAIDI, and MAIFI comparisons from summer 2013 to summer 2014 for several utilities implementing DA. The data demonstrates that many utilities experienced reliability improvements year over year with DA, while others saw *decreased* reliability after DA deployments. Without well-documented pre-deployment baselines for comparison, changing weather from year to year (e.g., more/fewer storms) or changing system configurations can obscure the true reliability impact of DA technologies.

[20] Baselines are not always explicitly stated.

Figure 8. Percentage Improvements in SAIFI in 2013 Compared to Pre-Deployment Baselines



Several other utilities also reported improvements in their major reliability indices:

- The Electric Power Board (EPB) of Chattanooga, TN reported a 30 percent reduction in SAIFI and a 20 percent reduction in SAIDI from 2011 to 2014.
- Between April 2013 and September 2014, the Sacramento Municipal Utility District (SMUD) achieved reductions of 28 percent in SAIDI and 19 percent in SAIFI.

→ See **Case Study:** Electric Power Board (page 36)

→ See **Case Study:** Sacramento Municipal Utility District (page 67)

Key Result: Reduced Impact, Duration, and Cost of Major Storms and Outage Events

CMI is the restoration time for each sustained interruption multiplied by the number of customers interrupted during that outage, making it a valuable metric for assessing customer impacts from DA operations (see Table 6 in previous section for a detailed definition).

Over one year, FLISR operations during certain feeder outages *reduced by half* the number of affected customers and total customer minutes of interruption, according to data from five utilities. Five utilities (representing 10 operating companies) applied similar FLISR operations during 266 events between April 2013 and March 2014.[21] FLISR operations applied to either: (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 9 shows substantial reductions in the number of CI and CMI for both types of outages. Table 7 provides supporting data.

[21] U.S. Department of Energy, *Fault Location, Isolation, and Service Restoration Technologies Reduce Outage Impact and Duration*, November 2014.

Figure 9. FLISR Effects on the Number of Customers Interrupted (CI) and Customer Minutes of Interruption (CMI) by Type of Outage

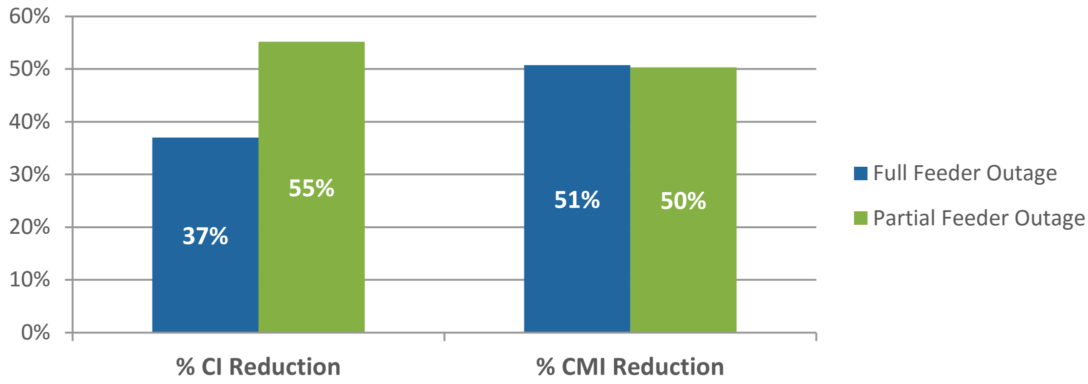


Table 7. Effects of FLISR Operations on CI and CMI by Type of Outage

Type of Outage	Total Estimated CI *without* SGIG technologies	Total Actual CI *with* SGIG technologies	**% Reduction of CI**	Total Estimated CMI ***without*** SGIG technologies	Total Actual CMI ***with*** SGIG technologies	**% Reduction of CMI**
Full Feeder Outage	255,424	160,972	**37%**	18,301,994	9,016,784	**51%**
Partial Feeder Outage	206,763	92,726	**55%**	17,470,615	8,676,751	**50%**

The same SGIG utilities found that fully automated switching and validation typically resulted in greater CI and CMI reductions than operator-initiated remote switching with manual validation. Figure 10 shows the percent reduction in CI and CMI by type of FLISR operating scheme for the same 266 FLISR events as above. Table 8 provides supporting data.

Figure 10. FLISR Effects on the Number of Customers Interrupted (CI) and Customer Minutes of Interruption (CMI) by Type of FLISR Operating Scheme

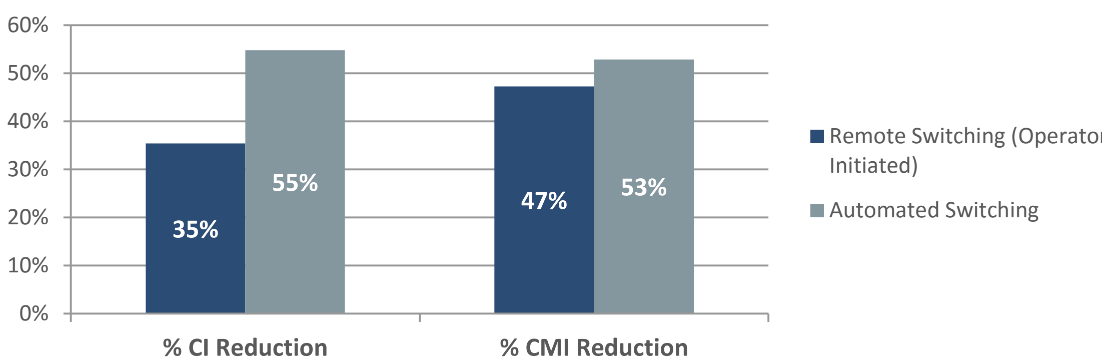


Table 8. Effects of FLISR Operations on CI and CMI by Type of FLISR Operating Scheme

Type of Switching	Total Estimated CI ***without*** SGIG technologies	Total Actual CI ***with*** SGIG technologies	**% Reduction of CI**	Total Estimated CMI ***without*** SGIG technologies	Total Actual CMI ***with*** SGIG technologies	**% Reduction of CMI**
Operator-Initiated	230,388	148,917	**35%**	15,037,440	7,926,425	**47%**
Fully Automated	231,799	104,781	**55%**	20,735,169	9,767,110	**53%**

Table 9 shows the potential magnitude of CMI impacts from DA operations over several months or years for 15 SGIG DA utilities. Due to data constraints, the period of data collection and reporting is not identical for all utilities; some reported data for only one month or one year, while others collected data for multiple years. The benefits of the technology likely continued well beyond these reporting periods.

Table 9. CMI Avoided by DA Operations

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

Several SGIG utilities experienced major storms or events during their project period and used DA technologies to significantly reduce restoration time and limit the number of customers affected. Fewer and shorter outages help customers avoid economic losses, inconveniences, and public health and safety risks. Individual case studies contain detailed descriptions of the following examples:

- FLISR and smart meters at EPB resulted in 36 million fewer CMI during a July 2012 derecho and helped operators restore system-wide power about 17 hours earlier than without DA. After another storm in February 2014, EPB was able to restore power 36 hours faster and reduce affected customers from 70,000 down to 33,000.
- When a garbage truck hit a power pole and caused almost 900 customers to lose power at Avista Utilities, FLISR restored more than 800 customers instantaneously, and the remainder within minutes.
- Florida Power and Light (FPL) saw about 9,000 fewer customer interruptions due to FLISR operations during Tropical Storm Isaac in 2012.

Many utilities use value-of-service studies, which involve statistical analyses of economic damages and willingness-to-pay by customers for more reliable electric service in order to estimate the monetary value of the benefits from reliability improvements. DOE developed the Interruption Cost Estimate (ICE) calculator, which is based on meta-analysis of utility value-of-service studies, as a tool for utilities to estimate economic benefits from investments in reliability improvements.[22] **At least three utilities were able to estimate their customers' savings as a result of DA operations during a major storm**:

→ See **Case Study:** Consolidated Edison (page 44)

→ See **Case Study:** Glendale Water and Power (page 81)

- Consolidated Edison used the ICE calculator to estimate more than $1.2 million in avoided interruption costs—largely benefitting industrial and commercial customers—for a 14-feeder system for a single year.
- Central Maine Power used the ICE calculator to estimate that SGIG DA investments in substation and line reclosers saved customers an average of $18,000 per outage involving line reclosers, and $29,000 per outage when the outage took out a substation. This utility estimated total customer savings of more than $935,000 in 2014, and expects avoided economic losses to total more than $20.7 million through 2020.[23]
- Glendale Water and Power (GWP) estimated the net present value of DA investments would increase by 42 percent if customer savings were included in the analysis.

A lack of standard metrics across utilities to measure storm response makes it difficult to compare benefits from investments in FLISR and automated feeder switching in a consistent manner across utilities. Outages occur in different seasons, at different times of day, or on different days of the week—all of which can affect how much an outage will cost utilities and customers, along with the estimated savings. Utilities that experience increased storm events in one year may realize greater overall benefits from DA technologies than other utilities that do not.

In addition, because weather events are random, predicting future storm impacts and benefits for inclusion in forward-looking business cases can be difficult. For example, the February 2014 snowstorm that affected the Electric Power Board (EPB) occurred on a weekend. Had the storm arrived on a weekday, there would have been lower overtime costs and the savings from fewer truck rolls would have been lower. Thus, the savings for improvements in outage management can be hard to estimate before the investments take place, as assumptions about weather events and other factors can turn out to be inaccurate. As a result, business cases need to contain contingencies that reflect uncertainties in the weather, timing, and other factors. To build a business case, it is important for utilities to collect data, no matter what metrics are used, to document impacts and benefits and provide information decision makers can use for business case analysis.

Key Result: Operations and Maintenance Efficiency and Savings

SGIG utilities reduced O&M costs by automating functions that previously required field crews to conduct on-site monitoring, maintenance, and repair functions. Reductions in labor costs, truck rolls, vehicle-miles traveled, and replacement parts can accrue to significant savings for operators. The SGIG DA utilities reported four major sources of labor cost savings in outage management:

[22] Lawrence Berkeley National Laboratory, "Interruption Cost Estimate Calculator," 2015.

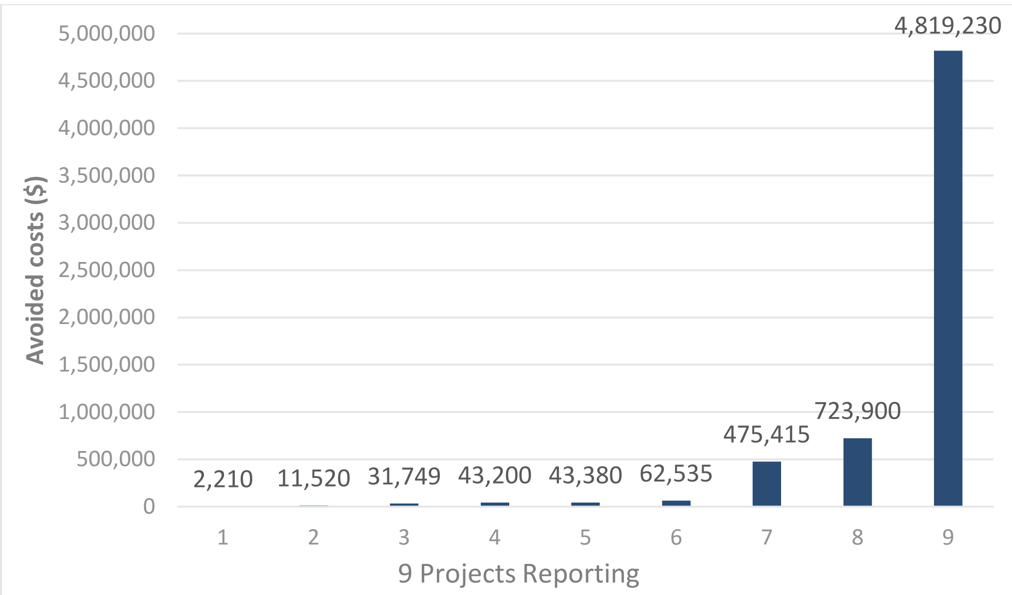
[23] Based on an estimate that the value of an average outage hour for an average customer (covering residential, commercial, and industrial customer classes) to be about $97 for 2014-2019.

- Pre-empting and avoiding outages before they occur
- Proactively identifying outages during work hours, rather than waiting for customer calls (which typically come during nights and weekends)
- Optimizing truck rolls during an outage
- Correcting nested outages along with primary outages instead of coming back to them later

Utilities generally do not apply consistent metrics and tools to measure and compare the benefits from investments in reliability and outage management.

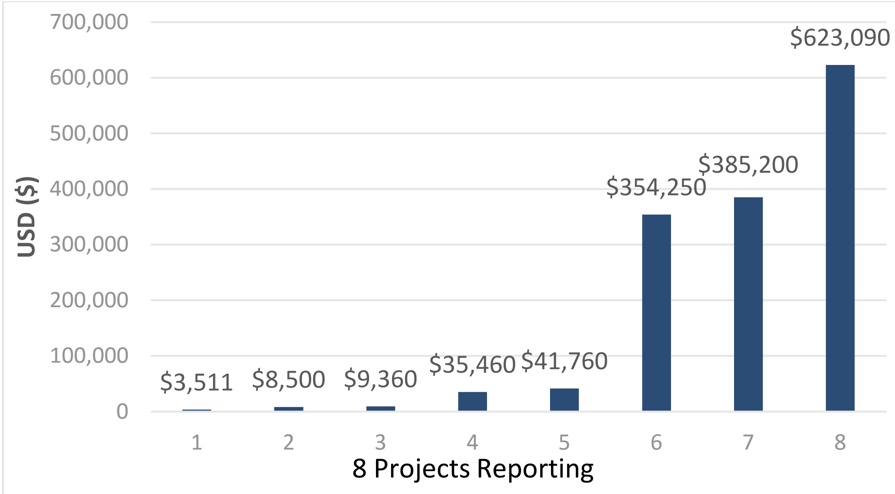
Nine SGIG DA utilities saved more than $6.2 million in total avoided distribution operations costs from April 2013 to September 2014 (see Figure 11). The utility that produced most of the benefits is one that implemented system-wide DA deployment.

Figure 11. Avoided Distribution Operations Costs for SGIG DA Utilities, April 2011 to September 2014 (9 Projects Reporting)



Savings from avoided switching costs totaled more than $1.46 million for eight SGIG DA utilities that reported savings from April 2011 to March 2014 (see Figure 12). Automated feeder switching reduces O&M costs by requiring fewer truck rolls and fewer instances where repairs crews are sent to accomplish feeder switching functions manually.

Figure 12. Avoided Switching Costs for SGIG DA Utilities, April 2011 – March 2014 (8 Projects Reporting)



There are several examples of SGIG DA utilities reducing labor resource requirements and service restoration costs, including the following:

- NOVEC's savings from DA operations were about $1,500 in avoided fuel and about $133,000 in labor savings from summer 2011-summer 2014.
- EPB reported saving about $1.4 million in avoided overtime costs following DA operations after a snowstorm in February 2014.
- Duke Energy (formerly Progress Energy) reduced its annual outage assessment activities by 20% (more than 500 hours).

Using an automated or remote-controlled approach to fault restoration and equipment health monitoring can resolve or prevent outages, ultimately reducing the labor hours of field crew and truck fleet vehicle miles. By identifying where on the grid a fault has occurred, DA also enables repair crews to be dispatched to precise locations for repair and restoration service activities. Reduced customer service labor hours also result from improvements in outage monitoring and notification. A more reliable estimated time of restoration (ETR) and more proactive customer outage notifications reduces call volume during outage events, thereby reducing labor hours for call center staff.[24]

In total, from April 2011 to March 2015, 16 reporting SGIG DA utilities avoided more than 197,000 truck rolls and 18 reporting DA utilities avoided more than 3.4 million vehicle-miles traveled as a result of various types of DA operations (see Figure 13 and Figure 14). The utilities in the two figures with the highest levels of O&M savings were the ones that pursued full-scale implementation of DA (i.e., #16 for truck rolls, and #17 and #18 for vehicle-miles traveled). The lowest savings per utility was 52 truck rolls and the highest per utility was 123,070. The lowest savings per utility was 86 avoided vehicle-miles and the highest was 1,705,601.

[24] Because these types of savings cross-cut all four DA applications discussed in this report, it is not possible to attribute the savings to reliability and outage management alone. The SGIG utilities were not required to report O&M impacts specific to these categories, as doing so would have been cost prohibitive.

Figure 13. Total Avoided Truck Rolls by 16 SGIG DA Utilities, April 2011 – March 2015

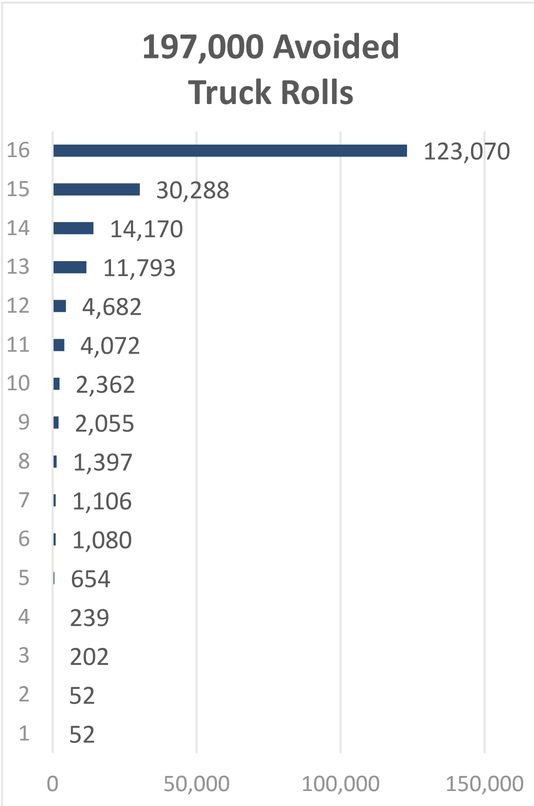
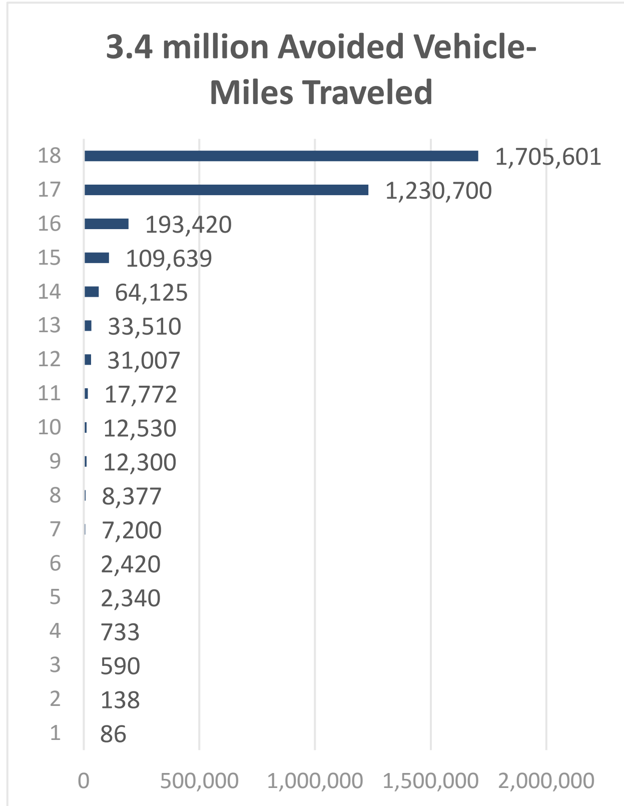


Figure 14. Total Avoided Vehicle-Miles Traveled by 18 SGIG DA Utilities, April 2011 – March 2015



Based on analysis of truck roll data from 18 SGIG DA utilities between April 2011 and March 2015, **it is estimated that DA operations resulted in reductions of about 2,350 metric tons of carbon dioxide-equivalent**, which equals the amount of carbon dioxide released from consuming about 264,000 gallons of gasoline.[25]

2.2 Outage Status Monitoring and Notification

Integrating information from monitoring devices and AMI with OMS and GIS enables utilities to provide customers with more accurate and timely information about the status of outages and restoration services. Automated features lower utility costs and customers benefit from better information about when services will be restored following outages.

Many utilities leverage smart meters and AMI to implement this functionality. Utilities set up automated processes for pinging meters over large areas when large outages are reported, and then target affected feeders and neighborhoods as service restoration activities progress. This saves valuable time in the minutes following an outage so operators do not have to undertake manual meter pings. Some utilities turn off the automated last gasp notifications in the initial phase of storm response, when emphasis is on restoring substations and transformers and a barrage of meter notifications can overwhelm OMS

[25] U.S. Environmental Protection Agency, "Greenhouse Gas Equivalencies Calculator," last updated April 2014; Argonne National Laboratory (ANL), *GREET Model*, (ANL Systems Assessment Laboratory, 2015).

screens if the system is configured in that fashion. In these cases, meter notifications get turned back on once outages have been located and restoration activities are underway.

Utilities with other monitoring devices such as line monitors, fault indicators, and relays integrate information from these with smart meter data and OMS operations. The next task involves communicating with customers about the status of outage restoration activities. Notifications involve multiple channels including phone and text messages, email alerts, and website posts, sometimes including the estimated time to restoration of services. Glendale Water and Power's interactive voice response (IVR) software and Burbank Water and Power's OMS system that supports customer call-backs and notifications are two examples. Additional examples of customer notification are reported in *Advanced Metering Infrastructure and Customer Systems: Results from the SGIG Program*.

Key Result: Improved Customer Satisfaction and Public Awareness

Customer notifications and estimated restoration times help improve public awareness and planning, reduce the burden on customers to report outages, and increased customer satisfaction. CenterPoint Energy's Power Alert Service updated customers on restoration progress, and earned an 85 percent overall satisfaction rating.

When Hurricane Isaac hit Mississippi in 2012, Magnolia Electric Power Association (MEPA), a member of South Mississippi Electric Power Association (SMEPA), was required to give the Mississippi Emergency Management Agency updates three times a day on the status of outages and restoration efforts by county. With 5-second updates on SCADA data from system relays and monitors, and 15-second smart meter updates, MEPA was able to provide the requested outage reports relatively easily. Previously, during Hurricane Katrina in 2005, it took MEPA several hours to provide this information.

2.3 Optimized Restoration Dispatch

The availability of timely, accurate, and more comprehensive information about outages and the ability to process that data and deliver it to grid operators and repair crews accelerates restoration times and lowers costs, which benefits both utilities and customers. A key tool for supporting this smart grid-enabled function involves integration of OMS operations with workforce management systems (WMS). WMS is used to help field crews with software tools for automated scheduling, resource optimization, dynamic routing, and workflow management. WMS can set priorities for restoration tasks based on multiple criteria for level of importance and supports crew management, by tracking crew sizes, locations, and performance in restoring services.

Another way DA enables optimized crew dispatch is by enabling hot line tags to be placed remotely on distribution equipment. Hot line tags are placed on equipment during field activities to ensure worker safety. Traditionally, utilities typically sent repair crews to manually place physical tags on distribution equipment before crews could conduct operations and maintenance activities. These tags would carry warnings not to operate certain switches/relays because another team was at work elsewhere on the feeder. With smart systems in place, utilities can "tag" DA equipment remotely through SCADA, allowing restoration efforts to proceed faster and more safely.

Key Result: Faster, More Targeted, and Safer Restoration

The SGIG DA utilities implemented a variety of approaches to optimizing restoration dispatch activities. Individual case studies provide more detailed explanations of the following examples:

- Following a February 2014 storm, PECO was able to dispatch repair crews and restore services three days faster than they would have otherwise using AMI data (when smart meter roll out was 50 percent complete).
- The Sacramento Municipal Utility District (SMUD) used software for correlating, analyzing, and visualizing data from field devices, DMS, OMS, GIS, and weather forecasts. The new system quickly synthesizes numerous streams of disparate data and provides on-the-fly assessments of grid, asset health, weather, power supply, and electricity demand conditions.
- Consolidated Edison's OMS has been merged with electric distribution and service mapping information, customer billing information, customer service call data, workforce and repair crew availability, and SCADA telemetry into one screen for control center operators.
- CenterPoint Energy's OMS enables operators to visualize outages the moment they occur and often times, trucks are rolled before customer calls are received.

CASE STUDY: **NORTHERN VIRGINIA ELECTRIC COOPERATIVE (NOVEC)**

Electric Cooperative

Virginia

143,196 Customers

Distribution Circuits Impacted:	**105 (of 235)**	**Distribution Substations Impacted:**	**37 (of 53)**

DA Communication Network: IP-based communication links

Total Cost of DA Implementation under SGIG

$10,000,000

Distribution Automation Devices Deployed					
Automated Feeder Switches	✓	**14**	Remote Fault Indicators	✗	
Automated Capacitors	✓	**164**	Transformer Monitors	✓	**56**
Automated Regulators	✓	**340**	Smart Relays	✓	**25**
Feeder Monitors	✗		Fault Limiters	✗	
Automated Reclosers	✓	117	Smart Reclosers	✓	19
Substation Battery Bank Monitors	✓	33			

DA Improved Reliability from Five-Year Benchmarks: NOVEC reported reliability improvements on the 41 feeders installed with electronic vacuum reclosers and motor-operated air break switches. NOVEC analysis compared 2011-2013 data from 41 feeders for the major reliability indices with pre-deployment, five-year benchmarks and showed improvements across the board, as shown in Table 10.

Table 10. NOVEC Reliability Analysis, 2011-2013.

Analysis Period	SAIFI	SAIDI	CAIDI	MAIFI
Summer Benchmark	0.62	54.49	88.50	0.39
Summer 2011	0.66	38.32	57.93	0.21
Summer 2012	0.37	27.71	74.20	0.20
Summer 2013	0.40	22.53	70.63	0.15
Winter Benchmark	0.48	36.08	74.93	0.39
Winter 2011	0.27	21.63	68.55	0.40
Winter 2012	0.28	16.03	71.09	0.13

Improved Efficiencies Reduce Truck Rolls and Fleet Miles: NOVEC reduced truck rolls and fleet vehicle miles from improved efficiencies from a variety of automated field activities. Table 11 provides a summary of the savings.

Table 11. Summary of NOVEC Savings from DA Operations from 2011 to 2013.

Activity	Truck Rolls Avoided	Vehicle Miles Saved
Substation Inspection Reductions	150	1,200
Fault Response/Forensic Data Retrieval	300	18,000
Remote Hot Line Tagging	3600	57,600
Remote Equipment Setting Changes	300	2,400
Remote Inspection	100	6,000

Efficiencies Reduce Labor Costs and Produce Fuel Savings: NOVEC, which serves 155,000 customers, avoided 59 truck rolls and 831 vehicle-miles traveled covering the summer of 2011 through the summer of 2014. Assuming average costs per mile to fuel and maintain typical repair trucks (diesel-light truck Class 5) are about $1.88 per mile, and average labor costs per truck roll are about $160 (excluding overheads), then NOVEC's savings from these DA operations were about $1,500 in avoided fuel, and about $133,000 in labor savings.

Power Quality Monitors Reduce Voltage Variations: NOVEC used power quality monitors on meters and transformers to help reduce voltage variations such as sags and surges and power harmonics. NOVEC received daily reports from these monitors and was able to check the number of regulator operations per device, tap positions of regulators, and feeder voltage levels. Based on the operational information from the power quality monitors, NOVEC ensured service voltage levels to customers remained within the acceptable level (114 volts to 127 volts) by remotely controlling, or making timely repairs to, voltage regulators.

READ MORE ABOUT NOVEC'S PROJECT ON SMARTGRID.GOV:

Northern Virginia Electric Cooperative Project Page

Northern Virginia Electric Cooperative Project Description – *July 2014*

CASE STUDY: **ELECTRIC POWER BOARD OF CHATTANOOGA (EPB)**

Municipal/Public Utility

Tennessee, Georgia

172,079 Customers

Distribution Circuits Impacted:	**232 (of 370)**

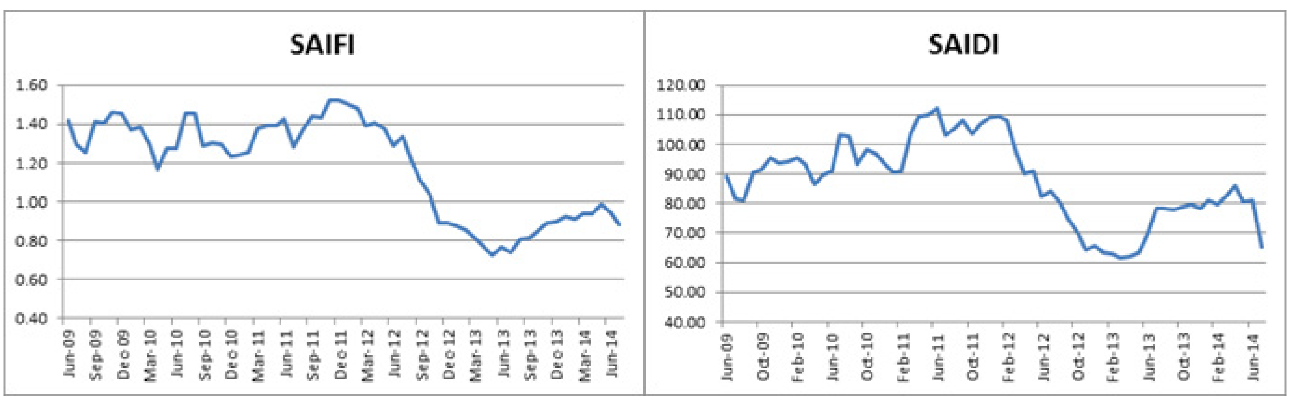
Communication Network: Fiber optic network

Total Cost of DA Implementation under SGIG	Distribution Automation Devices Deployed				
$49,878,568	Automated Feeder Switches	✔	1,294	Remote Fault Indicators	✖
	Automated Capacitors	✖		Transformer Monitors	✖
	Automated Regulators	✖		Smart Relays	✖
	Feeder Monitors	✖			

Communication Upgrades Support Smart Grid and More: EPB installed an ultra-speed, high-bandwidth, fiber optic network that provides services beyond those for electric grid applications.

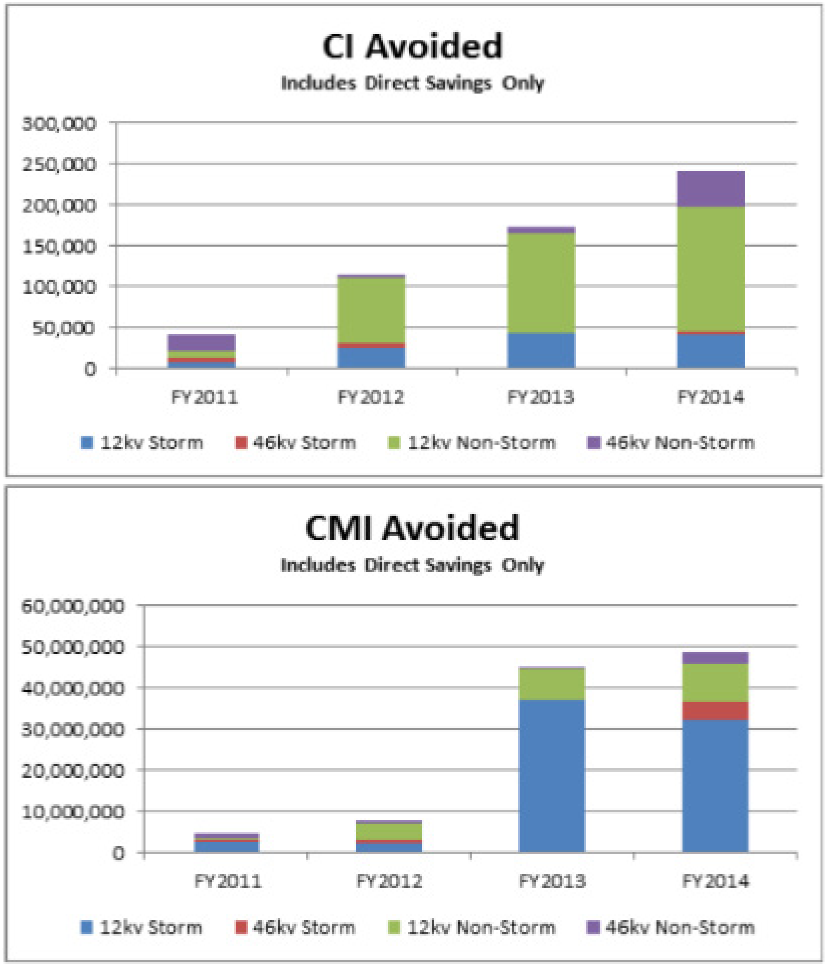
Sustained Outage Frequency Reductions Improve Reliability: EPB also reported a 30 percent reduction in SAIFI from 2011 to 2014. As shown in Figure 15, SAIDI also showed a 20 percent reduction over the same time period.

Figure 15. SAIFI and SAIDI Performance for EPB, 2009 – 2014



DA Operations Produce Customer Minutes of Interruption (CMI) Savings: Figure 16 shows improvement in CI avoided during the time period in which automated feeder switching (AFS), FLISR, and AMI technologies and systems were deployed and operated by EPB. The upper chart in the figure shows increases in avoided CI, and that in 2011-2013, the amount of avoided CI increased particularly for customers "upstream" of faults, an indicator that AFS and FLISR operations were effective. The lower chart in the figure shows improvements in the number of CMI experienced by customers.

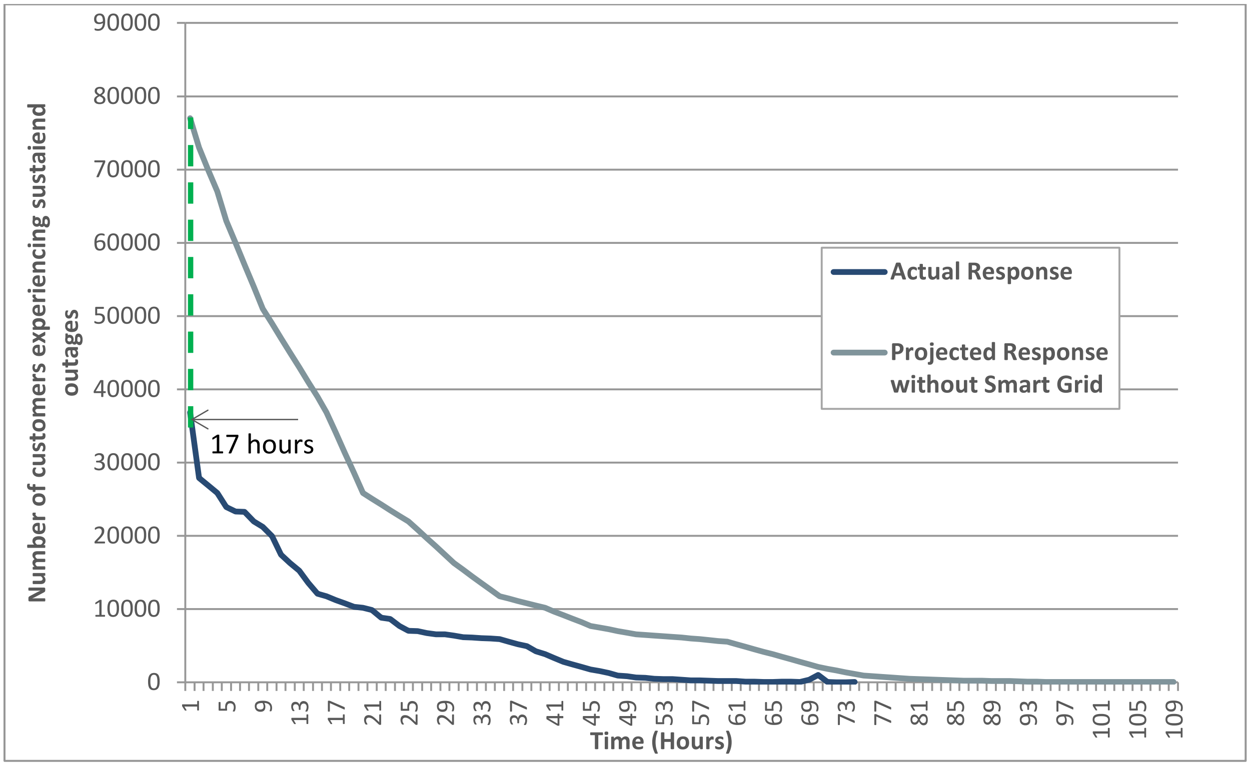
Figure 16. CI and CMI Improvements for EPB, 2010 – 2014



Instant Restoration Reduces the Extent of Major Outages: The July 2012 derecho that impacted much of the Midwest also struck Chattanooga, affecting about half of EPB's customers. Because of EPB investments in smart switches and smart meters, the outage duration for all affected customers decreased by about half. This resulted in about 36 million fewer CMI than would have occurred without the new technologies.

AFS Enables System-Wide Restoration Days Faster Following Major Storms: Figure 17 shows the results of using smart switches and smart meters for storm restoration at EPB. The blue line shows the time it would have taken EPB to restore power to affected customers in this storm without application of AFS and AMI. The green line shows the improvement in restoration time due to these practices. Overall, EPB's response was up to 17 hours faster due to the automated feeder switches, which restored power to 40,000 customers instantly and allowed crews to focus on a more limited number of issues. Smart meter data also helped operators verify outages, enabling EPB field crews to locate and fix downed lines faster and more efficiently.

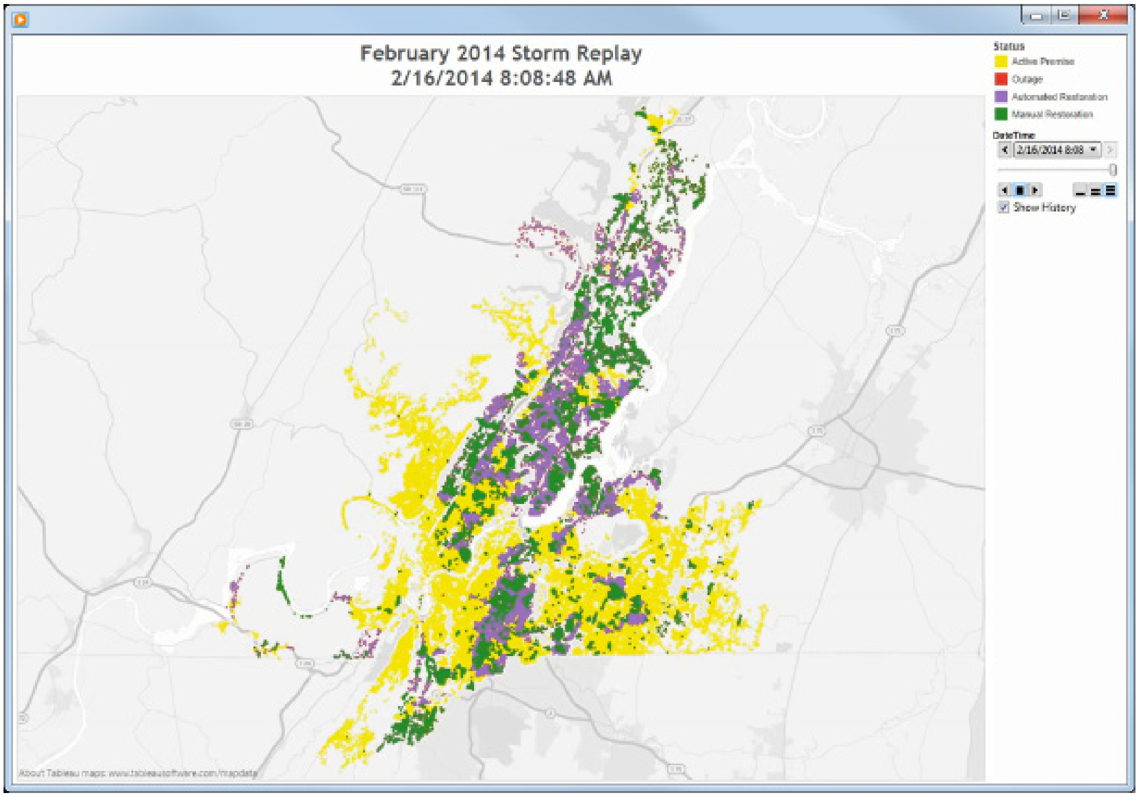
Figure 17. Improvement in Service Restoration by EPB Following a Storm in July 2012



EPB also experienced a snowstorm in February 2014 that affected more than 50 feeders and almost 33,000 customers. During the storm, EPB kept all of its smart switches active and did not deactivate FLISR capabilities. EPB reports that without the fault isolating capabilities of the smart switches, about 70,000 customers would have experienced sustained outages. EPB estimates that it was able to restore power about 36 hours earlier than would have been possible without smart grid deployments. Of those 36 hours avoided outage hours, EPB estimates about 16 were due to the self-healing actions of the smart switches, and about 20 were due to EPB's ability to "ping" smart meters, verify outage status, and redirect repair crews accordingly. EPB estimates it saved about $1.4 million in overtime costs for field crews during this storm.

Figure 18 shows a map of outage and restoration patterns from the snowstorm. The map shows the areas that were restored automatically (purple) and manually (green). Customers that were not interrupted are shown in yellow.

Figure 18: EPB Map of Outage and Restoration Patterns during a Snowstorm in February 2014



Business Case Analysis Considers Multiple Factors: The February 2014 snowstorm that affected the EPB occurred on a weekend. Had the storm arrived on a weekday, there would have been lower overtime costs and the savings from fewer truck rolls would have been lower. Thus, the savings for improvements in outage management can be hard to estimate before the investments take place, as assumptions about weather events and other factors can turn out to be inaccurate. As a result, business cases need to contain contingencies that reflect uncertainties in the weather, timing, and other factors. To build a business case, it is important for utilities to collect data, no matter what metrics are used, to document impacts and benefits and provide information decision makers can use for business case analysis.

Fiber Optic Network Extends Services: EPB installed an ultra-speed, high-bandwidth, fiber optic network which provides services beyond those for electric grid applications.

Future Deployment Will Provide Real-Time Information: EPB reports that the deployment of DA equipment is part of EPB's plan to more fully automate its distribution system. Moving forward, EPB expects data from the smart switches to provide information on real-time loadings on all of EPB's transformers so that demand can be better calculated and planned for, thus utilizing existing capital assets more effectively.

READ MORE ABOUT ELECTRIC POWER BOARD OF CHATTANOOGA'S PROJECT ON SMARTGRID.GOV:

Electric Power Board of Chattanooga Project Page

Electric Power Board of Chattanooga Project Description – *September 2014*

Electric Power Board of Chattanooga Case Study – *May 2011*

CASE STUDY: **DUKE ENERGY**

Investor-Owned Utility

Ohio, Indiana, Kentucky, North Carolina, South Carolina

4,514,000 Customers

Communication Network: Cellular DA and SCADA network

Total Cost of DA Implementation under SGIG

$189,471,768

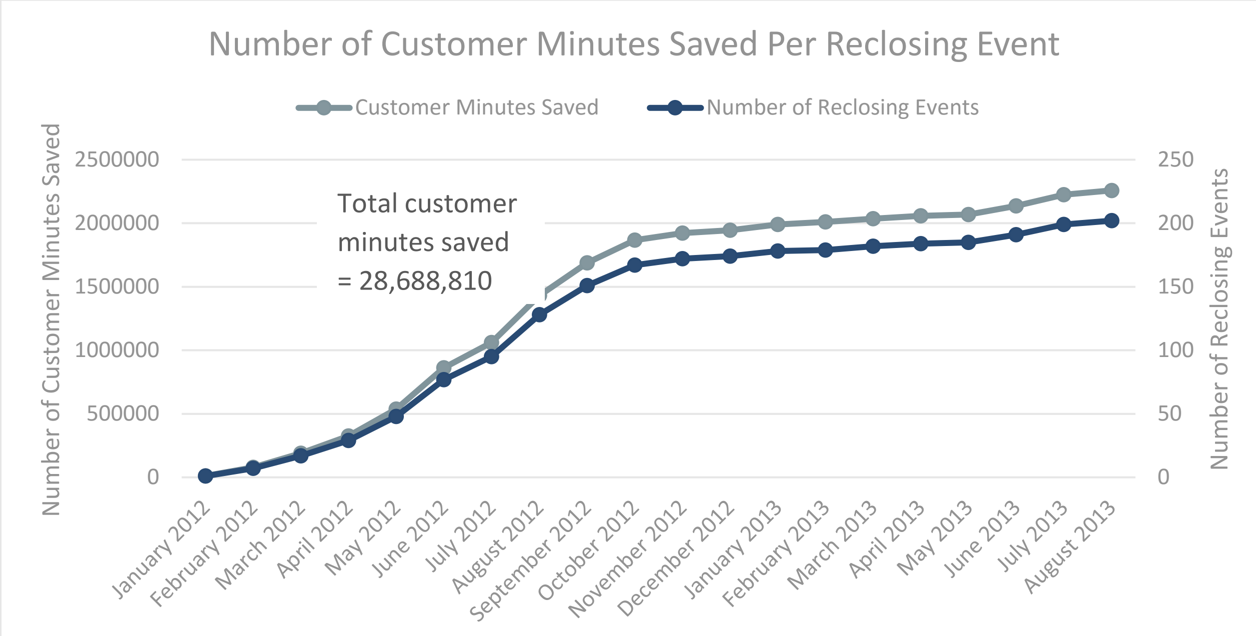
Distribution Automation Devices Deployed					
Automated Feeder Switches	✓	**914**	Remote Fault Indicators	✓	**4,755**
Automated Capacitors	✓	**2,098**	Transformer Monitors	✗	
Automated Regulators	✓	**914**	Smart Relays	✓	**4,755**
Feeder Monitors	✓	**83**			

DA Technologies Better Equip Field Crews: Duke Energy's approach emphasizes equipping field crews with key data and information tools. Instead of deploying field crews based on customer outage reports, line sensors and analysis software identify precise locations for repair, reducing costs and accelerating restoration of services.

Self-Healing Teams Enable Integrated FLISR Operations: Duke Energy 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 Energy 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 to enhance the utility's response for accelerating restoration of services. Data from the line sensors are communicated to the utility's control room.

Re-Closure Activations Result in Avoided CMI: From January 2012 to August 2013, Duke Energy estimated avoiding about 28,688,810 CMI, due to re-closure activations, as shown in Figure 19. In 2014, after an additional 200 re-closers were installed, an estimated 111,200 additional CMI were avoided (75,400 CMI if major storms are excluded).

Figure 19. Number of Customer Minutes Saved Per Reclosing Event at Duke Energy



Smart Meter Data Improves Outage Diagnostics: As a part of its AMI system deployment, Duke Energy installed 966,000 smart meters with outage diagnostics features that allow the utility to "ping" meters and determine fault location. Its AMI system helped resolve 1,393 cases of single-call outages with remote diagnostics between 2010 and 2014.

Annual Outage Assessment Time Reduced: Duke Energy reports reductions in the amount of time spent annually assessing outages (including fault location) by more than 560 hours[26]. This impact results from applications of both fault location technologies and systems and AMI for pinging meters and confirming the status of power outages and restoration activities. Table 15 shows the results of Duke's estimates.

Table 12. Duke Energy Estimates of Reductions in Outage Assessment Activities

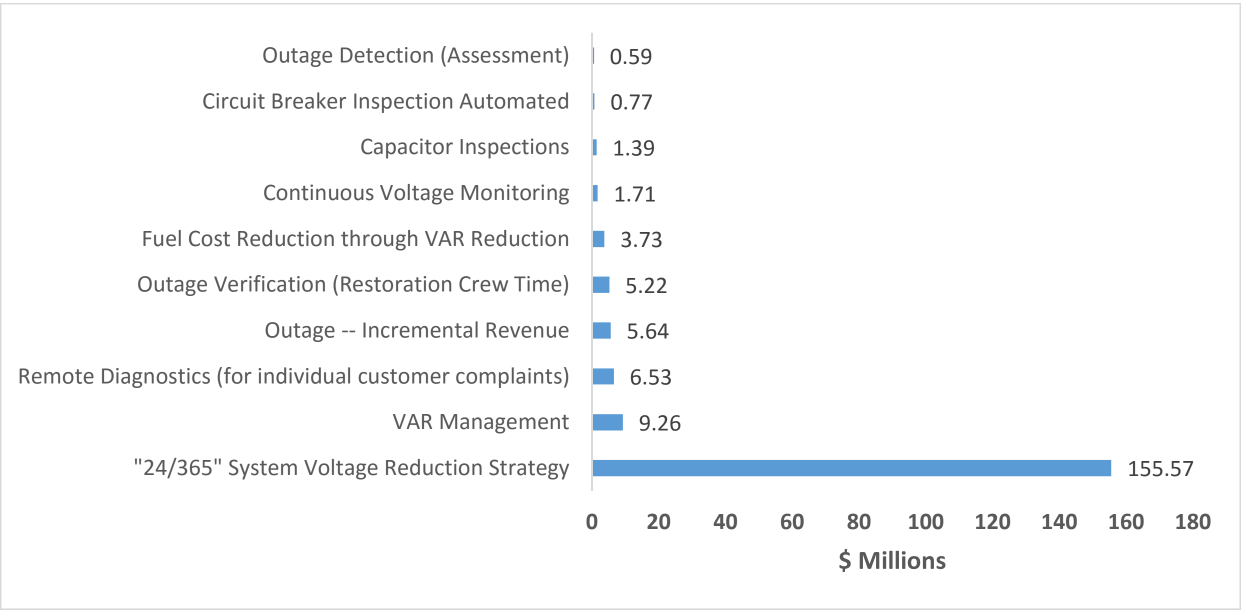
Duke Energy Estimates of Reductions in Outage Assessment Activities	
Outage Assessment Time Before SGIG (hours)	2,838
Outage Assessment Time After SGIG (hours)	2,270
Reduction in Outage Assessment Time (hours)	**568**
Percent Reduction in Outage Assessment Time (%)	**20%**

Service Voltage Level Reductions Lower Electricity Consumption: Management of peak demands through service voltage level reductions can reduce electricity consumption of end-use appliances and equipment and reduce customer bills. Reduction in electricity consumption is on the order of 1–3 percent. When implemented during peak hours, conservation voltage reductions (CVR) actions can supplement traditional demand-side management programs such as direct load controls, time-based rates, and incentive based programs. Duke Energy refers to its CVR actions as "Distribution System Demand Response" for this reason.

[26] Duke collected this data from work order management systems, service outage management systems, and labor timekeeping systems.

Continuous Voltage Optimization Vastly Improves Smart Grid Business Case: Duke Energy was among the first utilities to rigorously assess and establish the business case for its smart grid deployment. In 2011, Duke supported a third-party evaluation from the Public Utilities Commission of Ohio that validated 26 benefit areas.[27] Duke estimated the value of the revenue and benefit streams it can expect over 20 years, and discounted them to today's dollar to account for the changing value of money. Duke's deployment as of 2014 was tracking ahead of the 2011 estimated benefits in aggregate. Figure 20 shows that continuous voltage monitoring forms a large portion of the business case. Continuous voltage optimization can also reduce generation to avoid fuel costs and defer distribution capital investments. Other DA investments have smaller paybacks for Duke.

Figure 20. Estimated Net Present Value of Duke Energy's Smart Grid Program (2011 Dollars)



Integrated Volt/Volt-Ampere Reactive (VAR) Controls Achieve Voltage Reduction: Duke Energy used integrated volt/VAR controls to achieve consistent 2 percent voltage reduction on more than 200 circuits in Ohio. These reductions saved fuel and lowered customer bills, with no detrimental effects on service quality.

Remote Capabilities Reduce Physical Inspections: The remote capabilities of Duke Energy's new capacitor bank controllers reduced physical inspections by 1,085 units in 2013. Continuous monitoring instead of a once-a-year physical inspection reduces manual inspection costs and better optimizes voltage.

New DMS Integration Requires Change Management Practices: Under SGIG funding, Duke Energy installed a new DMS to enable new capabilities from device deployments, including FLISR, IVVC, and automated switching plans. The DMS now provides a data historian, Distribution Operations Training Simulator, and DMS/OMS interface capabilities across Duke's service territory. A key success for Duke Energy's smart grid project was the early implementation of business process management and change

[27] MetaVu for the Staff of the Public Utilities Commission of Ohio, *Duke Energy Ohio Smart Grid Audit and Assessment*, (MetaVu, June 2011).

management best practices. Implementing a DMS and deploying distribution automation were large-scale efforts that required leadership and coordination across multiple business units. Duke Energy facilitated business process management and change management through its newly formed Grid Modernization Organization, which is responsible for industry trend identification, business case development, business and regulatory approval, and upon project approval, project management and business readiness activities.

Change management prepares people and processes for business changes, particularly those with project benefits that depend on employee adoption, usage, and commitment to project timelines. Effective organizational change was particularly critical for the implementation of a DMS and integration of distribution automation devices, which required staff, technology, and process integration across business units. For example, DMS changes the roles of the GIS and IT support from traditional back-office staff to operational partners within the business. Adequate communication was a must. DMS required equal IT and business support, so joint business and IT leadership was required for its success. For any large-scale smart grid effort, communications, business process management, and change management structures should be built into the project plan, and relevant business units should be engaged early and often.

Deployment Expansions Planned: Duke Energy plans to complete its 10-year plan for grid modernization and expand deployments of fault location, isolation, and system restoration technologies and systems ("Self-Healing Teams") to additional substations and feeders with focus on service territories in Indiana, Kentucky, Florida, and the Carolinas.

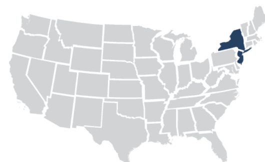
READ MORE ABOUT DUKE ENERGY'S PROJECT ON SMARTGRID.GOV:

Duke Energy Project Page

Duke Energy Project Description – *September 2015*

CASE STUDY: **CONSOLIDATED EDISON (CON EDISON)**

Investor-Owned Utility



New York, New Jersey

3,578,188 Customers

Distribution Circuits Impacted: 840 (of 2,297)

DA Communication Network: Master radio sites to upgrade SCADA and wireless

Total Cost of DA Implementation under SGIG

$272,341,798

Distribution Automation Devices Deployed					
Automated Feeder Switches	✓	**797**	Remote Fault Indicators	✓	**1,851**
Automated Capacitors	✓	**449**	Transformer Monitors	✓	**17,401**
Automated Regulators	✓	**111**	Smart Relays	✓	**205**
Feeder Monitors	✓	**617**	Recloser Controls		307
Remote Battery Monitors	✓	**17**			

OMS, DMS, SCADA, and GIS Integration: Con Edison OMS has been merged with electric distribution and service mapping information, customer billing information, customer service call data, workforce and repair crew availability, and SCADA telemetry into one screen for control center operators. During outages, embedded models and analysis tools provides operators with predictions of field operations, actual data streams on grid conditions from SCADA, number of customers affected or restored, damage assessment information, and tracking of outage and restoration activities for managing and dispatching service and restoration crews and resources. This system also provides customer call center staff with maps of the grid showing the location of meters without power. This information is updated in near real time, is used to direct and manage field crews to restore power, and enables communications with customers on outage locations and estimated return to service times.

DA Greatly Reduces Customer Costs from Fewer and Shorter Outages: Con Edison used the ICE calculator to estimate the reduction in cost to customers for power interruptions occurring on its Orange & Rockland feeders. The calculator (which includes savings realized when adding distribution automation to circuits) estimates over $1.2 million reduction in interruption costs for the 14-feeder feeder system for a single year. These benefits were largely estimated to occur in the commercial and industrial customer classes, with the residential customers saving about $27,000. The impact of interruptions on industrial and commercial customers varies widely according to the type of business and the processes interrupted. The customer-average savings was about $650 per customer for larger customers and about $230 per customer for smaller customers.

Voltage Management Improves Substation Capacity under Peak Conditions: Through the use of overhead medium voltage distribution circuits and improved voltage management, Con Edison was able to improve voltage management capabilities; enhance power system measurement; reduce reactive power consumption; and improve asset utilization, capacity management, and energy efficiency. Deployments included installation of pole mounted distribution capacitors, load tap changer (LTC) controllers at 4 kilovolt (kV) unit substation transformers, power quality and battery monitoring systems, and development of 4kV grid models for enhanced load flow analysis. Table 21 summarizes the key results based on data through the end of 2013.

Table 13. Summary of Con Edison Voltage Control Results

Summary of Con Edison Voltage Control Results		
Asset Utilization and Capacity Management	i.	Increased 4kV unit substation capability by 31.1 megavolt-ampere (MVA) or 2.8% under peak conditions, resulting in a net savings of $15.7 million.
	ii.	Reduced 4kV system primary losses by 2.3% under peak conditions.
Voltage Controls for Reactive Power Management and Energy Efficiency	iii.	Reduced reactive power requirements at the aggregate level of 33 substations in Queens by about 12.3% and 9.9% over a one-year test period through the application of advanced LTC controls.
	iv.	Increased power factor at these same substations by about 2% and 1% over the same one-year test period.
	v.	Reduced annual system energy losses by 4,500 megawatt-hours (MWh), resulting in estimated annual energy savings of about $340,000.

DERMs Improves Control of Demand Resources: Con Edison's distributed energy resource management system (DERMS) was used to monitor and control a variety of supply and demand resources including distributed generation and storage, building management systems, and demand response customers.

Data Historian Improves Data Access and Management: Con Edison's data historian project implements a centralized data repository for all electric distribution SCADA data. The system is integrated with existing corporate data systems and provides a single point of access for all users of the company's electric distribution data. BWP's data historian is responsible for capturing and storing operational measurements for the electric distribution network and for providing analytical tools for assessing distribution performance.

READ MORE ABOUT CON EDISON'S PROJECT ON SMARTGRID.GOV:

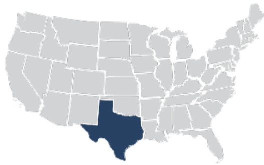
Consolidated Edison Company Project Page

Consolidated Edison Company Project Description – *August 2014*

Consolidated Edison Company Case Study – *May 2011*

CASE STUDY: **CENTERPOINT ENERGY**

Investor-Owned Utility



Houston, TX

2,320,156 Customers

Distribution Circuits Impacted:	**188 (of 1,516)**	**Distribution Substations Impacted:**	**31 (of 240)**

DA Communication Network: RF, WiMAX, and cellular technologies

Total Cost of DA Implementation under SGIG

$120,604,288

Distribution Automation Devices Deployed					
Automated Feeder Switches	✓	567	Remote Fault Indicators	✗	
Automated Capacitors	✗		Transformer Monitors	✗	
Automated Regulators	✗		Smart Relays	✓	171
Feeder Monitors	✗				

DA Technology Package Enables FLISR Functions: CenterPoint Energy implemented its Intelligent Grid Switching Devices—a comprehensive package of DA technologies that perform a number of integrated grid functions. For example, Intelligent Grid Switching Devices use enclosures similar to line reclosers to provide reliable switching operations across thousands of operations without maintenance. Intelligent Grid Switching Devices also include 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.

OMS Integration Enables Outage Visualization and Efficient Dispatch of Repair Crews: CenterPoint Energy's OMS enables operators to visualize outages the moment they occur and trucks are often rolled before customer calls are received. In several cases, outages have been restored before customers were even aware that they had lost power. During large events, CenterPoint's OMS system can display results from thousands of last gasp smart meter signals, as well as data from SCADA and customer calls all on one screen, which enables operators to dispatch field crews more efficiently. Before this system was used, once a fault had been repaired, operators assumed all customers on the feeders had their power restored, which is not an accurate assumption during large scale outages. In some cases, customers involved in nested outages would still be without power and field crews would have to be dispatched a second time.

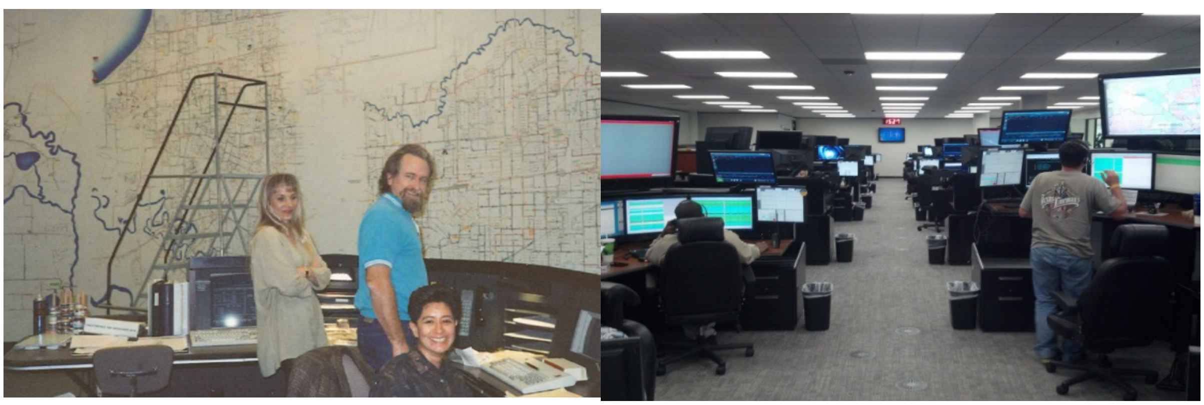
Improved Outage Alerts Increase Customer Satisfaction: CenterPoint Energy implemented a Power Alert Service (PAS) for customers using its OMS and AMI outage alerts to keep customers up-to-date with accurate information about the progress of restoration activities. Based on survey analysis, CenterPoint found customers highly satisfied with the service (see Figure 21).

Figure 21. Results of CenterPoint Energy Survey of Customer Satisfaction for Outage Information

Satisfaction Measures	
Overall Satisfaction with PAS: Combined responses for all delivery methods (email, text, and phone. 4 or 5 on a 5-point scale).	**85%**
Message Timeliness – "Power Out": Time to receive power out message met or exceeded expectations (4 or 5 on a 5-point scale).	**88%**
Message Timeliness – "Power On": Time to receive power on message met or exceeded expectations (4 or 5 on a 5-point scale).	**96%**
Usefulness of Information Provided: 4 or 5 on a 5-point scale.	**86%**
Estimated Restoration Time Accuracy: Power restored within +/- 30m of estimate.	**73%**

Advanced Distribution System Management Improves Planning: CenterPoint Energy's Advanced Distribution Management System (ADMS), which manages its FLISR operations, replaced the utility's legacy DMS, OMS, and distribution SCADA systems and allows the utility to use real-time smart meter and Intelligent Grid Switching Device data to better plan, engineer, and operate the grid. ADMS also integrates with the company's GIS, 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 22 shows CenterPoint's distribution management system in 1993 and in 2014, illustrating how new technologies have made system operations increasingly digital.

Figure 22. CenterPoint Energy's DMS – 1993 and 2014



Post-SGIG DA Activities Planned: The utility plans to continue activities with its DMS vendor and user community to develop and deploy additional advanced capabilities and applications. CenterPoint plans to expand the capabilities of its Intelligent Grid Switching Devices from requiring manual validations to full automation, which will be tested on a limited number of substations and feeders before larger-scale deployments are implemented.

READ MORE ABOUT CENTERPOINT ENERGY'S PROJECT ON SMARTGRID.GOV:

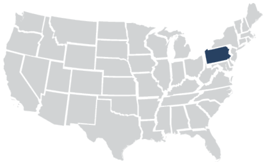
CenterPoint Energy Project Page

CenterPoint Energy Project Description – *September 2014*

CenterPoint Energy Case Study – *February 2012*

CASE STUDY: **PPL ELECTRIC UTILITIES CORPORATION**

Investor-Owned Utility



Pennsylvania

1,396,751 Customers

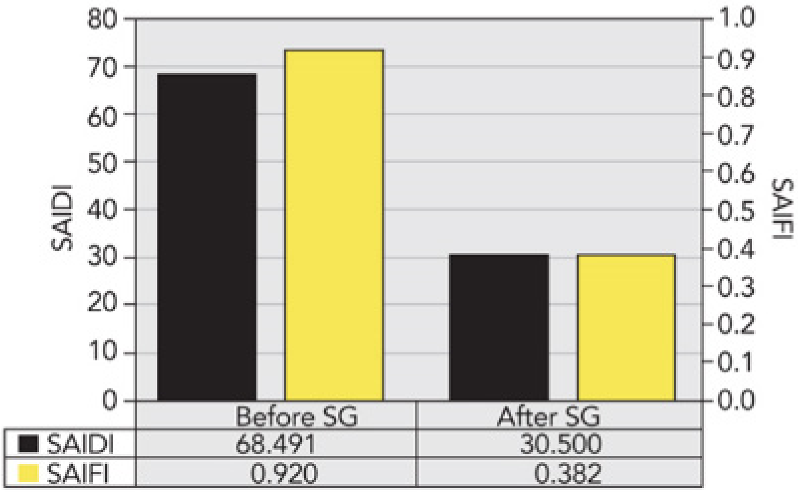
Distribution Circuits Impacted:	50 (of 1153)	Distribution Substations Impacted:	10 (of 376)

DA Communication Network: WiMAX, cellular, and fiber optic cable

Total Cost of DA Implementation under SGIG	Distribution Automation Devices Deployed					
$38,108,290	Automated Feeder Switches	✓	214	Remote Fault Indicators	✗	
	Automated Capacitors	✓	195	Transformer Monitors	✗	
	Automated Regulators	✗		Smart Relays	✗	
	Feeder Monitors	✗		Automated Reclosers	✓	77

DA Results in Sustained Reliability Improvements: PPL Electric Utilities Corporation estimated a 58 percent decrease in the average number of interruptions experienced by customers in 2013 (compared against a pre-deployment baseline), which also involved a 55 percent drop in the average number of customer minutes interrupted. PPL also estimated improvements in SAIDI over that same time period (see Figure 23).

Figure 23. SAIDI and SAIFI Improvements before and after Smart Grid (SG) Deployment, Estimated by PPL in 2013



Based on these results, PPL estimates a 25 percent improvement in reliability over the subsequent five years through the deployment of distribution automation. This estimate is based on analysis of PPL's three-phase distribution circuits only, and excluded major events. Because 2013 was a good year weather-wise, PPL expects long-term effects to be somewhat lower than the effects shown in Figure 23.

Remote Switching Improves CMI: In January 2012, PPL accomplished remote switching and restored 300 customers approximately 30 minutes earlier than if done manually, resulting in a CMI improvement of 9,000. Following an overload condition on two main lines in March 2012, PPL rerouted power in five minutes to prevent a sustained outage of 2,600 customers. In September, 2012 interference by a squirrel caused circuit breaker damage which affected more than 3,000 customers. PPL estimates that about 330,000 CMI were saved using remote detection and restoration procedures.

Future DA Investments Plan to Upgrade All Feeders: PPL Electric Utilities Corporation plans to continue DA investments through 2018 until all feeders (about 1,140 total) are upgraded. This involves installation or replacement of approximately 3,400 devices in addition to the 1,500 devices installed as of 2014 that will receive new communications devices. Plans call for completing DA upgrades on remaining feeders within five years, and to install sensors on all three-phase capacitors within three years. Future DA investments are estimated to cost about $118 million. Future projects include about 3,000 automated feeder switches and 4,000 automated capacitor banks.[28]

READ MORE ABOUT PPL ELECTRIC UTILITIES CORPORATION'S PROJECT ON SMARTGRID.GOV:

PPL Electric Utilities Corporation Project Page

PPL Electric Utilities Corporation Project Description – *September 2014*

PPL Electric Utilities Corporation Case Study – *December 2011*

[28] DOE, *PPL Electric Utilities Corporation (PPL Smart Grid Project)*, 2014.

CASE STUDY: **PEPCO - DC**

Investor-Owned Utility	Washington, DC	249,059 Customers

Distribution Circuits Impacted:	**19 (of 779)**
DA Communication Network:	Wireless mesh

Total Cost of DA Implementation under SGIG

$8,308,800

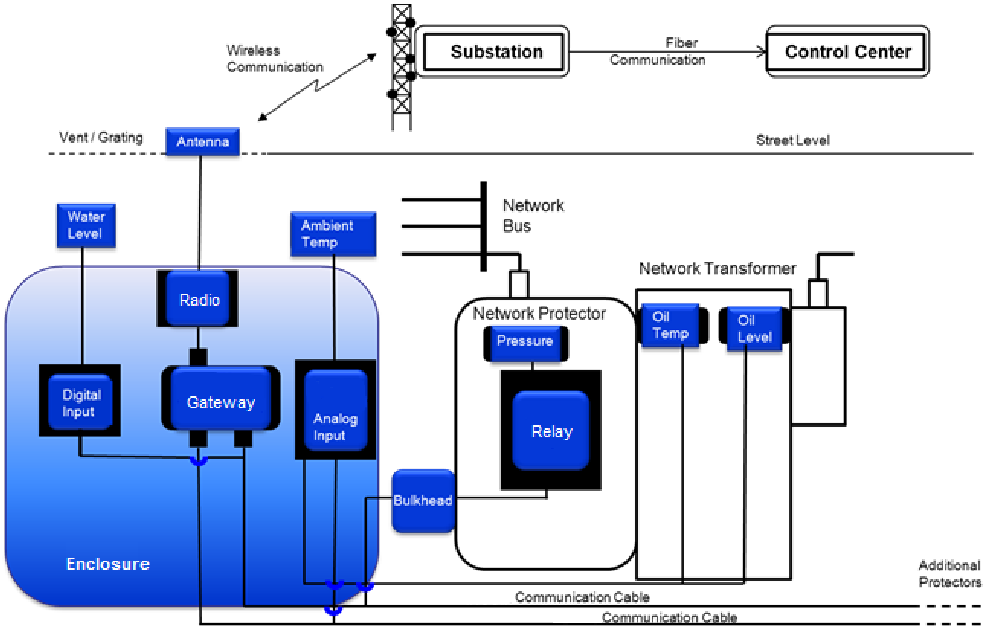
Distribution Automation Devices Deployed					
Automated Feeder Switches	✓	**42**	Remote Fault Indicators	✗	
Automated Capacitors	✗		Transformer Monitors	✓	**41**
Automated Regulators	✗		Smart Relays	✓	**306**
Feeder Monitors	✗		Substation DRTUs	✓	6
Transformer Health Sensors	✓	14	Automated Circuit Reclosers/Switches	✓	64

OMS and GIS Integration Improves Outage Management: In addition to OMS integration with AMI, Pepco's OMS has GIS mapping capabilities that display feeder and switch locations. The system shows operators and field crews the number of customers without power during outage events and the number of customer calls for each event. The system also allows operators to manually ping meters.

RMS and EMS Integration Improves Equipment Health Condition Monitoring: Pepco's remote monitoring system (RMS) is also integrated with the company's overall Energy Management System (EMS), enabling real-time and continuous data flows for operators and maintenance and repair crews to identify and address potential issues that can cause system disturbances. Pepco is also leveraging data from its remote monitoring system to improve its system planning process. It is using loads and voltages telemetry at peak time to verify the accuracy of the network computer model and the sizing of existing network transformers.

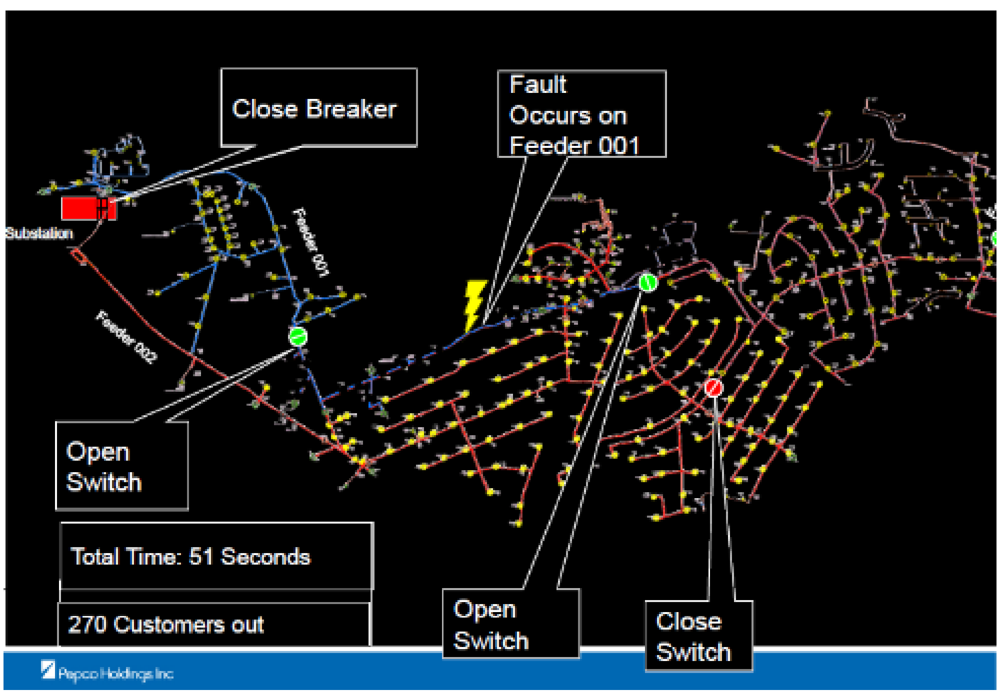
Figure 24 shows an example of how equipment health condition monitoring technologies and systems work together to implement actions. Pepco's approach focuses on transformers, and collects data such as oil level, oil temperature, and protector pressure (text in blue boxes without round corners), which is transmitted using radio communication to substations, and then is transmitted back to control centers using fiber-optic communications backhaul.

Figure 24. Illustration of Pepco's System for Equipment Health Condition Monitoring



Automatic Sectionalizing & Restoration Schemes Enable FLISR Operations: Pepco implements FLISR operations through its Automatic Sectionalizing & Restoration (ASR) schemes, which 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. Then, it restores the non-faulted sections by reclosing feeder breakers and/or closing open tie switches to other feeders. Figure 25 shows a screen shot of Pepco's ASR operations.

Figure 25. Screenshot of Pepco's Demonstration of FLISR Operations



Remote Software/Firmware Upgrades Reduce Time in Field: Pepco is moving toward 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.

DERMS Enabled Testing of Solar Systems Integration Revealed Challenges: Pepco developed a DERMS and measured voltage fluctuations from an 18 megawatt photovoltaic array connected to the distribution grid. The system simulated voltage levels that ranged from about 124 volts when the system was off to about 126 volts when system was set with a 0.97 leading power factor, and about 127 volts when the system was set with a 0.97 lagging power factor. With voltage level requirements set at 115.2 – 124.8 volts (+/- 4 percent of 120 volts), inverters were able to provide voltage management that reduced voltage fluctuations, and helped prevent voltage sags or collapses if large amounts of solar were to trip off line at one time. Pepco's photovoltaic system caused reverse flows on a few low load days, resulting in high voltage on the feeder and some damage to some customer equipment.

Future FLISR Deployments Planned: Pepco plans to continue its automatic sectionalizing and restoration deployments with the goal of reaching 15 percent of its systems, including expansion into areas covered by Delmarva Power, which was not part of its SGIG project.

READ MORE ABOUT PEPCO'S PROJECT ON SMARTGRID.GOV:

Note: Pepco Holdings, Inc. had three utilities with SGIG projects. Links to all three projects are included here.

Pepco Project Page

Pepco Holdings, Inc.—DC Project Description – *September 2015*

Pepco-MD Smart Grid Project Interim Report – *August 2013*

Atlantic City Electric Project Page

Atlantic City Electric Project Description – *September 2015*

3 Major Findings: Voltage and Reactive Power Management

Voltage monitoring and control and automated power factor correction enabled 38 SGIG utilities to reduce peak demands, efficiently utilize existing assets, and improve power quality.

Table 14. Voltage and Reactive Power Management Results from DA Investments

<table>
<tr><th>Primary Aim</th><td colspan="4">Reduced wear and tear on capital assets
Lower capital and operating costs to keep rates affordable for consumers
Protect sensitive electronic equipment—in utility and customer systems—from voltage and other power quality issues that can damage or limit equipment performance</td></tr>
<tr><th>Smart Grid Function</th><td>Integrated volt/volt-ampere reactive controls (IVVC)</td><td>Automated voltage regulation</td><td>Conservation voltage reduction (CVR)</td><td>Automated power factor correction</td></tr>
<tr><th>Description</th><td>IVVC enables automated and greater control of voltages and reactive power levels to improve feeder power factors and reduce line losses.</td><td>Enables utilities to monitor voltages, determine optimal control signals, and use manual or automated controls to regulate voltage levels on particular feeders</td><td>Monitoring and automated controls enable utilities to reduce feeder voltage levels to reduce electricity use, primarily during peak periods.</td><td>By monitoring voltages and using automated capacitor banks, utilities accomplish power factor corrections to improve energy efficiency and reduce energy requirements for electricity delivery</td></tr>
<tr><th>Key Impacts & Benefits</th><td colspan="2">Reduced line losses to improve energy efficiency and capacity management
Reduced peak demand
Improved reliability and reduced outage costs
Energy savings to reduce emissions and customer bills
Improved voltage management capabilities and power system measurement
Reduced reactive power consumption
Generation fuel supply and cost savings
Reduced damage to customer-side electronic equipment</td><td colspan="2">38 utilities employed conservation voltage reduction to reduce peak demands by 1%–3% on average per event.

One utility reduced annual system energy losses by an estimated 4,500 MWh, resulting in:
$0.34 million in annual energy savings
Reduced CO_2 emissions by about 340 metric tons
Several utilities improved power factors to near unity (where power factors equal 1).

One utility in particular:
Reduced reactive power requirements by about 10%–13% over a one-year test period
Increased power factors by 1%–2%</td></tr>
</table>

Historically, the size and placement of LTCs, voltage regulators, and capacitors were typically based on off-line modeling of peak- and light-load conditions, as well as operating experience. Most utilities did not monitor loads and voltages on the distribution system. For the last several decades, SCADA systems have been used by many utilities for distribution system monitoring, but these reach only substations and do not monitor feeder conditions from substations to customers. The lack of operating visibility on distribution feeders has historically required utilities to design and operate their systems in a relatively conservative manner to accommodate worst case scenarios. There has been little opportunity to optimize voltage and reactive power levels for constantly changing load conditions.

With the introduction of smart sensors, communications, and controls, utilities are now able to implement automated approaches to monitor and regulate voltage levels and reactive power levels, and to perform conservation voltage reduction and power factor correction to improve power quality. Many of the SGIG utilities pursued pilot-scale implementation of DA technologies for voltage monitoring and control to test the ability to improve efficiency and/or peak demand management.

As weather and climate conditions influence electricity demands, electricity generation and delivery assets are sized to serve demand when it reaches its highest levels, even though peak levels only occur less than 10 percent of the year. Because peak demand is one the most significant drivers of electricity costs, utilities attempt to reduce peak demands to improve asset utilization. This can result in lower capital requirements and operations and maintenance costs. Through rate cases and other proceedings, reduced peak demand can ultimately translate into lower electricity rates for consumers.

In addition, the use of digital electronics and computer controls in homes, offices, and factories is on the rise, enabling the nation's electricity consumers to operate more efficiently and expand capabilities for improving productivity, economic performance, and quality of life for consumers at home. However, changes from purely electro-mechanical to power-electronic-based components affect power quality requirements and other aspects of grid operations. For example, growing use of electronic, variable-speed-drive industrial motors can affect the inertial balance of the grid, which would impact the stability of local power systems. The changes in power quality requirements boost the need for addressing power quality issues on distribution systems.

Table 15 shows the impacts that result from the application of automated voltage controls.

Table 15. Utility and Customer Impacts from Voltage Management for Asset Utilization

Impacts	How Impacts are Accomplished
Utility Impacts	
Improved energy efficiency through reduced line losses and improved power factors	Feeder and substation sensors provide voltage and phase data to grid operators and/or DMS. Automated controls trigger voltage regulators and capacitor bank switching to optimize performance through conservation voltage reduction.
Reductions in peak demand	Smart meters and feeder sensors provide voltage data to grid operators and/or DMS. Automated controls implement conservation voltage reduction during peak periods which lower peak demands.

Impacts	How Impacts are Accomplished
Reductions in labor requirements	If automated volt/VAR control devices are replacing manually switched legacy equipment, this could result in avoided field visits for operations and maintenance of the devices without degrading the performance of the distribution system.
Improved reliability	Applications of conservation voltage reduction and real-time load balancing during peak periods reduces peak demands, risks for equipment overloads and the frequency of power disruptions.
Customer Impacts	
Energy savings and bill reductions	Applications of conservation voltage reduction reduce power consumption for affected customers and produces energy savings and lower bills.
Outage cost reductions	Reductions in the number of power disruptions reduce economic losses from outages for customers.

3.1 Integrated Volt/VAR Controls (IVVC) and Automated Voltage Regulation

Integrated volt/VAR technologies and systems provide new capabilities for grid operations to automate voltage controls and reactive power management. The SGIG DA utilities that implemented integrated volt/VAR controls employed a variety of techniques but all involved a common set of functions that began with data collection and telemetry for feeder voltage levels, feeder loads (real power in watts), and feeder reactive power (in VARs). Automated volt/VAR control devices (e.g., capacitor banks and voltage regulators) also report on their operational status (e.g., tap position of voltage regulators) to the utility's SCADA system.

The SCADA system collects the data and delivers it to utility back office systems and also typically to the DMS. In these cases, the DMS uses inputs from other grid assets and monitoring devices to continuously update models of electric distribution system operations. DMS models are used to estimate the effects of various grid elements on power flows and voltage profiles, including interconnected distributed generators such as rooftop photovoltaic or fossil-fuel fired gen sets. Given the available inputs and modeling capabilities, the DMS is used to determine optimal, coordinated volt/VAR control actions that are appropriate for given operational needs.

Once the optimal control actions are determined, the DMS sends switching commands to each volt/VAR control device through the SCADA system, which passes the commands to individual devices, such as switching capacitor banks and adjusting load tap changer and voltage regulator set points. If desired, grid operators can choose to manually override control actions determined by the DMS.

Grid operators can monitor, control, and optimize voltage from substations, along feeders, and all the way to customer premises using DA. Voltage level data at the customer from smart meters is sent to grid operators and DMS for use in optimizing grid performance. Voltage regulation down to the customer level is an important complementary objective for utilities implementing more comprehensive volt/VAR controls, like CVR (see more below).

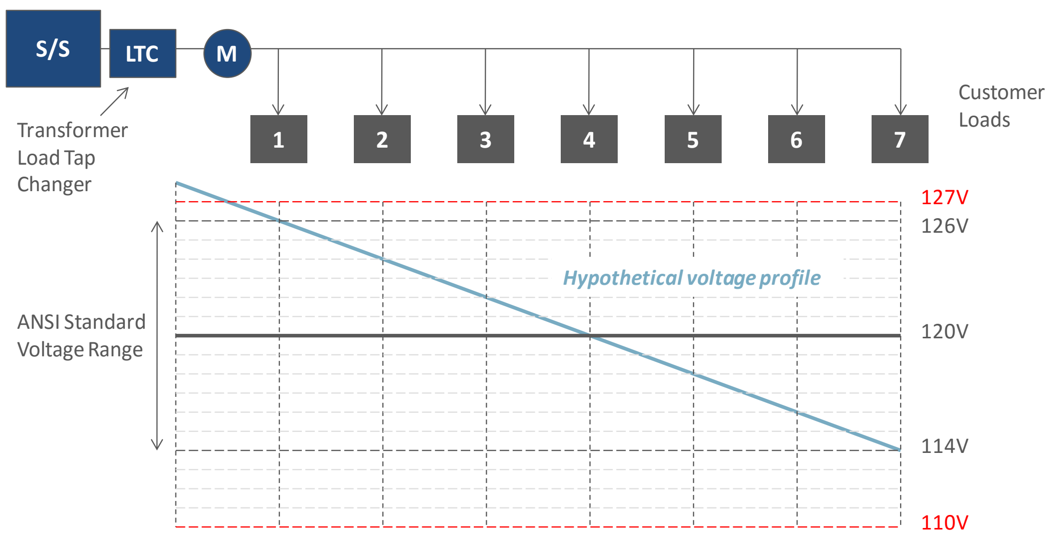
3.2 Conservation Voltage Reduction (CVR)

CVR optimizes distribution asset utilization by using monitoring and automated controls to reduce feeder voltage levels, improve the efficiency of distribution systems, and reduce energy consumption during peak periods or for longer-duration operations. Typical objectives of CVR include:

- Management of peak demands through service voltage level reductions, which can reduce electricity consumption of end-use appliances and equipment and reduce customer bills. Reduction in electricity consumption is on the order of 1–3 percent. When implemented during peak hours, CVR actions can supplement traditional demand-side management programs such as direct load controls, time-based rates, and incentive based programs. Duke Energy refers to its CVR actions as "Distribution System Demand Response" for this reason.
- Line loss reductions through feeder voltage level reductions and reactive power management results in lower electric resistance, which improves system energy efficiency and saves energy.

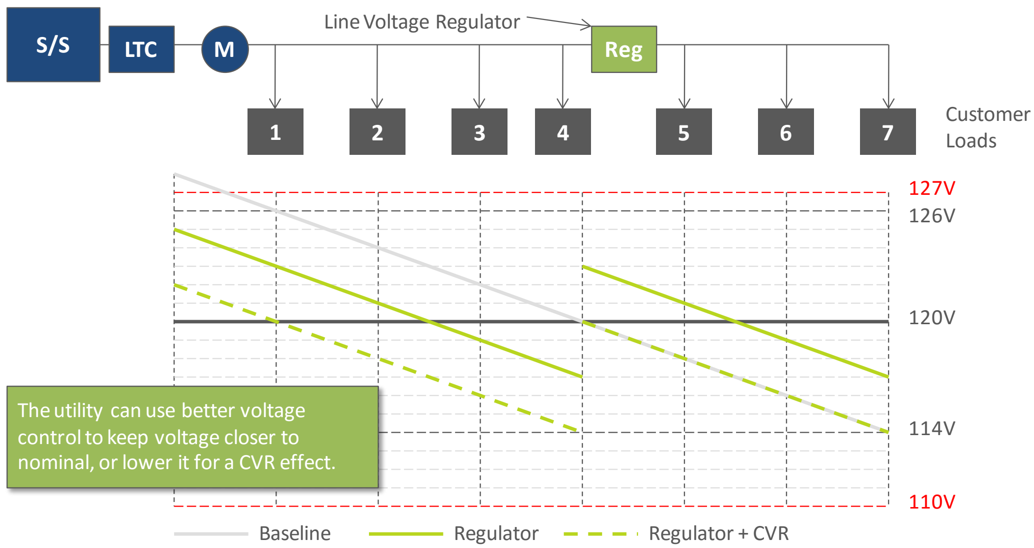
Operators use LTCs and voltage regulators to make small adjustments to voltage as load changes. Figure 26 and Figure 27 show the effects of LTCs and voltage regulators on a hypothetical distribution feeder voltage profile.

Figure 26. Hypothetical Feeder Voltage Profile with a Load Tap Changer



In Figure 27, the LTC can adjust the voltage at the head of the feeder to keep the profile within the acceptable voltage range, while voltage regulators placed mid-way along the feeder add a control point to raise or lower the downstream voltage levels.

Figure 27. Hypothetical Feeder Voltage Profile with a Load Tap Changer and Voltage Regulator



Operators can also use capacitors to compensate for reactive power caused by inductive loads. Figure 28 shows how capacitor banks placed along a feeder supports voltage profiles both downstream and upstream. The combined effect of the three types of equipment is to help utilities to keep overall profiles closer to desired levels under a variety of load conditions.

Figure 28. Hypothetical Feeder Voltage Profile with a
Load Tap Changer, Voltage Regulator, and Capacitor Bank

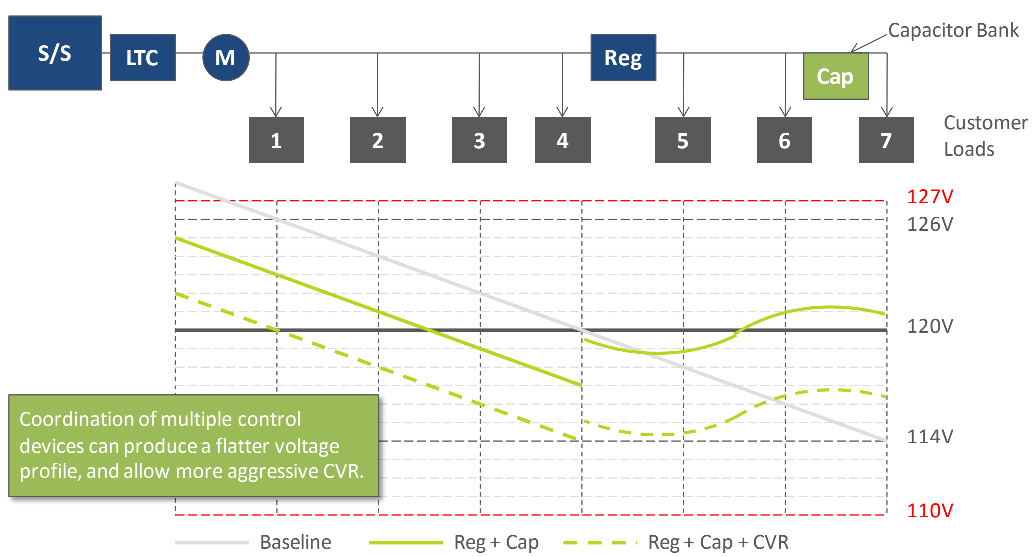


Table 16 provides a summary of the equipment for voltage support and reactive power control.

Table 16. Summary of Voltage Control Equipment, Functions, and Location

Equipment	Function	Area Impacted
Load tap changer	Raise or lower voltage	Entire feeders
Voltage regulator	Raise or lower voltage	Downstream of connection point
Capacitor banks	Compensate reactive load	Entire feeder with greatest effect closer to the load
	Support voltage	Upstream and downstream of connection point with greatest effect closer to the connection point

Historically, CVR often faced competing operational objectives. For instance, many utilities are subject to obligations and penalties with transmission operators for not maintaining reactive power levels within certain ranges (although CVR can also improve power factor to help meet transmission system objectives). In addition, reactive power management can also be operated for voltage support rather than line loss reductions, and in these instances, overcompensation is possible, in which voltages can increase.

DA can now provide operators with access to real-time voltage information to help reduce voltage while ensuring that voltage levels do not fall below acceptable levels. Remote, automated control of grid devices enables utilities to maintain reactive power level without overcompensating power factors. Smart meter data on voltages down to the customer level can be an important aspect of CVR to monitor voltage conditions and verify the performance of CVR operations.

Several DA utilities leveraged smart grid technologies in a selection of feeders to implement automated volt/VAR control. Central Lincoln Public Utilities District's case study provides an example of an innovative CVR system design combining distribution planning analytics, real-time management and control, and AMI.

Key Result: System Efficiency Improvements and Fuel Savings

SGIG DA utilities used conservation voltage reductions during peak and off-peak periods to improve system efficiencies. **Several utilities found that CVR could result in savings of 2-4 percent on affected feeders—a change that seems minor, but when applied system-wide, could result in comparable energy savings** and hundreds of thousands of dollars in energy costs.

Central Lincoln Public Utilities District, Wisconsin Power and Light (WPL), Duke Energy, and Glendale Water and Power (GWP) each saw improved feeder efficiencies on that scale due to CVR. Based on GWP's CVR pilot, it estimates a full-scale, five-year program could net power costs savings **of $470,000 to $1.2 million per year.**

→ See **Case Study:** Glendale Water and Power (page 81)

→ See **Case Study**: Wisconsin Power and Light (page 63)

The utilities used different analysis approaches to estimate energy savings and efficiency improvements due to CVR and volt/VAR controls, and applied pilots at different scales:

- Duke Energy estimates saving about 39,000 MWh over more than a year. The utility's rigorous business case assessment found that O&M savings from CVR formed the largest portion of the 20-year business case by far, with a net-present value of more than $155 million.
- Avista used model-based analysis of historical and current feeder loads to estimate an energy savings of about 42,000 MWh in 2014.
- Con Edison estimated annual energy loss reductions of about 4,500 MWh with estimated annual energy savings of about $340,000.

→ See **Case Study:** Duke Energy (page 40)

→ See Case Study: **Avista Utilities** (page 65)

→ See **Case Study:** Consolidated Edison (page 44)

Key Result: Reduced Peak Demand

CVR was also used by several of the SGIG DA utilities to achieve reductions in peak demands.

- Oklahoma Gas and Electric estimated peak demand reductions of about 2.3 percent on 22 circuits in 2012.
- Sacramento Municipal Utility District estimated a 2.5 percent reduction of peak demand in one pilot substation in summer 2011, and estimated a 1 percent average load reduction across 14 substations throughout the program.
- Southern Company used CVR to shave peak load during extreme weather, reducing the voltage level by 5 percent for approximately 5 hours, resulting in 300 MW of peak reduction.

→ See **Case Study:** Sacramento Municipal Utility District (page 67)

→ See **Case Study**: Southern Company (page 61)

3.3 Automated Power Factor Correction

Automated power factor correction provides grid operators with new capabilities for managing reactive power flows. Measurement devices provide grid operators and DMS with data on voltages and reactive power levels. Using this information, operators and DMS determine optimal control signals which trigger the switching of capacitor banks. When necessary, distribution operators can manually override commands generated by DMS.

Utility objectives for reactive power compensation include improving power factors and reducing line losses. Accomplishing these objectives potentially leads to significant cost savings due to lower energy and fuel requirements. Electric distribution systems operate most efficiently when power factors are equal to 1.

Key Result: Improved Power Factors and Better Power Quality

The SGIG DA utilities observed utility and customer impacts from actions to boost power quality. For example, Wisconsin Power and Light achieved overall power factor improvements from about 0.95 to about 0.97 between 2011 and 2013. Northern Virginia Electric Cooperative used power quality monitors on meters and transformers to help reduce voltage variations such as sags and surges, and power harmonics.

→ See **Case Study**: Wisconsin Power and Light (page 63)

→ See **Case Study**: Northern Virginia Electric Cooperative (page 34)

Key Result: Deferred Capacity Additions

There are several capacity deferral benefits from voltage control, CVR, and reactive power management. Two examples of this come from Con Edison and Southern Company. Con Edison used its voltage control and reactive power management technologies to increase its 4kV unit substation capability by 2.8 percent, resulting in a net savings of $15.7 million. Southern Company realized about $3.4 million in net present-value from deferred distribution capacity investments from reactive power loss reduction using automated capacitor banks, leading to power factor improvements to near unity.

→ See **Case Study**: Consolidated Edison (page 44)

→ See **Case Study**: Southern Company (page 61)

CASE STUDY: **SOUTHERN COMPANY**

Investor-Owned Utility

Alabama, Florida, Georgia, and Mississippi

4,395,000 Customers

Distribution Circuits Impacted:	**2,081 (of 4,706)**	**Distribution Substations Impacted:**	**359 (of 3,325)**

DA Communication Network: Radio communications via SCADA platform

Total Cost of DA Implementation under SGIG	Distribution Automation Devices Deployed					
$207,274,827	Automated Feeder Switches	✓	**2,193**	Remote Fault Indicators	✓	**263**
	Automated Capacitors	✓	**1,869**	Transformer Monitors	✗	
	Automated Regulators	✓	**3,339**	Smart Relays	✓	**848**
	Feeder Monitors	✗		Capacitor Monitors	✓	7,876

Reducing Reactive Power Loss Defers Capacity Investments: Southern Company realized about $3.4 million in net present value from deferred distribution capacity investments from reactive power loss reduction using automated capacitor banks, leading to power factor improvements to near unity.

DSCADA Reduces Truck Rolls & Vehicle Miles: Southern Company avoided over 94,000 truck rolls and almost 1 million vehicle miles traveled from October 2011 to September 2014 by using SCADA to remotely place and remove hot line tags, or to perform remote switching.

CVR Lowers Peak Load during Extreme Weather Event: Southern Company used CVR to shave the peak load during an extreme weather event in January 2014 (see Figure 29). With abnormally low temperatures, the system load was over 20 percent higher than the forecasted peak load for that day. Southern Company implemented CVR to reduce the voltage level by 5 percent for approximately 5 hours, resulting in 300 MW of peak reduction. This reduction helped Southern avoid the need for manual load shedding.

Figure 29. Southern Company CVR Results for the Polar Vortex in January, 2014

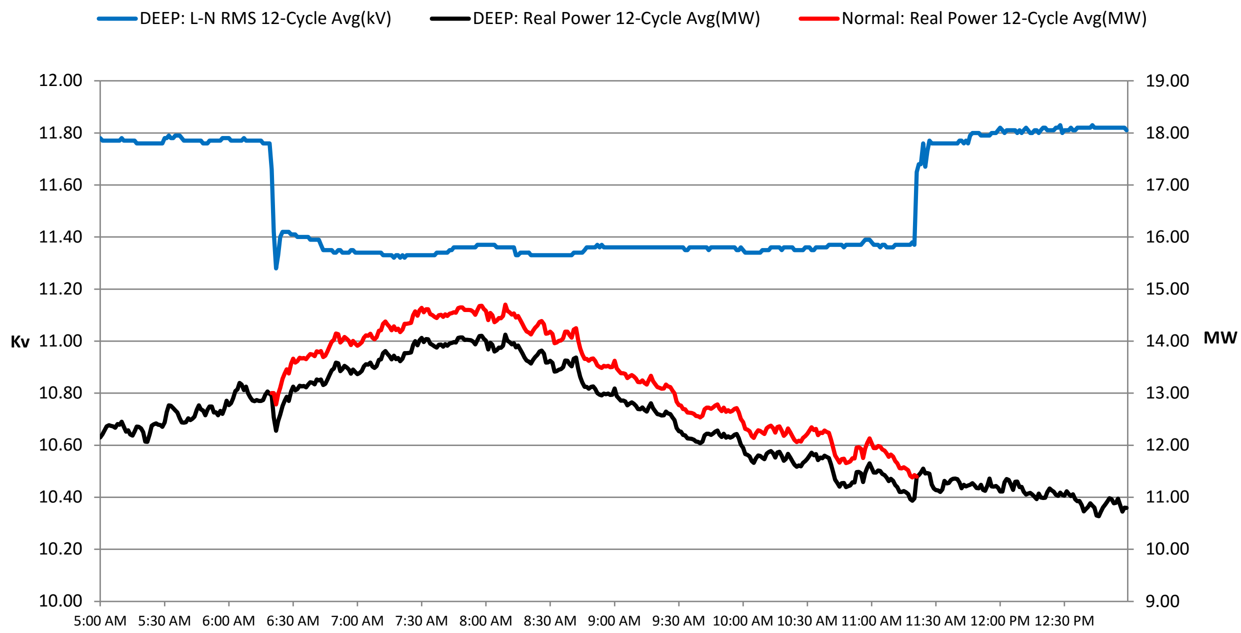


Figure 29 shows the voltage and load profile of a substation where CVR was implemented (blue line showing actual voltage; red line showing predicted higher load without CVR; and black line showing actual load, respectively).

Continued Integration of DMS and OMS Planned: Southern Company plans on moving forward with the integration of its distribution management and outage management systems, and will create a 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.

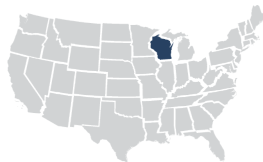
READ MORE ABOUT SOUTHERN COMPANY'S PROJECT ON SMARTGRID.GOV:

Southern Company's Project Page

Southern Company Project Description – *September 2014*

CASE STUDY: **WISCONSIN POWER AND LIGHT COMPANY (WPL)**

Investor-Owned Utility



Wisconsin

453,573 Customers

Distribution Circuits Impacted:	**298 (of 906)**

Communication Network: Capacitor control radios, take out radios, routers, hopper radios

Total Cost of DA Implementation under SGIG	**Distribution Automation Devices Deployed**				
$6,306,738	Automated Feeder Switches	✗		Remote Fault Indicators	✗
	Automated Capacitors	✓	**576**	Transformer Monitors	✗
	Automated Regulators	✗		Smart Relays	✗
	Feeder Monitors	✗			

DA Operations Improve Power Factors: WPL achieved overall power factor improvements from about 0.95 to about 0.97 between 2011 and 2013 as a result of DA operations for power quality. This result is based on data collected from four representative distribution substations.

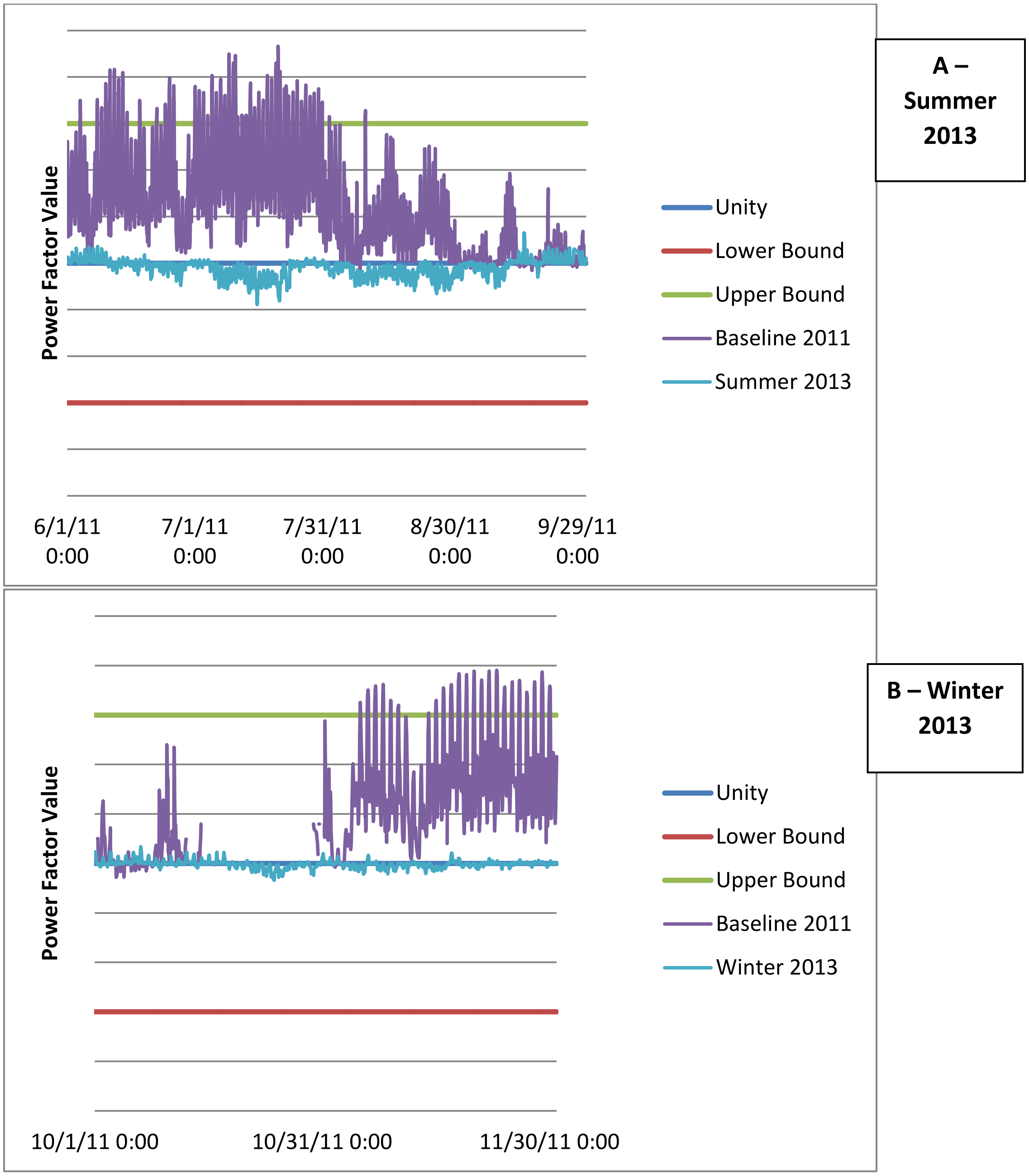
Table 17 shows that three out of the four substations realized power factor improvements, with two almost reaching a power factor of 1.0. While one of the four showed a decrease, the amount was small and within the range of error.

Table 17. Power Factor Data from Four WPL Substations, 2011 to 2013

Substation	Power Factor in 2011	Power Factor in 2013
Substation 1	0.97	0.96
Substation 2	0.96	0.99
Substation 3	0.95	0.99
Substation 4	0.93	0.96
Overall	**0.95**	**0.97**

Power Factors Less Variable after DA Operations: Figure 30 A and B compares power factor data at a fifth WPL substation for the summer and winter of 2013. The figures show power factor improvements in 2013 compared to baseline data before DA operations from 2011. In both cases, power factors were less variable and significantly closer to unity after DA operations were implemented than before.

Figure 30 A and B. Power Factors for a WPL Substation Before and After DA Operations, 2011 to 2013



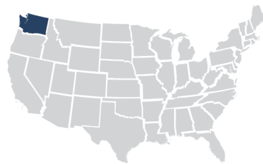
READ MORE ABOUT WPL's PROJECT ON SMARTGRID.GOV:

Wisconsin Power and Light Company Project Page

Wisconsin Power and Light Company Project Description – *June 2015*

CASE STUDY: **AVISTA UTILITIES**

Investor-Owned Utility



Washington

354,554 Customers

Distribution Circuits Impacted:	59 (of 330)	Distribution Substations Impacted:	13 (of 206)

DA Communication Network: Radio frequency mesh and fiber optic cable

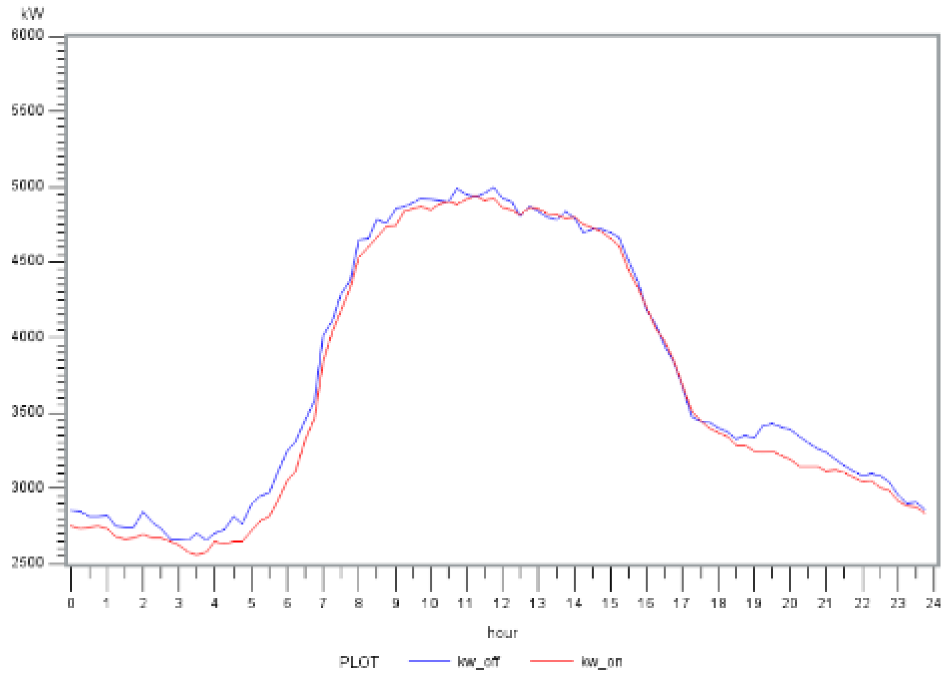
Total Cost of DA Implementation under SGIG	Distribution Automation Devices Deployed					
$41,657,885	Automated Feeder Switches	✓	263	Remote Fault Indicators	✗	
	Automated Capacitors	✓	123	Transformer Monitors	✗	
	Automated Regulators	✓	177	Smart Relays	✓	102
	Feeder Monitors	✓	102			

Automated Restoration Reduces CMI: A garbage truck hit an Avista Utilities power pole in August 2013, causing almost 900 customers to lose power. Avista Utilities' DMS automatically isolated the fault and restored more than 800 upstream customers instantaneously, saving an estimated total of 40 minutes of outage time per customer. The remaining downstream customers were restored several minutes later, saving 32 outage minutes. In total, 35,600 CMI were avoided as a result of DA operations.

CVR Results in Energy Savings: Avista Utilities estimates achieving energy savings of approximately 42,000 MWh during 2014 on feeders that serve a mix of residential, commercial, industrial, and agricultural customers in Spokane and Pullman, WA.

The SGIG DA utilities used different analysis approaches to estimate energy savings and efficiency improvements due to CVR. The Avista estimates are based on model-based analysis of historical and current feeder loads throughout the measurement period, normalized for weather, load characteristics, and customer behavior. Figure 31 shows two hourly load curves for one of the 25 feeders evaluated by Avista.

Figure 31. CVR Impacts on Hourly Load Curves for a Feeder



Note: The red line is with CVR, and the blue line is without CVR.

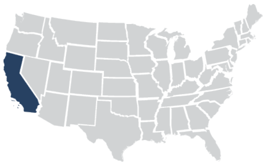
READ MORE ABOUT AVISTA UTILITIES' PROJECT ON SMARTGRID.GOV:

Avista Utilities Project Page

Avista Utilities Project Description *–July 2014*

CASE STUDY: **SACRAMENTO MUNICIPAL UTILITY DISTRICT (SMUD)**

Municipal/Public Utility



Sacramento, CA

672,860 Customers

Distribution Circuits Impacted: **171 (of 644)**

DA Communication Network: RF mesh and fiber

Total Cost of DA Implementation under SGIG	Distribution Automation Devices Deployed					
$62,172,480	Automated Feeder Switches	✔	156	Remote Fault Indicators	✔	26
	Automated Capacitors	✔	177	Transformer Monitors	✘	
	Automated Regulators	✘		Smart Relays	✔	155
	Feeder Monitors	✘				

New Software Supports Rapid Outage Response, Switching, and Restoration Operations: SMUD used software for correlating, analyzing, and visualizing data from field devices, DMS, OMS, GIS, and weather forecasts, and displayed the information for grid operators in the distribution control center. The geospatial and visual analytics displays merged and correlated data from a variety of sources including smart meters, line sensors, substation monitors, and weather reports, making the information easier for SMUD operators to act on and to understand. The system displays historical and real-time data side-by-side, and users have the flexibility to dynamically zoom in to specific parts of the grid or assets of interest for more detailed visualizations. The data displays can be viewed on an 8-by-30 foot video wall in SMUD's control center, and is also available to supervisors and field crews on desktop computers and mobile computing devices.

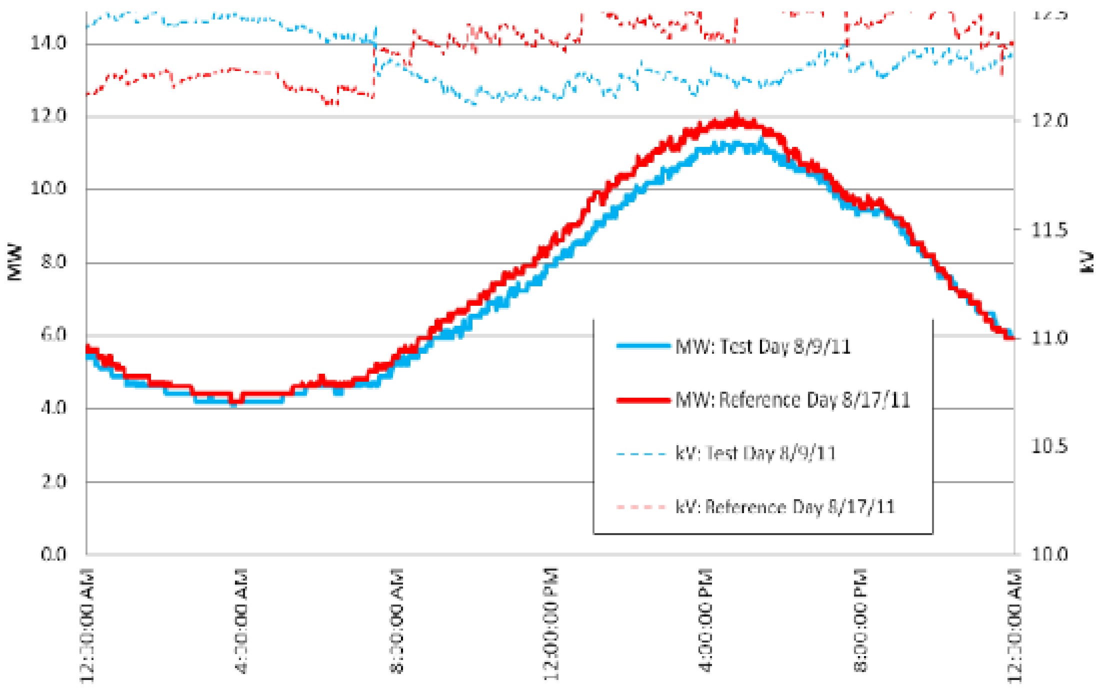
At SMUD, this system supplements the hands-on knowledge and experience of operators and field crews. The new system boosts capabilities, efficiency, and performance; quickly synthesizes numerous streams of disparate data; and provides on-the-fly assessments of grid, asset health, weather, power supply, and electricity demand conditions. The system helps managers and operators respond more quickly to outages, rapidly develop switching plans, and communicate outage restoration priorities to field crews.

Automatic Sectionalizing and Restoration System Improves Reliability: SMUD analyzed the effects of its automatic sectionalizing and restoration system on outages that result in feeder lock-out. Between April 2013 and September 2014, SMUD achieved 28 percent savings in SAIDI and 19 percent savings in SAIFI.

From April 2013 to September 2014, the SMUD experienced 46 unplanned, feeder-locking outages. SMUD was able to complete DA operations in 30 instances and saved about 705,500 CMI. Approximately 10,260 customers were affected in these 30 outages, 19 percent less than the number of customers who would have been affected otherwise.

CVR Program Reduced Peak Demand. In summer 2011, SMUD conducted a pilot test of its CVR program, which resulted in an estimated 2.5 percent reduction of peak demand on one of the pilot substations. Figure 31 shows peak demand reductions from CVR for a test day in August 2011. SMUD continued to deploy volt-VAR optimization technologies throughout the SGIG program, and estimates a 1 percent average load reduction across 14 substations and approximately 1.5 MWh of energy savings per day.

Figure 32. Reference versus Test Day CVR Impacts for a SMUD Substation



The figure compares two load curves: the red line is for a reference day; the blue line is for a test day involving CVR operations.

READ MORE ABOUT SMUD'S PROJECT ON SMARTGRID.GOV:

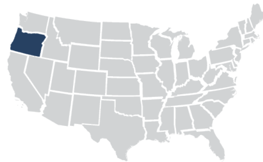
SMUD Project Page

SMUD Project Description – *November 2014*

SMUD 2013 PowerStat Study – *March 2014*

CASE STUDY: **CENTRAL LINCOLN PEOPLE'S UTILITY DISTRICT**

Municipal/Public Utility



Oregon

38,465 Customers

Communication Network: Fiber optic cable and high-speed wireless

Total Cost of DA Implementation under SGIG	Distribution Automation Devices Deployed				
$2,561,406	Automated Feeder Switches	✓	**17**	Remote Fault Indicators	✗
	Automated Capacitors	✗		Transformer Monitors	✗
	Automated Regulators	✓	**2**	Smart Relays	✗
	Feeder Monitors	✓	**14**		

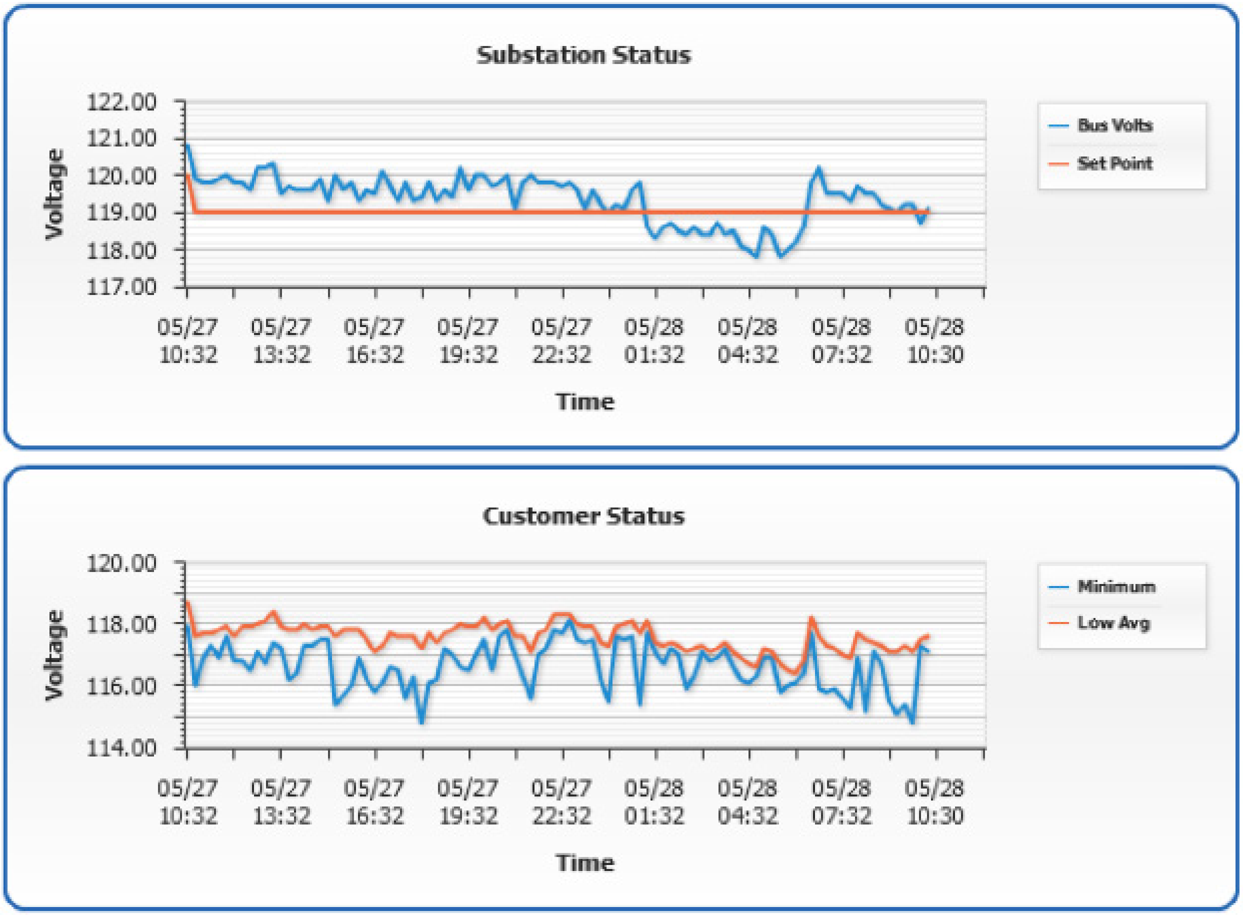
Innovative CVR Design: Central Lincoln implemented an innovative CVR system design that combines distribution planning analytics, real-time management and control, and an approved measurement and verification methodology by integrating its AMI system with adaptive control algorithms (see Figure 33). The CVR project was implemented in three phases:

1. **Distribution planning analytics:** During the initial planning phase, Central Lincoln resolved existing voltage outliers using collected load profile data, including average voltage over 15-minute intervals, from nearly 1,500 smart meters on a project substation.
2. **Real-time management and control:** The CVR control system was integrated with SCADA and AMI systems. Every 15 minutes, the system analyzes near-real-time AMI data for a small subset of meters. If AMI voltages are outside the target range, the affected smart meters send an alert to notify the control system, which then sends a SCADA command to adjust the source voltage at the appropriate substation. This adaptive process allows the utility to automatically adjust voltage for seasonal, monthly, weekly, and daily variations in load. Figure 33 is a screenshot from the Manager UI covering approximately 12 hours of data.
3. **Measurement and verification:** After sufficient data was collected for both summer and winter seasons, Central Lincoln analyzed the data for measurement and verification of its CVR program.

CVR Reduces Total Energy Consumption: Central Lincoln estimates saving approximately 360 MWh (about 2.4 percent of electricity consumption of the affected feeders) due to CVR in 2013 (compared to 2012). Going forward, Central Lincoln plans to implement conservation voltage regulation territory-wide and install additional DA devices on its system.[29]

[29] DOE, *Fault Location, Isolation, and Service Restoration Technologies Reduce Outage Impact and Duration*, (DOE, November 2014).

Figure 33. User Interface Screenshot of Central Lincoln's CVR Management System



Equipment Upgrades Lower Voltages across Entire Feeders: Central Lincoln identified upgrades to correct abnormal voltage sags, which provided additional headroom to lower voltages across entire feeders. These improvements included:

- Replacing undersized meter bases for a group of large seasonal loads (an RV park);
- Replacing a missing transformer that had been removed from the field, but was still mapped in GIS; and
- Rectifying feeder configuration design issues based on low voltages identified on the customers' meters.

READ MORE ABOUT CENTRAL LINCOLN PEOPLE'S UTILITY DISTRICT'S PROJECT ON SMARTGRID.GOV:

Central Lincoln People's Utility District Project Page

Central Lincoln People's Utility District Project Description – *August 2014*

4 Major Findings: Equipment Health Monitoring

Equipment health condition monitoring provides utilities with new tools and capabilities to improve operational efficiency and reduce the frequency and duration of outages. It involves installing sensors on key components (e.g., power lines and transformer banks) to measure equipment health parameters.

Table 18. Equipment Health Condition Monitoring Results from DA Investments

Primary Aim	• Provide grid operators with actionable equipment health information to conduct preventative maintenance and dispatch repair crews more efficiently	
Smart Grid Function	Equipment monitoring, data analysis, and preventative maintenance	
Description	Identified equipment problems in advance of failure. Implemented remedies, extended equipment life, and prevented outages.	
Key Impacts & Benefits	• Improved operational efficiency—by extending equipment life or removing equipment before it fails • Fewer and shorter power disruptions reduce customer outage cost and inconvenience	Several utilities **avoided transformer outages through preventative maintenance** activities using equipment sensors. One utility reported **fixing a transformer before it failed** and saved several thousand customers from losing power.

Transformer sensors are used to provide data to grid operators and equipment diagnostics software on the status of operations. Real-time telemetry for transformer sensors includes:

- <u>Ambient temperatures</u>: transformers can require cooling to dissipate heat. Excess heat can reduce efficiency, damage equipment, increase maintenance needs, and shorten lifespans.
- <u>Oil levels</u>: oil is used to insulate and suppress electrical discharges. Low oil level can lead to equipment failures.
- <u>Oil temperatures</u>: oil also serves as coolant to help dissipate resistance heat. Abnormal oil temperatures can interfere with proper heat dissipation.
- <u>Water levels</u>: rainwater can penetrate transformer vessels, which can cause equipment failures if critical levels are reached.
- <u>Pressure levels</u>: electric arcing (electrical breakdown of gas caused by current traveling through air) can cause sudden pressure increases inside transformer vessels, which can lead to equipment failures if critical levels are reached.

Grid sensors are used to provide data to grid operators on equipment status and including the potential risks of overloads. Real time telemetry for grid sensors includes: phase currents, phasing voltages, transformer loadings, and power factors.

Once the sensor data is received by utility back office systems, diagnostics software determines if there is an equipment failure. The diagnostics software, which is typically integrated with back office systems, retrieves sensor data for analysis. The data flows through the system continuously, and is available to the diagnostics software on an on-demand/as-needed basis.

Preventative maintenance scheduling is another new capability from equipment health monitoring. Utility personnel can assess equipment data histories and set priorities for maintenance and inspection activities. Data analysis can pre-diagnose equipment that are suspected of failures by reviewing operational parameters (e.g., pressure, temperature, and oil levels) before inspections to determine the best approach for proactive repair and/or replacement. Data analytics software can evaluate failure risks for specific devices and set priorities for maintenance and inspection activities accordingly.

Table 19 shows the types of utility impacts from equipment health monitoring and how they are accomplished by new smart grid functions and capabilities.

Table 19. Utility Impacts from Equipment Health Monitoring

Impacts	How Impacts are Accomplished
1. Reduced duration of equipment maintenance activities	• Shorter and more targeted field inspections from remote identification of actual/potential equipment issues. • More targeted and timely inspections from greater operator visibility and alerts when automated assets don't respond to controls properly. • Fewer field visits when operators can remotely adjust equipment setting to resolve simple equipment issues without the need to dispatch repair crews.
2. Reduced frequency of equipment failures	• Data analytics enables operators to implement preventative maintenance, which allows repair or replacement of critical equipment before failure. • Control room alerts warn operators of abnormal operating conditions and potential overloads.
3. Deferred cost of equipment replacement	• Operator can override equipment operations (e.g., transformers) based on sensor data from other local assets (e.g., feeder loads). Manual overrides can prevent unnecessary operations and prolong the life of the equipment by avoiding excessive wear and tear.
4. Reduced number or duration of sustained outages	• Monitoring systems can reduce outage durations caused by equipment failures and by expediting corrective maintenance.
5. Reduced frequency of sustained outages	• Outage frequencies reduced by: (1) reducing the frequency of equipment failures, and (2) by expediting resolution of equipment failures through remote operation by control room staff.
6. Reduced resource requirements associated with equipment maintenance activities	• Reduced duration of maintenance activities enables resource reallocation to other maintenance activities. • Reduced frequency of equipment failures, reduced frequency of outages, lead to reduced needs for physical field inspections, labor hours, truck rolls, and/or fleet vehicle miles.
7. Improved worker safety	• Control room operators can pinpoint feeder segment to de-energize and reduce the risk of safety incidents.

Key Result: Improved Failure Prediction and Proactive Maintenance Reduce Failure-Related Outages

Equipment health monitoring provides grid operators and maintenance crew with up-to-date feedback on the operational status of the network and identifies network components that require on-site inspection and maintenance. It can provide real-time alerts for abnormal equipment conditions, based on potential violations of equipment operational parameters. It can also provide analytics that help utility engineers plan preventative and proactive equipment maintenance, repair, and replacement activities, as well as the cause of equipment failures through post-mortem forensic analysis. The Pepco case study in this report provides an example of how the equipment health monitoring system was designed.

→ See **Case Study:** Pepco (page 50)

These technologies and systems equip grid operators with new capabilities to dispatch repair crews based on diagnostics data from equipment health monitoring. When systems alert control rooms of abnormal diagnostics data, operators can notify appropriate personnel (e.g., engineers, technicians, or field crews) to investigate the equipment in question. Monitoring systems can be designed for operators to remotely operate monitored equipment to correct the cause of abnormal diagnostics data, or control the equipment to prevent further damages or failures.

- Equipment health monitors at Florida Power and Light helped identify and prevent a potential transformer failure, preventing an outage for about 15,000 customers and avoiding at least $1 million in restoration costs. The utility's case study in this report provides information about additional cost savings and improvements in proactive equipment maintenance.
- Marblehead Municipal Lighting Department avoids 10-15 distribution line transformer outages annually during summer heat waves through transformer monitoring using 15-minute readings.

→ See **Case Study**: Florida Power & Light Company (page 74)

Key Result: Fewer Physical Inspections and Reduced Labor for Maintenance and Repairs

Several SGIG utilities reduced physical inspections of capacitor banks, reducing the labor needed for inspections. For example, Duke Energy's new capacitor bank controllers reduced physical inspections by 1,085 units in 2013. Preventative maintenance also reduced the labor hours and overtime associated with restoration and repairs following major equipment failures.

→ See **Case Study**: Duke Energy (page 40)

CASE STUDY: **FLORIDA POWER & LIGHT COMPANY (FPL)**

Investor-Owned Utility

Florida

4,524,000 Customers

Distribution Circuits Impacted:	**476 (of 3,124)**

DA Communication Network: Wireless mesh network

Total Cost of DA Implementation under SGIG	Distribution Automation Devices Deployed			
$84,667,288	Automated Feeder Switches	**285**	Remote Fault Indicators	**3,879**
	Automated Capacitors	**1,403**	Transformer Monitors	**2,716**
	Automated Regulators	**1,806**	Smart Relays	**1,084**
	Feeder Monitors	**1,014**	Throw-over Sensors	745

Equipment Health Monitoring Pre-Empts Transformer Failure: FPL installed remote monitors on power transformers in about 500 substations. FPL's Transmission Performance and Diagnostic Center (TPDC) and its System Control Center remotely monitor critical transformers and feeders for faults. Equipment health monitors evaluate conditions on high- and low-voltage transformer bushings, including capacitance, power factor, and the extent of current imbalance. Bushing failures can damage transformers, which may require costly repairs and create extended service interruptions. In 2012, the TPDC detected an out-of-tolerance high-voltage bushing using a newly installed monitor, indicating a potential transformer fault. FPL tested and replaced the unit, preventing an outage for about 15,000 customers and avoiding at least $1 million in restoration costs. Through the third quarter of 2014, FPL had proactively replaced more than 1,000 distribution transformers, preventing potential unplanned outages for an estimated 10,000 customers.

Monitoring Quickly Identifies Issues, Prevents Larger Problems: FPL monitors capacitance voltage transformers (CVTs) by measuring voltage magnitudes and calculating phase angles. To prevent further complications, engineers implemented an algorithm that used data on voltage magnitudes and phase angles to detect early CVT degradation. In September 2011, the control room received an alert indicating a potential problem with a degraded phase on a CVT. Local field engineers were able to locate and replace the defective CVT, thus preventing a failure that could have resulted in an extended outage for several thousand customers.

FLISR Operations Reduced Outages and Momentary Disturbances during Major Storms: FPL is using AFS and Automated Lateral Switches (ALS) as a key part of an unprecedented program to reduce the number of momentary outages—those lasting less than one minute. Tropical Storm Isaac, which struck Florida in August 2012, caused significant power outages in FPL service territory. Automated feeder switching and FLISR operations contributed to reductions in CI and momentary disturbances. The company reports that 9 operations serving almost 16,000 customers led to more than 9,000 fewer customer interruptions and approximately 2,500 fewer upstream momentary disturbances.

FPL also markedly increased the average annual customer minutes of interruption avoided by 5.1 million minutes from 2012 through the third quarter of 2014. This was achieved, in part, due to the absence of major storms, as well as AFS and FLISR operations. The company used technologies that led to reductions in the frequency of outages.

AFS Expansions Planned: FPL is increasing its AFS deployment beyond the 1,000 already installed to 10,000 ALS or more in ensuing years.

READ MORE ABOUT FPL's PROJECT ON SMARTGRID.GOV:

Florida Power & Light Company Project Page

Florida Power & Light Company Project Description – *April 2015*

Florida Power & Light Company Case Study – *July 2012*

5 Major Findings: Integration of Distributed Energy Resources

DERs include a variety of technologies such as rooftop photovoltaics, wind generators, high efficiency reciprocating engines, combined heat and power systems, micro-turbines, energy storage systems,[30] fuel cells, plug-in electric vehicles, and demand response programs. As DER costs come down, DER installations are growing—increasing the need for more effective and lower cost technologies, tools, and techniques for grid integration that also maintain safety and reliability.

Table 20. DER Integration Results from DA Investments

Primary Aim	• Reduce the costs and difficulties of interconnecting the growing numbers of DERs with local utility distribution systems	
Smart Grid Function	Automated DER dispatch and management	Operation of Thermal Energy Storage for Demand Management
Description	Analysis tools and DERMS are helping utilities to integrate DERs into grid operations while maintaining reliability and safety objectives.	Utilities and commercial and municipal customers collaborated in operating ice storage systems to shift building air conditioning from peak to off-peak periods.
Key Impacts & Benefits	• Lower electricity bills for consumers who act as both electricity producers and consumers • Reduced emissions from displaced traditional thermal generation • Increased resilience by reducing reliance on central power generation	Two utilities used DERMS to integrate ice storage to shift air conditioning load from peak to off-peak periods in commercial and municipal buildings—which in one case **reduced the buildings' cooling requirements by 5%**. DERMS provide **near real-time status reports on DERs** and help visualize their impact on the grid.

Grid integration requires tools to monitor and dispatch DERs, and to address electric power flow and control issues such as low-voltage ride through, harmonic injection, voltage fluctuations, and reactive power management. Solutions are needed to ensure that new DERs do not jeopardize the safety or reliability of electric distribution systems. Also needed are standards and protocols for DER interconnections, computer simulations, distribution management systems, and the addition of new hardware and protective devices.

[30] DOE's Smart Grid Demonstration Program included 16 energy storage projects that evaluated technologies and systems. Interim and final Technology Performance Reports can be downloaded from www.smartgrid.gov.

SGIG DA utilities evaluated DER-enabling technologies such as DERMS, and DERs including thermal energy storage for commercial and government buildings. The SGIG role focused not on DER evaluations, but on the tools and techniques for DER grid integration.[31] Several SGIG DA utilities did evaluate specific DERs, but not as part of their SGIG projects.

IADS are real-time control systems that integrate demand- and supply-side resources into day-ahead and real-time utility operations. These systems can be configured to optimize and automate dispatch of distributed and renewable resources, demand response and direct load control programs, and energy storage systems.

DERMS offer more capabilities than IADS, including network awareness, asset monitoring and control, scheduling and dispatch, active and reactive power import and export control, voltage control, constraint management, forecasting, resource valuation, and optimal demand response dispatch.

5.1 Automated DER Dispatch and Management

IADS help utilities to develop efficient operations and balance multiple objectives including system reliability, security, safety, and integration with wholesale markets. IADS are used to implement flexible monitoring and control of the distribution system to enable integration of distributed energy resources without degrading safety or reliability, or causing damages to the grid.

DERMS provide near real-time status reports on DERs and associated utility communications and control equipment to provide visualization or representation of DER impacts on the distribution grid; data for modeling and verification; and mitigation of both DER backfeeding and cold load pick-up. These capabilities support DA planning and operations.

Several of the SGIG DA utilities used IADS and DERMS (full case studies in this report provide more complete descriptions):

- Burbank Water and Power's IADS is used to manage all types of supply and demand resources, including the thermal storage operations the utility tested. It enables grid operators to turn units on and off remotely without disrupting cooling service to the host building.
- Consolidated Edison's DERMS was used to monitor and control a variety of supply and demand resources including distributed generation and storage, building management systems, and demand response customers.
- Pepco developed a DERMS and measured voltage fluctuations from an 18 MW photovoltaic array connected to the distribution grid, which caused reverse flows on a few low load days, resulting in high voltage on the feeder and some damage to some customer equipment.

→ See **Case Study**: Burbank Water and Power (page 79)

→ See **Case Study**: Consolidated Edison (page 44)

→ See **Case Study:** Pepco (page 50)

[31] Idaho Power Company implemented a SGIG project involving the grid integration of wind energy resources through the development of a wind forecasting model. This activity involved wholesale power markets at the transmission level and is not included in this report on distribution system operations. For further details see *New Forecasting Tools Enhance Wind Energy Integration in Idaho and Oregon*, August 2014.

5.2 Operation of Thermal Energy Storage

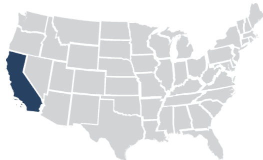
Thermal storage systems can be used by utilities and customers to improve asset utilization by shifting demand to off-peak periods. These were implemented by two California municipal utilities: Burbank Water & Power and Glendale Water & Power. Demand response aspects of these deployments are discussed further in two SGIG reports: DOE, *Municipal Utilities' Investment in Smart Grid Technologies Improves Services and Lowers Costs* and *Advanced Metering Infrastructure and Customer Systems: Results from the SGIG Program*.

→ See **Case Study**: Burbank Water and Power (page 79)

→ See **Case Study:** Glendale Water and Power (page 81)

CASE STUDY: **BURBANK WATER AND POWER (BWP)**

Municipal/Public Utility



California

51,858
Customers

94%

f distribution ystem with A

Distribution Circuits Impacted:	**130 (of 138)**

DA Communication Network: Fiber optic Ethernet

Total Cost of DA Implementation under SGIG	Distribution Automation Devices Deployed			
$10,932,246	Automated Feeder Switches	✗	Remote Fault Indicators	✗
	Automated Capacitors	✗	Transformer Monitors	✗
	Automated Regulators	✓ 130	Smart Relays	✗
	Feeder Monitors	✗		

OMS Integration Expands DA Capabilities: BWP's OMS not only records outage causes and locations, but also estimates restoration times, adjusts predictions based on field reports, and supports customer call-backs and notifications.

Smart Grid Investments Deliver Exceptional Reliability: An independent auditor's report found that BWP investments in smart grid technologies have helped them deliver "exceptional system reliability," noting that in fiscal year 2012 "the system experienced approximately 15 minutes of service outage once every 5.4 years compared to the typical industry system of approximately 96 minutes of service outage once every 1.2 years."[32]

BWP reported avoiding over 4.4 million CMI between 2010 and 2014. This was nearly a 50 percent reduction in estimated CMI of 8.4 million without SGIG upgrades. SGIG upgrades included relays with microprocessors with auto-reclosing capabilities.

Thermal Storage Load Management Reduces Peak Demand: BWP integrated the operation of 34 ice storage units installed on commercial and municipal buildings to reduce peak demands. The systems use electric chillers operated overnight to make ice, which can be used during the day to cool the buildings, thereby lowering air conditioning loads and reducing peak demand. BWP's 34 units reduced peak demand by at least 230 kilowatts and shifted about 1,400 kilowatt hours from peak to off-peak periods, which reduced the buildings' cooling requirements by about 5 percent, resulting in energy savings and emissions reductions for the municipality.

[32] Audited Financial Statements, Fiscal Year 2013-1013, Burbank Water and Power, Independent Auditor's Report by White, Nelson, Diehl, and Evans LLP, June 30, 2013.

BWP included ice storage operations in their Integrated Automatic Dispatch System (IADS) to dispatch and account for demand response operations. BWP's IADS is a comprehensive system that manages all types of supply and demand resources and integrates dispatch with wholesale operations and the California Independent System Operator. The system provided a dashboard that reports operating statistics and provides controls for remote operation of the units, enabling grid operators to turn units on and off remotely without disrupting cooling service to the host building. Building operators have the ability to override pre-determined or utility-directed controls for operation of the ice storage systems.

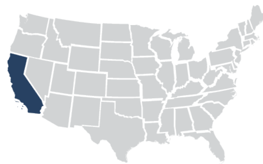
READ MORE ABOUT BURBANK WATER AND POWER's PROJECT ON SMARTGRID.GOV:

Burbank Water and Power Project Page

Burbank Water and Power Project Description – *August 2014*

CASE STUDY: **GLENDALE WATER AND POWER (GWP)**

Municipal/Public Utility



California

84,343
Customers

Distribution Circuits Impacted:	**4 (of 110)**

DA Communication Network: Wireless RF and Ethernet/IP backhaul

Total Cost of DA Implementation under SGIG

$7,645,153

Distribution Automation Devices Deployed					
Automated Feeder Switches	✓	18	Remote Fault Indicators	✗	
Automated Capacitors	✓	4	Transformer Monitors	✗	
Automated Regulators	✗		Smart Relays	✓	22
Feeder Monitors	✗				

Conservation Voltage Reduction Could Significantly Lower Power Costs: GWP is also piloting a CVR program that uses smart meter voltage data to improve feeder efficiency and to provide significant energy efficiency benefits to customers. GWP estimates that a full-scale CVR project can achieve energy savings of between 2 percent and 4 percent on 65 percent of GWP feeders, or between 14,000 and 28,000 MWh per year. At full scale, the program will include 68,000 GWP meters. Assuming GWP's current value of saved energy of $50 per MWh, a full-scale, five-year program could net GWP power cost savings of $470,000 to $1.2 million per year.

Customer Savings Increase Net Present Value of Investments: GWP used value-of-service estimates for business case analysis of DA investments. They estimated the net present value of investments in DA technologies and systems would increase by 42 percent if customer savings from fewer and shorter outages are included in the analysis. The value-of-service estimates used were $0.12 per minute avoided for residential customers, $73.11 per minute avoided for commercial customers, and $247.89 per minute avoided for industrial customers.

Customer Notification Improves: One customer notification approach involves use of telephone messaging and IVR software. GWP's IVR system gives customers the ability to report outages, listen to known outage details, request follow-up status reports and automated call backs. GWP also uses its IVR system to send bulk messages about outages and other matters to customers.

Thermal Energy Storage Offers Potential Demand Reduction:[33] GWP integrated 214 ice storage system units at more than 50 commercial and municipal locations (13 city buildings and 40 commercial

[33] Demand response aspects of these deployments are discussed further in DOE, *Municipal Utilities' Investment in Smart Grid Technologies Improves Services and Lowers Costs*, (DOE, September 2014).

customers), totaling about 1.3 megawatts (MW) of thermal energy storage capacity—and therefore potential peak demand reduction—under GWP's control (see Figure 34 for a photo).

Figure 34. Examples of Thermal Energy Storage Units under Control by GWP

Two Phases of Deployment Expansion Planned: GWP's distribution system consists of 42 12kV and 69 4kV feeders. GWP's SGIG project included a DA pilot program involving two feeders. GWP is planning to expand deployments in two phases, to be completed by 2026. The initial phase automates existing 12kV feeders at a rate of about six feeders a year with an estimated average cost of about $1.0 million per feeder. The second phase is to upgrade/automate existing 4kV feeders at an average rate of about seven feeders a year and an estimated average cost of about $1.6 million per feeder. [34]

READ MORE ABOUT GLENDALE WATER AND POWER'S PROJECT ON SMARTGRID.GOV:

Glendale Water and Power Project Page

Glendale Water and Power Project Description – *July 2015*

Glendale Water and Power Case Study – *March 2012*

[34] DOE, *City of Glendale Smart Grid Initiative - FINAL REPORT*, (DOE, 2015).

6 Key Lessons and Conclusions

Implementation of DA involves the installation of thousands of devices with two-way data communications capabilities supported by high-bandwidth and/or low-latency communications networks. With sensors monitoring electricity consumption, voltages, loads, and other variables, grid operators face unprecedented levels of data to process, analyze, store, and turn into actionable information for optimizing DA operations and implementing automated controls.

Multiple information management and control systems all need access to these new data streams to effectively accomplish DA functions. Systems integration proved to be one the most significant challenges during DA implementation under SGIG, particularly for those utilities deploying DA equipment for the first time. Many DA utilities faced a learning curve that required new business practices and extensive training and testing, and revealed valuable lessons learned and recommendations that can help other utilities embarking on DA projects.

6.1 DA Applications Produce Large Volumes of New Data for Processing and Analysis

One of the major technical challenges of DA implementation involves processing and analyzing vast quantities of new data from sensors, automated devices, and smart meters. Data management challenges are inevitable. With low-latency communications systems, incoming data streams can be quite large and spotting data inconsistencies and error checking becomes a major challenge. SGIG utilities reported the need for new analytical tools and more refined algorithms to flag suspect data components or conditions to prevent interpretation errors.

To prevent errors and keep DA/DMS systems from becoming outdated, data needs to be managed on an ongoing basis. Operators found they needed to build data management requirements into system designs from the start. They made use of data warehouses (for enterprise data) and data historians (for operation data), and established policies for data storage, retention, access, and security.

6.2 Standard Protocols for Data Interfaces Were Limited

Many DA utilities found it challenging to ensure data standards were uniform between different technologies, systems, and applications. Intelligent devices need to be configured and tested to comply with National Institute of Standards and Technology (NIST) standards. Compliance with standards helps ensure interoperability between DA technologies.

Software and firmware upgrades were often needed. For example, many SGIG DA utilities used the MultiSpeak protocol to build data interfaces among software applications. MultiSpeak was obtained from the National Rural Electric Cooperative Association (NRECA) and selected by NIST as a standard that supports the Smart Grid Standards Framework vision. Others used enterprise service buses to simplify the integration process and provide platforms for data distribution and enterprise application integration.

Many of the utilities used data historian software to support integration efforts and enable engineers and technicians to view distribution system information in real time. Data historians function as both data warehouses and analysis platforms for time series data generated from SCADA and distribution management systems.

For example, Con Edison's data historian project implements a centralized data repository for all electric distribution SCADA data. The system is integrated with existing corporate data systems and provides a single point of access for all users of the company's electric distribution data. BWP's data historian is responsible for capturing and storing operational measurements for the electric distribution network and providing analytical tools for assessing distribution performance.

6.3 Extensive Equipment Testing and Customization May Be Required

Automated devices typically need more frequent firmware and software upgrades than traditional utility equipment, requiring more frequent field tests and evaluations. Standard templates from vendors also typically require customization to meet each utility's unique distribution system configurations and integrate effectively with existing SCADA systems, OMS, and DMS. To address the need for frequent testing, Pepco is moving toward 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.

Turn-key solutions were not generally available for the SGIG DA utilities, created new learning curves for implementation. Most of the SGIG DA utilities functioned as test beds and in many cases assisted vendors in identifying fixes for subsequent equipment upgrades. In general, these experiences reflected the ongoing evolution of the industry at the time. Some issues were unknown before SGIG deployments and became evident only when large-scale deployments occurred. For example, Indianapolis Power & Light and the Town of Danvers, Massachusetts learned to specify to vendors that all necessary functionality be built-in and to allow sufficient time for application development and integration, or risk schedule and cost issues.

While almost all of the utilities recommend testing DA equipment for communications and interoperability before field deployment, many also reported that lab conditions for testing field device communications may not accurately represent field conditions:

- Snohomish PUD found that the radio network implemented in the lab did not simulate field conditions so that time delays, latencies, and packet losses could not be tested.
- Atlantic City Electric in New Jersey found that modeling and testing in the lab to validate interoperability of devices is essential to reduce implementation errors, but that it is also necessary to account for environmental factors such as tree foliage and radio coverage for adjusting radio mesh networks in the field.

Some utilities were able to leverage technology to avoid the need for extensive field testing. For example, Georgia Power developed a distributed network protocol (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.

6.4 DA Requires Increased Workforce Training and Expertise

SGIG DA utilities conducted extensive training programs to familiarize control room and field staff with the new technologies and systems and provide engineers and technicians with stronger IT-related skill sets, including information management, computer systems and cybersecurity. The training programs typically involved new business practices and processes for both control room operators and field crews and involved various levels of expertise from operations to maintenance and oversight of hardware and software applications.

Training courses among the SGIG utilities varied in length from short application orientations to comprehensive DA application training sessions. In general, the training programs started as soon as the DA projects were launched, and involved training for engineering staff so they could train others and involvement from vendors to customize sessions and provide live support.

→ See **Case Study**: Burbank Water and Power (page 79)

Some of the SGIG utilities used vendors for equipment installation, while others performed these functions in-house. Advantages of the in-house approach include better knowledge of field conditions and easier staff transition into new roles. A typical example of in-house installation involves Burbank Water and Power's auto-reclosing project, which was designed and implemented by BWP engineers and electrical construction crews. The field crews were given flexibility to conform the design to field conditions and measurements.

FLISR operations in particular 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 require the most training to learn new equipment capabilities and gain confidence in their proper operation. In many cases, meter reading personnel found new opportunities through training to serve new roles supporting DA deployments and operations.

6.5 Communications Systems Need Comprehensive Planning for Multiple Smart Grid Functions

→ See **Case Study**: Florida Power & Light Company (page 74)

→ See **Case Study:** Electric Power Board (page 36)

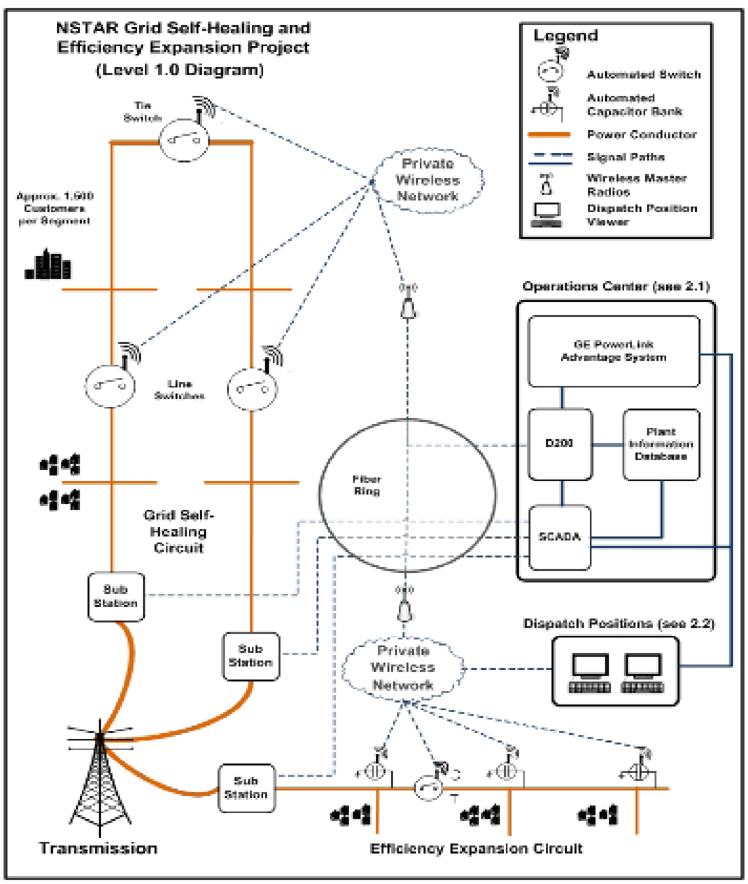
Many utilities attempted to realize synergies in their communications strategies. For example, FPL installed single networks to communicate with all end-point devices including smart meters, smart switches, and reclosers. The aim is to leverage resources and minimize training requirements, vendor interactions, IT interfaces, software solutions, and systems integration requirements. EPB installed an ultra-speed, high-bandwidth, fiber optic network, which provides internet services and communications for other city utilities beyond those services used for its AMI and DA electric grid applications.

The SGIG utilities learned that there is value in leveraging communications capacity to serve multiple smart grid applications, but that detailed planning is need to ensure that implementation proceeds smoothly and the devices and software operate as intended. In leveraging resources, the utilities were able to use the same networks for backhauling load data from smart meters to meter data management systems and for pinging meters during outages to determine which customers were without power.

Utilities found that FLISR communication networks in particular require increased resilience because they must operate under conditions where the grid itself is damaged or not functioning properly. The networks also need wide bandwidth and low latency to support near real-time operations. These factors can drive costs, constrain technology choices, and limit automation capabilities. The two-way communications network must have sufficient coverage, capacity, and latency characteristics to interface and interoperate with a wide variety of technologies and systems, including various field devices and DMS, OMS, and SCADA systems.

Some utilities found that implementation of FLISR would benefit from comprehensive evaluations for communications requirements from the start of project planning. For example, Eversource (formerly NSTAR) learned that less-than-robust radio communications can interfere with DA operations. Eversource'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 35 shows a schematic of FLISR communications architecture deployed by Eversource.

Figure 35. Schematic Communications Architecture at Eversource (formerly NSTAR)



6.6 Systems Integration is a Critical Element of DA Deployment

Information management and control systems such as DMS, SCADA, OMS, Meter Data Management System (MDMS), CIS, RMS, and GIS all need access to new data streams from sensors and controls to optimize DA functions and maximize the value of new technologies. In some cases, multiple systems need to access the same data stream and interoperate, such as when OMS use data from line sensors to identify faults along with data from smart meters to assess service restoration progress. Integration of new and legacy systems such as SCADA was a consistent challenge for virtually all of the SGIG DA utilities. While it is difficult to propose a one-size-fits-all solution for this challenge, several utilities favored making enhancements to existing systems when possible, or making incremental upgrades rather than substituting new systems.

Integration activities often involved development of customized software for data processing, error checking, and coding so that field information could be accepted and used by control room operators and management systems. The SGIG DA utilities all took on the task of systems integration to varying degrees, based on the extent of their deployment of smart grid technologies, resources, and functionality needs. The following sections describe how systems integration was generally conducted.

DMS Integration

The DMS is considered the brain of the smart distribution system. DMS establishes the load flow conditions of the distribution network and recommends (or, when fully automated, issues control commands to SCADA) switching scenarios to improve performance or resolve issues on the distribution system. The DMS also facilitates the modeling and dispatch of distributed generation, energy storage, and generators connected into the network.

Integration of DMS and AMI provides advantages for implementing automated controls for voltages and reactive power management. Premise-level voltage and VAR information allows utilities to confirm in near real-time whether the minimum service voltage level is met for all of their customers. This near real-time confirmation enables utilities to significantly improve performance and the quality of input data for DMS to determine set points for voltage and reactive power control devices. This is particularly important for CVR operations. If the voltage set point is too low, utilities risk not meeting the minimum service voltage level at the end of a feeder. With near real-time AMI data, DMS is able to achieve maximum voltage reduction while ensuring compliance with the service voltage requirements.

DMS integration typically includes accessing and using information for one of more of the following sources:

- Real-time sensory information from SCADA
- Energy consumption information from MDMS, data warehouses, and distribution models
- Switching commands to SCADA
- Circuit models from GIS
- Operating measurements from SCADA and MDMS
- Load forecasts

Under SGIG funding, Duke Energy installed a new DMS to enable new capabilities from device deployments, including FLISR, IVVC, and automated switching plans. CenterPoint Energy's Advanced Distribution Management Software (ADMS), which manages their FLISR operations, replaced the utility's legacy DMS, OMS, and distribution SCADA systems.

→ See **Case Study:** Duke Energy (page 40)

→ See **Case Study**: CenterPoint Energy (page 46)

SCADA Integration

SCADA, a legacy system for many utilities, is responsible for monitoring and control of substation relays, distribution switches, and other equipment and sensor points from throughout the electric distribution system to ensure that voltages and currents are managed within operational and financial requirements. When integrated with other DA systems, it provides a platform for a range of distribution management functions.

SCADA systems process operational data from the field and displays status on control center operator screens. Abnormal conditions trigger display alarms, which are then acted on by grid operators that can issue operator commands. DMS can also automatically issue SCADA commands. Locating faults using SCADA allows utilities to isolate and repair faults and restore service quickly, thereby increasing system resilience. SCADA equipment at the transmission and substation levels is also used when system conditions require load curtailments in ways that balance system protections with consumer needs.

SCADA technologies can also be used to facilitate monitoring of customer-owned generation to enhance safety and improve energy management. SCADA software and master stations, with proper switching and reclosers, can identify access points for customer loads and allow for real-time monitoring of all types of distributed generation assets, including back-up generators.

SCADA integration typically involves interfaces with a variety of systems and sources of grid information, including:

- GIS for distribution network models
- Real-time operating and switching information from DMS
- Measurements and data to DMS and data historians
- Measurements and data from MDMS, or data warehouses

When interoperable with other systems (i.e., DMS, MDMS, OMS, CIS, GIS, and DERMS), SCADA provides:

- Distribution control for substations, feeders, inter-tie points, and distribution equipment
- Sequencing of events, time-stamped data, trending, and diagnostic data for load management, outage analysis, and demand response
- Web-based access for operators, engineers, and managers for accomplishing system operations, outage management, and operations and maintenance activities every hour of every day throughout the year.

OMS and AMI Integration

Outage management involves integrating data streams from a variety of disparate information sources and coordinating the activities of both headquarters staff and field crews. AMI is the primary source of information about the outage status of customers and can provide data to field crews, thereby accelerating restoration times and lowering outage costs to customers.

Specifically, integration of OMS and AMI enables use of last gasp messages and "power on" notifications from smart meters, and provides outage status reports to control room operators, who can also "ping" meters to validate power delivery status. With this information and capabilities, field crews can determine outage locations and nested outages, improve outage restoration times, reduce truck rolls, and determine the best course of action to restore service to customers. Customer information systems (CIS) can also be engaged for messaging customers with status reports on restoration activities and estimates on when service will be restored. AMI-enabled outage indication functionality results in faster identification of service outage locations, improved labor productivity, and better customer service and satisfaction.

OMS integration typically involves interfaces with a variety of systems and sources of grid information, including:

- Outage events and restorations from MDMS, SCADA, DMS, and CIS
- Distribution network models from GIS
- Outage information and alerts to CIS, web portals, and interactive voice response stems
- Work orders to field crews using workforce management systems

RMS Integration

RMS integrates real-time monitoring capabilities for phase currents, phasing voltages, transformer loadings, power factors, and other key metrics. RMS also provides condition assessment information such as ambient temperatures, oil temperatures, oil levels, water levels, and protector housing pressure. RMS sensors send data to control centers indicating how the network is running and what systems need attention.

RMS is often augmented with transformer information and load management software which integrates smart meter data and distribution transformer data. This software evaluates transformer loadings, predicts potential overload conditions, and identifies transformers that are underutilized. See Pepco case study in this report for an example of RMS integration.

→ See **Case Study:** Pepco (page 50)

6.7 Utilities Approached Automation in Distinct Ways

Each utility used an individual approach to implementing and automating control packages for feeder switching and for voltage control and reactive power management.

Automation for FLISR and Feeder Switching

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.

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. 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.

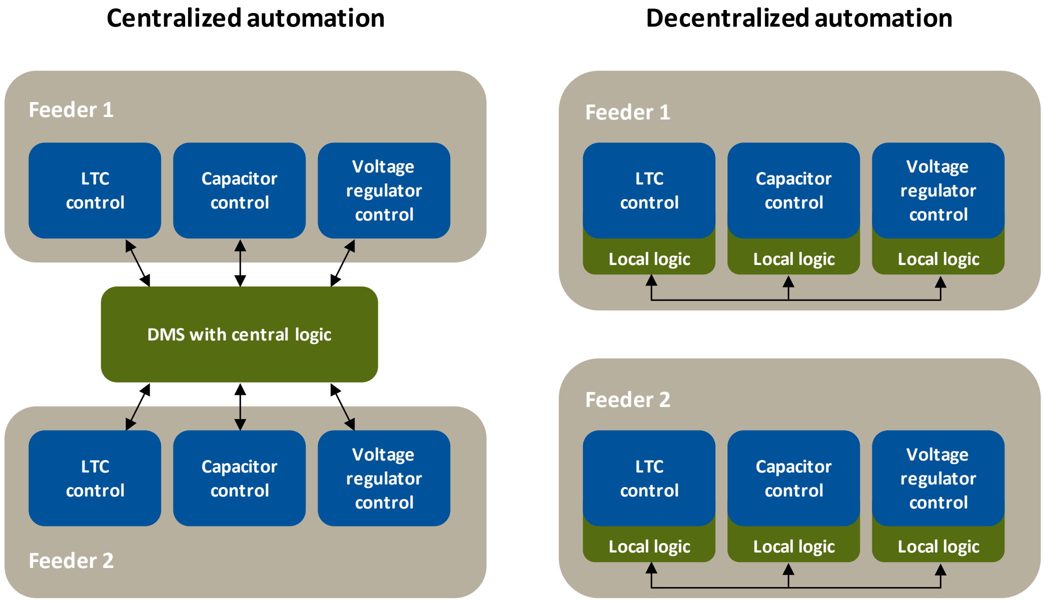
The different feeder switching devices, systems, and approaches depend on the project's objectives, legacy equipment and systems, long-term grid modernization goals, and investment timetables. Projects that seek to address a small group of feeders that are highly vulnerable to outages may favor a distributed 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.

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.

Automation for Voltage Regulation and Reactive Power Management

Utilities also implemented both centralized and decentralized control for voltage regulation and reactive power management. In general, centralized controls involve a centrally located computer and SCADA or other communication network to coordinate automated equipment operations among multiple feeders. In contrast, decentralized controls use local control packages to operate automated equipment on a single feeder, or on relatively small numbers of feeders, according to pre-established logic. Many projects use a combination of centralized and decentralized approaches, depending on feeder characteristics and volt/VAR optimization (VVO) objectives. Figure 36 provides a schematic that summarizes some of the differences between these two approaches.

Figure 36. Centralized and Decentralized Control Approaches



The two types of approaches can vary on the amount of time it takes to accomplish VVO actions. For example, centralized systems can account for more factors when determining control strategies but may take longer to execute the strategies than do decentralized systems. However, centralized systems can deal with a broader spectrum of system conditions and thus can be more flexible than decentralized systems.

6.8 Cybersecurity and Interoperability Are Integral to Smart Grid

A key objective of the SGIG program was to accelerate the development and deployment of effective cybersecurity protections for smart grid technologies and systems. A cradle-to-grave approach ensures cybersecurity protections are built into smart grid technologies and systems. This approach offers stronger and longer-lasting protection than security measures that are "bolted on" after systems are fully developed and deployed. Cybersecurity was a cornerstone of the SGIG program from its onset. DOE required all grant proposals to show how cybersecurity would be addressed in every phase of the project lifecycle and how security could be upgraded in response to changes to the threat or technological environment.

Prior to starting work, DOE required each awardee to develop and submit a Cybersecurity Plan (CSP) for approval. Plans identified cybersecurity risks and how they would be mitigated, cybersecurity criteria used for vendor and device selection, relevant cybersecurity standards and/or best practices that would be followed, corporate accountability to ensure successful implementation, and how the project would support emerging smart grid cybersecurity standards. Throughout the SGIG program, the Cybersecurity Plans and corresponding on-site reviews were DOE's primary tools for confirming adherence to good cybersecurity practices, monitoring progress, building lessons learned, sharing best practices, and continuously improving cybersecurity protections.

The DOE cybersecurity team participated in 311 annual site visits and more than 100 conference calls from 2011 to 2015 to monitor progress on cybersecurity implementation. During annual project site visits, SGIG cybersecurity team members rigorously reviewed all CSPs and their implementation against 13 cybersecurity criteria and, as needed, made recommendations. Year-to-year results showed improvements in nearly all projects and areas, reflecting a maturation of cybersecurity practices and management.

DOE developed a dedicated, secure website of cybersecurity resources, which served as a central repository of tools, guides, presentations, and resources specifically tailored to the needs of SGIG project teams. DOE also conducted cybersecurity webinars for SGIG grant recipients and hosted two Smart Grid Cybersecurity Information Exchanges, which promoted peer-to-peer discussions of lessons learned and best practices.

SGIG project participants improved their understanding of cybersecurity issues and specific needs in deploying smart grid technologies and systems. This was most readily apparent in smaller, utilities that saw a dramatic increase in the staff's sophistication in cybersecurity processes. Although not an SGIG program requirement, many utilities intend to continue to modify and use their SGIG CSPs as foundations of their organizations' ongoing cybersecurity programs.

Interoperability is also critical in a modern grid because it enables two or more networks, systems, devices, applications, or components to share and readily use information securely and efficiently with little or no inconvenience to the user.[35] Since 2009, the industry has made substantial progress in tackling key interoperability issues, and the SGIG projects were important for evaluating deployments, assessing needs, and accomplishing key activities in accelerating interoperability development.

Lessons Learned and Best Practices from the 2012 Smart Grid Cybersecurity Information Exchange

SGIG utilities shared valuable lessons learned from implementing their CSPs and shared them with peers during the 2012 Cybersecurity Information Exchange. [36] Insights from the SGIG utilities include:

- **Early cybersecurity planning with product vendors is key**. Develop cybersecurity specific procurement contract language and consider early engagement of 3rd-party software suppliers when planning smart grid investments. Demand that products meet cybersecurity standards and define those standards early. Provide strong contractual language in proposal requests. Request that vendors take responsibility for security and vulnerability mitigation over the full product lifecycle.
- **Ensure interoperability through robust testing with manufacturers and industry partners**. Collaborate with manufacturers to develop robust test environments that are fully representative of all factors in the field. Become active in national partnerships and support emerging smart grid cybersecurity standards. Create interoperability with legacy systems through gateway proxies and service buses.
- **Obtain strong cybersecurity support from executives and managers**. A CSP should behave like a business plan that includes a budget, defined risk, metrics and evidence, and is written so that

[35] GridWise Architecture Council, "Introduction to Interoperability and Decision Maker's Interoperability Checklist, v1.0."
[36] DOE, 2012 DOE Smart Grid Cybersecurity Information Exchange, June 2013.

senior management can understand it. Obtain upfront management support and resources, tie security needs to the business strategy, and communicate the business implications of cybersecurity investments. Keep executives informed throughout a project.

- **Eliminate company silos and define clear cybersecurity roles and responsibilities**. Undefined personnel roles and responsibilities are major obstacles and must be established at the beginning of any cybersecurity program. Company "silos" must be crossed so that the cybersecurity program is well understood by multiple stakeholders. Employees must work to narrow the gulf between operations and IT staff to fully address cybersecurity.
- **Conduct workforce training to build cybersecurity expertise and literacy**. There is often a lack of common vocabulary on cybersecurity issues and enterprise-wide cultural change is often needed. Utilities should conduct training to build deep cyber expertise for key staff, but also support cybersecurity training for all technical staff to promote awareness and familiarity across the organization.

7 Future Directions and Next Steps

The SGIG DA projects invested more than $2 billion in new technologies, tools, and techniques for the modernization of electric distribution systems. While substantial, these investments represent a relatively small portion of the total level of investment that the electric power industry is expected to contribute toward grid modernization over the next several decades.[37] The SGIG projects were specifically designed as learning opportunities, providing the electricity industry with additional data on smart grid performance and lessons learned that can catalyze continued investment in smart grid technologies and systems in the coming years.

This section discusses the future smart grid investment plans of several SGIG participants. It also identifies some of the key technical challenges that remain to be addressed to reduce the risks and improve the cost-effectiveness of investments in DA technologies, tools, and techniques.

7.1 SGIG Utilities Largely Plan to Expand Smart Grid Investments in DA

Most SGIG DA utilities implemented small-scale projects; only a few completed system-wide deployments. The vast majority are planning to build on their SGIG DA experiences and expand grid modernization investments. The pace of grid modernization expansions beyond SGIG are governed by distinct local conditions and needs.

Several of the participating SGIG DA utilities that invested in partial deployments plan to further invest in the phased upgrade of additional substations and feeders. Many utilities are upgrading the worst performing substations and feeders first, or those serving customers with critical business needs for shorter and fewer outages. For example:

- Glendale Water and Power plans a system-wide upgrade to be completed by 2026.
- PPL Electric Utilities Corporation plans to upgrade all feeders by continuing DA investments through 2018.
- Florida Power and Light is rapidly expanding its deployment of additional automated feeder switches based on project success.
- Duke Energy's SGIG project was part of a 10-year plan for grid modernization and FLISR deployment.
- Pepco plans to deploy its FLISR technologies to 15 percent of its systems.
- Central Lincoln Public Utility District plans to implement CVR territory-wide.

Several utilities also plan to add or expand DA capabilities in existing deployments by upgrading communications capacity, making greater use of unused DA functions embedded in existing devices and management systems, and installing new devices and systems on already automated feeders and substations. Examples include:

- CenterPoint Energy plans to expand FLISR capabilities to include full automation.
- Westar Energy in Kansas plans to implement an enterprise smart grid data analytics platform to integrate and leverage data from field devices with new asset and work management systems.

[37] Electric Power Research Institute, *Estimating the Costs and Benefits of the Smart Grid*, 2011.

- Southern Company plans to create single-user interfaces for grid operators by integrating its DMS and OMS.
- Georgia Power plans to have all of its automated normal open points controlled by a centralized FLISR system.
- Florida Power and Light is exploring how to tie new fault location capabilities to substations to minimize customer interruptions and improve power quality by addressing voltage flicker issues.
- PECO Energy Company plans to use DA and AMI to improve its ability to respond to "nested" outages, which can occur within major events and can often go unnoticed.

Additional SGIG utilities (beyond the 62 included in this report) that were not part of the DA program also plan to leverage their SGIG-funded deployments toward future DA deployments. For example, NV Energy's new statewide communications network now links a variety of smart grid components. NV Energy plans to deploy DA devices and applications, upgrade the DMS, integrate AMI meter power failure messages with the DMS, enhance outage communications, and pilot VVO.

7.2 DA Projects Highlighted Continuing R&D Challenges

The transition from traditional to modern electric distribution systems using smart grid technologies is under way, but efforts are in the very earliest stages of development and deployment. The SGIG DA utilities have shown the potential to enable fewer and shorter outages and reduce energy requirements by using automated controls. Continued modernization of distribution management systems will require the electricity industry to continually address R&D challenges as new technologies emerge. Several of these challenges are summarized below.

Cybersecurity and Interoperability

Cybersecurity and interoperability remain important technical challenges for modernizing electric distribution systems. Standards, protocols, tools, and techniques are needed for ensuring secure and interoperable technologies and systems. Success in these areas involves ongoing activities for government and industry, including changes in regulations, business practices, and consumer data privacy protections.

Modeling, Visualization, and Data Analytics

Evolving system-level challenges underscore the need for a new class of monitoring, control, and analytic capabilities. These challenges include the integration of large amounts of variable generation; increased susceptibility of the system to destabilizing events; and rapidly developing security issues. In the last few years, parallel computing techniques, lower cost high-speed communications, advanced modeling frameworks, and wide-area coordination mechanisms have become available, and together hold the promise for faster simulation methods and more robust control approaches necessary for operating modern grid systems.

Currently, most distribution system operators have limited visibility into the conditions and state of the system, except for distribution substations. As more distributed energy resources are deployed, greater visibility (e.g., along feeders to utility meters and possibly into buildings) is needed to ensure reliability, power quality, and enable advanced applications. The installation of approximately 50 million smart meters, covering about 43 percent of U.S. homes, has been a valuable step in improving distribution visibility.[38] However, phenomena associated with system dynamics and protections require much better sensors that can inform operations on the order of milliseconds.

Because of the large number of feeders and substations, high-resolution sensors will need to be lower in cost for wide-scale deployment. Micro-synchrophasors, or distribution phasor measurement units, are one technology that can provide the enhanced visibility needed for the future grid. Other technologies include advanced sensors that provide configuration and/or real-time condition information on field assets. Communications and data management requirements must link to the type of decisions that will be made. Advanced applications using the sensor data can help map and update the topology of distribution systems, determine asset health, enable “real-time” distribution operations, and accelerate post-event recovery.

Recent experiences with the aggregation of demand response resources into electricity market structures presents a potential framework for coordination of distributed energy resources. Advanced DERMS can be valuable contributors for improving utility integration of distributed resources.

Advanced Grid Devices and Power Electronics

Solid state distribution transformers involve design concepts that combine power electronics and high-frequency magnetics for more compact transformers and new control capabilities. In these early stages of development, it is envisioned that solid state transformers will not be drop-in replacements for existing transformers but will be deployed, once market-ready, in strategic locations that can fully utilize their enhanced functionality and flexibility.

Solid state transformers can perform a variety of functions now played by a variety of devices, including voltage regulation and reactive power supplies, and can be used to form hybrid AC and DC systems that can increase total system efficiency. They can also be used to manage the interaction between microgrids and utility systems. Solid state transformers can regulate the process of disconnecting and reconnecting with the main grid, quickly and precisely change the direction of power flows, and limit fault currents.

Microgrid Management and Energy Storage

Microgrids involve groups of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. It can connect and disconnect from the grid to enable it to operate in both grid-connected or island mode and can be nested one within another. Single-customer microgrids are generally facilities with a need for generation, such as large university campuses, hospital complexes, military bases, and industrial parks. Advanced tools and techniques are needed for integration with electric distributions systems to occur safely and reliably.

One of the major challenges common across the various energy storage technologies is cost. The total cost of electric storage system include all subsystem components, installation, and integration costs. While there is a strong focus on reducing the cost of the “energy storage” component, such as battery chemistries or the spinning mass in flywheels, this component only constitutes approximately 30 to 40

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[38] The Edison Foundation Institute for Electric Innovation (IEI), *Utility-Scale Smart Meter Deployments*, (IEI, September 2014). The SGIG program installed more than 16 million smart meters.

percent of the total system cost. A total systems approach is needed to reduce balance-of-system costs and achieve the desired cost and performance targets. Other technical challenges include improving the safety of these technologies and assessing the appropriate value streams for the multiple services electricity storage can provide.

Advanced Demand-Side Solutions

There are many opportunities to make a variety of end-use loads more "grid-friendly," which may blur the lines between the utility and customer sides of the meter blur. For example, automated responsive customer equipment can be designed to detect voltage and frequency levels from the grid or respond to signals from control systems. However, manufacturers must ensure that these loads will be capable of providing grid services without jeopardizing the quality and reliability of their primary function.

Smart loads may include building control systems that are optimized for individual services—such as lighting, heating, cooling, ventilation, and pumping—but that can also interact with utility or operator signals. Communications-enabled thermal energy storage systems (hot and cold) have been used in demand response programs. Electric water heaters are emerging as another form of thermal energy storage that can be used to provide greater grid flexibility. Advancing these technologies will require consideration of how efficiency improvements will need to be optimized with greater system flexibility.

DOE expects to continue supporting grid modernization through research, development, demonstration, analysis, and technology transfer activities, especially in areas where there is a demonstrated federal role such as cybersecurity, interoperability, and advanced concepts and technologies based on new discoveries in science, engineering, and mathematics.

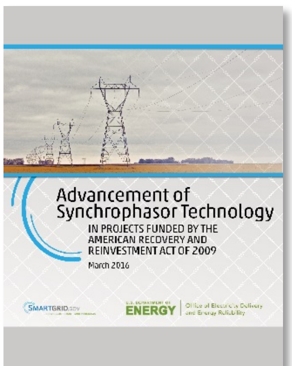
While the SGIG program is now complete, grid modernization remains an important national priority. DOE through the Grid Modernization Initiative (GMI) recently released a Grid Modernization Multi-Year Program Plan (MYPP) that describes the challenges and opportunities for achieving a modern, secure, sustainable, and reliable grid and how DOE will help achieve this through programs and activities. The Grid Modernization Lab Consortium, a multi-year collaboration among 14 DOE National Laboratories and regional networks, will assist DOE in developing and implementing the activities in the MYPP. [39]

[39] DOE, Grid Modernization Initiative, *Grid Modernization Multi-Year Program Plan*, November 2015.

APPENDIX A.
Where to Find Additional Information

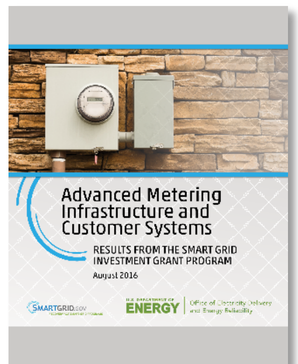
To learn more about national efforts to modernize the electric grid, visit the [Office of Electricity Delivery and Energy Reliability's website] and the [SmartGrid.gov website]. DOE has also published several reports that contain findings on topics similar to those addressed in the projects featured in this report.

A.1. Final SGIG Technology Analysis Reports



Advancement of Synchrophasor Technology in Projects Funded by the American Recovery and Reinvestment Act of 2009

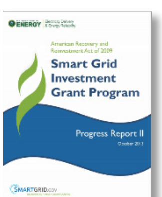
2016



Advanced Metering Infrastructure and Customer Systems: Results from the Smart Grid Investment Grant Program

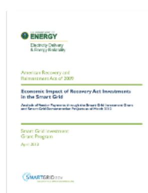
2016

A.2. SGIG Program-Level Interim Progress Reports



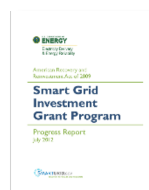
Smart Grid Investment Grant Progress Report 2013

September 2013



Economic Impact of Recovery Act Investments in Smart Grid

March 2013



Smart Grid Investment Grant Progress Report 2012

July 2012

A.3. Key SGIG Technology Analysis Interim Reports

Demand Reductions from the Application of Advanced Metering Infrastructure, Pricing Programs, and Customer-Based Systems - Initial Results	Dec 2012
Operations and Maintenance Savings from Advanced Metering Infrastructure - Initial Results	Dec 2012
Reliability Improvements from the Application of Distribution Automation Technologies - Initial Results	Dec 2012
Application of Automated Controls for Voltage and Reactive Power Management - Initial Results	Dec 2012

Synchrophasor Technologies and their Deployment in the Recovery Act Smart Grid Programs	Aug 2013
Municipal Utilities' Investment In Smart Grid Technologies Improves Services and Lowers Costs	Oct 2014
Smart Grid Investments Improve Grid Reliability, Resilience, and Storm Response	Nov 2014
Evaluating Electric Vehicle Charging Impacts and Customer Charging Behaviors - Experiences from Six Smart Grid Investment Grant Projects	Dec 2014
Fault Location, Isolation, and Service Restoration Technologies Reduce Outage Impact and Duration	Dec 2014

A.4. DA Project Case Studies

Case Studies	Project Performer	Date
A Smarter Electric Circuit: Electric Power Board of Chattanooga Makes the Switch	EPB	May-11
Bright Lights, Big City: A Smarter Grid in New York	Con Edison	May-11
At the Forefront of the Smart Grid: Empowering Consumers in Naperville, Illinois	City of Naperville	Sep-11
Vermont Pursues a Statewide Smart Grid Strategy	eEnergy Vermont	Nov-11
Building a Smarter Distribution System in Pennsylvania	PPL	Dec-11
A "Model-Centric" Approach to Smarter Electric Distribution Systems	ORU	Dec-11
Glendale, California Municipal Invests in Smart Grid to Enhance Customer Services and Improve Operational Efficiencies	GWP	Feb-12
CenterPoint Energy's Smart Grid Solutions Improve Operating Efficiency and Customer Participation	CenterPoint	Feb-12
Smart Grid Solutions Strengthen Electric Reliability and Customer Services in Florida	FPL	Jun-12
Using Smart Grid Technologies to Modernize Distribution Infrastructure in New York	Con Edison	Jul-14
Integrated Smart Grid Provides Wide Range of Benefits in Ohio and the Carolinas	Duke Energy	Aug-14
Smart Grid Technologies Cut Emissions and Costs in Ohio	AEP Ohio	Oct-15
Renovating the Grid and Revitalizing a Neighborhood	KCP&L	Oct-15

APPENDIX B.
Approach to Data Collection and Analysis

The 62 SGIG DA projects collected and analyzed data about the deployed technologies and systems, resulting grid impacts, benefits, and lessons learned.

DOE compiled this information for analysis of DA operations, and for sharing with the electric power industry through DOE's **Smart Grid Investment Grant (SGIG) website**.

The primary purpose of SGIG's data collection and analysis is to provide electric power industry stakeholders and decision makers – public and private – with information on grid impacts, benefits, costs, and lessons-learned to help assess the cost-effectiveness of investments in DA technologies and systems. The goal is to help accelerate modernization of the nation's electric distribution systems.

B.1. Analysis Approach

Figure B-1 shows the overall DOE approach for analysis of SGIG DA projects.[40] The analysis begins with assessments of the deployed ***smart grid assets***. The assessments include the technologies and systems, such as automated capacitor banks or distribution management systems, and how these are being installed and operated by the SGIG DA utilities. The next step involves assessments of the new ***smart grid functions*** that the new assets enable. This includes assessments of the new functions and capabilities, such as automated feeder switching or conservation voltage reductions, and how to make them operational to achieve certain grid impacts and benefits.

Figure B-1. SGIG Analysis Approach

The third step involves assessments of the ***smart grid impacts***, which generally includes analysis of specific physical metrics that measure changes resulting from deployment of assets and implementation of functions, such as improvements in reliability indices or reductions in the numbers of truck rolls. The last step involves the determination of ***smart grid benefits***, which generally includes monetization of the impacts for use in business case analysis, such as the value of reductions in customer losses from fewer/shorter outages, or financial savings from deferral of capital investments.

Benefits analysis can include utility, customer, and societal perspectives and covers two general types of benefits: those that can be monetized, such as cost savings; and those that are difficult to monetize,

[40] See DOE, "Analytical Approach" on SmartGrid.gov; Electric Power Research Institute (EPRI), *Guidebook for Cost/Benefit Analysis of Smart Grid Demonstration Projects*, Revision 1, (DOE, December 2012); and DOE and EPRI, *Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects*, December 2009.

such as reductions in carbon dioxide emissions or increases in customer choices, services, and satisfaction.

B.2. Data Collection Approach

To conduct effective analysis of the SGIG DA projects, accurate data is needed from the utilities on the performance of the deployed assets, functions, impacts, and benefits. At the outset of the SGIG program in 2009-2010, DOE collaborated with each of the SGIG project teams to develop Metrics and Benefits Reporting Plans (MBRP). Each SGIG project was required to have an approved MBRP before equipment installations could begin. The MBRPs were customized to reflect each project's unique scope and objectives.

A series of meetings between DOE and SGIG project teams developed these plans, outlined specific data to collect, and identified when and how it would be reported to DOE. Each plan discussed two separate sets of data collection efforts: Build Metrics and Impact Metrics.

- **Build Metrics** comprise the set of devices and systems and related costs to buy and install; this information was posted and updated on the SGIG website every three months to inform stakeholders about the pace of progress with SGIG project implementation. DA build metric data includes information on the numbers and costs of installed devices and systems.
- **Impact Metrics** comprise the set of information developed by the project teams to assess the effects of the new technologies and systems on grid operations and business practices. Impact Metrics submissions to DOE occurred twice a year and required the project teams to collect and analyze information to show how the installed technologies and systems operated to achieve grid modernization objectives in several key areas: reliability and outage management, asset utilization, power quality, integration of distributed energy resources (DER), and asset health condition monitoring.

The Impact Metric data submissions typically involved the utilities calculating quantitative values that show the effects before and after, or with and without, deployment and operation of DA technologies and systems. One of the challenges in estimating DA impacts involves the need to develop accurate baselines (before DA or without DA) against which impacts can be measured.

B.3. Scope of Data Collection

Table B-1 lists the assets, technologies, and systems that were collected for build metrics reporting from the SGIG DA projects. Build metric data collection compiles information on the installation of electric distribution smart grid assets deployed under SGIG. Because each of the projects had its own unique scope and objectives, not all of the SGIG DA projects provided information on all of the build metrics.

Table B-1. List of Key DA Build Metrics for SGIG Projects

List of Key SGIG DA Build Metrics – Assets, Technologies, and Systems

• Advanced metering infrastructure and smart meters
  ○ Smart meters with outage notification feature enabled
  ○ Smart meters with power quality monitoring feature enabled
• Automated feeder switches

List of Key SGIG DA Build Metrics – Assets, Technologies, and Systems

• Automated capacitors
• Automated voltage regulators
• Distribution automation/substation communications networks
• Distribution management systems (DMS)
  ○ Integration of DMS with AMI
  ○ Integration of DMS with OMS
• Feeder monitors
• Remote fault indicators
• Smart relays
• Substation/transformer monitors

Table B-2 lists the impact metrics that were collected for the SGIG DA projects. Because each of the projects had its own unique scope and objectives, not all of the SGIG DA projects contributed to all of the impact metrics. In addition, the usefulness of the data on impact metrics varies across the projects so it was necessary for DOE to screen the information and report on selected projects and impacts.

Table B-2. List of DA Impact Metrics for SGIG Projects

List of SGIG DA Impact Metrics.	
Impact Areas	**Impact Metrics**
Reliability and outage management	• Reduced truck rolls and vehicle miles • Improved reliability indices • Reduced outage duration
Asset utilization	• Reduced line losses (kWh) • Reduced demand (kW) • Avoid occasional truck rolls and vehicle miles • Improved power factors • Reduced electricity usage
Power quality	• Reduced line losses (kWh) • Reduced demand (kW) • Avoid occasional truck rolls and vehicle miles
Integration of DER	• Reduced peak demands (kW) • Reduced truck rolls and vehicle miles • Reduced electricity usage (kWh)
Asset health conditions	• Reduced truck rolls and vehicle miles • Reduced the instances of equipment failures

While there are 62 utilities that deployed DA assets, technologies, and systems under SGIG, 47 of them contributed impact metrics to this report. As shown in Table B-3, the number of utilities contributing DA impact metrics varies.

Table B-3. Number of SGIG DA Utilities Contributing Impact Metrics Data for DA

DA Impact Metrics	Number of DA Utilities Reporting	Percentage of 62 Total DA Utilities
System Average Interruption frequency Index	36	58%
System Average Interruption Duration Index	37	60%
Customer Average Interruption Duration Index	36	58%
Momentary Average Interruption Frequency Index	12	19%
Avoided Distribution Operations Vehicle Miles	18	29%
Avoided Distribution Operations Costs	9	15%
Avoided Distribution Operations Truck Rolls	16	28%
Distribution Feeder Switching Operations Count	12	19%
Avoided Distribution Feeder Switching Operations Costs	8	13%

B.4. Data Collection Challenges and Limitations

DOE's data collection and analysis activities produced a variety of reports and case studies on the results and lessons learned from the SGIG DA projects.[41] The extent of the DOE analysis is limited in various ways due to challenges that were faced by the SGIG DA utilities in the data collection and analysis process.

One of the most significant challenges concerned the development of accurate baselines for assessing grid impacts. Most of the SGIG utilities encountered challenges in collecting and analyzing appropriate data for the development of accurate baselines. Other utilities underestimated the amount of time, effort, and engineering expertise needed for accurate impact metric estimation and reporting.

One difficulty in assessing grid impacts stemmed from the use of historical data from affected feeders in order to assess smart grid impacts before and after data collection and analysis. However, this technique was complicated in most cases by the need to make weather adjustments so that smart grid impacts on key metrics such as reliability indices could be separated from other factors that could affect reliability such as the weather. For many utilities weather adjustments were not exact and raised questions about the accuracy and validity of the before-and-after impact estimates. However, some utilities were successful in accomplishing weather adjustments for estimating DA impacts and DOE's DA analysis focused on the experiences and reported results from these utilities.

In addition to weather adjustment issues, many of the utilities also experienced other difficulties including changes to feeders from one year to the next due to routine maintenance, storm damages, and the types and numbers of customers served by the upgraded feeders. DOE was able to identify the utilities with these problems and during the metrics realignment process made adjustments in the types

[41] See Appendix A for a list of documents and web links.

of impact metrics to be submitted to DOE. In some cases, the utilities offered to substitute technical reports that they produced in lieu of impact data to send to DOE. DOE was often able to use the reports as sources of data for analysis. Selected reports provided by the utilities on DA impact analysis results are posted on the DOE website.

Another challenge with DA data collection and analysis concerned the lack of commonality among the projects in their respective goals and objectives. While some of the utilities deployed and operated DA on large numbers of feeders, most utilities conducted small- and pilot-scale tests on relatively small numbers of feeders. Because of these differences, aggregating data for analysis by utilities with such starkly different objectives is not generally useful.

A final challenge concerned differences in the level of experience and know-how among the SGIG utilities with DA technologies and systems. In many cases, the technologies and systems deployed by the SGIG DA utilities involved learning curves to determine how to install and operate new assets and functions properly. In many cases impact analysis was not worthwhile during periods when the utilities were primarily trying to figure out the best ways to install and operate the DA technologies and systems. This limited the number of useful impact metric reports from these types of utilities. However, the experiences from the DA utilities facing these circumstances produced valuable information on lessons-learned for DA deployments and operations.

There are also several caveats associated with the analysis of the cost data. One is that the utilities did not use uniform cost categories. As a result, cost data from some of the utilities could not be used in the analysis because cost categories included combinations of different cost items, in unknown proportions, that could not be separated. In addition, much of the hardware and software used in the SGIG DA projects were purchased up to five years ago, and equipment functionality and costs for certain devices have changed substantially since then. As a result, the cost information reflects the wide range of experiences of the SGIG DA utilities but are may not be indicative of the costs of the equipment today or in the future.

To address these challenges and issues, in 2013—about midway through the SGIG program—DOE conducted a re- assessment of the MBRPs and contacted each of the project teams to determine how to improve the quality and usefulness of the impact metrics submissions. For most of the SGIG DA utilities, this reassessment effort for impact metrics reporting resulted in a greater focus on a smaller number of the most valuable impact metrics. In many cases, it also resulted in the utilities agreeing to prepare separate reports on grid impacts in lieu of submitting data sets on grid impacts.

APPENDIX C.
Supporting Build Metrics Data

A total of 62 utilities deployed DA assets, technologies, and systems under the SGIG program. Of those projects, 52 projects reported at least one DA-related build metric to DOE; the remaining 10 projects only installed DA technologies at a very small scale (as part of projects that were focused more on AMI technologies) and were not required to report DA-related build metrics. (Build metrics for these 10 projects specific to AMI and customer technologies are reported separately in *Advanced Metering Infrastructure and Customer Systems: Results from the SGIG Program*). These 10 recipients that did not report DA build metrics include:

1. Black Hills Corporation/Colorado Electric
2. Cobb Electric Membership Corporation
3. Connecticut Municipal Electric Energy Cooperative
4. Guam Power Authority
5. Idaho Power Authority
6. Madison Gas and Electric Company
7. Marblehead Municipal Light Department
8. New Hampshire Electric Cooperative
9. San Diego Gas and Electric Company
10. South Kentucky Rural Electric Cooperative Corporation

Build metrics for the 52 reporting DA utilities are reported in this appendix.

C.1. DA Device and System Deployments (by Project)

ID	Utility Name	% of System with SCADA	% of System with DA	Automated Feeder Switches (#)	Automated Capacitors (#)	Automated Regulators (#)	Feeder Monitors (#)	Remote Fault Indicators (#)	Transformer Monitors (#)	Smart Relays (#)
1	Atlantic City Electric Company		9	164	27					55
2	Avista Utilities	75	21	263	123	177	102			102
3	Burbank Water and Power	100	94			130				
4	CenterPoint Energy Houston Electric	100	11.7	567						171
5	Central Lincoln People's Utility District	100	9	17		2	14			
6	City of Anaheim Public Utilities Department			101	26			272		
7	City of Auburn, IN	100	20	5	10					22
8	City of Fort Collins Utilities, CO	8	0.45	2						

ID	Utility Name	% of System with SCADA	% of System with DA	Automated Feeder Switches (#)	Automated Capacitors (#)	Automated Regulators (#)	Feeder Monitors (#)	Remote Fault Indicators (#)	Transformer Monitors (#)	Smart Relays (#)
9	City of Glendale Water & Power, CA	100		8						4
10	City of Leesburg, FL	100	16.3	6	20					
11	City of Naperville, IL		3.9	7						12
12	City of Ruston, LA			6	10		28			28
13	City of Tallahassee, FL	11.2	11.2	93						
14	City of Wadsworth, OH			31	13					
15	Consolidated Edison Company of New York	39	37	797	449	111	617	1,851	17,401	205
16	Cuming County Public Power District	100				76	67			
17	Denton County Electric Cooperative			2	2	2	2	6		
18	Detroit Edison Company	1.54	1.56	9	40	16			2	75
19	Duke Energy Business Services	100	98	914	2,098	914	83	4,755		4,755
20	El Paso Electric	1	2.6	13			6	8		8
21	Electric Power Board of Chattanooga, TN	100	100	1,294						
22	First Energy Service Corporation	5.9	2.3	30	187	4	236			
23	Florida Power & Light Company			285	1,403	1,806	1,014	3,879	2,716	1,084
24	Golden Spread Electric Cooperative	48.25	37.9	97	23	16	114	34		138
25	Hawaiian Electric Company	7	7	29						
26	Indianapolis Power & Light Company		27	184	1,308	76		3	17	618
27	Knoxville Utilities Board	6.8	6.4					117		
28	Lafayette Consolidated Government, LA	9.8	35		47					
29	Memphis Light, Gas and Water Division	100	95							489
30	Minnesota Power	0.3	0.3	5			5			
31	Modesto Irrigation District		2.8		5					

ID	Utility Name	% of System with SCADA	% of System with DA	Automated Feeder Switches (#)	Automated Capacitors (#)	Automated Regulators (#)	Feeder Monitors (#)	Remote Fault Indicators (#)	Transformer Monitors (#)	Smart Relays (#)
32	Municipal Electric Authority of Georgia	92.7	80			813				284
33	Northern Virginia Electric Cooperative		100	14	164	340			56	25
34	Eversource (formerly NSTAR)	81.62		360	109		360	360		
35	Oklahoma Gas and Electric Company		11.62		456					14
36	PECO Energy Company			100	63					221
37	Pepco of Washington, DC		2.4	42					41	306
38	Pepco of Maryland		9.6	103				186		466
39	Powder River Energy Corporation	100				30				
40	PPL Electric Utilities Corporation		4	214	195					
41	Duke Energy (formerly Progress Energy)	98.5	48.5	829	589	2,320	1,583			
42	Public Utility District No. 1 of Snohomish County	100	2.3	6		13	45	45		382
43	Rappahannock Electric Cooperative	90.91	23.6			300	64			
44	Sacramento Municipal Utility District	17.1	18.84	156	177			26		155
45	South Mississippi Electric Power Association	83.3					65		18	118
46	Southern Company Services	95	44.2	2,193	1,869	3,339		263		848
47	Southwest Transmission Cooperative	67	39	22	10	78		54		154
48	Talquin Electric Cooperative	15	15		62					
49	Town of Danvers, MA	94	94	50	14		12			
50	Vermont Transco	33.11	13.87	42		102	30	9	12	276
51	Westar Energy	100	1	31	6			27		
52	Wisconsin Power and Light Company		32		576					

APPENDIX D.
Supporting Impact Metrics Data

Individual utilities reported impact metrics for key data points, which are anonymized and included in the following tables. Utility names are replaced with a generic ID number in each table; however, one utility ID number does not refer to the same utility across tables (e.g., the utility represented by ID 1 in the first table is not the same utility represented by ID 1 in the second table).

D.1. Avoided Vehicle Miles, Truck Rolls, Switching Operations, and Associated Costs (By Project)

ID	Avoided Distribution Operations Vehicle Miles	Avoided Distribution Operations Cost ($)	Avoided Distribution Truck Rolls (#)	Distribution Feeder Switching Operations Count (#)	Avoided Distribution Feeder Switching Operations Cost ($)
1	2,340	$43,380	239	291	$41,760
2	109,639		1,397	478	
3				597	
4	7,200		1,080		
5				37	
6	64,125		2,055	2,055	$7,500
7	138				
8				20	$8,500
9	1,705,601				
10	17,772		14,170	14,170	$354,250
11	12,530	$62,535	4,072	44	
12	193,420	$723,900	11,793		$385,200
13				9	$3,511
14	86	$475,415			
15	733		52	60	
16	8,377	$2,210	2,362		
17	590	$11,520	52		$9,360
18	2,420	$43,200	202	280	$35,460
19	31,007	$31,749	654		
20	33,510		4,682		
21			30,288		
22	1,230,700	$4,819,230	123,070	9,586	$623,090
23	12,300		1,106		
24	2,340	$43,380	239	291	$41,760
25	109,639		1,397	478	

D.2. Year over Year Comparison of Key Reliability Indices (By Project)

The following four tables show changes in SAIFI, SAIDI, CAIDI, and MAIFI between the summers of 2013 and 2014 for those SGIG DA utilities that contributed these metrics.

Changes shown are year over year, not against a baseline. The table data highlight the importance of pre-deployment baselines to effectively evaluating the reliability impacts and benefits of smart grid technologies. As the data demonstrate, several utilities experienced reliability improvements year over year on affected feeders, while others saw decreased reliability. This could be due to changes in weather patterns or system configurations, or due to the fact that DA deployments were not at a sufficient scale to create significant system impacts. Simply comparing reliability indices from year to year—rather than against a pre-deployment baseline—cannot effectively measure the full impact of DA investments. However, the following tables offer insight into potential year-over-year changes to reliability indices when implementing DA.

Table D-1. SAIFI Comparisons, Summer 2013 and Summer 2014

ID	Summer 2013	Summer 2014	% Change
1	0.190	0.220	-15.8%
2	0.507	0.640	-26.4%
3	0.494	0.645	-30.6%
4	0.183	0.030	83.8%
5	0.326	0.309	5.1%
6	0.319	0.436	-36.7%
7	0.730	0.630	13.7%
8	1.140	0.630	44.7%
9	0.390	0.341	12.5%
10	1.310	1.850	-41.2%
11	1.780	1.150	35.4%
12	0.063	0.302	-379.4%
13	0.240	0.370	-54.2%
14	0.520	0.427	17.9%
15	0.403	0.530	-31.6%
16	0.134	0.101	24.9%
17	0.710	0.800	-12.7%
18	1.744	1.800	-3.2%
19	0.710	0.920	-29.6%
20	0.388	0.053	86.4%
21	1.588	1.027	35.3%
22	0.440	0.538	-22.3%
23	0.690	0.842	-22.0%

Note: 36 utilities contributed SAIFI values to this report; 23 utilities provided data for both summer 2013 and summer 2014.

Table D-2. SAIDI Comparisons, Summer 2013 and Summer 2014

ID	Summer 2013	Summer 2014	% Change
1	6.88	8.87	-28.9%
2	48.66	51.40	-5.6%
3	42.12	68.43	-62.5%
4	10.40	0.06	99.4%
5	21.22	13.65	35.7%
6	31.16	37.40	-20.0%
7	102.63	54.11	47.3%
8	82.87	59.00	28.8%
9	20.85	20.66	0.9%
10	175.80	218.40	-24.2%
11	134.16	36.00	73.2%
12	157.00	108.00	31.2%
13	2.52	19.97	-692.5%
14	0.08	0.50	-559.2%
15	25.10	44.04	-75.5%
16	50.34	37.09	26.3%
17	22.53	28.84	-28.0%
18	11.28	1.49	86.8%
19	63.00	79.78	-26.6%
20	134.88	131.69	2.4%
21	85.20	104.88	-23.1%
22	55.36	4.18	92.4%
23	212.08	162.09	23.6%
24	0.29	0.37	-28.6%
25	62.27	73.34	-17.8%

Note: 37 projects contributed SAIDI values to this report; 25 utilities provided data for both summer 2013 and summer 2014.

Table D-3. CAIDI Comparisons, Summer 2013 and Summer 2014

Number	Summer 2013	Summer 2014	% Change
1	36.00	39.00	-8.3%
2	96.09	80.37	16.4%
3	85.26	105.28	-23.5%
4	65.09	44.12	32.2%
5	97.55	85.70	12.1%
6	140.92	86.54	38.6%
7	72.70	94.00	-29.3%
8	53.71	60.52	-12.7%
9	134.40	117.60	12.5%
10	1.32	1.38	-4.5%
11	88.00	94.00	-6.8%
12	12.26	34.75	-183.4%
13	1.20	1.66	-38.2%
14	105.00	120.00	-14.3%
15	97.23	86.92	10.6%
16	70.63	73.49	-4.0%
17	84.06	14.76	82.4%
18	88.71	118.55	-33.6%
19	63.31	64.83	-2.4%
20	120.00	114.00	5.0%
21	142.77	79.11	44.6%
22	133.58	157.80	-18.1%
23	1.53	1.43	6.5%
24	90.23	87.10	3.5%

Note: 36 projects contributed CAIDI values to this report; 24 utilities provided data for both summer 2013 and summer 2014.

Table D-4. MAIFI Comparisons, Summer 2013 and Summer 2014

Number	Summer 2013	Summer 2014	% Change
1	2.84	3.36	-18.3%
2	0.57	0.43	25.4%
3	3.31	5.84	-76.5%
4	1.88	2.20	-17.0%
5	1.83	1.17	36.1%
6	0.40	1.67	-316.3%
7	0.15	0.11	26.7%
8	0.23	0.12	46.8%
9	0.58	2.80	-382.8%

Note: 12 utilities contributed MAIFI values to this report; 9 utilities provided data for both summer 2013 and summer 2014.

APPENDIX E.
Acronyms and Abbreviations

Acronym	Definition
AC	alternating current
ADMS	Advanced Distribution Management System
AFS	automated feeder switching
ALS	automated lateral switch
AMI	advanced metering infrastructure
ANSI	American National Standards Institute
ARRA	American Recovery and Reinvestment Act
ASR	Pepco's Automatic Sectionalizing and Restoration
BHCOE	Black Hills/Colorado Electric
BPM	business process management
BWP	Burbank Water & Power
CAIDI	Customer Average Interruption Duration Index
CI	customers interrupted
CIS	customer information systems
CM	change management
CMEEC	Connecticut Municipal Electric Energy Cooperative
CMI	customer minutes of interruption
CMP	Central Maine Power
CSP	Cybersecurity Plan
CVR	conservation voltage reductions
CVT	capacitance voltage transformers
DA	distribution automation
DC	direct current
DER	distributed energy resources
DERMS	distributed energy resources management system
DMS	distribution management system
DNP	distributed network protocol
DOE	U.S. Department of Energy

Acronym	Definition
DSCADA	distribution supervisory control and data acquisition
EMS	Energy Management System
EPB	Electric Power Board of Chattanooga
ETR	estimated time of restoration
FCC	Federal Communications Commission
FLISR	fault location, isolation, and service restoration
FPL	Florida Power and Light
GIS	geographic information systems
GWP	Glendale Water and Power
HES	head end systems
IADS	Integrated Automated Dispatch Systems
ICE	Interruption Cost Estimate
ICP	Integrated Control Platform
IED	intelligent electronic device
IEEE	Institute of Electrical and Electronic Engineers
IOU	investor-owned utility
IP	Internet Protocol
IPL	Indianapolis Power & Light Company
IT	information technology
IVR	interactive voice response
IVVC	integrated volt/volt-ampere reactive controls
KUB	Knoxville Utilities Board
kV	kilovolt
kVAR	kilovolt-ampere reactive
kW	kilowatt
kWh	kilowatt hour
LAN	local area network
LBNL	Lawrence Berkeley National Laboratory
LTC	load tap changer
MAIFI	Momentary Average Interruption Frequency Index
MBRP	Metrics and Benefits Reporting Plan

Acronym	Definition
MDMS	meter data management systems
MEAG	Municipal Electric Authority of Georgia
MEPA	Magnolia Electric Power Association
MGE	Madison Gas and Electric
MHz	megahertz
MMLD	Marblehead Municipal Lighting Department
MVA	megavolt-ampere
MW	megawatt
MWh	megawatt hour
NIST	National Institute of Standards and Technology
NOVEC	Northern Virginia Electric Cooperative
O&M	operations and maintenance
OG&E	Oklahoma Gas and Electric
OMS	outage management system
PAS	Power Alert Service
PLC	Power Line Carrier
R&D	research and development
RF	Radio Frequency
RMS	remote monitoring systems
RMS	remote monitoring systems
RV	recreational vehicles
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	supervisory control and data acquisition
SDG&E	San Diego Gas and Electric
SGDP	Smart Grid Demonstration Program
SGIG	Smart Grid Investment Grant
SMEPA	South Mississippi Electric Power Association
SMUD	Sacramento Municipal Utility District
TPDC	Transmission Performance and Diagnostic Center
VAR	volt-ampere reactive

Acronym	Definition
VSAT	very small aperture terminal
VVO	volt/VAR optimization
WiMAX	Worldwide Interoperability for Microwave Access
WMS	workforce management systems
WPL	Wisconsin Power and Light